January 17, 2014

VIA ELECTRONIC FILING

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

Re: ISO New England Inc. and New England Power Pool, Filings of Performance Incentives Market Rule Changes; Docket No. ER14- -000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, ISO New England Inc. (the "ISO"), joined by the New England Power Pool ("NEPOOL") Participants Committee, hereby submits with this cover transmittal letter two alternative versions of Market Rule changes intended to improve the operating performance of capacity resources in New England.[1] One version is advocated by the ISO, the other by NEPOOL. Together, the ISO and NEPOOL join in asking the Federal Energy Regulatory Commission (the "Commission") to choose between these two alternatives.

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

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

proposal not supported by either the ISO or NEPOOL unless it concludes first that neither of those two proposals satisfies the standard for acceptance under the Federal Power Act.[2]

The ISO Materials Submitted for this Filing

The ISO's proposal is being submitted to the Commission in two parts. Due to technical limitations associated with the Commission's eTariff system, the ISO is not able to submit multiple changes to the same Tariff section that have different effective dates in one submission. Accordingly, the first part of the ISO's overall submission includes the Tariff changes that are proposed to become effective on June 1, 2014, and the second part of the ISO's overall submission includes the Tariff changes that are proposed to become effective on June 1, 2018. The explanation and supporting materials for all of the Tariff changes is contained in the first submission. Although the ISO's overall filing has been divided into two parts to accommodate the eTariff system, the Commission should treat the ISO's submissions as a single filing.

In the first part of its overall submission, the ISO is submitting materials in Attachments I-1a through I-1j. These materials include a transmittal letter that describes the ISO's proposed Tariff changes, as well as the testimony of Peter Brandien, Matthew White, Peter Cramton, David LaPlante and Seyed Parviz Gheblealivand, and Marc Montalvo in support of the ISO's proposal. The ISO materials also include the affidavit of Todd Schatzki of the Analysis Group Inc. ("Analysis Group") along with a report by Analysis Group entitled "Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives." Finally, the materials include the Tariff sheets for the Tariff changes that are proposed to become effective on June 1, 2014. In the second part of its overall submission, the ISO is submitting materials in Attachments I-2a through I-2c. These materials include a cover letter explaining the reasons for the two-part submission and the Tariff sheets for the Tariff changes that are proposed to become effective on June 1, 2018.

In its materials, the ISO satisfies the requirements in the jump ball provision by explaining the ISO's reasons for not adopting the NEPOOL proposal and by providing an explanation as to why the ISO's proposal is superior to the NEPOOL proposal.

The NEPOOL Materials Submitted for this Filing

The NEPOOL materials also are being submitted, like the ISO materials, in two parts. The first part is contained in Attachments N-1a through N-1h include: (i) the NEPOOL transmittal letter containing an explanation of the NEPOOL proposal, including a discussion of why the NEPOOL proposal is preferable to the ISO proposal and should be accepted by the Commission; (ii) testimony of Peter D. Fuller, Director of Regulatory Affairs, NRG Energy Inc., East Region; testimony of Calvin A. Bowie, NEPOOL Transmission Sector Representative; testimony of Brian E. Forshaw, Chief Regulatory and Risk Officer, Connecticut Municipal Electric Energy Cooperative; testimony of Elin S. Katz, Consumer Counsel, Connecticut Office

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

of Consumer Counsel; and affidavit and report of Richard D. Tabors, Ph.D., all on behalf of NEPOOL; (iii) a summary of the stakeholder process that resulted in a vote of 80.28% in support of the NEPOOL proposal; (iii) a tabulation of the votes taken by the Participants Committee at its the December 6, 2013 meeting with respect to the NEPOOL and ISO proposals; and (iv) blacklined and clean Tariff sheets, included in Attachments N-1i through N-1j, reflecting the portion of the NEPOOL proposal proposed to become effective on June 1, 2014. Technical limitations associated with the Commission's eTariff system also preclude a single filing from having multiple changes to the same Tariff section that have different effective dates. Accordingly, the second part of the NEPOOL proposal, reflecting the Tariff changes that are proposed to become effective on June 1, 2018, are being included with Part 2 of the ISO's overall submission as Attachment N-2a through N-2c. These materials include a NEPOOL cover letter explaining the reasons for the two-part submission and the Tariff sheets for the Tariff changes in the NEPOOL proposal that are proposed to become effective on June 1, 2018. Again, like the ISO's proposal, although the NEPOOL's proposal is divided into two parts to accommodate the eTariff system, the Commission should treat the NEPOOL proposal as a single package.

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

Respectfully submitted,

ISO NEW ENGLAND INC.

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TABLE OF CONTENTS

Part 2

Attachment I-1a

Transmittal letter on behalf of the ISO

January 17, 2014

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

RE: ISO New England Inc., and New England Power Pool, Filings of Market Rule Changes To Implement Pay For Performance in the Forward Capacity Market; Docket No. ER14- -000 (Part 1 of 2)

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("Section 205"),[1] ISO New England Inc. (the "ISO") hereby electronically submits this transmittal letter and revised Tariff provisions to modify the Forward Capacity Market ("FCM").[2] The incentive structure in the FCM design must be significantly improved to address real, pervasive, and escalating resource performance problems that pose a serious threat to the reliable operation of the system. The capacity market must compensate resource owners for needed investments in reliability, while not continuing to pay resources that do not perform. The revised approach, dubbed "Pay For Performance," will strongly link capacity payments to resource performance during scarcity conditions.

The New England Power Pool ("NEPOOL") Participants Committee did not support the Pay For Performance Tariff changes. NEPOOL did, however, garner sufficient support for an alternative approach to invoke the "jump ball" provisions in Section 11.1.5 of the Participants Agreement. Hence, the NEPOOL alternative is presented in a separate part of this filing package. The NEPOOL proposal – which centers on a small increase to the energy price during scarcity conditions and changes to the FCM rules that further weaken the already ineffective incentive

[1] 16 U.S.C. § 824d (2006 and Supp. II 2009).

[2] 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.

structure – simply will not provide either the incentives nor the consequences necessary to induce needed investment in reliable performance. The ISO's Pay For Performance approach, on the other hand, is a comprehensive solution to the identified problems; it will pay resources that perform well more than under the current design, while imposing real consequences if they fail to deliver what consumers have paid for.

I. INTRODUCTION

When sellers can depend on payment regardless of the quality of the product delivered, quality tends to suffer. When payments reward higher quality, quality tends to improve. While there have been many efforts to refine the FCM over the years, its design has always failed to reflect these most basic principles, and reliability in New England is deteriorating as a result.

Much of the reason for the FCM's failure in this regard is its complexity. The product is poorly defined; while the region requires resources that reliably provide energy and reserves when supply is scarce, the FCM instead buys something only vaguely related to that, called "availability." The FCM applies different rules and different standards to different types of resources (even though it seeks to buy the same product from all of them), and includes numerous one-off provisions and exceptions. And at the end of the day, capacity "obligations" mean little because there are rarely financial consequences for failing to perform.

Each of these elements of the current FCM is contrary to sound market design. This is not surprising, however, because the core FCM design was not based on any standard market model. Rather, the FCM was built from the ground up, without a blueprint, through a long series of negotiations and compromises. The result is an idiosyncratic design that is failing to meet its most basic objectives – ensuring reliability in a cost-effective manner. The solution to these problems is assuredly not more of the same. The FCM design must be fixed on a fundamental level.

The Pay For Performance design presented here replaces the FCM's esoteric design with one that is familiar. Pay For Performance is a true, two-settlement forward market, following a blueprint that has been tested, refined, and applied successfully in myriad other markets, including New England's own energy markets. Pay For Performance is built around a well-defined product – the delivery of energy and reserves when they are needed most. Its rules are much more simple than the current FCM design, and those rules apply in the same manner to all resource types, without exceptions. With greater transparency and less uncertainty, Pay For Performance will create strong incentives for resource performance consistent with the goals of the capacity market.

II. EXECUTIVE SUMMARY

In the current FCM design, capacity payments are poorly linked to resource performance. In many cases, capacity resources are being paid for simply existing, rather than for actually performing when they are needed. With the linkage between payments and performance broken, there is little incentive for resource owners to make investments to ensure that their resources will be ready and able to provide energy and reserves when needed. The lack of such investment is posing serious threats to the reliable operation of the system.

Indeed, as fully detailed in the testimony of Peter Brandien, the ISO's Vice President of Operations,[3] the ISO has observed and documented pervasive and worsening performance problems among the existing generation fleet in New England. These problems, which are not limited to a single resource or fuel type, fall into three general categories. First, the region's growing dependence on natural gas leaves it extremely vulnerable to interruptions in gas supply, which can occur with little notice and which can affect multiple generators simultaneously. Second, a significant portion of New England's oil and coal units cannot provide reliable backup when gas problems arise due to increased outage rates, start-up problems, and other operational difficulties. Third, across the entire fleet, the ISO is observing increasing outage rates, poor responses to contingencies, and a host of other issues, such as failure to maintain liquid oil inventory, mothballing dual fuel capability, and inadequate staffing.

Many of these problems could be resolved if suppliers undertook additional operational-related investments, whether in dual-fuel capabilities, short-notice or non-interruptible gas supply agreements, liquefied natural gas, new fast-responding demand response assets, comprehensive maintenance, resource upgrades to provide faster starts, or other arrangements to similar effect. However, the present FCM design provides little incentive for suppliers to invest in secure fuel arrangements or to undertake other investments that would assure their resources will perform when needed.

In the current FCM, the consequences for non-performance are negligible. As an initial matter, even with recent revisions to the definition, Shortage Events are extremely rare. A supplier that is confident that the performance of its resource will rarely be measured is unlikely to feel a strong incentive to take steps to ensure the resource's ability to perform. Furthermore, the current rules include numerous exemptions, under which resources are considered "available" during a Shortage Event even when they do not provide any energy or reserves whatsoever. A supplier that receives its full capacity payment while providing no energy or reserves is unlikely to see the need to invest in the ability of its resource to perform. Finally, even where a capacity resource *is* exposed to penalties under the current design, those penalties are

[3] *See* Testimony of Peter Brandien on behalf of the ISO, submitted with this filing as Attachment I-1b ("Brandien Testimony").

capped such that there can be no net loss on FCM obligations, no matter how poorly the resource performs; participation in the current FCM essentially constitutes a free option. A supplier that cannot lose money for failure to perform as obligated is poorly incented to meet its obligations.

These problems clearly demonstrate that an individual supplier does not face the proper incentives to make investments to ensure that its resource can and will perform as needed. But there is an even graver implication when looking at the cumulative effects of these problems on the quality of the region's fleet over time. The "money for nothing" nature of the current FCM design results in adverse selection of capacity resources. It encourages resources that are likely to be poor performers to participate in the market when they should exit. Resources with lower going-forward costs and relatively poor performance clear in the Forward Capacity Auction instead of those with higher going-forward costs but better performance, even where the latter are more cost-effective. This structural bias towards clearing of less reliable resources in the FCM can only lead to serious reliability problems on the system, and is of course contrary to the goals of good capacity market design.

For all of these reasons, capacity payments must be linked to actual performance during scarcity conditions. Moreover, payments and performance must be linked as directly as possible; simply increasing the severity of the current penalties would not suffice.

The central purpose of the capacity market is to provide financial incentives for participants in New England's restructured electricity system to build and maintain the resources necessary to assure reliable service. The region developed the FCM in recognition of critical shortcomings in the energy market, which result in insufficient financial incentives for such investment. In effect, the energy market is "missing" a portion of the revenue stream that properly functioning, uncapped competitive markets normally provide to investors to ensure that no demand goes unserved at the prevailing price. If this "missing" revenue stream is not replaced by the capacity market, suppliers could not expect to recover their total costs and would not enter the marketplace – or will soon exit. In that event, additional demand would go un-served and reliable service would not be achieved. A central objective of the FCM is to create a revenue stream that replaces the "missing" revenue stream, and to thereby induce suppliers to undertake the investments necessary for reliable electric service.

But it is not enough to simply calculate the amount of the missing revenue and give that amount to suppliers; if it were the current design would be adequate. In a fully functioning and uncapped energy market, the "missing" revenue would be paid only to resources that are actually providing energy or reserves during periods of scarcity. It would not simply pay out that revenue to all resources that exist or that are conceptually "available." Having that money paid for actual performance during periods of scarcity is precisely what incents resource owners to make investments to ensure that their resources will be ready and able to provide energy or reserves

during those periods. To be effective, the capacity market must replicate the performance incentives that would exist in a fully functioning and uncapped energy market by linking payments to performance during scarcity conditions. Without this linkage, individual suppliers lack the incentive to make investments that ensure their resources can perform when needed most. And worse, precisely because they have not made such investments, these less-reliable resources become *more* likely to clear in future Forward Capacity Auctions because they can offer at lower prices than resources that are more reliable and more expensive (but more cost-effective, from a reliability viewpoint). This creates a structural bias in the FCM to clear less-reliable resources, which over time is eroding reliability.

The Pay For Performance design presented here is a straightforward solution to these difficult problems. The Pay For Performance design is based on the two-settlement logic generally used in forward markets. This entails two key elements: First, a forward position in which a quantity of capacity is obligated, or sold. Each MW is paid at the auction clearing price. This sale in the capacity auction creates a resource-specific physical obligation and forward financial position in the capacity market. A resource's forward financial position is a share of the system's energy and reserve requirements during reserve deficiencies. Second, a settlement for deviations. If a resource delivers more than its share of the system's requirements during a reserve deficiency, it will be paid for that incremental production; if it delivers less than its share, it will "buy out" of its position by paying other resources that did deliver. Positive and negative deviations are paid/charged at the same pre-specified rate, which is specified in the Tariff.[4] The two-settlement approach is completely standard in forward contracts, both for electricity and commodities ranging from oil to pork bellies to iron ore. In fact, the two-settlement design underlies the design of New England's Day-Ahead and Real-Time electricity markets, and is well understood by stakeholders.

Consumers will pay the auction clearing price to all resources that clear in the auction. Resources that provide more than their share of the system's requirements during scarcity events will be paid by those that provide less so that consumers will not bear the short-run risk of covering any unexpectedly high performance payments. This will continue to provide consumers with a predictable capacity price three years out, after the close of each Forward Capacity Auction. Having under-performers pay over-performers will also provide strong incentives for each resource to perform as needed, and for resources that can meet the system's needs by exceeding their share to benefit by doing so. These incentives will place performance risk on all FCM resources, and this risk will need to be priced in each resource's bid in future capacity auctions.

[4] The Capacity Performance Payment Rate must be specified in the Tariff because the absence of price-sensitive demand in the Real-Time Energy Market prevents determination of a market-clearing price when demand exceeds supply.

To provide the desired incentives, and hence to solve the problems identified above with the current FCM design, the Pay For Performance mechanism must be implemented without compromising the standard, efficient market principles typically embodied in a two-settlement mechanism. There are three market design principles that warrant special attention. First, a well-designed market must pay more for better performance and less for worse performance. Accordingly, a resource should earn its capacity market revenue based on the amount it delivers during scarcity conditions. Second, suppliers – and not consumers – must bear the risk and the rewards associated with their resources' performance. Hence, Pay For Performance includes no exemptions. This is a hallmark of competitive markets, and it places risk in the right place in order to incent investment by suppliers and to enable the capacity market's price signal to select a reliable, cost-effective resource portfolio. Third, the Pay For Performance design is resource neutral. In a well-designed market, two suppliers that provide the same good or service receive the same compensation. Their compensation is not dependent on what technology they use; it depends solely on whether they deliver the product.

If the Pay For Performance mechanism is implemented, it will provide numerous important benefits, which together should address the problems identified above. These benefits include:

- Operational-related investment. Strong performance incentives provide suppliers with the economic motivation, and the financial capability, for operational-related investments that ensure resources are available when needed to maintain reliability. This might include dual-fuel capability, short-notice or more reliable fuel supply arrangements, continuous staffing at resources, improved operating practices, more robust maintenance arrangements, shorter planned outages, incremental capital investments that shorten start times or increase ramp rates, rapid price-responsive demand behavior, and other improvements to similar effect.

- Cost-effective solutions. Markets motivate suppliers to deliver services in the most cost-effective ways. Pay For Performance will enable individual suppliers to select the solutions that work best for the technologies and features of their resources. This market-based approach rewards suppliers that pursue the most cost-effective means to improve performance and reliability.

- Efficient resource evolution. Stronger performance incentives will, over time, lead to a change in the capacity resource mix that directly improves system reliability at lowest cost. Resources that are unreliable and have high operating costs may submit higher offers into the Forward Capacity Auction, based on their expectation of performing poorly and experiencing negative performance payments during the commitment period. These resources will become less likely to clear the auction, relative to today. In contrast, the compensation provided for strong performance will enable highly efficient or highly flexible resources to profitably

make lower offers in the Forward Capacity Auction, and they will therefore be more likely to clear future capacity auctions.

The many features of the Pay For Performance design are discussed at length in the balance of this filing letter and in the attached testimony of the ISO witnesses:

- Witness Peter Cramton, Professor of Economics at the University of Maryland, provides a concise overview of the Pay For Performance design and its merits.

- ISO witness Peter Brandien, Vice President of Operations, describes in detail the resource performance problems that the ISO has been observing and the reliability implications of those problems.

- ISO witness Matthew White, Chief Economist, provides a detailed explanation of how the incentive structure in the current FCM design leads to precisely the types of performance problems actually observed, how capacity market incentives ought to be structured to avoid these problems, and how the Pay For Performance mechanism is designed to effectively solve these problems.

- The joint testimony of ISO witnesses David LaPlante, the Internal Market Monitor, and Seyed Parviz Gheblealivand, Economist, explains the changes to market monitoring and mitigation in the Pay For Performance design.

- Finally, ISO witness Marc Montalvo, Director of Enterprise Risk Management, explains revisions to the financial assurance provisions needed to implement Pay For Performance.

III. REQUESTED EFFECTIVE DATES

The majority of the Pay For Performance Tariff revisions will become effective on June 1, 2018, which is the start of the Capacity Commitment Period associated with the ninth Forward Capacity Auction. These include revisions to five separate sections of the Tariff: Section III.13 (the FCM rules); Section I, Exhibit IA (the Financial Assurance Policy); Section I.2 (defined terms); Section III.1 (minor changes to conform defined terms); and Section III.A.8 (minor changes to conform defined terms).

A smaller set of the Pay For Performance revisions will become effective on June 1, 2014, after the eighth Forward Capacity Auction is run but before the Existing Capacity Qualification Deadline for the ninth Forward Capacity Auction.[5] This is necessary because the

[5] The Existing Capacity Qualification Deadline for the ninth Forward Capacity Auction is June 2, 2014.

changes related to market monitoring and mitigation in the FCM must apply during the qualification process for the ninth Forward Capacity Auction. These include revisions to two separate sections of the Tariff: Section III.13 (the FCM rules); and Section I.2 (defined terms).

Because several sections of the Tariff (Section I.2, Section III.13.1, and Section III.13.2) each contain some revisions to be effective in 2014 and other revisions to be effective in 2018, this filing is being submitted in two parts.[6]

The ISO respectfully requests that the Commission issue an order no later than May 14, 2014 accepting the Pay For Performance design in its entirety, including all provisions to be effective in both 2014 and 2018. It is important that all of the rule changes are approved simultaneously because, although many of the rule changes will not be effective until 2018, those rule changes will significantly affect participation in the ninth Forward Capacity Auction, which will be conducted in February 2015, the qualification process for which will take place throughout the balance of 2014.

IV. DESCRIPTION OF THE ISO AND 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 standards established by the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Council ("NERC").

All correspondence and communications in this proceeding should be addressed to the undersigned for the ISO as follows:

[6] This filing letter and its attachments are the first part of a two-part contemporaneous submission to the Commission. Due to technical limitations associated with the Commission's eTariff system, the ISO is not able to submit multiple changes to the same Tariff section that have different effective dates in one submission. Accordingly, the first part of the ISO's overall submission includes the revisions that are to become effective on June 1, 2014. The second part of the ISO's overall submission includes the revisions that are to become effective on June 1, 2018. The explanation and supporting materials for all of the Pay For Performance revisions is contained in the first submission. Although the ISO's overall filing has been divided into two parts to accommodate the eTariff system, the Commission should treat the submissions as a single filing.

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V. STANDARD OF REVIEW

The Tariff changes included in both the ISO proposal and the NEPOOL proposal are being submitted pursuant to the ISO's rights under Section 205, which "gives a utility the right to file rates and terms for services rendered with its assets."[7] Section 11.1.5 of the Participants Agreement (referred to as the "jump ball" provision) requires that the ISO, as part of a Section 205 filing, present to the Commission any alternative Market Rule proposal that is approved by a Participant vote of at least 60 percent in detail sufficient to permit reasonable review by the Commission, explain the ISO's reasons for not adopting the proposal, and provide an explanation as to why the ISO believes its own proposal is superior to the proposal approved by the Participants Committee.

Under Section 205, the Commission "plays 'an essentially passive and reactive role'"[8] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[9] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable - and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[10] The changes proposed herein "need not be the only reasonable methodology, or even the most accurate."[11] As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must

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

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

[9] *Id.* at 9.

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

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

accept the Section 205 filing if it is just and reasonable.[12] This standard of review applies to both the ISO proposal and the NEPOOL proposal in terms of evaluating any other alternatives.

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

VI. PAY FOR PERFORMANCE: RATIONALE AND DETAILED DESCRIPTION

A. There Are Serious Resource Performance Problems, And Poor Resource Performance Threatens The Reliable Operation Of The System

As described in the testimony of Mr. Brandien, New England is experiencing fleet-wide performance issues. Mr. Brandien concludes that the problems are so pervasive that they threaten the ISO's ability to operate the system reliably. He explains that these performance problems are not limited to a specific segment of the fleet, and are worsening.[13]

Specifically, gas-fired generators are not taking steps to assure availability of natural gas, of which there is simply not enough to supply both generators and other demand. These generators have limited access to alternatives like liquefied natural gas. Although the ISO's system operators are actively managing these issues, New England has experienced some sizeable reductions in generators' output as a result of gas supply interruptions. Because of the just-in-time nature of the gas supply, these reductions occur with little warning to the ISO.[14] Making this matter worse, generators are abandoning the dual-fuel capability of their units and no new dual fuel capability is being added. Operationally, where dual-fuel capability is available and operational on a gas-fired unit, it is a very effective substitute for unavailable gas. Seeing this capability decline is a very troubling development.[15]

The region turns to oil and coal generators when gas-fired generators are unavailable, but these resources have their own set of problems. As Mr. Brandien's testimony shows, oil- and coal-fired generators are the biggest contributors to underperformance relative to their Capacity

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

[13] *See* Brandien Testimony at 2-5.

[14] *See id.* at 6-24.

[15] *See id*. at 12.

Supply Obligations, reducing their economic maximum generation levels during the peak hours of peak days more than any other category of generator. These resources also have trouble starting on time (or at all), and their rate of unplanned outages is the highest in the fleet; they are unavailable on an unplanned basis more than 15 percent of the time that they are needed.[16]

While the problems with gas, oil, and coal units are significant, they are not the fleet's only performance problems. As Mr. Brandien notes, performance problems are truly fleet-wide, and include poor response to dispatch following a contingency, with an average response rate of only 71 percent. Increasing rates of unplanned outages are further evidence of deteriorating fleet-wide performance. The overall rate of unplanned outages across the entire New England generating fleet has more than doubled since 2007. Among other issues, generators of different types have failed to staff their units and, as a result, are unable to respond to dispatch in a contingency.[17]

While these performance issues are fleet-wide, gas supply is one of the core issues challenging reliability, given the region's increasing dependence on gas. However, even with additional gas infrastructure to improve supply, the region has a system that is dependent on gas and will be vulnerable to gas supply interruptions. This "systemic risk" may be realized in the event of one of a number of pipeline problems, which include maintenance, pressure problems, fuel quality problems, and operational flow orders during periods of high demand. During one of these events, multiple units that simultaneously draw from the pipeline could be affected, causing a correlated outage of multiple generators (including reserves). The scope of the potential problem is illustrated by the fact that a single pipeline can supply generators representing thousands of megawatts of electricity.[18]

In short, the region must have resources on which it can rely to perform, even following contingencies related to gas supply. As discussed below, the flawed incentive structure in the current FCM design has perpetuated these performance problems.

B. The Incentive Structure In The Current FCM Design Is Broken And Leads Directly To The Poor Performance That Is Observed

It is not a novel idea that incentives to motivate resource performance during scarcity conditions must be an important feature of the capacity market. As Dr. White explains, from its inception, the FCM has included provisions aimed at this goal.[19] The FCM currently includes a

[16] *See* Brandien Testimony at 26-36.

[17] *See id.* at 36-52.

[18] *See id.* at 22-24.

[19] Testimony of Matthew White on behalf of the ISO, submitted with this filing as Attachment I-1c ("White Testimony") at 13.

"Shortage Event" mechanism that imposes a financial penalty on resources that fail to be "available" during certain scarcity conditions. Generally, a "Shortage Event" is a period of thirty or more contiguous minutes during which the supply of energy and reserves is insufficient to meet the demand for energy and the real-time reserve requirements. Under the current FCM rules, for each Shortage Event, the ISO calculates an "availability score" for each resource having a Capacity Supply Obligation. The availability score, conceptually, is the resource's "available" MW divided by its Capacity Supply Obligation.[20]

With the benefit of experience, however, it is now clear that the Shortage Event mechanism is fundamentally flawed. Because of these flaws, the FCM not only fails to provide the necessary incentives to motivate suppliers to make investments that would ensure that they are able to perform during scarcity conditions, but in fact it creates strong *disincentives* for suppliers to do so. As a result, individual suppliers do not take needed steps to ensure the performance of their resources during scarcity conditions. And worse, these problems create a structural bias in the FCM to clear less-reliable resources. These consequences correlate directly with the problems observed with the New England fleet, as described above and in the testimony of Mr. Brandien.

There are two fundamental problems with the Shortage Event mechanism. First, basing capacity payments on a resource's "availability" is deeply flawed. Second, the mechanism includes numerous exemptions that remove almost all financial consequences for non-performance. There are other notable problems with the current design as well, including caps on performance penalties that undermine the incentive structure, and a penalty rate that is too low and needlessly complex. Each of these problems is explained in more detail below.

1. Basing Capacity Payments On "Availability" Is Deeply Flawed

For the FCM to achieve its goals, it must provide incentives for resources to perform – to actually deliver energy or reserves – during scarcity conditions. At bottom, "availability" is not the same thing as actually delivering energy or reserves, and basing capacity payments on "availability" will only incent availability, not actual performance. As an example, under the current FCM rules, a resource that is off line with a metered output equal to zero (but available for dispatch and following ISO dispatch instructions) and that has a ten-hour start-up time is deemed fully "available." If a scarcity condition occurs with little notice, such a resource can contribute nothing to restoring the system. Another resource that can start quickly will be called on to provide energy or reserves to address the problem. This more flexible resource that does contribute to restoring the system is also deemed fully "available." Both of these resources receive the same capacity payment.[21]

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[20] *See* current Tariff Section III.13.7.1.

[21] *See* White Testimony at 15-24.

Making the same capacity payment to different resources that make very different contributions to system reliability is a terrible way to encourage resources to make investments that will allow them to contribute to system reliability. A resource that consistently delivers energy and reserves during scarcity conditions contributes greatly to system reliability and should be financially rewarded for that performance. A resource that is unable to deliver energy or reserves during scarcity conditions is less valuable, and should be paid less, regardless of whether it is nominally "available." Basing payments on a proper measure of performance will directly incent suppliers to make investments to enable their resources to contribute to system reliability during scarcity conditions.

Making the same capacity payment to resources that make different contributions to system reliability not only fails to provide the proper incentives, it may actually *discourage* the desired investments. This is because all resources face the possibility of an unforeseen start-up failure that might result in an availability penalty under the current rules. An inflexible resource that is rarely called to help during scarcity conditions faces fewer such potential penalties than a flexible resource that is frequently called to help at such times. The results can be perverse: a flexible resource that performs ably four times out of five, but has a failed start one time, receives *less* capacity revenue than the inflexible resource that is never even called because it cannot possibly help in any of the five events. Because the flexible resource has a higher likelihood of being penalized, it has higher expected costs associated with taking on a Capacity Supply Obligation. To cover these greater costs, the flexible unit would require a higher price in the Forward Capacity Auction. In effect, its flexibility – which should of course make it more valuable – not only reduces its expected profits due to the availability penalty mechanism, it makes it less likely to clear in the Forward Capacity Auction in the first place. This constitutes a strong disincentive to build flexible resources of any kind, which are often the most valuable resources to manage an unanticipated scarcity conditions.[22]

Even worse than its effects on the investment decisions for individual resources, however, is the effect of this exemption-laden, flawed availability-based performance metric on the New England fleet as a whole. Because resources that do not contribute to system reliability during scarcity conditions earn the same capacity payments as resources that do, it is profitable for resources with low costs and poor performance during scarcity conditions to remain in the capacity market. These low-cost, but poorly performing resources displace higher-cost, but better performing resources. These higher-cost resources, because they would contribute more to system reliability, are actually more cost-effective than the resources that displace them. In effect, then, the current FCM has a structural bias to select less-reliable resources, an outcome completely at odds with the goals of maintaining reliability in a cost-effective manner.[23]

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[22] *See* White Testimony at 19-20.

[23] *See id.* at 21-22.

2. Exemptions For Non-Performance Are Incompatible With Sound Capacity Market Design

Another fundamental problem with the current Shortage Event mechanism is that it includes numerous exemptions under which resources that are not able to provide energy or reserves during a Shortage Event are nonetheless deemed fully "available." As a result they are not subject to capacity payment reductions, despite providing zero contribution to system reliability during the Shortage Event.

For example, a resource that is on a planned outage when a Shortage Event occurs will be deemed available up the MW amount submitted in the outage request.[24] A resource that is not committed due to an outage or derate of certain transmission equipment is considered fully available.[25] And an import capacity resource that is properly offered, but that cannot be delivered because the relevant external interface is constrained, is considered to be fully available.[26] Intermittent Power Resources are not subject to the Shortage Event provisions at all.[27] And, as already described, resources that are unable to help alleviate a scarcity condition due to lengthy startup times are considered fully available.[28] The economic effects of these exemptions will distort the mix of capacity resources in undesirable ways, and are contrary to sound capacity market design.

In similar ways to the "availability" problems discussed above, these exemptions break the important link between capacity payments and resource performance during scarcity conditions. If an exemption allows a resource that does not provide energy or reserves during scarcity conditions to collect the same capacity payment as a resource that does, the exempted supplier does not face strong incentives to invest in ways that can improve its resource's ability to deliver during those conditions. And when poor performance is excused and exempt from financial consequences, a poorly performing resource does not need to raise its bid price in the capacity auction to account for any expected penalties – but resources without the exemption do. This again skews the bids in the auction in an especially problematic way: It lowers bid prices from resources that expect to be poor performers and that expect to be exempt from the financial consequences for non-performance. As a result, the auction becomes more likely to clear these poor-performing, less-reliable resources. At bottom, selling capacity becomes an 'empty' obligation when non-performance is exempt from any financial consequence.[29]

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[24] *See* Tariff Section III.13.7.1.1.4(b).

[25] *See* Tariff Section III.13.7.1.1.3(f).

[26] *See* Tariff Section III.13.7.1.2(d).

[27] *See* Tariff Section III.13.7.1.3.

[28] *See* Tariff Section III.13.7.1.1.3(c).

[29] *See* White Testimony at 24-29.

Importantly, exemptions are equally problematic, and equally inappropriate, in cases where the non-performance is arguably not the fault of the supplier. The market design must allocate the risks and costs of non-performance either to suppliers or to consumers. While suppliers may argue that some causes of poor performance are not their fault, it does not mean that consumers – who are even less likely to be at fault for the supplier's non-performance – should bear those risks and costs.[30]

In fact, it is sound market design for suppliers to bear the risks of non-performance, regardless of fault. An important role of the capacity market is to award Capacity Supply Obligations to resources that can be expected to contribute to reliability during scarcity conditions. To do so, a well-designed capacity market should lead a supplier to incorporate into its capacity offer price *all factors* that affect its ability to deliver during scarcity conditions, regardless of whether these factors are within or beyond its control. No other entity is better-positioned to price these factors. In this way, offers in the capacity market serve an essential role as price signals of both a resource's cost *and its reliability*. That property is crucial to efficient market design: It is what ensures that the capacity market does not award capacity obligations to resources that expect to perform poorly. Exemptions undermine this central role of prices as signals of resources' future performance and reliability.[31]

In a market designed in large part to help the region meet specific reliability objectives, exemptions are particularly damaging to the market's ability to achieve these objectives at least cost. For all of these reasons, exemptions are incompatible with sound capacity market design. They serve to destroy essential incentives, and inappropriately shift costs to those even less able to manage the risk.

3. Caps On Capacity Payment Reductions For Non-Performance Further Erode Performance Incentives

Another problem with the current FCM design is that penalties for non-performance are capped such that they cannot exceed the resource's total FCM revenue.[32] In other words, there is no way that a resource can lose money by taking on a Capacity Supply Obligation, even if it fails entirely to perform. This is contrary to sound market design, and is at odds with how two-settlement forward markets function.[33]

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[30] *See* White Testimony. at 27-29; *see also* Testimony of Peter Cramton on behalf of the ISO, submitted with this filing as Attachment I-1d ("Cramton Testimony") at 5-9.

[31] *See* White Testimony at 28-29.

[32] *See* current Tariff Section III.13.7.2.7.1.3.

[33] *See* White Testimony at 29-32.

The possibility of losing money as a result of taking on a Capacity Supply Obligation serves important purposes. It motivates suppliers to consider and price the reliability of their resources into their Forward Capacity Auction offers, such that only sellers that expect to be able to perform reliably take on an obligation. And once an obligation is assumed, the possibility of losing money motivates suppliers to take steps to ensure that their resources are able perform when needed.

The current FCM design breaks this basic precept of forward markets, such that poorly performing resources are not taking on a proper forward obligation. Rather, they are playing a game of "heads I win, tails I don't lose" with consumers' capacity payments. Economists call this a "free option problem." Providing free options is exceptionally poor market design, because they undermine essential performance incentives. They make it a worthwhile gamble for suppliers who rarely expect to perform to take on obligations because they have nothing to lose. Worse still, the free option problem helps make it profitable for even the poorest performing resources to remain in the capacity market, potentially displacing entry by more reliable resources that would be able to perform when needed.

4. The Penalty Rate In The Current FCM Rules Is Needlessly Complex And Is Too Low To Be Effective

The penalty rate in the current FCM rules has a structure that defies economic logic. As explained by Dr. White, the formula in the current FCM rules that determines Shortage Event penalties[34] results in penalty rates that actually decrease, rapidly, as the length of the scarcity condition increases.[35] This makes little sense, as scarcity conditions with longer durations can be expected to occur when the system faces more severe challenges meeting system energy and reserve requirements, and longer periods of heightened reliability risk. In effect, as scarcity conditions continue, the price signal for resources to perform plummets. This perverse property is difficult to reconcile with economic logic.[36]

In addition to their odd structure, the current penalty structure is needlessly complex. That makes the current FCM performance incentives lack transparency. It hampers the ability of investors to gauge whether additional capital expenditures to improve performance during scarcity conditions would be a profitable investment. For example, even if a resource owner has a reasonably informed view on how many hours, in total, the system may experience Shortage Events each year, that information is not enough to gauge its expected penalty for non-performance. The resource owner must also estimate the particular duration of *each* non-

[34] *See* current Section III.13.7.2.7.1.2

[35] *See* White Testimony at 33.

[36] *See id.* at 32-35.

contiguous Shortage Event during the year – likely an impractical task. This needless complexity impedes the ability for a resource owner to quantify whether investments that would improve the resource's performance during Shortage Events would yield a positive return, in the form of reduced penalties. In effect, its complexity undermines the very goals that these performance incentives are intended to serve.

Furthermore, the current Shortage Event penalty rate is generally low, and far too low to mirror the central principle of well-designed capacity market performance incentives. Over a broad range of possible Forward Capacity Auction clearing prices and scarcity condition durations, the effective penalty rate under the current mechanism is on the order of several hundred dollars per MWh. As Dr. White explains in detail,[37] to provide appropriate incentives for cost-effective investments, the marginal incentive to perform during scarcity conditions should be significantly larger than under the current rules – in some cases, by an order of magnitude. The low rate that presently applies to non-performance in the FCM directly undermines the financial incentives for resources to undertake capital investments to improve performance during scarcity conditions.

5. The Reliability Problems Actually Observed In New England Are Exactly What You Would Expect As A Result Of The Current Flawed Capacity Market Design

As explained by Dr. White, given the flawed incentives described above, and the resulting systematic bias towards clearing less reliable resources in the Forward Capacity Auctions, one would expect to see a deterioration of the reliability of the New England fleet over time, rather than the gradual improvement that would result from sound market design. And indeed, as detailed in the testimony of Mr. Brandien, the system's resources overall exhibit declining performance by a number of different measures. The system's operators no longer have confidence that resources will be able to perform when needed. This uncertain performance is manifest in many different ways and across a broad array of resource types and technologies. Moreover, a portion of the system's capacity resources have exhibited chronically poor performance during scarcity conditions, collecting capacity payments while doing little to assist with reliability during these periods of heightened risk. And it appears that these problems are getting worse, not better.[38]

[37] *See* White Testimony at 35.

[38] *See id.* at 46-48.

C. How A Well-Designed Capacity Market Should Be Structured To Address These Problems

Pay For Performance addresses each of the core problems described above, in a very straightforward manner. Instead of "availability," the FCM will allow consumers to procure the product that is needed in New England – resources that reliably provide energy and reserves when supply is scarce. There are no exemptions under Pay For Performance; consistent with sound market design, the reasons for non-performance are not relevant. Pay For Performance is resource-neutral and the same rules apply to all types of resources. The caps that currently ensure that a resource can never lose money in the FCM are replaced under Pay For Performance with a stop-loss mechanism that prevents unlimited risk exposure, but appropriately exposes poorly performing resources to potential losses. And under Pay For Performance, the rate at which deviations are settled is transparent and sufficiently high to incent the needed investments in resource performance.

As Dr. Cramton and Dr. White explain in detail in their respective testimonies, there is a simple logic to how performance incentives are achieved in markets.[39] During scarcity conditions, a supplier's payments should depend on what it actually delivers (energy and reserves) at the time. This logic is followed to good effect in the energy markets, and in many other types of markets, and must also be followed in the capacity market.

In markets other than for electricity, generally, when demand is less than supply, the competitive market price will be set at the incremental production cost of the most expensive supplier serving demand. When demand reaches or exceeds supply – that is, during scarcity conditions – the competitive market clearing price rises above the suppliers' incremental production costs. During such conditions, the price rises to the value that consumers place on the last unit produced; in other words, the price rises to what the market will bear. These higher prices during scarcity conditions play a critical role in properly functioning markets. Because prices fall close to marginal cost during non-scarcity conditions, suppliers in many markets must cover their total costs and earn the return on their investments based on what they deliver during scarcity conditions. This scarcity revenue (sometimes called scarcity "rent") provides a very strong motivation for suppliers to be able to deliver during scarcity conditions. This is the essential point: *Because such a critical portion of revenue is earned during scarcity conditions, suppliers are highly motivated to make cost-effective investments to assure they can deliver during scarcity conditions*.[40]

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[39] *See* Cramton Testimony at 3-14; White Testimony at 35-46.

[40] *See id.* at 37-38.

Electricity markets generally behave like other markets when supplies are ample, but when supplies are tight, things are different. When electricity demand reaches the energy market's short-run capacity limit, the market price for energy is not determined by the value that consumers place on the last unit produced – it does not rise to the price that the market will bear. Instead, it continues to be set based on sellers' offers and the ISO's administrative pricing rules.

There are a number of reasons for this, but the root cause is that the demand side of electricity markets remains under-developed. For a host of technological, political, and regulatory reasons, the vast majority of electricity consumers are not exposed to real-time electricity prices. That is, consumers have neither the information (about real-time prices) nor the incentive to reduce their electricity consumption in response to scarcity conditions in the wholesale market. Without a natural demand-side response mechanism by consumers, there is no means for suppliers in the wholesale market to determine what price the market is willing to bear for the limited supply available during scarcity conditions.[41]

As a result, wholesale energy markets such as New England's have alternative mechanisms to set price during scarcity conditions. Specifically, during periods of scarcity the energy market price is determined by the offer price of the marginal supplier, plus an administratively-determined price adder. The adder, which is informally called a scarcity price (and in the Tariff is referred to as a Reserve Constraint Penalty Factor or "RCPF"), helps to replace the energy market's missing scarcity revenue during tight market conditions.

Unfortunately, this scarcity pricing mechanism is not flexible enough to equilibrate electricity supply and electricity demand during scarcity conditions. That is, the energy market's administrative price adders do not – and cannot – adjust the total energy price to ensure no demand goes un-served during scarcity conditions, as naturally occurs in other markets. The ISO cannot do this because it does not have the information this requires (there are insufficient demand-side bids in the Real-Time Energy Market), and because the absence of natural demand-side response by consumers means that electricity demand may not react as required. These shortcomings mean that even with administrative scarcity pricing in the energy market, electricity markets still face a reliability problem and an investment problem.[42]

The reliability problem is that electricity markets require administrative rules to assure consumers receive reliable service. Because electricity markets, with present technology, cannot reveal how much reliability consumers would prefer to purchase and at what price (because consumers cannot respond directly to price), consumers face the prospect that some of their demand for electricity may go un-served when supply is scarce. To limit the frequency with

[41] *See* White Testimony at 38-41.

[42] *See id*. at 40.

which this occurs, a reliability rule is necessary to determine the amount of reliability that consumers should receive. In New England, this administrative rule takes the form of the resource adequacy criterion.

The investment problem occurs because the energy market's scarcity revenue is too low to attract the level of investment necessary to achieve the reliability objective. If the scarcity revenue is too low, marginal suppliers will not expect to recover their total costs and will not enter the market (or will soon exit). In that case, additional demand will go un-served, undermining reliability further. Importantly, the scarcity revenue a seller may earn by producing at these times motivates the seller to do more than just install capacity; it motivates the seller to undertake cost-effective investments to ensure its capacity will perform reliably when demand is high or alternative sources of supply are scarce. Without these investments, the power system will also have poor reliability.

As Dr. White explains, at a fundamental level, capacity markets exist to remedy these shortcomings of the energy market.[43] There is no realistic fix to the energy or capacity market that will obviate the need for an administratively-determined reliability criterion, at least for the foreseeable future. A well-designed capacity market can simply and effectively achieve this reliability objective by enabling resources to earn the necessary scarcity revenue that the energy market does not provide.

However, it cannot pay out this revenue irrespective of resource performance. Doing so would eliminate the natural mechanism that scarcity revenue provides for encouraging investments that enable resources to perform reliably during scarcity conditions. Instead, the capacity market must pay out the scarcity revenue that the energy market fails to provide in the same way normal markets do – based on what resources provide during scarcity conditions. If that incentive structure is not replicated, then suppliers will not have the incentive to make the investments necessary to ensure that they are able to perform when needed most – during periods of scarcity.

In sum, a resource's capacity revenue must depend on its performance (actual delivery of energy or reserves) during scarcity conditions. Linking payments to performance is how properly functioning markets work, and rewards cost-effective capital expenditures in assets or capabilities that help ensure resources can perform during scarcity conditions, when reliability is at heightened risk. Moreover, linking payments to performance addresses the structural bias in the present FCM to clear less reliable resources. With proper rewards for reliable performance during scarcity conditions, more reliable, better performing resources can afford to submit lower bids in the capacity auction because of the additional performance-based revenue they obtain,

[43] *See* White Testimony at 42.

making them more likely to clear in the capacity auction. Less reliable, poorly performing resources cannot afford to submit lower bids in the capacity auction because the reduced capacity payments they receive will no longer cover their capacity costs. This makes poor performers less likely to clear in the capacity auction. Improving the capacity market's performance incentives will change which resources clear, selecting a better performing, more reliable fleet, rather than being biased toward less reliable resources.[44]

D. Core Concepts Of The Pay For Performance Design

1. The Central Principles Of The Pay For Performance Design

The Pay For Performance design adheres to three fundamental market design principles that characterize efficient, competitive markets. First, a well-designed market must pay more for better performance and less for worse performance. Accordingly, a resource should earn its capacity market revenue based on the amount it delivers during scarcity conditions. To do this, Pay For Performance replaces "availability" as the performance metric, and will instead measure actual energy and reserves provided during scarcity conditions.[45]

Second, suppliers – and not consumers – must bear the risk and the rewards associated with their resources' performance. Hence, Pay For Performance includes no exemptions. This is a hallmark of competitive markets, and it places risk in the right place, in order to incent investment by suppliers and to enable the capacity market's price signal to select a reliable, cost-effective resource portfolio. Suppliers are in the best position to manage their performance risk, whether those risks are within or beyond their control, through undertaking new investments to reduce their performance risk, or by making arrangements with other suppliers or entities to cover their obligations during periods they may be unable to perform. This risk will need to be priced in each resource's bid in future Forward Capacity Auctions.

Third, the Pay For Performance design is resource neutral. In a well-designed market, two suppliers that provide the same good or service receive the same compensation. Their compensation is not dependent on whether or not they use the same technology to produce it. The Pay For Performance design honors this principle by providing all resources with the same compensation for the same performance, regardless of resource type or technology. This harnesses the full strength of markets and leaves suppliers free to identify and develop the most cost-effective means to improve resource performance.

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[44] *See* White Testimony at 42-46.

[45] *See id*. at 48-54.

2. Pay For Performance Is A True Two-Settlement Market Design

As explained in the testimonies Drs. Cramton and White, two-settlement systems are widely used for forward-sold goods, whether in centralized markets or in bilaterally-arranged forward contracts.[46] They are well-understood, and have numerous benefits. Two-settlement systems are conceptually simple, transparent, and provide a clear product definition. They reduce volatility for both suppliers and consumers. And perhaps most importantly, a two settlement design provides strong performance incentives in both the short-run and in the long-run. It motivates suppliers to take any and all cost-effective investments that will enable them to deliver on their future obligations. It also results in strong incentives for only the most reliable, cost-effective resources to take on obligations in the first place.[47]

The three main characteristics of a two-settlement design are a forward price, a forward position, and a settlement for deviations. These are incorporated in the Pay For Performance design as follows.[48]

a. Forward Price

Under Pay For Performance, the forward price is established through the Forward Capacity Auction. This is paid to resources having a Capacity Supply Obligation during the commitment period in the Capacity Base Payment. The Capacity Base Payment is determined by multiplying the Capacity Supply Obligation by the Forward Capacity Auction clearing price (or by the relevant prices for obligations assumed in reconfiguration auctions or bilaterally). Resources that do not take on a Capacity Supply Obligation do not receive Capacity Base Payments. The Capacity Base Payment represents the first of the two settlements in the two-settlement system.

b. Forward Position

A supplier that clears in the Forward Capacity Auction acquires both a physical obligation and a forward financial position in the capacity market. The physical obligation is to offer the MW amount of the Capacity Supply Obligation in both the Day-Ahead Energy Market and the Real-Time Energy Market during the commitment period. These offer requirements are largely the same under Pay For Performance as in the current FCM. The forward financial position under Pay For Performance is the financial obligation to cover the resource's share of the system's total energy and reserve requirements during scarcity conditions.

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[46] *See* Cramton Testimony at 6-9; White Testimony at 54-56.

[47] *See id.* at 56-58.

[48] *See id.* 58-60.

c. Settlement For Deviations

When a scarcity condition occurs during the commitment period, a resource with a Capacity Supply Obligation will have its performance measured against its forward financial position, that is, against its share of the system's requirements at the time of the scarcity condition. The resource will receive a Capacity Performance Payment based on the deviation from its share of the system's requirements. If the resource provides more than its share of energy and reserves, it will receive a positive Capacity Performance Payment. If the resource provides less than its share of energy and reserves, it will receive a negative Capacity Performance Payment. The Capacity Performance Payment represents the second of the two settlements in the two-settlement system.

An example will help to illustrate the concepts. Consider a resource that acquires a 300 MW Capacity Supply Obligation in the Forward Capacity Auction. If the total Capacity Supply Obligations of all suppliers is 30,000 MW, then this resource's share of the system's requirements is 1 percent (300 / 30,000). During the commitment period, the resource will be obligated to offer into the energy markets at 300 MW, and it will receive monthly Capacity Base Payments for 300 MW at the auction clearing price.[49]

During any scarcity condition in the commitment period, the resource's financial obligation is a 1 percent share of the system's total energy and reserve requirements at the time. For example, suppose a scarcity condition occurs during an off-peak period when the system's total load is 16,000 MW and the reserve requirement is 2,000 MW. This gives a total system energy and reserve requirement of 18,000 MW. The resource's pro-rata share of the system's requirements during this scarcity condition is its 1 percent share applied to the system's requirements of 18,000 MW. Its pro-rata share is therefore 1 percent × 18,000 MW, or 180 MW. The resource's Capacity Performance Payment for this scarcity condition will be based on its performance relative to 180 MW. Its Capacity Performance Payment will be positive if the resource delivers more than 180 MW of energy and reserves during the scarcity condition, and its Capacity Performance Payment will be negative if it delivers less than 180 MW of energy and reserves during the scarcity condition. In other words, deviations at delivery are determined by comparing the actual performance of the resource, measured by the energy and reserves it supplies, to its share of the system's requirements during the scarcity condition.

It is important to observe that in the Pay For Performance design, a negative Capacity Performance Payment is in no respect a "penalty." In a two-settlement forward market design, the settlement for deviations, whether positive or negative, is simply the second of the two settlements, as agreed to and understood by the parties upon initiating the transaction (in this

[49] *See* White Testimony at 60-65.

case, upon the supplier taking on a Capacity Supply Obligation). If a grain supplier agreed to deliver ten tons of grain in six months, and then only delivered eight, its underperformance would be settled at the spot price. Even if the spot price happens to be higher than the six-month-ago forward price, the grain supplier is not being penalized. The transaction is simply being settled as previously agreed.[50]

In two-settlement forward markets having a liquid spot market, the second settlement price for deviations is typically the spot price, which reflects the cost the buyer incurs due to the seller's non-performance. For example, the Real-Time Energy Market serves this role with respect to Day-Ahead Energy Market positions. As there is no spot market for capacity, under Pay For Performance, deviations are settled at an administratively-determined rate specified in the Tariff called the Capacity Performance Payment Rate.

As discussed at length below, the full Capacity Performance Payment Rate as calculated by the ISO is $5,455/MWh. However, the Pay For Performance design includes a phase-in period, such that for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2,000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3,500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5,455/MWh.

The phase-in of the Capacity Performance Payment Rate will smooth the introduction of the Pay For Performance incentives for a number of reasons. First, participants will be able to gain experience under the revised incentives both with the capacity market and with system operations and performance under the new design. The phase-in will also allow the ISO to evaluate the performance of the Pay For Performance approach. Given that there have been concerns expressed that the ultimate Performance Payment Rate might be too high, or that the general approach might be too risky, the ISO can evaluate how people react to the initial low rate and adjust course as needed. This would be based on indicators such as the bids submitted to the IMM and their formulation, changes in system operations, investments in reliability made by resource owners, and entry and exit decisions. For example, if a substantial number of resources have dual fuel at $2,000, and the least reliable resources are leaving the market and being replaced by reliable resources, the ISO can reevaluate the need to increase the Capacity Performance Payment Rate, or the pace at which it is increased. If the risk premiums evident in resource bids appear to be higher than warranted, the ISO can evaluate the cause and adjust course as required.

[50] *See* White Testimony at 53-54.

Finally, it is important to note that resources under Pay For Performance are not asked or expected to physically operate at a MW level equal to their share of the system's requirements. Rather, they are expected to operate as dispatched, regardless of their forward positions. During scarcity conditions, the dispatch software directs resources to produce at a level that maximizes the sum of the energy and reserves they can provide during each interval, subject to the resource's offered capabilities (such as its ramp rate) and the transmission network's capabilities. A supplier's financial incentives under Pay For Performance – which are to maximize its resource's capabilities to provide energy and reserves – are fully aligned with the system's dispatch objectives to make maximum use of those capabilities during scarcity conditions. The share-of-system forward position, then, is not a physical dispatch target. It is a financial arrangement that serves to link payments to performance and thereby create stronger economic incentives for resources to enhance their capabilities to deliver.[51]

3. Resources Without A Capacity Supply Obligation Are Eligible To Receive Capacity Performance Payments

For a resource with a Capacity Supply Obligation, its Capacity Performance Payment is based on the deviation between its actual performance and its share of the system's requirements. For a resource without a Capacity Supply Obligation, its share of the system's requirements is zero. Any energy or reserves that it delivers during scarcity conditions can be viewed as a positive deviation from its share of the system requirements, and should be credited – like all positive deviations – at the same Capacity Performance Payment Rate. This design feature is important because it provides strong performance incentives to all resources, of whatever type, to deliver energy and reserves during scarcity conditions when system reliability is at heightened risk. During scarcity conditions, the pool of potential over-performers that might be able to relieve the shortage should be as broad as possible, and there is no reason to limit that pool to resources having a Capacity Supply Obligation. Also, as noted in the testimony of Mr. LaPlante and Dr. Gheblealivand, resources will be able to price different resource blocks at different prices; thus, while a resource's highest-priced blocks may not take on a Capacity Supply Obligation, they are still eligible to receive Capacity Performance Payments for providing energy or reserves during scarcity conditions.[52]

4. Capacity Performance Payments Are Transfers Among Suppliers

Under the Pay For Performance design, consumers only pay for the Capacity Base Payments, which are fixed at the time of the Forward Capacity Auction. The Capacity Performance Payments are structured as transfers of money from under-performing suppliers to

[51] *See* White Testimony at 64-65.

[52] *See id.* at 67-69.

over-performing suppliers. Hence, the costs to consumers are hedged once the Forward Capacity Auction is complete. They do not bear the financial risk of unexpectedly high Capacity Performance Payments earned by suppliers that perform well during the commitment period. During a scarcity condition, some resources will perform well (above their share of the system's requirements) and others will perform poorly (below their share of the system's requirements). It is the suppliers whose resources perform poorly – below their share of the system's requirements – that bear the risk of covering the positive Capacity Performance Payments to resources that over-perform.[53]

5. Pay For Performance Will Improve Reliability In A Cost-Effective Manner, Unlike The Current FCM Design

One of the most important features of the Pay For Performance design is that it will improve reliability in a cost-effective manner. Cost-effectiveness is simply the ratio of cost to performance. A resource that provides little or no contribution to reliability, even if it offers its capacity in the Forward Capacity Auction at a low price, is not cost-effective. A resource that contributes greatly to reliability, even at a higher price, is likely to be much more cost-effective. In other words, the important measure is not simply the price paid for capacity, but rather the price paid relative to the reliability purchased.[54]

Flaws in the current FCM design result in the clearing of resources that make little or no contribution to reliability. Because capacity payments are not well linked to resource performance, resources that are likely to be poor performers are nonetheless encouraged to participate in the market when they should exit. This leads to numerous problems. Because resources are not selected on the basis of cost effectiveness, consumers are frequently paying an unnecessarily high price for the level of service they obtain during scarcity. Resources with poor performance may clear in the Forward Capacity Auction, displacing competing resources with substantially better performance. The market produces a worse-performing resource mix, which lowers the amount of energy and reserves the ISO can expect to obtain during tight system conditions when reliability is at heightened risk. And, perversely, suppliers find poor performance may be *more* profitable than better performance.

Pay For Performance is designed to address all of these problems. Because payments are strongly linked to performance, suppliers are incented to account for their expected performance when they bid in the Forward Capacity Auction, and each resource's capacity offer price will reflect the resource owner's own estimate of its cost-effectiveness and risk. This will allow the Forward Capacity Auction to select the set of resources that represent the most cost-effective

[53] *See* White Testimony at 66-67, 82-86.

[54] *See id.* at 116-133.

way to meet the system's needs during scarcity conditions. That is, it selects resources with the lowest capacity costs *relative to* the expected amount of energy (and reserves) that the resources will deliver. The less reliable and less cost-effective resources will tend to de-list (not clear) in the Forward Capacity Auction, rather than displace resources with more cost-effective performance.

E. Pay For Performance Is Far Superior To The NEPOOL Alternative

At its December 6, 2013 meeting, the NEPOOL Participants Committee voted in favor of an alternative proposal sponsored by NRG Energy Inc. The NEPOOL proposal includes four components: (1) increasing by $500/MWh the existing administrative price adder in the energy market during scarcity conditions; (2) eliminating the existing Shortage Event mechanism in FCM entirely; (3) adding a "long-term availability incentive," via an annual credit or charge for changes to a resource's five-year EFORp; and (4) adding yet another exemption from performance penalties, in this case when a resource cannot perform because of events that are "out of management control." In short, rather than pursue meaningful and fundamental market-based fixes to the FCM, the NEPOOL proposal will barely increase incentives while effectively eliminating consequences for non-performance. Indeed, the NEPOOL proposal essentially converts the FCM payment stream into a cost-of-service-like payment.

First, if the goal of these changes is to improve incentives for resources to perform during scarcity conditions, NEPOOL's proposed $500/MWh adder is an order of magnitude too small. Dr. White provides extensive testimony explaining how the calculation of the Capacity Performance Payment Rate of $5,455/MWh in the Pay For Performance design was derived, and demonstrates that this level of incentive is necessary during periods of scarcity to meet the region's reliability objectives cost-effectively. NEPOOL's $500/MWh adder, which was not supported by any analysis in the stakeholder process, is simply too small to have any useful impact on resource performance during scarcity conditions.

Second, while the ISO has conceded that the existing Shortage Event mechanism provides only weak incentives for resource performance during scarcity conditions, it is the only feature of the current FCM design that performs such a role. If the Shortage Event mechanism is to be removed, it must be replaced with something that provides even better protections against non-performance. The other elements of the NEPOOL proposal certainly do not fill that gap, and so the FCM would be left even weaker than it is today.

Third, NEPOOL's proposed "long-term availability incentive" cannot succeed. As fully explained by Dr. Cramton and Dr. White in their respective testimonies, the product that must be purchased in the capacity market is actual performance – the delivery of energy and reserves –

during scarcity conditions.[55] This is what the revenue stream that is "missing" from the energy market would compensate, and it is what consumers are paying for in the capacity market. As explained above, using availability, instead of performance, for determining capacity payments is ineffective for inducing investments that improve reliability – yet this is what the NEPOOL proposal would do. Using EFORp, which is essentially measuring availability during summer and winter peak hours, does not ensure that performance is measured when it matters most. Instead it measures performance during what are likely to be some high load hours, and lots of hours of moderate load. And it may be that none of these hours experience shortage conditions. If the system has sufficient, well-performing resources during peak conditions, there is no need to measure performance during those hours. And by averaging in many hours when the system is very unlikely to be under stress, it significantly waters down the effect of performance during the most critical hours. What the market must incent is performance during scarcity conditions; the NEPOOL proposal does not do this.

Indeed, use of the five-year average of EFORp as the benchmark by which to measure availability and purportedly incent performance has a significant perverse result which can be demonstrated by a simple example. Assume two resources of the same size whose performance is being measured. The first resource is a historically poor performer that has an EFORp value of 0.5. As long as that resource raises its EFORp, to say 0.6, it will receive an enhanced performance payment. Assume the second resource has been an excellent performer with an EFORp of 0.95, but its EFORp falls to 0.9. That resource will be penalized for "poor performance." It is patently obvious that consumers are getting much better value from the second resource, yet the first resource will be paid more under NEPOOL's proposal.

Fourth, the ISO has explained at length why exemptions are inconsistent with sound market design. Nonetheless, NEPOOL would add a new and potentially very broad exemption to the FCM design for events that are "out of management control." Exemptions break the much-needed link between payments and performance, and while it is true that suppliers may not be able to prevent some force majeure events, it is obvious that consumers cannot manage any such risks. Sound market design places these risks on suppliers regardless of fault. Adding more exemptions, especially ones as broad and vague as the new one proposed by NEPOOL, is moving completely in the wrong direction.

At bottom, rather than ameliorating the significant problems that the ISO has identified, the NEPOOL proposal will further reduce the already low risk of losing capacity revenues for non-performance, essentially creating a cost-of-service payment for all resources, regardless of their performance. While this section only points out the most critical flaws in the NEPOOL proposal and describes how that proposal moves in the wrong direction, it demonstrates that the

[55] *See* Cramton Testimony at 18-19; White Testimony at 15-17, 42-43.

NEPOOL proposal must be rejected. In its answer to NEPOOL's filing, the ISO will fully critique the proposal and explain further why the Commission must reject it.

F. Details Of The Pay For Performance Design And Tariff Revisions[56]

The core Pay For Performance rules are contained in Section III.13.7 of the Tariff, titled "Performance, Payments and Charges in the FCM." As revised, III.13.7 contains three primary topics:

- Capacity Base Payments are detailed in new Section III.13.7.1. The Capacity Base Payments are very similar to the current FCM capacity payment provisions, and so the provisions in new Section III.13.7.1 are largely made up of existing provisions that have been moved and modified.

- Capacity Performance Payments are detailed in Section III.13.7.2., with potential adjustments described in Section III.13.7.3 and Section III.13.7.4. As the Capacity Performance Payments are an entirely new construct, the language in these provisions is new.

- Charges to Market Participants with a Capacity Load Obligation are detailed in Section III.13.7.5. These provisions are largely unchanged from the currently effective Tariff, except for renumbering and minor conforming changes.

The opening paragraph of Section III.13.7 is being revised to reflect these structural changes to Section III.13.7, and to delete language made obsolete by the implementation of Pay For Performance. All of the remaining provisions of Section III.13.7 are discussed in further detail below.

1. Calculation Of Capacity Base Payments

The monthly Capacity Base Payment under Pay For Performance is described in new Section III.13.7.1, which is substantially the same as currently effective Section III.13.7.2 (though revised to reflect new terminology under Pay For Performance). The general monthly payment or charge (based on a resource's Capacity Supply Obligations) is described in new Section III.13.7.1.1, and the potential peak energy rent deduction is described in new Section III.13.7.1.2.

[56] Unless otherwise specified, all of the Tariff revisions described in this section are shown in the ISO's blacklined Tariff sheets effective June 1, 2018, which are being submitted with Part 2 of this filing as Attachment I-2b.

a. Monthly Payments and Charges Reflecting Capacity Supply Obligations

The provisions in new Section III.13.7.1.1 that describe the monthly Capacity Base Payment are almost identical to the provisions for monthly capacity payments to generating capacity resources in currently effective Section III.13.7.2.1.1. These provisions essentially state that there will be a monthly payment or charge based on Capacity Supply Obligations acquired or shed in a Forward Capacity Auction, in a reconfiguration auction, or through a Capacity Supply Obligation Bilateral. These provisions ensure that the various prices associated with each portion of a resource's Capacity Supply Obligation are properly tracked and accounted for. Treatment of resources that elected a multi-year commitment and of new resources that are prevented from becoming commercial due to a planned transmission facility not being in service are also unchanged from the current rules.[57] Furthermore, the defined term "FCA Payment," included in current Section III.13.7.2.1.1, is no longer needed due to the elimination of the availability provisions, so that has been excluded as a defined term from new Section III.13.7.1.1.

As discussed above, a significant advantage of Pay For Performance is that it is resource-neutral. The same payment provisions apply regardless of resource type. This is in sharp contrast to the current FCM rules, which include separate monthly capacity payment provisions for the various resource types.

b. Peak Energy Rents

The Capacity Base Payment may be decreased by Peak Energy Rents, as is the case with monthly capacity payments under the currently effective Tariff. The Peak Energy Rent provisions in currently effective Section III.13.7.2.7.1.1 are being moved to new Section III.13.7.1.2 and modified to conform to the Pay For Performance structure and terminology.

The opening paragraph in new Section III.13.7.1.2 contains minor revisions to the same paragraph in current Section III.13.7.2.7.1.1. First, it is revised slightly to reflect the Capacity Base Payment terminology of Pay For Performance. Second, references to Section III.13.7.1.1.3(h) and III.13.7.1.1.3(i) are updated to reflect the deletion of those Sections under Pay For Performance. Third, a final sentence has been added to the paragraph stating that Self-Supplied FCA Resources shall not be subject to a Peak Energy Rent adjustment on the portion of the resource that is self-supplied. This is not a new sentence, but rather is being moved from current Section III.13.7.2.7.6, which is being deleted because, as discussed above, there will no longer be separate payment provisions based on resource type.

[57] What is a reference to Section III.13.7.1.1.3(i) in the current rules is instead spelled out in revised Section III.13.7.1.1(a) because current Section III.13.7.1.1.3 is being deleted as part of the Pay For Performance changes.

The "Hourly PER" calculation provisions in new Section III.13.7.1.2.1 are identical to the currently effective Section III.13.7.2.7.1.1.1.

The "Monthly PER Application" provisions in new Section III.13.7.1.2.2 are substantively the same as current Section III.13.7.2.7.1.1.2, but the new Pay For Performance design allows for the language in that section to be greatly simplified. Under the current rules, the PER deduction generally is calculated as the product of the Average Monthly PER and the resource's Capacity Supply Obligation (less any self-supplied MW). Using a minimization function, this amount is limited on the high end to something called the "PER cap." And the deduction is limited on the low end to zero by current Section III.13.7.2.7.1.1.2(c). The "PER cap" is conceptually the same as the Capacity Base Payment under Pay For Performance, and current Section III.13.7.2.7.1.1.2(c) (as well as current Section III.13.7.2.7.1.1.2(b)) uses terminology related to availability penalties, which is obsolete under Pay For Performance. All of these provisions are being deleted and replaced with new language based on the Pay For Performance terminology. This new language in new Section III.13.7.1.2.2 is functionally equivalent to the language in current Section III.13.7.2.7.1.1.2 – it calculates the Peak Energy Rent deduction as the Average Monthly PER multiplied by the resource's Capacity Supply Obligation (less any self-supplied MW), and limits the deduction to no more than the Capacity Base Payment and to no less than zero – but is far more simple and clear.

As explained in detail in the testimony of Dr. White, the Peak Energy Rent deduction is *not* being modified to include a resource's Capacity Performance Payments in determining whether the Peak Energy Rent strike price has been exceeded and by how much. To do so would negate the performance incentives that Pay For Performance is designed to provide. The effect would be to increase the Peak Energy Rent deduction as the resource's Capacity Performance Payments increase. If the positive Capacity Performance Payments that were earned by good-performing resources were then removed from the resource's net FCM revenue each month, the incentive disappears. This is not consistent with the design objectives of Pay For Performance.[58]

2. Calculation Of Capacity Performance Payments

How Capacity Performance Payments will be calculated is set forth in detail in new Section III.13.7.2. Generally, during each five-minute interval in which there is a scarcity condition, each resource will receive a separate performance score according to the following formula:

$$\textit{Capacity Performance Score} = \textit{Actual MW} - (\textit{Balancing Ratio} \times \textit{CSO MW})$$

[58] *See* White Testimony at 166-169.

A resource's Capacity Performance Payment for each five-minute interval during a Capacity Scarcity Condition will be its Capacity Performance Score multiplied by the Capacity Performance Payment Rate. Each of these terms is explained in detail below.

a. Definition of Capacity Scarcity Condition

As previously explained, an important design element of Pay For Performance is strongly linking capacity revenue to actual performance during scarcity conditions. The first step in calculating the Capacity Performance Payment, then, is defining the scarcity conditions in which they will apply. For this reason, the first subsection in III.13.7.2 sets out the definition of a new defined term "Capacity Scarcity Condition." Each Capacity Zone, for each five-minute interval, is assessed separately, such that there could be a Capacity Scarcity Condition lasting for only five minutes in a single Capacity Zone. As explained in the testimony of Dr. White, this enables the frequency of Capacity Scarcity Conditions to match the frequency of scarcity pricing in the energy market, allowing performance incentives in both markets to work in harmony and under the appropriate system conditions.[59]

As stated in new Section III.13.7.2.1, a Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement; (ii) the system-wide Ten-Minute Non-Spinning Reserve requirement; or (iii) the local Thirty-Minute Operating Reserve requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

Stated more simply (as explained in the testimony of Dr. White), the ISO has several distinct reserve requirements, and different types of real-time reserves. There are three primary real-time reserve requirements, and a Capacity Scarcity Condition will be based on whether the real-time energy price incorporates a scarcity price adder (indicating the supply of reserves is less than the required level of reserves) for one or more of the following reserve requirements:[60]

(i) The *system minimum 30-minute reserve* requirement, which is satisfied with offline or online generation capability available in thirty minutes or less. The supply of reserves that helps satisfy this requirement includes all resources' thirty-minute operating reserves ("TMOR"), ten minute non-spinning reserves ("TMNSR"), and ten-minute spinning reserves ("TMSR").

[59] *See* White Testimony at 140-146.

[60] *See id.* at 141-143.

(ii) The *system 10-minute reserves* requirement (sometimes called the system's *contingency reserves* requirement), which is satisfied with offline and online generation capability available in ten minutes or less. The supply of reserves that helps satisfy this requirement includes all resources' TMNSR and TMSR.

(iii) The *zonal 30-minute reserve* requirements, for the zones described above. The supply of reserves that helps satisfy this requirement includes the resources within the zone providing TMOR, TMNSR, and TMSR

This list does not include a zonal 10-minute reserve requirement, because the New England system does not have a 10-minute reserve requirement at the zonal level.

However, new Section III.13.7.2.1 also states that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing applies only because of resource ramping limitations that are not binding on the energy dispatch. This is because such resource ramping limitations do not represent a scarcity of energy, but rather a scarcity of the ramping capabilities of the on-line resources. For example, if the system is ramping total energy production up to match rapidly climbing load, the system may have a transitory violation of a reserve requirement that could not be reduced even if the system had one less MW of energy demand. In this case, the real-time Locational Marginal Price for energy does not incorporate the reserve market's scarcity price. That is, the reserve market has an Reserve Constraint Penalty Factor-based price, but there is no scarcity price adder incorporated into the energy price. For this reason, the Capacity Scarcity Condition definition specifically excludes the circumstance in which Reserve Constraint Penalty Factor-based pricing occurs in the reserve market only because of resource ramping limitations that are not binding on the energy dispatch.

b. Calculation of Actual Capacity Provided During a Capacity Scarcity Condition

Again, a central design element of Pay For Performance is strongly linking capacity revenue to actual performance during Capacity Scarcity Conditions. The second step in calculating the Capacity Performance Payment, then, is determining the resource's actual performance, defined as the quantity of energy and reserves actually provided, during each Capacity Scarcity Condition. For this reason, the second subsection in III.13.7.2 sets out the definition of a new defined term "Actual Capacity Provided."

As stated in new Section III.13.7.2.2, for each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. Actual Capacity Provided is calculated for all resources, whether or

not they have a Capacity Supply Obligation, because all resources are eligible for Capacity Performance Payments, even if they do not have a Capacity Supply Obligation. As explained by Dr. White, this is an important design feature of Pay For Performance because during periods of reserve deficiency, any and all resources that might contribute energy or reserves to relieve the deficiency should face the same strong incentive to do so.[61]

Since some types of resources increase supply, and other types reduce consumption, in order to alleviate a reserve deficiency, the determination of Actual Capacity Provided for each resource depends on the resource type as described below. Because the resource type categories used correspond to resources that have a Capacity Supply Obligation, new Section III.13.7.2.2 states explicitly that for resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision applicable to the resource type. As stated above, a Capacity Supply Obligation is not needed for a resource to be eligible for Capacity Performance Payments.

i. Generating Capacity Resource

As stated in new Section III.13.7.2.2(a), a Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Real-Time Reserve Designation (including any regulation capability available but not used for energy) during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the resource's Desired Dispatch Point during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f) (capacity backed exports), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

This provision generally states that the Actual Capacity Provided by a Generating Capacity Resource shall be the quantity of energy and reserves it provides during the relevant interval. The Actual Capacity Provided is limited to the resource's Desired Dispatch Point if the resource's output was limited by a transmission system limitation during the Capacity Scarcity Condition. This limitation is important to encourage resources to follow dispatch instructions rather than seek higher Capacity Performance Payments by over-performing in ways that might damage the transmission system or otherwise jeopardize reliability. As explained by Dr. White, resources are expected to operate as dispatched, regardless of their forward positions. During scarcity conditions, the dispatch software directs resources to produce at a level that maximizes

[61] *See* White Testimony at 67-69.

the sum of the energy and reserves they can provide during each interval, subject to the resource's offered capabilities (such as its ramp rate) and the transmission network's capabilities.

Section III.13.7.2.2(a) also states that where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f) (capacity backed exports), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales. This circumstance applies to generators within New England that are serving load outside of the New England control area, through associated capacity-backed export external transactions. Because such a generator is not serving load in New England during the Capacity Scarcity Condition, the amount of its export is not credited to the applicable generating unit's Actual Capacity Provided.

ii. Import Capacity Resource

As stated in new Section III.13.7.2.2(b), an Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered (but not less than zero) during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata. This is because unlike a portfolio of physical generating assets, for example, where the output of each resource is explicitly and unambiguously associated with that resource, energy transactions bringing energy into New England are not explicitly assigned to a participant's Import Capacity Resources. In this case, allocating the energy delivered pro rata obviates the need for a more complicated mechanism for allocating the delivered energy among a Market Participant's multiple resources, and provides a simple and transparent basis for settlement. Explicit assignment of real-time External Transactions to an Import Capacity Resource is not required at external interfaces with enhanced scheduling,[62] and Pay For Performance is not intended to change these enhanced scheduling provisions of the Tariff. In addition, enabling a Market Participant to explicitly assign its Actual Capacity Provided to different Import Capacity Resources it controls could create inappropriate outcomes if one of its Import Capacity Resources with a Capacity Supply Obligation has reached the resource's stop-loss limit.

iii. On-Peak Demand Resource

As stated in new Section III.13.7.2.2(c), an On-Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the resource's Average Hourly Output or Average Hourly Load Reduction multiplied by 1.08. The Average Hourly Output applies to an

[62] *See* Tariff Section III.13.6.1.2.3.

On-Peak Demand Resource configured to supply energy to the system, and the Average Hourly Load Reduction applies to an On-Peak Demand Resource that reduces load on the system. In the latter case, the Average Hourly Load Reduction is multiplied by 1.08 to account for transmission and distribution losses that are avoided because the resource is reducing load rather than increasing supply, consistent with existing Tariff provisions.[63]

iv. Seasonal Peak Demand Resource

As stated in new Section III.13.7.2.2(d), a Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the resource's Average Hourly Output or Average Hourly Load Reduction multiplied by 1.08. Again, the Average Hourly Output applies to a Seasonal Peak Demand Resource configured to supply energy to the system, and the Average Hourly Load Reduction applies to a Seasonal Peak Demand Resource that reduces load on the system. In the latter case, the Average Hourly Load Reduction is multiplied by 1.08 to account for transmission and distribution losses that are avoided because the resource is reducing load rather than increasing supply.

v. Real-Time Emergency Generation Resource

As stated in new Section III.13.7.2.2(e), a Real-Time Emergency Generation Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be either: (i) the sum of the electrical energy output of all of the Real-Time Emergency Generation Assets associated with the Real-Time Emergency Generation Resource as registered with the ISO during the interval in which the Capacity Scarcity Condition occurred; or (ii) the sum of the baseline electrical energy consumption minus the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO during the interval in which the Capacity Scarcity Condition occurred; and shall be multiplied by 1.08. Condition (i) applies to a Real-Time Emergency Generation Resource configured to supply energy to the system, and condition (ii) applies to a Real-Time Emergency Generation Resource that reduces load on the system. In the latter case, the amount is multiplied by 1.08 to account for transmission and distribution losses that are avoided because the resource is reducing load rather than increasing supply.

vi. Demand Response Capacity Resource

As stated in new Section III.13.7.2.2(f), a Demand Response Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Real-Time demand reduction for each Demand Response Asset (in accordance with Section 7.1 of

[63] The 1.08 multiplier is consistent with existing Tariff provisions, *see e.g.* current Section III.13.7.1.5.1.

Appendix E2 to Market Rule 1) associated with the Demand Response Capacity Resource multiplied by 1.08, plus the sum of the Net Supply from each Net Supply Generator Asset associated with the Demand Response Capacity Resource, plus the resource's Real-Time Reserve Designation. For purposes of these calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline (adjusted pursuant to Section III.8B.5) of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, any Net Supply of a Net Supply Generator Asset located at the same Retail Delivery Point shall be reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset. A Demand Response Capacity Resource may include both assets that supply energy to the system and that reduce load on the system. In the latter case, the amount is multiplied by 1.08 to account for transmission and distribution losses that are avoided because the resource is reducing load rather than increasing supply. The additional clarification regarding Net Supply is required to avoid double counting where both a Real-Time Emergency Generation Resource and a Net Supply Generator Asset are located at the same Retail Delivery Point.

c. Calculation Of The Capacity Balancing Ratio

The third step in calculating the Capacity Performance Payment is determining the Capacity Balancing Ratio that applies for the Capacity Scarcity Condition. As explained by Dr. White, the Capacity Balancing Ratio is used to determine a resource's share of the system's energy and reserve requirements during a Capacity Scarcity Condition. Conceptually, the calculation of the Capacity Balancing Ratio is simple. As stated in new Section III.13.7.2.3, for each five-minute interval in which a Capacity Scarcity Condition exits, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

The values used for this calculation, however, will vary depending on the type of reserve deficiency and whether it occurs system-wide or only in a single Capacity Zone, as follows:

i. RCPF Pricing Due To A Violation of System-Wide Thirty-Minute Operating Reserve Requirement

If the Capacity Scarcity Condition is a result of a violation of the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

- Load = the total amount of Actual Capacity Provided (excluding reserve designations) from all resources in the New England Control Area during the interval. Load excludes reserve designations so as to avoid double counting – the reserve requirement is included in the numerator separately.

- Reserve Requirement = the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning Reserve requirement during the interval plus the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement during the interval. The sum of these three values is the minimum Thirty-Minute Operating Reserve Requirement.

- Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval.

ii. RCPF Pricing Due To A Violation of System-Wide Ten-Minute Non-Spinning Reserve Requirement

If the Capacity Scarcity Condition is a result of a violation of the system-wide Ten-Minute Non-Spinning Reserve requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

- Load = the total amount of Actual Capacity Provided (excluding reserve designations) from all resources in the New England Control Area during the interval.

- Reserve Requirement = the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning Reserve requirement during the interval. The sum of these two values is the system-wide ten-minute reserve requirement.

- Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval.

iii. RCPF Pricing Due To A Violation of Local Thirty-Minute Operating Reserves Requirement

If the Capacity Scarcity Condition is a result of a violation of the local Thirty-Minute Operating Reserves requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

- Load = the total amount of Actual Capacity Provided (excluding reserve designations) from all resources in the Capacity Zone during the interval plus the net amount of energy

imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero).

- Reserve Requirement = the local Thirty-Minute Operating Reserve requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface. Reserve support coming into the Capacity Zone is subtracted because resources inside the Capacity Zone are not needed to meet this portion of the reserve requirement.

- Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval.

iv. Simultaneous Violations

The Capacity Balancing Ratio provisions also include rules to determine which values should be used in the Capacity Balancing Ratio formula if a Capacity Zone is simultaneously subject to more than one type of reserve deficiency.[64]

Specifically, in any Capacity Zone subject to both Reserve Constraint Penalty Factor pricing associated with the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement and Reserve Constraint Penalty Factor pricing associated with the system-wide Ten-Minute Non-Spinning Reserve requirement, but not to Reserve Constraint Penalty Factor pricing associated with the local Thirty-Minute Operating Reserves requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) (in particular, the Reserve Requirement is the sum of the Ten-Minute Spinning Reserve requirement plus the Ten-Minute Non-Spinning Reserve requirement plus the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement during the interval). This rule is used because the value of the Reserve Requirement in the Capacity Balancing Ratio reflects the required amounts of each type of reserves that can help alleviate the Capacity Scarcity Conditions. If the system dispatch software activates RCPF pricing for the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserve requirement, then Ten-Minute Spinning Reserves, Ten-Minute Non-Spinning Reserves, and Thirty-Minute Operating Reserves all contribute toward meeting the violated requirement.

And in any Capacity Zone subject to both Reserve Constraint Penalty Factor pricing associated with the local Thirty-Minute Operating Reserves requirement and either subject to Reserve Constraint Penalty Factor pricing associated with the minimum Thirty-Minute Operating

[64] *See* White Testimony at 158.

Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement or subject to Reserve Constraint Penalty Factor pricing associated with the system-wide Ten-Minute Non-Spinning Reserve requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(c) (using values applicable to a violation of the local Thirty-Minute Operating Reserves requirement). This rule ensures that a resource located in a Capacity Zone experiencing a zonal reserve requirement violation will have its Capacity Performance Score evaluated relative to its share of the Capacity Zone's energy and reserve requirements. A resource in the rest-of-system has its Capacity Performance Score evaluated relative to its share of the system's requirements (which, in this situation, are also experiencing a violation at the time).

d. Calculation Of The Capacity Performance Score

The fourth step in calculating the Capacity Performance Payment is calculating the resource's Capacity Performance Score for the Capacity Scarcity Condition. As stated in new Section III.13.7.2.4, each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval minus the product of the resource's Capacity Supply Obligation and the applicable Capacity Balancing Ratio. The resulting Capacity Performance Score may be positive or negative. This calculation was stated previously as follows:

$$\textit{Capacity Performance Score} = \textit{Actual MW} - (\textit{Balancing Ratio} \times \textit{CSO MW})$$

Because the values for each of these terms have been calculated in previous steps, it is now possible to calculate the resource's Capacity Performance Score for the Capacity Scarcity Condition.

As explained by Dr. White, the Capacity Performance Score is simply the MW amount by which a resource over-performs or under-performs relative to its share of the system's financial performance obligation at the time of a scarcity condition. The resource's share of the system's requirements is captured in the expression *(Balancing Ratio × CSO MW)*. If the Capacity Balancing Ratio is 0.75 and the resource's Capacity Supply Obligation is 100 MW, then that resource's share of the system's requirements during the five-minute Capacity Scarcity Condition interval would be 75 MW. If the resource's Actual Capacity Provided during that interval is greater than 75 MW, then its Capacity Performance Score will be positive. If its Actual Capacity Provided during the interval is less than 75 MW, then its Capacity Performance Score will be negative.[65]

[65] *See* White Testimony at 71-76.

e. The Capacity Performance Payment Rate

Because a resource's Capacity Performance Payment for the five-minute Capacity Scarcity Condition interval is its Capacity Performance Score for that interval multiplied by the Capacity Performance Payment Rate, the fifth step in the process of calculating the Capacity Performance Payment is establishing the applicable Capacity Performance Payment Rate. Under Pay For Performance, this value is set forth in the Tariff.

As stated in new Section III.13.7.2.5, for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2,000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3,500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5,455/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

i. Derivation Of The $5,455 Per MWh Full Capacity Performance Payment Rate

As explained in the testimony of Dr. White, Pay For Performance is a two-settlement design, with a forward price and a price at which deviations are settled. Under Pay For Performance, the forward price is the Forward Capacity Auction clearing price. When there is a liquid spot market for the forward-sold good, the second settlement price for deviations is typically the spot price, which reflects the cost the buyer incurs due to the seller's non-performance. In forward-sold goods markets that do not have liquid spot markets at the time of delivery, the settlement price for deviations is stipulated in advance in the forward contract terms. As there is no spot market for capacity, under Pay For Performance, deviations are settled at an administratively-determined rate specified in the Tariff – the Capacity Performance Payment Rate.[66]

The Capacity Performance Payment Rate plays an important role in affecting suppliers' performance and investment incentives. As Dr. White explains, the Capacity Performance Payment Rate serves as a scarcity price 'premium,' in addition to the real-time energy and reserve prices, during periods of scarce supply on the system. More importantly, the Capacity Performance Payment Rate affects resources' longer-term investment incentives. Over time, resources that perform well during scarcity conditions accrue positive performance payments and greater net FCM revenue. Resources that perform poorly (or not at all) during scarcity conditions

[66] *See* White Testimony at 86-111.

earn comparatively less net FCM revenue. Through this mechanism, Pay For Performance creates financial incentives for the system to evolve toward a resource mix that performs well when the power grid experiences operating reserve deficiencies and faces heightened risk to reliability.[67]

In his testimony, Dr. White provides a detailed explanation of how the full Capacity Performance Payment Rate of $5,455 per MWh is calculated. He begins with two specific economic principles that guide the derivation of the Capacity Performance Payment Rate. First, the Capacity Performance Payment Rate must be set at a level such that a new capacity resource is willing to enter the market if new entry is needed to satisfy the Installed Capacity Requirement. Second, a resource that expects to have zero performance (that is, it expects to supply zero energy and reserves) during all expected scarcity conditions over the course of the commitment period should expect zero net capacity revenue (this is referred to as the "zero revenue for zero performance" principle). Dr. White provides a detailed discussion of how these principles are translated into formulas that, when combined, yield a simple result for the Capacity Performance Payment Rate:[68]

$$PPR \geq \frac{Net\ CONE + RF_{new}}{Scarcity\ Hours_{new} \times Actual_{new}}$$

As Dr. White explains, the Capacity Performance Payment Rate spreads the total capacity revenue that a new entrant requires over its expected production (of energy and reserves) during scarcity conditions. The sum in the numerator of the formula ($Net\ CONE + RF_{new}$) is the new entrant's total cost, including a risk premium (if any), that it must expect to recover from the capacity market in order to be willing to enter. The amount in the denominator ($Scarcity\ Hours_{new} \times Actual_{new}$) is the new entrant's expected total annual performance during scarcity conditions. Performance, in this context, is measured in MWh delivered in the form of energy or reserves, per Capacity Supply Obligation MW, during scarcity conditions. In this way, a new capacity resource earns its capacity revenue by performing during scarcity conditions.[69]

Similarly, an existing capacity resource – one that clears in the auction, whether or not new entry sets price – earns greater net FCM revenue to the extent that it delivers more energy and reserves during scarcity conditions. The resources that clear have positive expected profit in the capacity market (with the possible exception of the marginal resource that sets the capacity clearing price, which may have zero profit).

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[67] *See* White Testimony at 87-88.

[68] *See id.* at 88-102.

[69] *See id.* at 101.

Dr. White describes in detail the values used as inputs into the formula and how they were selected, and demonstrates that they lead to a result of $5,455 per MWh. He concludes by noting that while values above $5,455 per MWh would satisfy the inequality expressed in the formula, the Capacity Performance Payment Rate is being set to the lowest value that meets the requirement.[70]

ii. Phase-In Of The Capacity Performance Payment Rate

As indicated above, for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2,000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3,500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5,455/MWh.

The phase-in is being included because Pay For Performance represents a major shift in the Forward Capacity Market design that will significantly impact the capacity revenue streams for some suppliers and impact costs to consumers. It is reasonable to smooth the transition to the new paradigm, and phasing in the Capacity Performance Payment Rate will help to accomplish that. The lower initial value will tend to reduce the financial risk and uncertainties that capacity sellers face under the Pay For Performance design while participants gain experience with the design prior to the full Capacity Performance Payment Rate becoming effective.

During the phase-in period, market participants will acquire greater information and experience about the frequency, timing, and duration of scarcity conditions on the system. They will also acquire years of additional experience with how their individual resources perform during these conditions. This additional information will help suppliers better gauge the risks and rewards they face under the new design, provide additional time for new bilateral arrangements to develop in the marketplace that can help manage and spread risk, and enable the region to better assess the likely impacts of incremental changes in the Capacity Performance Payment Rate on Forward Capacity Auction prices prior to reaching the full Capacity Performance Payment Rate.[71]

f. Calculation Of The Capacity Performance Payment

Finally, as a sixth step, the resource's Capacity Performance Payment for the five-minute Capacity Scarcity Condition interval can be calculated. As stated in new Section III.13.7.2.6, for

[70] *See* White Testimony at 105-111.

[71] *See id.* at 111-116.

each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. Because the Capacity Performance Score may be positive or negative, the resulting Capacity Performance Payment for an interval also may be positive or negative. The Capacity Performance Payment can therefore be either positive (for resources that perform well) or negative (for resources that perform poorly).

g. Monthly Capacity Payment And Capacity Stop-Loss Mechanism

As stated in new Section III.13.7.3, a resource's Monthly Capacity Payment for an Obligation Month shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month. Again, because the total of a resource's Capacity Performance Payments may be positive or negative, its Monthly Capacity Payment may be positive or negative. Furthermore, the Monthly Capacity Payment may be subject to the monthly or annual stop-loss provisions described in new Sections III.13.7.3.1 and III.13.7.3.2, respectively.

The stop-loss provisions essentially limit a supplier's downside exposure in the FCM under Pay For Performance. Although a supplier's net FCM revenue can be negative (which, as described above, is an important incentive component of Pay For Performance), the stop-loss provisions ensure that a capacity supplier does not face unlimited losses for non-performance. The stop-loss mechanisms are designed to provide this protection with minimal distortion to the Pay For Performance incentives and in a manner that is relatively simple and transparent.[72]

As Dr. White explains, the stop-loss mechanism is effectively a mutual insurance system among all resources with a Capacity Supply Obligation. Each capacity supplier receives insurance against the possibility of a large negative Capacity Performance Payment – that is, in excess of the stop-loss limit – in the event that its capacity resource performs poorly in a month with many scarcity hours. This insurance is paid for out of the net surplus that accrues during scarcity conditions.[73]

As described above, the Pay For Performance design results in a net surplus each time scarcity conditions occur. This is because the total amount of resource under-performance (in

[72] *See* White Testimony at 172-176.

[73] *See id.* at 176-184.

MW) exceeds the total amount of resource over-performance (in MW) during any scarcity condition (if this were not the case, there would have been no scarcity condition). Because the under-performance and over-performance are settled at the same price (the Capacity Performance Payment Rate), for each scarcity condition, slightly more will be collected from under-performers than is distributed to over-performers.

As part of the stop-loss mechanism design, that net surplus will be allocated among the pool of capacity suppliers. However, if there is a capacity resource with sufficiently poor performance that its negative Capacity Performance Payment reaches the stop-loss limit – a threshold specified in the Tariff – its negative payment will be capped at the limit, and the net surplus that remains to be shared among all other capacity suppliers will decrease. Hence, if one or more capacity resources reaches the stop-loss limit, other capacity suppliers will receive reduced net FCM payments.

It is even possible in the design that if there are a large number of capacity suppliers that perform very poorly in a month with many scarcity hours, that application of the stop-loss limit could produce a negative net surplus (that is, a net deficiency). In this case, each capacity supplier that does not reach the stop-loss limit will still be allocated a pro-rata share of the negative net surplus. Dr. White's testimony includes several examples demonstrating how the stop-loss mechanism will work in various circumstances.[74]

i. Monthly Stop-Loss

As stated in new Section III.13.7.3.1, if the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month.

This means that in any month, the most that can be subtracted from a resource's Capacity Base Payment is the Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation. This is the monthly stop-loss limit. This specific limit was chosen for several reasons. It is simple and transparent; it can be calculated prior to the Forward Capacity Auction and incorporated into the resource's valuation of a Capacity Supply Obligation. It is high enough that it is unlikely to be reached frequently, and so it will only minimally affect the Pay For Performance incentive structure.[75]

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[74] *See* White Testimony at 176-184.

[75] *See id.* at 184-199.

Furthermore, the monthly stop-loss limit is consistent with existing Tariff provisions. Pursuant to existing Section III.13.4.2.1.3(b), if a capacity resource suffers a significant decrease in expected performance before the third annual reconfiguration auction (held approximately four months before the capacity commitment period begins), the ISO would submit a bid on behalf of the capacity resource in that reconfiguration auction for its capacity reduction at the Forward Capacity Auction Starting Price. As Dr. White explains, that provision can be used to calculate a limit to a resource's liability under these existing Tariff provisions. The monthly stop-loss limit was specifically calculated to harmonize with the existing liability limit in the existing significant decrease provisions. If it were set lower, it could undermine the existing incentives by decreasing the financial consequences of failing to either perform or to cover the obligation bilaterally or through a reconfiguration auction.[76]

A resource that reaches the monthly stop-loss limit early in the month can, with strong performance in scarcity conditions that occur subsequently during the same month, finish the month with a net financial position better than the monthly stop-loss limit. This design element helps to reduce the frequency with which resources may reach the stop-loss limit and provides a resource with a continuing incentive to perform even in the event that its losses have reached the monthly stop-loss limit.[77]

It is worth noting that new Section III.13.7.3.1 specifically excludes any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval from the resource's net Capacity Performance Payments for purposes of applying the monthly stop-loss limit. If a resource's performance exceeds its Capacity Supply Obligation, the performance above its obligation is not incorporated in the monthly stop-loss calculation. It is credited in a resource's monthly Capacity Performance Payment, but is excluded from the stop-loss calculations. This treatment of the non-obligated MW of a resource with a Capacity Supply Obligation provides comparability to the non-obligated MW of a resource without a Capacity Supply Obligation. It addition, in some circumstances, it further helps improve a resource's incentives to perform.[78]

Finally, new Section III.13.7.3.1 also includes slightly different treatment for resources that cleared as new resources before the implementation of Pay For Performance and elected to have the relevant Capacity Clearing Price apply for one or more additional Capacity Commitment Periods. This treatment is discussed in subsection iii. below ("Treatment Of Resources Clearing As New Prior To The Ninth Forward Capacity Auction And Electing Multiple-Year Treatment").

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[76] *See* White Testimony at 191-195.

[77] *See id.* at 195-196.

[78] *See id.* at 197-199.

ii. Annual Stop-Loss

The second aspect of the stop-loss mechanism is the annual stop-loss limit. While the monthly stop-loss mechanism prevents a large loss resulting from poor performance concentrated in a single month, the annual stop-loss protects against severe losses if a large number of scarcity hours occur during many months in which the capacity resource experiences ongoing poor performance. Generally, under the annual stop-loss mechanism, a capacity resource cannot be worse-off, on an annual basis, than three times its maximum monthly potential net loss.[79]

Specifically, pursuant to new Section III.13.7.3.2, for each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

$$MaxCSO \times [3\ months \times (FCAcp - FCAsp) - (12\ months \times FCAcp)]$$

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCAcp = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited by the monthly stop-loss limit, if applicable, as described in Section III.13.7.3.1.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the annual stop-loss amount

[79] *See* White Testimony at 199-210.

calculated pursuant to the formula above and the resource's cumulative Capacity Performance Payments.

Effectively, the annual stop-loss limit is applied to a resource's cumulative Capacity Performance Payments on a rolling basis during the Capacity Commitment Period. That is, each Obligation Month, the ISO will check whether the resource's cumulative year-to-date Capacity Performance Payments (after application of the monthly stop-loss limit each month) exceed the annual stop-loss limit. If this occurs, the Capacity Performance Payment for the current Obligation Month will be limited so that the resource's cumulative negative Capacity Performance Payments do not exceed the annual stop-loss limit. The resource will continue to receive its monthly Capacity Base Payment even if its Capacity Performance Payment is limited by the annual stop-loss limit prior to the end of the commitment period.[80]

Like the monthly stop-loss mechanism, a resource that reaches the annual stop-loss limit early in the commitment period can, with strong performance in scarcity conditions that occur subsequently, finish the year with a net financial position better than the annual stop-loss limit. Again, this design element helps to reduce the frequency with which resources may reach the stop-loss limit and provides a resource with an incentive to perform in the event that its losses have reached the monthly stop-loss limit.[81]

Also like the monthly stop-loss mechanism, the annual stop-loss approach is simple and transparent; it can be calculated prior to the Forward Capacity Auction and incorporated into the resource's valuation of a Capacity Supply Obligation. It is unlikely to be reached frequently, and so it will only minimally affect the Pay For Performance incentive structure.

Finally, the annual stop-loss calculation in Section III.13.7.3.2 also specifically excludes any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval from the resource's net Capacity Performance Payments, for the same reasons as described above with respect to the monthly stop-loss limit.

iii. Treatment Of Resources Clearing As New Prior To The Ninth Forward Capacity Auction And Electing Multiple-Year Treatment

As mentioned above, the monthly stop-loss provisions in new Section III.13.7.3.1 include slightly different treatment for resources that cleared as new resources before the implementation

[80] *See* White Testimony at 201-204.

[81] *See id.* at 208-209.

of Pay For Performance and elected to have the relevant Capacity Clearing Price apply for one or more additional Capacity Commitment Periods. Specifically, in the case of a resource subject to a multiple-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month.

The reason for this differing treatment is that resources that cleared as new prior to the ninth Forward Capacity Auction and elected multiple-year treatment had no knowledge of the rewards and risks to which they would be subject under Pay For Performance, which will apply to at least some portion of their multiple-year commitment. Such resources did not have the opportunity to price those factors into the Forward Capacity Auction offers (when they cleared as new resources). Hence, the monthly stop-loss for such resources will be based on the applicable Forward Capacity Auction clearing price, instead of the starting price. This stop-loss treatment will limit the risk under Pay For Performance for such resources in a manner consistent with their offers in the Forward Capacity Auction.[82]

Some of these resources, however, may prefer to be subject to the greater rewards and risks offered by full participation in Pay For Performance. For this reason, the Pay For Performance rules include new Section III.13.7.3.3, which allows resources that cleared as new prior to the ninth Forward Capacity Auction and elected multiple-year treatment to opt out of the remaining years of its multiple-year election. This option can be exercised at any point in the resource's remaining multiple-year commitment, but the request much be made in writing to the ISO no later than the Existing Capacity Qualification Deadline for the relevant Forward Capacity Auction. Pursuant to new Section III.13.7.3.3, a decision to so opt out shall be irrevocable, and a resource choosing to so opt out will participate in subsequent Forward Capacity Auctions in the same manner as other Existing Capacity Resources.

h. Allocation Of Deficient Or Excess Capacity Performance Payments

As described above in the discussion of the stop-loss mechanism, the Pay For Performance design results in a net surplus each time scarcity conditions occur because the total amount of resource under-performance (in MW) exceeds the total amount of resource over-performance (in MW) during any scarcity condition. Also as described above, application of the stop-loss mechanism may reduce the amount of this surplus, and could possibly even reduce it so

[82] *See* White Testimony at 210-212.

much that it becomes a deficit. The last major piece of the Capacity Performance Payments calculation addresses what to do with the surplus or deficit.

Pursuant to new Section III.13.7.4, the surplus or deficit remaining after all other relevant settlements have been performed as described above is allocated to resources in proportion to their Capacity Supply Obligations, excluding resources that have reached the stop-loss limit.

Specifically, pursuant to Section III.13.7.4(a), if the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month. If this charge causes a resource to reach the stop-loss limit, then the stop-loss cap will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in Section III.13.7.4(a).

Similarly, pursuant to Section III.13.7.4(b), if the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism, and the remaining excess will be further allocated to other resources in the same manner as described in Section III.13.7.4(b).

Pursuant to new Section III.13.7.4, these calculations are performed separately for each type of Capacity Scarcity Condition and for each Capacity Zone. If, for example, Capacity Scarcity Conditions occur in only one Capacity Zone during a particular Obligation Month, then the net surplus is allocated, in proportion to each resource's Capacity Supply Obligation for the Obligation Month, among the capacity resource in that Capacity Zone. Alternatively, if all Capacity Scarcity Conditions apply to all Capacity Zones during a particular Obligation Month, then the net surplus is allocated, in proportion to each resource's Capacity Supply Obligation for the Obligation Month, among all capacity resources in the system. And, last, if there are some Capacity Scarcity Conditions that apply to all Capacity Zones, and other Capacity Scarcity Conditions that apply to only one Capacity Zone, both during the same Obligation Month, then the net surplus is first divided in proportion to the duration of each type of Capacity Scarcity Condition, and then each portion is allocated as in the two previous cases. This process ensures that the resources whose performance contributes to the net surplus due to a Capacity Scarcity Condition in their Capacity Zone are also the resources that primarily bear the benefit (if the net

surplus is positive) or cost (if it is negative) of the insurance that the stop-loss mechanism provides.[83]

As Dr. White explains, allocation of the net surplus or deficit 'in proportion to each resource's Capacity Supply Obligation for the Obligation Month' means in equal dollar amounts per Capacity Supply Obligation MW. Other things equal, if one capacity resource has twice the Capacity Supply Obligation MW of another, the larger of the two resources would receive twice the net allocation of the smaller resource (in dollar terms), but they would each receive the same allocation in dollars per Capacity Supply Obligation MW terms. In other words, the allocation is not a function of individual resources' performance during the month, only their Capacity Supply Obligation MW each month. That is by design, and minimizes distortions to a resource's marginal performance incentives during scarcity conditions.[84]

3. Capacity Performance Bilaterals

The Pay For Performance design includes a simple mechanism for resources to trade their performance bilaterally. Capacity Performance Bilaterals replace the more complicated Supplemental Availability Bilaterals in the current FCM rules. Pursuant to revised Section III.13.5.3, if a resource has a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five-minute interval so long as both resources were subject to the same Capacity Scarcity Condition.[85] A Capacity Performance Bilateral does not affect in any way either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Capacity Performance Bilateral is to modify the Capacity Performance Scores of the transferring and receiving resources for the Capacity Scarcity Conditions subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments.[86]

The Lead Market Participant for the transferring resource must submit the bilateral, which must also be confirmed by the Lead Market Participant for the resource receiving the Capacity Performance Score.[87] The submission must identify the transferring and receiving resources, the MW amount of Capacity Performance Score being transferred, and the specific five-minute interval or intervals for which the Capacity Performance Bilateral applies.[88] As Dr.

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[83] *See* White Testimony at 212-216.

[84] *See id.* at 215-216.

[85] *See* revised Tariff Section III.13.5.3.1.

[86] *See* Tariff Section III.13.5.3.3 (renumbered from current Tariff Section III.13.5.3.2.4).

[87] *See* Tariff Section III.13.5.3.2.

[88] *See* Tariff Section III.13.5.3.2.2.

White explains, under Pay For Performance there is no need, nor reason, to exclude any resource type from entering into a Capacity Performance Bilateral.[89] For this reason, in revised Section III.13.1.4.1.6, a provision that limits how Real-Time Emergency Generation Resources can participate in such bilaterals is being deleted.[90]

While Capacity Performance Bilaterals may be submitted to the ISO after the relevant Capacity Scarcity Condition occurs,[91] as Dr. White explains, such bilaterals are most valuable to the transacting parties if arranged in advance. Capacity Performance Bilaterals are a highly flexible instrument that enables a resource owner to mitigate the risk of negative Capacity Performance Payment during periods shorter than a month, or on shorter notice than a Capacity Supply Obligation can be shed. The transacting parties may find it valuable to enter into a Capacity Performance Bilateral when they have different expectations about the number of scarcity hours that will occur during a specified period of time, or when one party expects its resource may perform poorly during a specific time period.[92]

4. Market Monitoring And Mitigation Under Pay For Performance[93]

The joint testimony of Mr. LaPlante and Dr. Gheblealivand describes in detail the four main changes to market monitoring and mitigation in the FCM required by the implementation of Pay For Performance. First, under Pay For Performance, only de-list bids from resources associated with Lead Market Participants that are pivotal may be mitigated by the IMM. For this purpose, the revised rules include a new test to determine if a Lead Market Participant is pivotal. Second, the IMM's de-list bid analysis is being revised to remove the risk adjustment from the calculation of net going-forward costs. As a result, the current "net risk-adjusted going forward costs" bid component is being simplified to "net going forward costs," and the risk premium will be included as a separate component of the de-list bid. It is important to the success of Pay For Performance that resources price the risks they perceive from Pay For Performance in their offer. By making the risk premium a separate component, resource owners will be able to fully describe their risk analysis to the IMM. Third, expected Capacity Performance Payments under Pay For Performance are being added as a distinct de-list bid component. Fourth, the threshold below which resources may leave the capacity market without cost review by the IMM (the "Dynamic De-List Bid Threshold") is being increased from $1.00/kW-month to $3.94/kW-

[89] *See* White Testimony at 160-166.

[90] *See* Tariff Section III.13.1.4.1.6 (renumbered from current Tariff Section III.13.1.4.1.3).

[91] *See* Tariff Section III.13.5.3.2.1.

[92] *See* White Testimony at 162-164.

[93] All of the Tariff revisions related to market monitoring and mitigation under Pay For Performance described in this section are shown in the ISO's blacklined Tariff sheets effective June 1, 2014, which are being submitted with this filing as Attachment I-1h, and in the Joint Testimony of David LaPlante and Seyed Parviz Gheblealivand on behalf of the ISO, submitted with this filing as Attachment I-1e (the "LaPlante/Gheblealivand Testimony").

month beginning with the ninth Forward Capacity Auction. Each of these changes, as well as some smaller conforming changes, is discussed below.

a. Under Pay For Performance, The IMM May Only Mitigate De-List Bids From Pivotal Suppliers

Under the current FCM rules, de-list bids submitted at prices equal to or above $1.00/kW-month (the current threshold for submission of Dynamic De-List Bids) are reviewed by the IMM to determine whether the bid is consistent with the resource's net risk-adjusted going forward costs and opportunity costs. Any such bid that is found inconsistent with the resource's net risk-adjusted going forward and opportunity costs is subject to mitigation. Under Pay For Performance, however, the IMM may only mitigate de-list bids at prices above the Dynamic De-List Bid Threshold from resources associated with Lead Market Participants that are found to be pivotal suppliers.[94]

This change is being made because the Forward Capacity Auction can clear without any of a non-pivotal supplier's capacity, and so a non-pivotal supplier cannot exercise unilateral market power and profitably set the price at a non-competitive level. Thus, IMM review of the de-list bids of non-pivotal suppliers is not necessary to assure competitive market outcomes, and it is appropriate to apply mitigation only to the de-list bids of pivotal suppliers whose offers are inconsistent with their going forward costs.[95]

Specifically, revisions to Section III.13.1.2.3.2.1.1.1 and Section III.13.1.2.3.2.1.1.2 state that a de-list bid submitted for a resource that is associated with a Lead Market Participant that is not pivotal will be entered into the Forward Capacity Auction as submitted.[96] For a de-list bid for a resource associated with a Lead Market Participant that is found to be pivotal by the IMM, if the IMM determines that the bid *is* consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as submitted.[97] (Each of these de-list bid components will be described below.)

For a de-list bid for a resource associated with a Lead Market Participant that is found to be pivotal by the IMM, if the IMM determines that the bid is *not* consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance

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[94] *See* LaPlante/Gheblealivand Testimony at 19-20.

[95] *See id.* at 20-21.

[96] *See* Tariff Section III.13.1.2.3.2.1.1.1(a) and Section III.13.1.2.3.2.1.1.2(a).

[97] *See* revised Tariff Section III.13.1.2.3.2.1.1.1(b) and revised Tariff Section III.13.1.2.3.2.1.1.2(b).

Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be rejected. In this case, a revised de-list bid based on the IMM-determined values can be accepted by the participant and used in the auction. While the process for a rejected de-list bid varies somewhat depending on whether the bid is a Static De-List Bid, a Permanent De-List Bid, or an Export Bid, these processes are not being changed from the currently effective rules.[98]

The IMM's pivotal supplier determinations will be included in the qualification determination notifications sent to the Lead Market Participants no later than 127 days prior to the Forward Capacity Auction,[99] and in the informational filing submitted to the Commission no later than 90 days prior to the auction.[100]

b. The Pivotal Supplier Test

The new pivotal supplier test that will be applied by the IMM is contained in Section III.13.1.2.3.2.[101] Conceptually, a Lead Market Participant will be considered pivotal if any of the capacity from the existing resources controlled by that Lead Market Participant is needed to satisfy the capacity requirements either system-wide or in an import-constrained Capacity Zone.[102]

A Lead Market Participant is evaluated to determine if it is a pivotal supplier either system-wide or in an import-constrained Capacity Zone. System-wide, a de-list bid will be associated with a pivotal supplier if at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area minus the Installed Capacity Requirement (net of HQICCs) is less than or equal to the greater of: (a) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and (b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW.[103]

As explained by Mr. LaPlante and Dr. Gheblealivand, the Lead Market Participant's capacity amount is compared to the difference between the total amount of existing capacity and the Installed Capacity Requirement (net of HQICCs) because if the total amount of existing

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[98] *See* revised Tariff Section III.13.1.2.3.2.1.1.1(c) and revised Tariff Section III.13.1.2.3.2.1.1.2(c).

[99] *See* revised Tariff Section III.13.1.2.4.

[100] *See* revised Tariff Section III.13.8.1(a)(viii).

[101] A minor conforming change is being made to Tariff Section III.13.2.8.2(b)(iii) to clarify that the pivotal determination in that section, having to do with Insufficient Competition in the Forward Capacity Auction, is distinct from the new Pay For Performance pivotal supplier test described here.

[102] *See* LaPlante/Gheblealivand Testimony at 22.

[103] *See* revised Tariff Section III.13.1.2.3.2.

capacity is greater than the Installed Capacity Requirement (net of HQICCs), then the difference between the two will be a positive value that represents the amount by which the system is "long." In that case, for a supplier to be pivotal, it would have to control an amount of capacity equal to or greater than the excess amount in order for some of its capacity to be needed to satisfy the requirement. Otherwise the resource is not pivotal. If the amount of existing capacity is less than the Installed Capacity Requirement (net of HQICCs), then the difference between the two is the amount by which the system is "short." In that case, all capacity is needed to satisfy the requirement and all suppliers are pivotal.[104]

Witnesses LaPlante and Gheblealivand also explain that the total amount of summer Qualified Capacity of all existing resources used in the pivotal supplier determination will be reduced by an amount equal to the total of all pending Non-Price Retirement Requests and Permanent De-List Bids other than those submitted by the Lead Market Participant for the resource being evaluated. This is because pending Non-Price Retirement Requests and Permanent De-List Bids represent capacity that is highly likely to be removed from the capacity market in the Capacity Commitment Period, and hence is properly excluded from the total amount of capacity in making the pivotal supplier determination. However, this exclusion will not apply to Non-Price Retirement Requests and Permanent De-List Bids submitted by the Lead Market Participant for the resource being evaluated. It is appropriate to include such amounts in the quantity of total existing capacity because its removal is within the control of the Lead Market Participant and exclusion of such amounts could lead to situations where the IMM fails to identify a pivotal supplier with potential market power.[105]

Because the IMM must perform the pivotal supplier test before the Installed Capacity Requirement and related values are approved, the IMM shall use the best available estimates of those values available at that time it does the pivotal supplier analysis, which is in the third quarter of each year. The IMM shall publish those estimated values to the ISO website no later than the date that the qualification determination notifications are issued.[106]

Witnesses LaPlante and Gheblealivand also explain that the Lead Market Participant's amount of existing capacity used in the pivotal supplier determination is increased by the greater of 10 percent or 200 MW. This is again because the Installed Capacity Requirement and related values in the pivotal supplier determination will not be not approved by the Commission at the time the pivotal supplier determination must be completed, and so it is reasonable to err on the conservative side by building into the design a small buffer or margin of safety to ensure that de-list bids from Lead Market Participants "near the line" – that could potentially be pivotal once

[104] *See* LaPlante/Gheblealivand Testimony at 23.

[105] *See id.* at 24.

[106] *See* revised Tariff Section III.13.1.2.3.2. *See also* LaPlante/Gheblealivand Testimony at 27-28.

the Installed Capacity Requirement is final – will also be subject to mitigation. This is accomplished by adding a small amount to the Installed Capacity Requirement. If this buffer were not included, and the final Installed Capacity Requirement were higher than previously estimated, then a pivotal supplier might incorrectly appear non-pivotal at the time of the IMM's evaluation.[107]

In an import-constrained Capacity Zone, the pivotal supplier determination will work largely in the same manner as it does system-wide, except that zonal values are used instead of system-wide values for the total amount of existing capacity, the capacity requirement, and the amount of existing capacity controlled by the Lead Market Participant.[108] Also, the buffer to be used in this case is the greater of 10 percent or 100 MW (as opposed to 10 percent or 200 MW, in the system-wide determination). According to Mr. LaPlante and Dr. Gheblealivand, this smaller value reflects the smaller amount of variation in capacity in an import-constrained Capacity Zone than system-wide. The IMM believes that this smaller value is reasonable because each import-constrained Capacity Zone is only a portion of the system and uncertainty about the Local Sourcing Requirement is only a portion of that about the Installed Capacity Requirement.[109]

Mr. LaPlante and Dr. Gheblealivand state that capacity from new resources is excluded from the pivotal supplier determination because including capacity from new resources would not change the pivotal status of the Lead Market Participant of the new resource from pivotal to non-pivotal. But it could change the pivotal status of *other* participants from pivotal to non-pivotal. In other words, some participants that are in fact pivotal might be flagged as non-pivotal if the capacity from new resources is included in the determination of pivotal suppliers.[110]

It is possible that the pivotal supplier test might flag some non-pivotal suppliers as pivotal, Mr. LaPlante and Dr. Gheblealivand concede, but the pivotal supplier test necessarily involves this tradeoff, however, and in its effort to guard against the exercise of market power, the IMM believes there is far less risk to competitive outcomes and market integrity in flagging some non-pivotal suppliers as pivotal than in failing to flag some actually pivotal suppliers. The harm to the owner of the resource in the case of such "false positives" is minimal. Such a resource is not automatically mitigated; it is simply subject to potential mitigation if the submitted de-list bid is inconsistent with its going forward costs. If the de-list bid is consistent with its costs, there is no mitigation. The potential harm from failing to identity an actually pivotal supplier is far more serious. Unmitigated de-list bids from truly pivotal suppliers can

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[107] *See* LaPlante/Gheblealivand Testimony at 29.

[108] *See id.* at 30.

[109] *See id.* at 32.

[110] *See id.* at 32-34.

inappropriately set the auction price significantly higher than it would have been where all offers are competitive. For these reasons, the pivotal supplier test is calibrated to identify virtually all potentially pivotal suppliers, even at the (minimal) risk of a false positive.[111]

Finally, Mr. LaPlante and Dr. Gheblealivand explain that the number or size of the resources controlled by a Lead Market Participant is not relevant to the pivotal supplier determination. A Lead Market Participant can be pivotal if only a small amount of its capacity is needed, regardless of the overall number and size of resources controlled. Furthermore, an exception based on the number or size of resources could provide an incentive to spin-off a pivotal generation asset for the purpose of exercising market power. When the amount of existing capacity is smaller than or equal to the applicable capacity requirement, all Lead Market Participants, large or small, and irrespective of the number of assets they control, are pivotal.[112]

c. Changes To The IMM's Review Of De-List Bids

Under the current FCM rules, there are two main components of a de-list bid that are reviewed by the IMM: net risk-adjusted going forward costs, and opportunity costs. The Pay For Performance rule revisions instead break the de-list bid into four distinct components for IMM review: net going-forward costs, expectations about the resource's Capacity Performance Payments, risk premium assumptions, and opportunity costs. Each of these four components will be discussed below, but the notable changes here are: (1) the removal of the risk adjustment from the net going-forward cost calculation and the creation of a distinct risk premium component; and (2) the addition of a new component for expectations about Capacity Performance Payments.[113]

With respect to all of the de-list bid components, Section III.13.1.2.3.2.1.1 is being revised to state that the IMM shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. In making this determination, the IMM shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

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[111] *See* LaPlante/Gheblealivand Testimony at 34-35.

[112] *See id.* at 35-36.

[113] *See id.* at 36. A number of Tariff sections are being revised to refer to all four of these de-list bid components, instead of just the two components that exist under the currently effective rules. *See* revised Tariff Sections III.13.1.2.3.2.1, III.13.1.2.3.2.1.1.1, III.13.1.2.3.2.1.1.2, and III.13.8.1(a)(viii).

Mr. LaPlante and Dr. Gheblealivand note that under Pay For Performance, resources will continue to have the ability to submit de-list bids that vary by block for a single resource. Under Pay For Performance, it is important for a resource to be able to submit bids by block, since factors affecting the resource's performance during the Capacity Commitment Period may vary by block. For example, if a resource owner is risk averse, and believes that there is a greater risk that higher output blocks are not able to perform as reliably as lower blocks, it can price this higher risk into the upper blocks. That is economically desirable, as it means the auction is less likely to clear, and the region less likely to rely upon, the blocks of resources that owners believe are less reliable. In addition, the going forward costs of higher blocks may be greater than lower blocks. Allowing de-list bids to be broken into blocks permits this to be reflected in a resource's offer.[114]

i. Net Going Forward Costs

Under Pay For Performance, risks faced by resources are very different that those in the current market. Risks under Pay For Performance vary greatly depending on several factors, including the size of a participant's portfolio, its risk tolerance, and uncertainty about the number of hours with Capacity Scarcity Conditions during the Capacity Commitment Period three years in the future. A risk adjustment is included in the current net risk-adjusted going forward cost formula, but that formula is overly simplistic for use under Pay For Performance since it only reflects unit availability.

Additionally, since each participant's risk tolerance and its method for assessing risk are likely to be different, it is not possible to develop a single formula that would enable all market participants to accurately reflect their risk preferences. Therefore, to permit each participant to thoroughly represent and fully explain their risk premium, under Pay For Performance the risk adjustment is being removed from the net going-forward costs formula, and is being replaced by a separate risk premium component of the bid. As Mr. LaPlante and Dr. Gheblealivand explain, using a formula for calculating the risk premium would force all participants to use the same methodology for calculating their risk premium; this seems an unwarranted intrusion into an area that should be the prerogative of the resource owner.[115]

As a result, the current net risk-adjusted going forward costs formula is being changed from:

[114] *See* LaPlante/Gheblealivand Testimony at 36-37.

[115] *See id.* at 37-38.

$$NRAGFC = \frac{\left[\frac{GFC}{1-EFORd} + RF - (IMR - PER)\right] \times InflationIndex}{Q_{summer} \times 12}$$

To the following net going-forward cost formula:

$$NGFC = \frac{GFC - (IMR - PER) \times InflationIndex}{Q_{summer} \times 12}$$

Except for removal of the risk adjustment terms ("(1-EFORd)" and "RF"), the other variables will remain largely unchanged. These other variables have been in place and calculated successfully by participants for several years.[116] The revisions also include a minor change to the "Inflation Index" term in the net going-forward costs calculation. That term is currently based on the 1-Year Constant Maturity Treasury Rate. After reviewing issues with the current inflation index and studying several historical and forward looking indices, the IMM has determined that the expected 4-year inflation prediction published monthly by the Federal Reserve Bank of Cleveland is the most comprehensive forward looking index for changes in the costs of capacity suppliers.[117] These changes are reflected in Section III.13.1.2.3.2.1.2.[118]

ii. Risk Premium

With the risk adjustment removed from the net going forward cost calculation, the Tariff revisions implementing Pay For Performance include a new Section III.13.1.2.3.2.1.4 that details the separate risk premium component of a de-list bid. That section states that the Lead Market Participant for a resource submitting a de-list bid that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing any risk premium included in the bid. Such documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for

[116] *See* LaPlante/Gheblealivand Testimony at 39-40.

[117] *See id.* at 40. The data on expected inflation is available at: http://www.clevelandfed.org/research/data/inflation_expectations/.

[118] A minor conforming change is also being made in several sections to change the term "net risk-adjusted going forward costs" to "net going forward costs." *See* revised Tariff Sections III.13.1.2.3.2.1, III.13.1.2.3.2.1.2, and III.13.1.2.4. Also, in current Section III.13.1.2.3.2.1, there is a provision stating that de-list bid costs shall be submitted using spreadsheets and forms provided by the ISO. Because these spreadsheets and forms are specific to net going-forward costs, this provision is being moved to revised Section III.13.1.2.3.2.1.2.

net going forward costs may be included in the risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the FCM is consistent with the participant's corporate risk management practices. The IMM will review the affidavit and the risk analysis, compare it to those submitted by other participants, and ask for additional information if necessary.

Mr. LaPlante and Dr. Gheblealivand explain that the IMM views the risk premium as an essential part of each participant's offer. The future number of scarcity hours, the Capacity Balancing Ratio, and a resource's performance during the commitment period are all uncertain when a resource owner submits a new supply offer or a de-list bid. In making decisions about future investments and expenditures, we expect that resource owners will consider that uncertainty. Therefore, it is necessary for their de-list bids to also include that uncertainty so that the bids accurately reflect the price that resources require to participate in the market and meet the associated obligations.[119]

More technically, the IMM defines the risk premium as the amount of expected profit a participant would be willing to forego in order to avoid some of the "downside" risk of losing money in the capacity market. Participants form their expectations about relevant market variables, calculate their expected profit-maximizing bid, and then add a premium depending on how much of the downside they want to avoid. Adding any risk premium to an expected-profit maximizing bid lowers the probability of clearing in the Forward Capacity Auction by enough that it will reduce the resource's expected profit. However, if the resource still clears in the auction, it may increase the resource's Capacity Base Payment – and therefore lowers its risk of losing money during the Capacity Commitment Period.[120]

Mr. LaPlante and Dr. Gheblealivand state that the IMM will evaluate each de-list bid in two ways. First, for units that are part of a multi-unit portfolio, the IMM will ascertain whether the risk premium requested for each of the units in the portfolio reflects consistent assumptions on key parameters affecting risk across the portfolio, including the expected number of hours of Capacity Scarcity Conditions. This may require the IMM to ask for information from a participant about other resources it owns for which it has not submitted de-list bids to determine if applying the assumption used in the submitted bids to other units would result in going forward costs higher than the Dynamic De-List Bid Threshold. If this occurs, the IMM will

[119] *See* LaPlante/Gheblealivand Testimony at 40-41.

[120] *See id.* at 41.

likely discuss these results with the participant to understand why de-list bids were submitted for the selected units and not others.[121]

The second way in which the IMM will evaluate the risk premium portion of de-list bids is by comparing the risk premia across participants. If all of the risk premia are within the same range, then that would support a finding of a reasonable risk premium consistent with competitive market behavior. Participants with risk premium submittals that are noticeably outside of the range of reasonableness established by all of the risk premia taken together will likely be asked for further explanation. The results of these analyses will be used by the IMM to determine if the risk premium is reasonable and consistent with the resource's net going forward costs.[122]

iii. Expected Capacity Performance Payments

Pursuant to Section III.13.1.2.3.2.1.3 of the revised rules, the Lead Market Participant for a resource submitting a de-list bid shall also provide documentation separately detailing its expected Capacity Performance Payments for the resource. This documentation must include assumptions regarding the Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

The Capacity Performance Payments are being included as a separate component of the de-list bid because the assumptions supporting a resource's estimate of its expected Capacity Performance Payment will enable the IMM to evaluate whether the resource's bid is competitive.[123]

From the IMM's perspective, the significance of a resource's expected Capacity Performance Payments is their importance in determining a competitive bid for the resource. For most resources, a competitive bid will simply be the opportunity cost of taking on a Capacity Supply Obligation. Each resource will have its own estimate of that opportunity cost. This component of the de-list bid will enable the IMM to review the assumptions used by the resource in calculating its opportunity cost. For a minority of resources, however, a bid based simply on the opportunity cost of taking on a Capacity Supply Obligation will not be enough to cover their net going forward costs. The competitive bid for those resources must include an adder to their

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[121] *See* LaPlante/Gheblealivand Testimony at 45. Tariff Section III.13.1.2.3.2.1.1 is revised to state explicitly that the IMM may seek information from the Lead Market Participant about other existing or potential new resources in the Lead Market Participant's portfolio.

[122] *See id.* at 45.

[123] *See id.* at 46.

estimate of opportunity costs large enough to assure that they cover all of their going forward costs during the commitment period.[124]

The assumptions used in the calculation of a resource's expected Capacity Performance Payments enable the IMM to determine the resource's opportunity cost of taking on a Capacity Supply Obligation. Under Pay For Performance, a resource that has not taken on a Capacity Supply Obligation will also be paid the Capacity Performance Payment Rate multiplied by the amount of energy and reserves that it provides during a Capacity Shortage Condition.[125]

Resources that do take on a Capacity Supply Obligation are selling forward their pro-rata share of the system's energy and reserve requirements during Capacity Scarcity Conditions. In other words, in exchange for the Capacity Base Payment, they agree to provide their share of the system's requirements during Capacity Shortage Conditions in the commitment period. For a resource to take on this obligation, it will want to receive at least the amount of money it could have received by not taking on a Capacity Supply Obligation – that is, its opportunity cost.[126]

The difference between a resource's Capacity Performance Payment with a Capacity Supply Obligation and without a Capacity Supply Obligation is the Capacity Performance Payment Rate times the expected number of hours of Capacity Scarcity Conditions times the expected Capacity Balancing Ratio. This is the resource's opportunity cost of acquiring a Capacity Supply Obligation, and therefore is the minimum payment that a resource will require to take on a Capacity Supply Obligation. The resource owner's expectations of the number of hours of Capacity Scarcity Conditions and the Capacity Balancing Ratio enable the IMM to evaluate the resource's opportunity cost of taking on a Capacity Supply Obligation.[127]

A resource's expected revenues under Pay For Performance must be considered in evaluating its de-list bid to determine if these revenues are sufficient to cover the resources going-forward costs net of energy revenues. For a resource to take on a Capacity Supply Obligation, it must expect that it will earn enough money through its participation in the FCM to cover its net going forward costs. The going forward cost calculation described above shows whether or not a resource will earn enough revenue from the energy and ancillary services markets to cover its going forward costs. If a resource earns enough revenue from the energy and ancillary services markets to cover its going forward costs, then its competitive bid in the capacity market is simply its opportunity cost, as described above.[128]

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[124] *See* LaPlante/Gheblealivand Testimony at 47.

[125] *See id.* at 48.

[126] *See id*.

[127] *See id.* at 48-49.

[128] *See id.* at 49.

If a resource does not earn enough revenue from the energy and ancillary services markets to cover its going forward costs, then additional calculations must be done to determine whether its competitive bid in the capacity market is simply its opportunity costs or if the bid has to be increased to assure recovery of its net going-forward costs. The first such calculation is to determine whether the resource would earn enough revenue from Capacity Performance Payments (absent a Capacity Supply Obligation) to cover its net going-forward costs. If it does, the resource would not *need* to assume a Capacity Supply Obligation to receive Capacity Base Payments to cover its net going-forward costs and consequently the only cost it incurs in taking on a Capacity Supply Obligation is its opportunity cost. If the first calculation shows that the expected revenue from Capacity Performance Payments (absent a Capacity Supply Obligation) is not enough, then a second calculation has to be done to determine how much additional revenue is needed. This calculation is done by subtracting the Capacity Performance Payments (absent a Capacity Supply Obligation) from the net going-forward costs. This difference has to be added to the resource's opportunity cost to assure that it will be able to cover both its share of the system financial obligation and its net going-forward cost if it receives a Capacity Supply Obligation.[129]

As explained by Mr. LaPlante and Dr. Gheblealivand, the IMM will evaluate the Lead Market Participant's expectations regarding the applicable Capacity Balancing Ratio, the number of Capacity Scarcity Conditions, and the resource's performance during Capacity Scarcity Conditions using information from various sources. For the Capacity Balancing Ratio and the number of hours of Capacity Scarcity Conditions, the IMM will rely on two sources. The first source is the ISO's estimates of these two variables depending on the expected nature of Capacity Scarcity Conditions (whether they are expected in the summer or winter) and the total amount of capacity available in the system. The number of hours with Capacity Scarcity Conditions is inversely related to the amount of excess supply in the system. The second source for reasonable estimates of these variables is the range that is established by other Static De-List Bid and Permanent De-list Bid submissions. The IMM can use other Static and Permanent De-list Bid submissions because (unlike resource-specific performance) the Capacity Balancing Ratio and the number of hours with Capacity Scarcity Conditions affect all resources. We will treat these estimates in the same way as estimates of the risk premium. Participants with submittals that are noticeably outside of the range of reasonableness established by the universe of submissions will likely be asked for additional information. In addition, and similar to evaluation of risk premia, the IMM may ask for information from a participant about resources that belong to that participant that have not submitted de-list bids to determine if applying the assumptions used in the submitted bids, particularly on Capacity Balancing Ratio and the expected number of scarcity conditions, to other resources would warrant submission of Static or Permanent De-List Bids for those other resources. If this occurs, the IMM will likely discuss

[129] *See* LaPlante/Gheblealivand Testimony at 49-50.

these results with the participant to understand why de-list bids were submitted for the selected resources and not others.[130]

For resource performance during reserve deficiencies, the IMM can rely on years of data on existing resources. If a participant believes that its performance may be significantly different than what has been observed in the past, it can explain this in its Static De-List Bid and Permanent De-list Bid submission or in response to IMM inquiries.[131]

iv. Opportunity Costs

Unlike risk premia and expected Capacity Performance Payments, opportunity costs are already a de-list bid component under the current FCM rules. To conform with the revisions described above, however, some minor changes are being made to the opportunity costs provisions.[132] First, the provision is being reworded to clarify that opportunity costs should only include costs not reflected in the net going-forward costs, expected Capacity Performance Payments, or risk premium components of the bid. This is necessary to ensure that costs are appropriately categorized and that there is no double-counting. Second, references to quantifiable risk in the current opportunity cost provisions are being deleted. This is because any risk elements should be instead be included in the new risk premium de-list bid component. Third, the revisions remove redundant procedural language from the opportunity costs provisions.[133]

d. Increasing The Dynamic De-List Bid Threshold

In the current FCM, there are two types de-list bids that enable a resource to leave the capacity market for a single Capacity Commitment Period. Resources that wish to leave the market at prices equal to or above $1.00/kW-month, must submit Static De-List Bids in advance of the Forward Capacity Auction for review by the IMM. If resources wish to leave the market at prices below $1.00/kW-month, they may submit a Dynamic De-List Bids during the Forward Capacity Auction without review by the IMM.[134]

Throughout the currently effective FCM rules, this $1.00/kW-month threshold between the two types of de-list bids is spelled out as "$1.00/kW-month." Whenever the threshold for submission of Dynamic De-List Bids is changed, each of these many instances must be updated

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[130] *See* LaPlante/Gheblealivand Testimony 50-51.

[131] *See id.* at 51-52.

[132] The opportunity cost provisions are in Section III.13.1.2.3.2.1.3 of the current FCM rules, but this is being renumbered to Section III.13.1.2.3.2.1.5 in the revised rules.

[133] *See* LaPlante/Gheblealivand Testimony at 52-53.

[134] *See, e.g.*, current Tariff Sections III.13.1.2.3.1.1 and III.13.2.3.2(d).

in the Tariff. For simplification, the revised rules submitted here replace each of those instances with a new defined term, the "Dynamic De-List Bid Threshold." A new Section III.13.1.2.3.1.A is being added to the Tariff to specify the numeric value of the Dynamic De-List Bid Threshold. If that value is changed in the future, it will no longer be necessary to update numerous sections of the Tariff; a single change to the new section will suffice.[135]

As explained by Mr. LaPlante and Dr. Gheblealivand, beginning with the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018), the Dynamic De-List Bid Threshold is being raised to $3.94/kW-month. This is because the Pay For Performance design changes the definition of the capacity product and therefore changes the level of a competitive offer in the capacity market for all resources. Ideally, the IMM would set the Dynamic De-List Bid Threshold at the competitive bid of the marginal unit. By doing this, the IMM would only review non-competitive bids that could have material impact on the market outcomes. However since it is obviously not possible to know the marginal unit prior to the auction, the IMM used values representative of fossil steam units to set the Dynamic De-List Bid Threshold because these are the type of existing resources most likely to seek to leave the auction and therefore could be the marginal unit if there is more existing capacity than needed to meet the Installed Capacity Requirement.[136]

Mr. LaPlante and Dr. Gheblealivand explain how the IMM calculated the Dynamic De-List Bid Threshold, using the following formula:

$$b_i = PPR \times Br \times H + \max\{0,\ GFC_i - PPR \times A_i \times H\}$$

Where:

- *PPR* is the Capacity Performance Payment Rate specified in the Tariff.
- *Br* is the expected Capacity Balancing Ratio.
- *H* is the expected number of hours with Capacity Scarcity Conditions during the commitment period.
- *GFC* is the resource's net going forward cost.
- *A* is the expected average performance of the resource during Capacity Scarcity Conditions during the commitment period.

[135] The new term "Dynamic De-List Bid Threshold" replaces the specific numeric value in the following Tariff Sections: III.13.1.2.3.1.1, III.13.1.2.3.1.2, III.13.1.2.3.1.3, III.13.1.2.3.2.1, III.13.1.2.3.2.1.1.1, III.13.1.2.3.2.1.1.2, III.13.1.2.3.2.1.2, III.13.1.2.3.2.1.5 (formerly Section III.13.1.2.3.2.1.3), III.13.1.8(e), and III.13.2.3.2(d).

[136] *See* LaPlante/Gheblealivand Testimony at 54-55.

Mr. LaPlante and Dr. Gheblealivand provide a detailed explanation of each of the components of this formula and why it is appropriately used in calculating the Dynamic De-List Bid Threshold.[137]

As stated in the revised rules, the Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the IMM will review the results of the recalculation with stakeholders and the new Dynamic De-List Bid Threshold shall be filed with the Commission under Section 205 of the Federal Power Act prior to the Existing Capacity Qualification Deadline for the associated Forward Capacity Auction.[138]

e. Other Conforming Changes

In the current FCM rules, Static De-List Bids and Permanent De-List Bids are each described as a means to "opt out of the capacity market." Under Pay For Performance, however, resources without a Capacity Supply Obligation will nonetheless be eligible for Capacity Performance Payments and so in that sense are not technically "out of the capacity market." For this reason, those provisions are revised to state instead that Static De-List Bids and Permanent De-List Bids "specify a price below which it [the resource] would not accept a Capacity Supply Obligation."[139]

In Section III.13.1.2.4, there is a sentence stating that each accepted de-list bid shall be binding and shall be entered into the Forward Capacity Auction as submitted. Because under certain circumstances, Static De-List bids may be revised after they are submitted (as provided in Section III.13.1.2.3.2.1.1.2), this sentence in Section III.13.1.2.4 is no longer accurate, and hence is being deleted here.

5. Financial Assurance Under Pay For Performance

The testimony Mr. Montalvo describes in detail the revisions to the Financial Assurance Policy ("FAP") needed with the implementation of Pay For Performance.[140] To date, financial assurance related to participation in the FCM has been limited to new resources that are not yet commercial. For a resource that is operating commercially, taking on a Capacity Supply

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[137] *See* LaPlante/Gheblealivand Testimony at 55-61.

[138] *See* revised Tariff Section III.13.1.2.3.1.A.

[139] *See* revised Tariff Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2

[140] All of the Tariff revisions related to financial assurance under Pay For Performance described in this section are shown in the ISO's blacklined Tariff sheets effective June 1, 2018, which are being submitted with Part 2 of this filing as Attachment I-2b, and described in the Testimony of Marc D. Montalvo on behalf of the ISO (the "Montalvo Testimony"), submitted with this filing as Attachment I-1f.

Obligation in the FCM currently does not result in any additional financial obligations. Capacity payments during a Capacity Commitment Period under the current FCM design cannot be negative, and hence, for commercial resources, there has been no potential financial obligation to collateralize.[141] As described above, and in the testimony of Dr. White, however, under Pay For Performance, a resource's net capacity payments may be negative.[142] In this way, Pay For Performance introduces the possibility that commercial resources with Capacity Supply Obligations will have net payment obligations (i.e., owe money) to the market. The goal of the FAP is to ensure that there is sufficient cash available to clear the market each day and to cover a participant's settled obligations in the case of default.[143] Hence, the FAP must be revised to account for the possibility of net payment obligations for commercial resources under Pay For Performance.

To collateralize this additional potential obligation, a Market Participant with a Capacity Supply Obligation will be required to add Forward Capacity Market Delivery Financial Assurance ("FCM Delivery FA") to its total FA requirements calculation. As explained by Mr. Montalvo, FCM Delivery FA is designed to address three types of risk: (1) clearing risk, (2) credit risk, and (3) liquidation risk.[144] Clearing risk is the risk that a Market Participant does not timely discharge settled payment obligations incurred in an already completed delivery month, which could result in a cash imbalance that impairs the ability of the ISO to clear all market positions. Credit risk is the risk that a Market Participant will default on payment obligations arising from negative capacity payments associated with Capacity Supply Obligations in the current delivery month. Liquidation risk in this context has two components: the risk that losses may continue to accrue against a Capacity Supply Obligation position post default up to the annual stop-loss in any Capacity Commitment Period before a Market Participant is able to close the position, and the risk that the defaulted position, when closed, is sold at a loss. In addition to addressing these three types of risk, the FCM Delivery FA amount is adjusted to account for the phase-in of the Capacity Performance Payment Rate.

The monthly FCM Delivery FA requirement will be calculated using the following formula:

$$\text{FCM Delivery FA} = \text{MCC} + \text{DFAMW} \times \text{PE} \times \max[(\text{ABR} - \text{CWAP}), 0.1)] \times \text{SF} \times \text{DF}$$

Each of these terms, and its role in addressing the three types of risk, is discussed below.

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[141] *See* Montalvo Testimony at 2-3.

[142] *See* White Testimony at 77.

[143] *See* Montalvo Testimony at 2-3.

[144] *See id.* at 3.

a. Clearing Risk

The first of the three risks is clearing risk – the risk that a Market Participant does not timely discharge settled payment obligations incurred in an already completed delivery month. To address clearing risk, the first component of the FCM Delivery FA formula is MCC, the "monthly capacity charge." This is simply an amount equal to all negative capacity payments incurred in previous months, but not yet paid.[145]

b. Credit Risk

The second of the three risks is credit risk – the risk that a Market Participant will default on payment obligations arising from negative capacity payments associated with CSOs in the current delivery month. This risk is addressed in the portion of the FCM Delivery FA formula that states: DFAMW × PE × max[(ABR – CWAP), 0.1)]. At a high level, the "DFAMW" term represents the MW amount on which a Market Participant must submit FCM Delivery FA; "PE" is the dollar per MW value that will apply in calculating the Market Participant's FCM Delivery FA; and "max[(ABR – CWAP), 0.1]" is a ratio reflecting the performance of the Market Participant's capacity resources.[146] Each of these terms is described in more detail below.

DFAMW, or "delivery financial assurance MW," is, simply, the total MW amount of a Market Participant's resources subject to a Capacity Supply Obligation in the current month. As explained by Mr. Montalvo, this MW amount serves as the basis for the credit risk portion of the FCM Delivery FA calculation. The DFAMW is equal to the sum of the Capacity Supply Obligations of all resources in the Market Participant's portfolio for the current month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss amount.[147] A resource that has reached the annual stop-loss amount cannot incur any further negative capacity payments in the current month, and so there is no additional amount of FA associated with that resource that is needed to protect against default, and so such resources are excluded from the calculation.[148] In no case will DFAMW be less than zero.[149]

PE, or "potential exposure," is the dollar per MW value that will apply in calculating the Market Participant's FCM Delivery FA. As Mr. Montalvo explains, PE is a monthly value calculated for the Market Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply

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[145] *See* Montalvo Testimony at 4-5.

[146] *See id.* at 5-6.

[147] *See id.* at 6.

[148] *See id.* at 6-7.

[149] *See id*. at 6, 7.

Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss amount.[150] The difference between the Forward Capacity Starting Price and the capacity price is used because, as a general matter, this is equivalent to how the stop-loss amounts are calculated under Pay For Performance, and so represent the amount per MW that the Market Participant might be required to pay if its resources fail to perform.[151] Mr. Montalvo's testimony contains further details regarding the calculation of PE.[152]

The term Max[(ABR – CWAP), 0.1] is a ratio reflecting the performance of the Market Participant's capacity resources. As described above, under Pay For Performance, a resource is not held to the standard of providing the full amount of its Capacity Supply Obligation in all cases. Rather, the amount of capacity that a resource provides during a Capacity Scarcity Condition is measured against the ratio of the total amount of load plus the reserve requirement, divided by the total amount of Capacity Supply Obligations – the Capacity Balancing Ratio.[153]

As Mr. Montalvo explains, because capacity payments are linked to the Capacity Balancing Ratio, FCM Delivery FA must be as well. Requiring a Market Participant to provide FA based on the full amount of its Capacity Supply Obligations would over-state the amount needed to protect against default because negative capacity payments will only be tied to the full Capacity Supply Obligation amount when the Capacity Balancing Ratio is 1.0 – that is, when the system is so stressed that the amount of load plus reserves is equal to the total amount of Capacity Supply Obligations. The term "max[(ABR – CWAP), 0.1]" is the minimum percentage of the calculated potential exposure (PE) that must be posted as financial assurance given assumptions regarding the average system-wide Capacity Balancing Ratio and on the performance of the Market Participant's resources.[154]

The term "ABR," or "average balancing ratio," is the seasonally adjusted, duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period.[155]

The term "CWAP," or "capacity weighted average performance," is the capacity weighted average performance of the Market Participant's portfolio. Generally, the better a

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[150] *See* Montalvo Testimony at 7.

[151] *See id*. at 7-8.

[152] *See id.* at 8-9.

[153] *See id*. at 9.

[154] *See id*. at 9-10.

[155] *See id*. at 10-12.

Market Participant's resources have performed, the higher its CWAP value will be, and the lower the value (ABR – CWAP) becomes. The worse a Market Participant's resources have performed, the lower its CWAP value will be, and the higher the value (ABR – CWAP) becomes.[156]

For a resource with a CWAP value that approaches or exceeds ABR, the value (ABR – CWAP) will become very low, or possibly even negative. If this value reached zero, the credit risk portion of the FCM Delivery FA would also become zero. As Mr. Montalvo explains, although this would occur because the Market Participant's resources were performing well, even those portfolios with a CWAP value higher than the ABR are not completely without risk. The ABR and the CWAP are based on historical data, and if future performance is worse, holding some FA associated with credit risk is a reasonable and prudent protection. For this reason, the maximization function included in the term "max[(ABR – CWAP), 0.1]" ensures that the value of that term will not be below 0.10, and hence, at least ten percent of the potential exposure amount will be included in the FCM Delivery FA amount.[157]

The testimony of Mr. Montalvo includes numerous additional details about the calculation of max[(ABR – CWAP), 0.1].[158]

c. Liquidation Risk

The third of the three risks is liquidation risk – the risk that losses may continue to accrue against a CSO position post default up to the annual stop-loss limit in any Capacity Commitment Period before a Market Participant is able to close the position, and the risk that the defaulted position, when closed, is sold at a loss. Liquidation risk is addressed in the "SF," or "scaling factor," term included in the FCM Delivery FA formula. The scaling factor is a month-specific multiplier, as follows:[159]

- June: 2.000;
- December and July: 1.732;
- January and August: 1.414;
- all other months: 1.000.

As Mr. Montalvo explains, the risk that losses may continue to accrue against a Capacity Supply Obligation position post default (up to the annual stop-loss limit) before a market participant is able to close the position is not uniform across all months of the Capacity

[156] *See* Montalvo Testimony at 12-15.

[157] *See id.* at 17-18.

[158] *See id.* at 12-18.

[159] *See id.* at 18.

Commitment Period. The likelihood of a severe scarcity event is different each month of the year. The risk of scarcity is highest in the summer months (June – September), followed by the winter months (December – February) and lowest in the shoulder months (the other months). Furthermore, given that in the summer and winter, there are consecutive high-risk months in a row, should a resource default early in the summer season, for example, there is the risk that it will accrue additional losses in subsequent months due to the higher potential for additional Capacity Scarcity Conditions.[160]

In large measure this risk exists because a defaulted Capacity Supply Obligation position is not terminated from the market. Rather, the Market Participant must close the position through a bilateral contract or continue to be exposed to charges up to the annual stop-loss limit. While the maximum possible exposure is the annual stop-loss limit, the probability that a resource will hit the monthly stop-loss limit three months in a row (the annual stop-loss limit equals three times the monthly stop-loss limit) is low. Thus, requiring Market Participants to post financial assurance up to the annual stop-loss limit would unnecessarily over-collateralize the market. Nonetheless, additional financial assurance is required to address the risk that a defaulted position will accrue additional losses in subsequent months due to the higher potential for additional Capacity Scarcity Conditions in the summer and winter seasons when Capacity Scarcity Conditions are likely to be more frequent. For this purpose, the ISO has assumed that the potential exposure in any remaining months of a season are normally distributed and that the exposure to incremental losses declines with the square-root of the number of months remaining in the season. Thus, during high risk months (summer and winter), the scaling factor (SF) is calculated as the square root of the number of summer or winter months remaining in the seasonal period. For example, the SF is two (square root of four) in June, and becomes one (square root of one) in September. During all the shoulder months, the scaling factor is one. This is explained further in Mr. Montalvo's testimony.[161]

d. Adjustment To FCM Delivery FA To Account For The Phasing In Of The Capacity Performance Payment Rate

As described above, under the Pay For Performance design, the Capacity Performance Payment Rate is being phased in. For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2,000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3,500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5,455/MWh.

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[160] *See* Montalvo Testimony at 19.

[161] *See id.* at 19-21.

As Mr. Montalvo explains, an adjustment to FCM Delivery FA is warranted to reflect the reduced exposure to losses during the years in which the Capacity Performance Payment Rate is being phased in. For this purpose, the FCM Delivery FA calculation includes a discount factor, "DF," which is a multiplier to the credit risk portion of the FCM Delivery FA amount. The discount factor is based on the likelihood of a single resource portfolio reaching its monthly stop-loss under different Capacity Performance Payment Rates. For a single resource portfolio, a lower Capacity Performance Payment Rate requires more hours of Capacity Scarcity Conditions to reach the monthly stop-loss amount.[162]

As Mr. Montalvo further explains, based on the data analyzed by the ISO, for a Capacity Performance Payment Rate of $2,000/MWh the PE is 60 to 90 percent of the value at a Capacity Performance Payment Rate of $5,455/MWh. However, given the uncertainly in the data and the imprecision of the calculation, the ISO has opted to split the difference and set the PE when the Capacity Performance Payment Rate is $2,000/MWh at 75 percent of its full value. Thus, for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the discount factor shall equal 0.75, and thereafter, it equals 1.00. Mr. Montalvo explains the rationale and derivation of the discount factor further in his testimony.[163]

6. Other Conforming Rule Changes

a. Import Capacity Resource Offer Obligations

Pursuant to the currently effective FCM rules, an Import Capacity Resource with a Capacity Supply Obligation must offer energy associated with the resource into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions priced at or below an administratively-determined daily offer price threshold. Pay For Performance makes this requirement unnecessary. Accordingly, this administrative requirement is being removed from the Tariff. Specifically, currently effective Tariff Sections III.13.6.1.2.1(a), III.13.6.1.2.1(b), III.13.6.1.2.1(c), as well as portions of Section III.13.6.1.2.1, are being deleted. The remaining subsections of Section III.13.6.1.2.1 are being renumbered accordingly. More detail as to how Pay For Performance makes this offer requirement for Import Capacity Resources unnecessary is in the testimony of Dr. White.[164]

Also, a portion of Section III.13.6.1.2.1(e) is being deleted. That subsection requires a Market Participant submitting certain priced External Transactions supporting an Import Capacity Resource to link the transaction to an associated transmission reservation and NERC E-

[162] *See* Montalvo Testimony at 21-24.

[163] *See id.* at 22-24.

[164] *See* White Testimony at 169-172.

Tag by a certain deadline. Currently, subsection (e) also states that if the Market Participant fails to link the transaction to an associated transmission reservation and NERC E-Tag, the associated Import Capacity Resource shall be treated as having not delivered energy. This latter provision, stating the consequences of failing to link the transaction, is being deleted because under Pay For Performance, whether the Market Participant has linked the transaction is not relevant to the determination of the Import Capacity Resource's Actual Capacity Provided.

b. Poorly Performing Resources

Currently effective Section III.13.7.1.1.5 states that if a resource meets certain thresholds of poor performance, it shall be prohibited from participating in subsequent Forward Capacity Auctions and from otherwise assuming a Capacity Supply Obligation. Because Pay For Performance includes strong performance incentives and significant financial consequences for failure to perform, such special administrative provisions are no longer necessary. For this reason, Section III.13.7.1.1.5 is being deleted, along with a reference to that section contained in Section III.13.1.4.1.1.

c. Capacity Performance Bilaterals

As explained above, Capacity Performance Bilaterals under Pay For Performance are more simple than the Supplemental Availability Bilateral construct that they replace. As a result, currently effective Sections III.13.5.3.1.2, III.13.5.3.1.3, and III.13.5.3.1.4 are being deleted. The remaining provisions in Section III.13.5.3 are being revised to reflect the new Capacity Performance Bilateral construct. In addition, in several other sections of the Tariff, references to Supplemental Availability Bilaterals are being revised to refer instead to Capacity Performance Bilaterals, including Sections III.1.1, III.1.4.2, and III.13.5.

d. Charges To Market Participants With Capacity Load Obligations

Currently effective Section III.13.7.3, titled "Charges To Market Participants With Capacity Load Obligations," includes several minor conforming changes as a result of the Pay For Performance revisions. First, because the Pay For Performance provisions have been inserted earlier in Section III.13.7, currently effective Section III.13.7.3 is being renumbered as new Section III.13.7.5. This includes both the section numbers themselves as well as numerous internal cross-references.

Second, language is added in renumbered Section III.13.7.5 (which is Section III.13.7.3 in the currently effective rules) excluding Capacity Performance Payments from the definition of Net Regional Clearing Price. This is because the Net Regional Clearing price is defined, very

generally, as the sum of the sum of all payments to resources with a Capacity Supply Obligation divided by the total quantity of all Capacity Supply Obligations. While Capacity Performance Payments are indeed payments to resources with a Capacity Supply Obligation, they are structured as transfers among suppliers rather than charges to load, and hence are not properly included in the numerator of the Net Regional Clearing Price calculation.

e. Defined Terms

Section I.2.2 of the Tariff lists all of the capitalized, defined terms used in the Tariff. Consistent with the implementation of Pay For Performance, the defined terms section is being fully updated to include new defined terms established under Pay For Performance, to eliminate defined terms that will no longer be used with the elimination of existing FCM provisions, and to update section number references where provisions have been moved or renumbered. The defined terms revisions are being filed in two separate documents, because some of these defined terms changes must become effective in 2014 (with the market monitoring and mitigation changes),[165] while others must become effective with the balance of the Pay For Performance changes in 2018.[166]

f. Obsolete Provisions

Because the Pay For Performance mechanism is replacing the Shortage Event construct in the currently effective rules, and because it is a more simple design (largely due to its resource neutrality and lack of exemptions), large portions of the current FCM rules, especially in Section III.13.7 (home of the new Pay For Performance provisions), are being deleted.

First, the entire Shortage Event construct is being deleted. This includes the following currently effective Tariff provisions: III.13.7.1.1, III.13.7.1.1.1, III.13.7.1.1.1.A, III.13.7.1.1.2, III.13.7.1.1.3, and III.13.7.1.1.4. Some of these section numbers are re-used under Pay For Performance, others are being deleted.

Related to this, in several sections of the Tariff, references to "Shortage Event" are being updated to refer instead to "Capacity Scarcity Condition." These are Sections III.13.1.2.2.2.1(c), III.13.1.2.2.2.2(c), III.13.6.1.5.4.3.3.1, and III.A.8. In two of those sections, Section III.13.1.2.2.2.1(c) and Section III.13.1.2.2.2.2(c), revisions are also made to reflect the fact that Capacity Scarcity Conditions will not be "declared," they will simply occur under the circumstances as defined.

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[165] *See* ISO's blacklined Tariff sheets effective June 1, 2014, submitted with this filing as Attachment I-1h.

[166] *See* ISO's blacklined Tariff sheets effective June 1, 2018, submitted with Part 2 of this filing as Attachment I-2b.

Also related to the deletion of the Shortage Event provisions, in Section III.13.3.4, what were references to currently effective Sections III.13.7.1.1.3(h) and III.13.7.1.1.3(i) are – because those sections are being deleted – being replaced with text similar to that included in those currently effective sections.

Second, because all resource types will be subject to the same monthly Capacity Base Payment provisions (in new Section III.13.7.1), most of the remaining provisions in current Section III.13.7.2, detailing monthly capacity payment by resource type, are being deleted. This includes Sections III.13.7.2.2 (Import Capacity), III.13.7.2.3 (Intermittent Power Resources), III.13.7.2.4 (Settlement Only Resources), portions of III.13.7.2.5 (Demand Resources), and III.13.7.2.6 (Self-Supplied FCA Resources).[167]

Third, again because all resource types will be subject to the same monthly Capacity Base Payment provisions (in new Section III.13.7.1), separate subsections detailing the various adjustments to capacity payments applicable to different resource types are being deleted. This allows for the deletion of most of old Section III.13.7.2.7, including III.13.7.2.7.1 (Generating Capacity Resources),[168] III.13.7.2.7.2 (Import Capacity), III.13.7.2.7.3 (Intermittent Power Resources), III.13.7.2.4 (Settlement Only Resources), III.13.7.2.5 (Demand Resources), and III.13.7.2.6 (Self-Supplied FCA Resources). Among the subsections being deleted as a result is Section III.13.7.2.7.5.4, which described Demand Resource Performance Penalties and Demand Resource Performance Incentives. Because those provisions are being deleted, it is also necessary to delete two references to those penalties and incentives, in renumbered Sections III.13.7.5 and III.13.7.5.3.1 (which are Sections III.13.7.3 and III.13.7.3.3.1, respectively, in the currently effective tariff).

Fourth, and again because all resource types are treated the same way under Pay For Performance, provisions detailing separate performance measures for different types of resources are being deleted. This includes Section III.13.7.1.2 (Import Capacity Resources), III.13.7.1.3 (Intermittent Power Resources), III.13.7.1.4 (Settlement Only Resources), III.13.7.1.5 (Demand Resources), and III.13.7.1.6 (Self-Supplied FCA Resources).

Fifth, as discussed above, the Pay For Performance design does not include any measurement of resource "availability." Hence, the main availability penalties provisions in currently effective Section III.13.7.2.7.1 are being deleted. This also requires the deletion of

[167] Several subsections are still applicable, however, and so are unchanged by the Pay For Performance revisions (except for renumbering and conforming of internal cross-references). Accordingly, current Section III.13.7.2.2.A is retained (but renumbered as Section III.13.7.1.3); current Section III.13.7.2.5.2 is retained (but renumbered as Section III.13.7.1.4); current Section III.13.7.2.5.4 is retained (but renumbered as Section III.13.7.1.5); and current Section III.13.7.2.5.4.1 is retained (but renumbered as Section III.13.7.1.5.1).

[168] Except for the Peak Energy Rent provisions, which have been moved (to new Section III.13.7.1.2) and modified under Pay For Performance, as discussed above.

numerous references to availability penalties in other areas of the FCM rules, specifically, in Sections III.13.2.8.1.1(d), III.13.2.8.2(b), III.13.6.1.1.2, III.13.6.1.2.1, III.13.6.1.5.2, and III.13.6.4.

g. Moving Demand Reduction Value and Capacity Value Provisions

Portions of currently effective Section III.13.7 describing Demand Reduction Values for Demand Resources are still needed in the FCM rules for purposes other than measuring performance. For this reason, currently effective Sections III.13.7.1.5.3, III.13.7.1.5.4, III.13.7.1.5.5, III.13.7.1.5.6, III.13.7.1.5.7, and III.13.7.1.5.8 are being moved into new Section III.13.1.4.1.3. Except for renumbering, these new provisions are identical to their existing counterparts. This move also requires the renumbering of several sections immediately after Section III.13.1.4.1.3. Moving these provisions reflects the fact that under Pay For Performance, a Demand Resource's Demand Reduction Value is not a parameter used in assessing its performance. For this reason, Section III.13.6.1.5.4.8(c), which addresses using audit results to calculate a Demand Resource's Demand Reduction Value, is also being deleted as no longer applicable under Pay For Performance.

Like the Demand Reduction Value provisions, currently effective Section III.13.7.1.5.1 and Section III.13.7.1.5.2 describing Capacity Values for Demand Resources and Distributed Generation, respectively, are still needed in the FCM rules for purposes other than measuring performance. For this reason, those sections are being moved to new Section III.13.1.4.6.2.3 and Section III.13.1.4.6.2.4, respectively. New Section III.13.1.4.6.2.3 is not identical to existing Section III.13.7.1.5.1 because the first portion of existing III.13.7.1.5.1 only applied prior to June 1, 2012 and is hence obsolete. Except for renumbering, new Section III.13.1.4.6.2.3 is identical to the latter half of existing Section III.13.7.1.5.1, which applied beginning on June 1, 2012. Except for renumbering, new Section III.13.1.4.6.2.4 is identical to existing Section III.13.7.1.5.2.

Along with this change, Section III.13.8.1(a)(v) is being deleted. That section requires the ISO to file the Capacity Value multipliers with the Commission as part of the informational filing made no later than 90 days prior to each Forward Capacity Auction. Such a filing is not necessary because the multipliers are stated expressly in the Tariff (in currently effective Section III.13.7.1.5.1, and in new Section III.13.1.4.6.2.3 under Pay For Performance) and do not change from year to year. And because those numbers are specified in the Tariff, if any change were to be made, it would be discussed with stakeholders and filed with the Commission.

h. Tables Of Contents

Finally, the table of contents for each of the documents being revised under Pay For Performance is being updated to reflect the various added, deleted, and renumbered Tariff sections.

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 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.[169] Notwithstanding its request for waiver, the 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
- Testimony of Peter Brandien
- Testimony of Matthew White
- Testimony of Peter Cramton
- Joint Testimony of David LaPlante and Seyed Parviz Gheblealivand
- Testimony of Marc Montalvo
- Affidavit of Todd Schatzki and Impact Assessment by Analysis Group, Inc.
- The ISO's blacklined Tariff sheets effective June 1, 2014
- The ISO's clean Tariff sheets effective June 1, 2014
- 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) – The ISO requests that the Market Rule changes set forth herein become effective as set forth in Section III above.

[169] 18 C.F.R. § 35.13 (2012).

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at http://www.iso-ne.com/committees/nepool_part/index.html. 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 VI of this transmittal letter.

35.13(b)(6) – The ISO's approval of the Market Rule changes submitted herein is evidenced by this filing. The Participant Processes required by the Participants Agreement have been complied with.

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 Market Rule changes herein does not modify a traditional "rate," and the statement required under this Commission regulation is not applicable to the instant filing.

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

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

VIII. CONCLUSION

For all of the reasons discussed above, the ISO respectfully requests that the Commission accept the Pay For Performance design without modification to become effective as requested above in Section III.

Respectfully submitted,

ISO NEW ENGLAND INC.

By: _____/s/_____

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Dated: January 17, 2014

Attachment I-1b

Testimony of Peter Brandien on behalf of the ISO

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-_____-000**
New England Power Pool	**)**	

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

I. INTRODUCTION

Q: Please state your name, title and business address.

A: My name is Peter Brandien. I am employed by ISO New England Inc. (the "ISO") as the Vice President of System Operations.

Q: Please describe your educational background and work experience.

A: I have a Bachelor of Science degree in Electrical Engineering from the University of Hartford. I have over 26 years of energy industry experience in control room operations. I joined the ISO in 2004 as the Vice President of System Operations. In that capacity, I am responsible for the day-to-day operations of New England's bulk power system and oversight of transaction management, outage coordination, unit commitment, economic dispatch, system restoration, operator training, certain compliance functions, and development of operating procedures. Prior to joining the ISO, I spent 17 years at Northeast Utilities, most recently as Director of Transmission Operations. Before Northeast Utilities, I served in the United States Navy as a submarine nuclear propulsion plant operator/ electrician.

II. PURPOSE AND ORGANIZATION OF TESTIMONY

Q: What is the purpose of your testimony?

A: One of the predicates for the ISO's Pay For Performance proposal is the fact that generators are not performing adequately and need better incentives to do so. My testimony is offered to describe these performance issues, various aspects of which have been described in prior documents.[1] In this testimony, I endeavor to present the entire spectrum of performance issues, which, together, threaten the ISO's ability to operate the system reliably.

Q: Can you summarize your conclusions?

A: My testimony will show that the performance problems among the generating fleet in New England are pervasive and the deteriorating performance is threatening a reliable electric supply. These performance problems are not limited to a specific segment of the fleet, and are worsening.

While the performance issues are fleet-wide, gas supply is one of the core issues challenging reliability. Very simply, with the increase in domestic gas supplies,

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[1] *See, e.g.,* Winter Operations Summary: January – February 2013 at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf; Analysis Group's Analysis of Reserve Resources: Activation Response following Contingency Events at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/analysis_group_reserve_resource_analyses_5_29_2012.pdf; Addressing Gas Dependence at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/natural-gas-white-paper-draft-july-2012.pdf.

generators' demand for gas has skyrocketed, but there is simply not enough infrastructure to deliver that gas to all of the parties in New England that want it. This has put the ISO in the position of monitoring the region's gas supply and, when the pipelines are constrained, managing the output of large portions of the generating fleet based on available fuel supply. This is not the appropriate role for the ISO; we should be focused on operating the power system, not the fuel supplies of the region's generating fleet.

When the gas-fired generators that produce more than half of the region's electricity cannot procure fuel, the ISO must find replacements. We often turn to oil- and coal-fired units, but their performance as a group is deteriorating as well. They have the highest outage rates of any category of generators and, in peak hours of peak days, unit operating issues result in them reducing their capacity more than any other group. These units also have difficulty starting on time (or starting at all).

While the gas, oil and coal units represent the vast majority of New England's capacity, they do not represent the entire spectrum of performance problems. As my testimony shows, the performance of the entire fleet is deteriorating. Nearly every category of generator has seen its rates of unplanned outages increase. Resources do not respond adequately to contingencies. Units are failing to staff their generators. Liquid fuel inventories are kept low, and units are mothballing their ability to switch fuels.

What does this mean? It means that we need a fundamental change. Simply put, generators do not have incentives to perform.

To be clear, this is not just a gas problem. Even when the pipelines are not constrained, there is always the potential for an interruption in gas service to the thousands of megawatts of energy supplied by a single pipeline. Accordingly, even if the pipelines expanded overnight, we need all generators (including non-gas-fired generators) to perform in order to mitigate the systemic risk of a correlated outage.

We have a fleet-wide problem and it cannot be solved simply through improvements to the ISO's operating practices and markets – although those have been undertaken. In terms of operating practices, the ISO has advocated for better pipeline information sharing, changed commitment practices under certain circumstances, and even hired a gas industry professional to help forecast gas supply problems. On the markets side, the ISO has proposed changes to increase offer flexibility, accelerate the timelines in the Day-Ahead Energy Market, increase reserves, enhance reserve market incentives, improve generator auditing, and redefine Shortage Events in the Forward Capacity Market ("FCM"). The ISO has even adopted an out-of-market solution in the form of a winter reliability program.

In short, the ISO has taken many steps to allow reliable operation of the system in the face of these mounting problems, but these steps can only achieve so much; they do not solve the underlying problems and will not help us avoid more severe reliability problems in the future. At the end of the day, the region needs its resource owners to make investments – investments in firm fuel, fuel inventory, alternate fuels, maintenance, appropriate staffing, dual fuel capability, and new resources. The ISO's role should be to provide the incentives for those investments, which is why we are proposing modifications to the incentives in the FCM.

Q: How is your testimony organized?

A: I have divided my testimony into three main sections. In Section III, I discuss the risks related to the increasing dependence on gas. These risks are manifest in the sudden and sometimes sizeable unavailability of generation due to gas supply issues. I also discuss how these risks are magnified by the "just-in-time" nature of the gas supply and the dependence of multiple generators on a single pipeline that can be disrupted on short notice. (This is the "systemic risk problem.")

Section IV describes the performance problems of the region's oil and coal units, which I sometimes refer to herein as "fossil steam" units. In the past, New England has relied on the diversity of its fleet to mitigate problems like our current gas issues. Unfortunately, a significant portion of the region's fossil steam generators, which comprise about 25% of the fleet, cannot reliably provide

an alternative when gas-fired generators are unavailable. This situation is evidenced in these generators' outage rates, problems starting on time (or at all), and unit-specific operating issues that result in reductions to its economic maximum operating levels ("ecomax") on peak demand days.

In Section V, I discuss performance issues that span the entire fleet. These include increasing outage rates across nearly all generator categories, poor responses to contingencies, inadequate staffing, and failure to maintain oil inventory.

III. RISKS RELATED TO THE INCREASING DEPENDENCE ON GAS

A. Gas Dependence

Q: Please discuss New England's increasing demand for gas.

A: New England's reliance on natural gas for electric generation has increased dramatically over the past decade. In 2000, natural gas-fired generators supplied approximately 15% of New England's electricity; currently, natural gas-fired generators supply approximately 51% of the region's electricity. On most days, nearly the entire fleet of dispatchable resources available to ISO system operators consists of gas-fired generators.

A contributing factor to this increase is the abundance of shale gas in the last few

years, and the resulting lower cost of natural gas compared to other fuels. The increased demand for this gas, both to fuel electric generators and for home heating and other purposes, has increased competition for the use of the northeast interstate natural gas pipelines to transport the gas to New England. In recent years, these pipelines have become constrained relatively often, reducing their operating flexibility and ability to support the region's generation fleet. Although gas availability for power generation is a concern throughout the year, the problem is worse during cold weather, when home heating use peaks, and during pipeline maintenance and construction.

Q: Please discuss New England's supply of gas.

A: In short, the supply is insufficient to meet the demand. To quantify the problem, the ISO commissioned ICF International, LLC to perform a study, released in July 2012, of the capacity of the natural gas pipelines serving New England.[2] The study concluded that, in the various scenarios studied, "there is not enough gas supply capability …to meet the anticipated power sector gas demand." Specifically, there was a gas supply deficit into the region in every scenario on a winter peak day in each year from 2012 through 2020. These deficits ranged from a low of 1,500 MW on a day where the 50/50 forecast was used, to a high of

[2] The study can be found at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_public_slides.pdf. *See also* ICF's whitepaper entitled Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/nov202013/icf_upstream_gen_impacts_white_paper_11-18-2013.pdf.

5,700 MW on a day in winter 2020 where the 90/10 forecast is used and there is a large non-gas plant out-of-service.[3] On the winter days studied, gas transportation capabilities are usually below the amount needed to supply the gas required for the activation of the operating reserve units on the system. The deficits grow when existing non-gas generators are replaced with additional gas-fired resources and in a variety of contingency scenarios (e.g., loss of a pipeline or interruption of supplies of liquefied natural gas ("LNG")).

The study noted that, in other seasons, the existing pipeline capacity available for electric generation will shrink as use by gas distribution companies increases. Notably, the study was conducted assuming that all pipelines are fully available in each scenario (i.e., there are no contingencies or maintenance) and that flows on the various pipelines are perfectly coordinated in order to maximize the throughput on the pipeline system; accordingly, ICF has acknowledged that the study *overestimates* gas availability.

Input from regional pipeline companies and electric system operating experiences substantiate the study's conclusions. The pipelines have confirmed that the pipes connecting New England from supply points to the west, including the Marcellus shale fields, are becoming constrained for most of the winter and are constrained

[3] The 50/50 forecast has a 50% chance of being exceeded, while the 90/10 forecast has a 10% chance of being exceeded and is therefore a more conservative estimate.

1 or operating near capacity in periods other than the winter. For example, as
2 reported by Spectra Energy Corp., the owner/operator of the Algonquin Pipeline,
3 at its 2012 customer meeting, the number of days that the pipeline is restricted
4 through the Cromwell compressor station in Connecticut increased from a single
5 day during the 2009/2010 winter to over a hundred days during the 2011/2012
6 winter. The Kinder Morgan Tennessee Pipeline has also experienced a significant
7 increase in the number of days that the pipeline is restricted through compressor
8 Station 245 (upstate New York). Winter restrictions have increased from 42%
9 during the 2009/2010 winter to over 99% of the days during the 2011/2012
10 winter. In addition, the Tennessee Pipeline has begun experiencing restrictions
11 during the summer months. Specifically, summer restrictions have increased to
12 78% of the days in the summer of 2011. In contrast, in 2009, there were no
13 restricted summer days.[4]
14
15 **Q: Is LNG an alternative?**
16 A: The availability of alternatives is shrinking as well. LNG, which traditionally has
17 served as additional fuel capacity for gas-fired generators during the winter, is
18 being shipped to other parts of the world given the sustained high global price and
19 the lack of firm gas customers, which has resulted in deliveries to the northeast

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[4] For more information, *see* Addressing Gas Dependence at http://www.iso-ne.com/committees/comm_wkgrps/ strategic_planning_discussion/materials/natural-gas-white-paper-draft-july-2012.pdf. *See also* the December 12, 2013 Forbes article entitled "Cold Snap Sends Energy Prices into the Stratosphere in New England" at http:// www. forbes.com/sites/williampentland/2013/12/12/cold-snap-sends-energy-prices-into-stratosphere-in-new-england/.

declining.[5] As the Commission noted in its Winter 2013-14 Energy Market Assessment:

> LNG is likely to remain in short supply this winter with price spikes in New England not sustained long enough to incentivize LNG cargos. GDF Suez, the owner of the Everett LNG plant in Massachusetts, is under contract to divert almost half of its supplies to higher priced areas elsewhere in the world. Everett LNG now supplies only Mystic Power Plant Units 8 & 9, and local above ground LNG storage, but does not send out significant quantities of regasified LNG into interconnecting pipelines. Repsol, the owner of Canaport LNG, does not anticipate receiving many cargos this winter or going forward. As of mid-2013, Repsol is under contract to receive about two shipments of LNG a year, just enough to keep the terminal operating.[6]

Q: Does it make sense to you from an operational perspective that the two LNG facilities that serve New England are not being fully utilized by generators?

A: No. As an operator, I would like to see those facilities able to provide gas to New England's generators when the pipelines from the west are full. This would significantly enhance reliability by allowing more gas generators to operate in tight system conditions.

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[5] "LNG imports into Everett were at their lowest levels during January and February 2013, with no cargos imported under short-term or spot provisions, compared with five such cargos during the same period in 2012." See p. 10 of the ICF paper Gas-Fired Power Generation in Eastern New York and its Impact on New England's Gas Supplies at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/nov202013/icf_upstream_gen_impacts_ white_ paper_11-18-2013.pdf.

[6] *See* the October 2013 report at http://www.ferc.gov/CalendarFiles/20131017101835-2013-14-WinterReport.pdf.

Q: If world LNG prices are higher than those in New England, why should these facility operators buy this LNG?

A: If generators are given increased financial incentives to operate, they would have the incentive to sign option agreements with the LNG facilities that could assure that gas is available when needed.

Q: Would dual fuel capability at gas generators significantly reduce the gas risks you have discussed?

A: Yes. Dual fuel generators can provide valuable fuel diversity and flexibility by switching from one fuel to another. This flexibility can be utilized not only to replace a fuel that the generator has run out of, but also to preserve gas supplies that the market can allocate to other, non-dual fuel generators. In fact, in terms of ensuring reliable fuel service, the Analysis Group has stated that implementation of dual fuel capability is likely the lowest-cost option to ensure fuel security, when compared to procuring firm gas pipeline transportation or LNG.[7] These benefits can be realized, however, only when generators have the economic incentives to install, maintain, test, and procure fuel for dual fuel resources. Unfortunately, rather than increasing, we have seen a marked decline in dual fuel capability.

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[7] *See* p. 19 of Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives (September 2013) in Attachment I-1g of this filing.

Q: What evidence is there that generators are mothballing or otherwise allowing their dual fuel capability to become inoperable?

A: The ISO's Capacity, Energy, Load and Transmission ("CELT") Reports show that generators are mothballing their dual fuel capacity. In the 2004 CELT report, generators reported 9,541 MW of dual fuel capability, or 30% of total summer system capability. The 2012 CELT report shows that only 18.7%, or 6,132 MW, of summer capability are dual-fuel capable. In other words, in less than ten years, the region has lost more than 3,400 MW of dual fuel capability.[8] We believe that this problem may be worse than reported, with other generators failing to maintain their dual fuel capability through testing and maintenance. In fact, to encourage testing, the ISO included compensation for dual fuel testing in its 2013-2014 Winter Reliability Program.

B. Gas Reductions

Q: How is this supply and demand problem evident in New England?

A: The problem is evident through sudden, sizeable reductions in gas units' output. To illustrate the problem, we provide examples of generation losses in excess of 700 MW that resulted from gas supply issues in the years 2010-2013. **Figure 1** below shows these large reductions, which can last for periods of less than four

[8] *See* Section 1.3 of the 2012 CELT report at http://www.iso-ne.com/trans/celt/report/2012/2012_celt_report.pdf and page 3 of the 2004 CELT report at http://www.iso-ne.com/trans/celt/report/2004/2004_CELT_Report.pdf.

hours (10/13/2012), or extend over multiple days (3/19/2013). The number of simultaneously affected units also varies, and ranges from two (12/28/2010) to ten (2/22/2011) in the examples shown below.

Figure 1: Examples of Significant Generation Losses as a Result of Gas Supply Issues

Date	Hours of reduction	Max Number of Units Concurrently Reduced	Maximum Concurrent Average Reduction (MW)	Average Reduction (MW)
12/10/2010	20.5	6	787	344
12/28/2010	9.2	2	791	610
1/22/2011	23.1	8	815	438
2/20/2011	19.7	5	732	449
2/21/2011	15	9	1013	698
2/22/2011	25	10	1375	851
7/5/2012	17.6	8	813	568
10/13/2012	3.9	7	819	559
2/9/2013	27.8	5	1311	532
3/19/2013	58.6	7	846	338

Q: Does the frequency of these reductions comport with your experience?

A: No. I believe that the issues related to gas dependency are actually more critical than the data implies. The severity of these issues has been masked, because

system operators have adapted to chronically limited gas supplies and regularly take actions that diminish the frequency of generation outage impacts due to gas reductions. Specifically, operators monitor pipeline bulletin boards, call generators and pipelines, and attempt to keep track of LNG inventory levels. The operators monitor generators' scheduled volume of gas in comparison with their anticipated electric energy schedules, and communicate concerns to the generators, particularly when there is limited flexibility on the pipelines. If operators are uncertain about gas supply, they will hedge this uncertainty through supplemental commitments of other, preferably non-pipeline fueled, generators and may also reallocate operating reserves to conserve fuel by, for example, posturing pump storage units (pumping and generating) to preserve water for contingency response.[9] More formally, the ISO has attempted to forestall the likelihood of electric system capacity deficiencies due to gas supply limitations by implementing a Winter Reliability Program for the current winter. Among other things, this program pays oil-fired generators to keep oil inventory on hand in case they are needed to run this winter.

In sum, I believe that the ICF study and our surveys of generators' fuel supplies are more accurate indications of the scope of the gas dependency problem than the actual incidence of gas reductions to date. These surveys indicate that many

[9] Many of these actions require the payment of "uplift" to generators, which results in increased costs to consumers in the region and depressed electricity prices by undermining the price signals that guide resources' fuel procurement.

gas units only procure gas for their anticipated run as scheduled in the prior day, although, in every hour of every day, operating reserves are allocated among these gas units. If the operating reserves were activated due to a source loss on a tight gas supply day, the likelihood of these generators arranging for additional gas after supplying the requested energy would be low, and system operators would be required to implement emergency actions to maintain reliability; in the worst case, these actions would include load shedding. In short, I believe we are managing around what has become a chronic gas supply problem, and this active management has created the false impression that the gas supply constraints are less dire than they really are.

Q: Please elaborate on your statement that gas disruptions and related reductions in generation can occur suddenly.

A: The fuel supply chain for gas-fired generators is fundamentally different than that of coal and oil. Coal and oil are stored on-site, and generators may have sufficient inventory to afford them days or weeks of operations in the event of a disruption in the supply chain. Because gas is not stored on-site, generators are dependent on "just-in-time" fuel deliveries, which may be unavailable or disrupted with little or no notice. An example using Storm Nemo is illustrated in **Figure 2**. Storm Nemo occurred on Friday, February 8, 2013 and continued into Sunday, February 10, knocking out power to more than 645,000 distribution customers, primarily in southern New England.

Figure 2: Sudden, No-Notice Loss of Generation During Storm Nemo

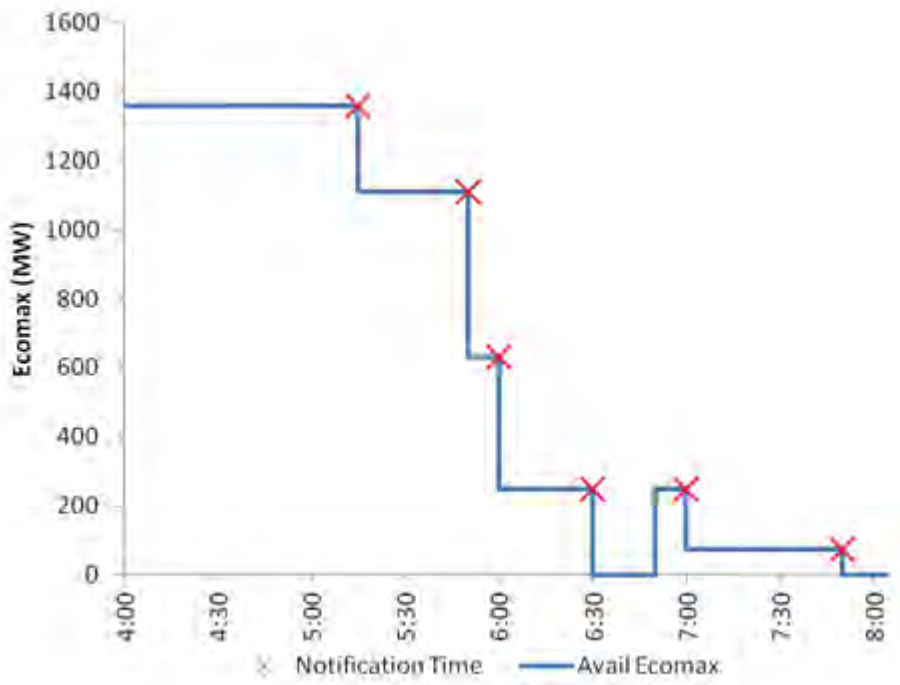

Figure 2 shows reductions in unit capability due to reduced gas supplies, and the notice provided to the control room for each of the reductions. Specifically, the blue line represents the cumulative ecomax across five gas-fired generators that reduced their output capability due to reduced fuel availability on the morning of February 9, 2013; the red X's show the notification time for each of these reductions based on communication between the generators and the control room. In this particular example, the overall reduction was severe, resulting in a loss of more than 1,300 MW of capacity without a generation contingency or physical problem other than fuel supply. As shown by the graph, the majority of this reduction occurred very quickly, with 860 MW of ecomax lost within fifteen minutes. Significantly, each time the ecomax available on these units is reduced, we can see that the control room has no advance notification.

1 **C. <u>Causes of Gas Reductions</u>**

2

3 **Q: Beyond the imbalance between supply and demand, what specifically is**

4 **causing gas reductions?**

5 A: Gas reductions can occur as a result of procurement problems or pipeline

6 problems. Procurement problems occur when a generator hasn't procured enough

7 gas. This issue generally arises when the ISO directs the generator to produce

8 electricity in an amount that exceeds the unit's day-ahead commitment because

9 load is greater than expected or there is a contingency on the system. Generators

10 are required to produce this energy; as affirmed by the Commission, generators

11 must offer into both the day-ahead and real-time energy markets a MW amount

12 equal to or greater than its Capacity Supply Obligation when the resource is

13 physically available. The Commission has agreed with the ISO that generators

14 must respond to the ISO's directives to start, shutdown or change output levels,

15 and must keep their supply offers open throughout the operating day.[10]

16 Pipeline problems refer to the pipeline's inability to deliver gas to generators as a

17 result of pressure problems, fuel quality problems, maintenance, or operational

18 flow orders brought on by high demand during times of peak residential

19 consumption. These types of operational issues are to be expected; much like

20 electric power system operators, natural gas pipeline operators must balance

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[10] *See New England Power Generators Association, Inc. v. ISO New England Inc*., 144 FERC 61,157 (2013) at P 49.

injection and withdrawals to maintain reliable operations and may, at times, be required to interrupt operations at different locations to protect the system.

Q: Please discuss the nature of procurement problems.

A: Natural gas is sold through brokered markets, and, in a separate transaction, is transported through an interstate pipeline system. The pipelines offer a number of transportation services that vary in priority (and expense). Historically, the companies that distribute natural gas to home heating customers (Local Distribution Companies or "LDCs") purchase most of the pipelines' highest priority, most expensive "firm" (non-interruptible) pipeline capacity. (In fact, these purchase commitments are the de facto financing that pipelines rely on to build and expand their infrastructure.) The capacity that is not utilized by the LDCs and other firm customers is available for purchase by generators.

As indicated by the ICF study discussed above, there is insufficient pipeline capacity to supply both the LDC loads and electric generation during times of peak gas usage, which generally occurs on cold winter days. The issue also arises when pipelines schedule major maintenance or construction outages, which the pipelines coordinate with their firm customers (i.e., not generators).

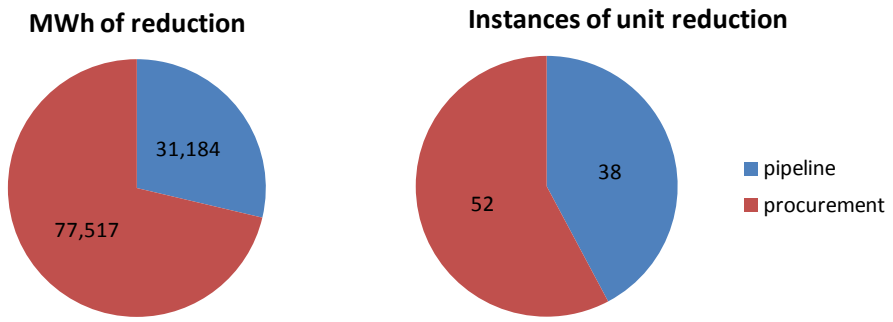
Accordingly, if generators have not made arrangements for fuel in advance, they often may not be able to secure gas transportation when the ISO schedules them beyond their day-ahead commitment. (As discussed above, generators are obligated to produce energy in excess of their day-ahead commitment if the

requested amount is less than their offer.) The challenge of rapidly securing additional gas transportation can be exacerbated by timing issues and high prices during periods of peak gas demand.

Q: What is the relative frequency of procurement problems?

A: The ISO has classified gas reductions as either procurement problems or pipeline problems. Since the classification of these events began, most events and MWhs of unit reduction (computed as average event reduction multiplied by hours of event duration) have resulted from procurement issues. The breakdown for 2013 is displayed in **Figure 3**.

Figure 3: Gas Reductions as a Result of Procurement v. Pipeline Issues



Q: Can you give examples of procurement problems?

A: We investigated events between January 4, 2012 and September 28, 2012 in which generators failed to follow dispatch instructions due to gas availability issues. In each case, the generators were asked to run within the parameters of their offers, but failed to do so because they did not have adequate fuel arrangements. These events involved 13 unique units. Although the performance issues occurred throughout the study period, there were concentrations in June,

July and September, with six different failures in June and September and seven in July. The following are examples of these events:

- In January, a unit decreased its offer price for the next day during the reoffer period, after which it was committed. The ISO called the unit and the unit confirmed that it had gas ("gas is yes"). Three hours into the operating day, the ISO received a call from the unit that it would be coming offline because it had "used up all [its] gas for the gas day." When the ISO operator asked what had happened, he was told "you guys called, we have it logged. You guys called numerous times making sure we had gas for the day … and each time we call them [the participant's dispatch desk] they say, 'yes, tell them yes' and that's what we told you guys. I … you know, I'm just the middle guy. I don't know what to tell you." In later conversations, the participant attributed the incident to confusion caused by the differences in the gas and electric days.

- In June, the ISO committed a unit in the day-ahead market, after which the unit increased the price of its offer. The ISO called the unit to verify that it had nominated and scheduled gas. On the operating day, during its start up, the unit called the ISO and said that it was having trouble getting gas. It subsequently failed to generate in accordance with its offer.

- In June, a unit received a day-ahead commitment, after which the ISO called to confirm that the unit had procured and scheduled gas. On the morning of the operating day, the ISO received a call from the unit's supplying gas pipeline, which expressed concern about the lack of gas scheduled for three units, including the committed unit. The ISO contacted all three plants to confirm they had gas, but did not hear back from the committed unit. A few hours later the unit called and reported "gas constraints" that required it to reduce its output.

- In September, a participant submitted offers and was not committed day-ahead. When it was committed in the Reserve Adequacy Assessment process to satisfy operating reserve requirements, the unit stated that it could not procure enough fuel to make the run for operating reserves as committed, and its alternate fuel (oil) was unavailable as well. Later, the unit indicated that it could have burned the alternate fuel but chose not to because its offer did not reflect the higher fuel cost.

- In September, after offering for each hour, a unit received a day-ahead commitment for all but the first six hours of an operating day. When the unit was contacted to run in those first six hours for reliability reasons, the unit stated that it had not procured enough fuel.

Unfortunately, these incidents – in which generators dispatched in accordance with their offers renege because they haven't procured gas – have become commonplace. System operators can no longer be assured that offers are accurate, or that generators will perform when needed.

D. <u>The Systemic Risk Problem</u>

Q: What is the significance of pipeline problems?

A: As noted above, pipeline problems refer to the pipeline's inability to deliver gas to generators as a result of pressure problems, fuel quality problems, maintenance, or operational flow orders. While pipeline problems account for fewer reductions than procurement problems, the problems are potentially much more severe because of the possibility that they will affect multiple units that simultaneously draw from the pipeline. In other words, pipeline problems are a "systemic risk" because they could lead to a correlated outage involving multiple generators (including reserve units) simultaneously. To illustrate this problem, consider that a single pipeline can supply generators representing thousands of MW of electricity. Accordingly, this systemic risk can lead to serious reliability issues in the New England region.

As an example, a pipeline could have a compression problem or a segment of pipe that must be isolated, thereby restricting throughput. When this happens, gas pressure can drop, resulting in the requirement that multiple units reduce their gas

draw or come off-line to maintain the reliability of the pipeline system. Units that are further down the pipeline may be affected as well, and this contributes to New England's supply problems, since we are at the end of the supply chain. In fact, ICF International, LLC has recently written a white paper that describes the gas supply issues that can arise in New England as a result of gas usage in New York.[11]

Q: Do you believe that the systemic risk problem is likely to lead to a correlated outage?

A: I do, for the reasons discussed above, including our increasing dependence on gas and the suddenness with which gas supply issues arise. In fact, we have already had some "near misses."

Q: Can you describe situations where New England narrowly missed a catastrophic correlated outage?

A: January 28, 2013 was a "near miss." It was a cold day, with Hartford temperatures 2° F lower than forecast and Boston temperatures 7° F lower than forecast. As the region approached peak hours, a gas-fired plant tripped offline due to pipeline pressure issues, resulting in a loss of nearly 300 MW of capacity.

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[11] *See* the ICF paper Gas-Fired Power Generation in Eastern New York and its Impact on New England's Gas Supplies at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/nov202013/icf_upstream_gen_impacts_white_paper_11-18-2013.pdf.

At 17:17, an oil-fired unit tripped offline, resulting in an additional loss of more than 400 MW of capacity and a deficiency in operating reserves and total ten-minute reserves. The operating reserve deficiency lasted for 19 minutes, and required the implementation of Master/Local Control Center Procedure No. 2 ("Abnormal Conditions Alert"), dispatch of 373 MW of demand response pursuant to Operating Procedure No. 4 ("Action During a Capacity Deficiency"), and the posturing of a hydroelectric plant. Had the pipeline pressure issues been more severe and affected more than one generator, the problem could have easily escalated, especially given the contingent loss of a large oil-fired unit.

In another example, on the afternoon of December 10, 2010, without notice to the ISO, the gas pipelines had to reduce the supply of gas to generators within New England, equivalent to approximately 900-1,000 MW. In particular, one pipeline reported serious problems with gas pressure with the potential to interrupt gas flow to certain generators due to generators over-drawing their gas nominations. An additional 800 MW of gas-fired generation was at risk over the peak load hour due to questionable gas supplies.

To date, we have been able to manage through these and other operational issues. We have been fortunate that, so far, weather, non-gas generator outages, and gas reductions have not converged to create a catastrophic correlated outage.

1 **E. <u>Alleviating Gas Dependence</u>**

2

3 **Q: What can be done to mitigate the risk of gas supply issues?**

4 A: To mitigate these risks, the ISO has advocated for enhanced communications with
5 gas pipelines and increased its information gathering from generators about fuel
6 supplies. That said, these problems should not be managed indirectly through
7 ISO operations; they should be managed directly through the actions of the
8 generators. To that end, the ISO has worked to improve markets, including
9 through the Pay For Performance changes, to give generators the incentives to
10 avoid these sorts of problems and ensure that they are able to produce electricity.
11 With the right incentives, there are a number of actions that generators could take
12 to significantly mitigate these risks. These include investing in sufficient firm gas
13 transportation and/or securing back-up LNG. According to the Analysis Group,
14 the most cost-effective solution for reliable fuel service may be investment in (and
15 maintenance of) dual fuel capability.[12]

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[12] *See* p. 19 of <u>Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives</u> (September 2013) in Attachment I-1g of this filing.

IV. PERFORMANCE PROBLEMS OF THE REGION'S "FOSSIL STEAM" UNITS

Q: When gas generators are unavailable, what other resources can you call on?

A: After gas-fired generation, the next largest segment of the region's capacity is oil-fired generation, at 21.6%. Coal is also a significant segment at 7.8%.[13]

Q: Can you measure the performance of these units?

A: Yes. Because at times it is more accurate to measure performance by technology rather than fuel, I sometimes refer to the performance of "fossil steam units" instead of coal- and oil-fired units. These fuel and technology categories have significant overlap, as all units that operate primarily on coal and about 70% of generation fired primarily by oil are fossil steam units.

We used three metrics to measure the performance of these units. Specifically, we measured reductions in fossil steam units' ecomax on peak days; the ability of oil- and coal-fired units to start on time; and outage rates of fossil steam units.

Q: Are these units reliable performers?

A: By any measure, a significant portion of these units have not performed reliably. In part, this is due to their design. These units were built as base-load or

[13] *See* pp. 102-103 of the 2013 Regional System Plan at http://www.iso-ne.com/trans/rsp/index.html.

intermediate units, and were intended to be run 24/7 or, at a minimum, five days a week. However, given the relative prices of oil and gas, it is not currently profitable for these units to run on a day-to-day basis, and, as a result, they are often off-line for months at a time. The ISO calls them in response to contingencies or during peak load periods, but these units were not built to run intermittently and on short notice, and have trouble starting within their claimed start time, or, in the case of older non-combined cycle units, sustaining an extended run due to tube leaks and other metal stresses.[14]

A. Fossil Steam Units' Ecomax Reductions on Peak Days

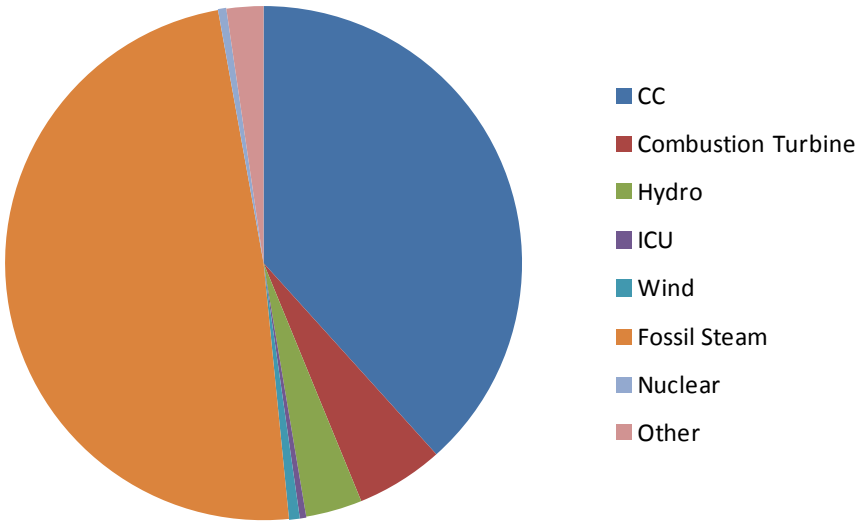
Q: Have these units failed to produce electricity when needed?

A: Yes. For example, on July 19, 2013, during a heat wave, there was dramatic underperformance by generators (as compared to their Capacity Supply Obligations) despite significant notice that they would be run. Specifically, 4,611 MW of generators' total Capacity Supply Obligations were unavailable. Four of the five top underperforming units were fossil steam units.

[14] Increased notice often improves performance, and may be feasible when we are aware that gas reductions may result, for example, during an upcoming storm where we expect gas demand to be high. However, this practice can lead to the payment of Net Commitment Period Compensation to these units, which is an out-of-market cost that participants have difficulty estimating, and can suppress energy market prices because other units are dispatched down to account for the unexpected early output on the system.

Figure 4 shows underperformance on July 19 by technology type as a percentage of the total MW by which units underperformed on that day. As the chart indicates, nearly half of the underperformance comes from fossil steam units, despite the fact that they represent about a quarter of the capacity on the system.

Figure 4: Underperformance on July 19 by Technology Type



Q: Does your conclusion about the poor performance of fossil steam units extend to system operations on dates other than July 19?

A: Unfortunately, yes. We examined data from the beginning of the FCM to the present to review how resources perform relative to their Capacity Supply Obligations over time. We concluded that fossil steam units are the biggest contributors to underperformance.

Q: What methodology did you use?

A: For this analysis, we looked at the five days with the highest peak load in each year from 2010 through 2013 (for a total of 20 days), because these are the days that the fossil steam units would likely be needed to run. We quantified the MW by which units reduced their ecomax below their Capacity Supply Obligation in the peak hour of each of these days, and then examined performance based on technology type. The results are shown in **Figure 5**. The blue line in the graph is measured against the vertical axis on the right, and shows the average peak load across the five peak days for each year.

Figure 5: MW of Reduction in Ecomax by Technology Type During Peaks

Q: What conclusions did you reach?

A: Looking at reductions across technology type shows fossil steam units to be the largest contributors to reductions in almost every year,[15] although they are only about a quarter of the fleet. These units have consistently high reductions as compared to units of other types. In years with lower peak loads such as 2011 and 2012, it follows that the system is less stressed, the units are called upon less frequently, and fewer reductions are made.

B. Oil- and Coal-Fueled Generators' Start-Up Problems

Q: Do oil- and coal-fueled units have difficulty starting?

A: Yes. Based on their experience running the system, operators identified the units known to most commonly have startup issues. The identified units are all either coal- or oil-fueled generators and, together, account for approximately 3,740 MW of capacity (about 11% of total generation capability). We assessed the performance of these units when they were scheduled through the Security Constrained Reserve Adequacy ("SCRA") over the period January, 2005 through September, 2013.

Q: What methodology did you use?

[15] Hydro units have the highest EFORd in 2010 because of one unit's protracted outage. Without this anomaly, fossil steam units would have the highest EFORd in 2010 as well.

A: We used the finalized SCRA case schedule that is shared with units on the evening prior to the operating day[16] to determine the expected start time for each unit. We defined a "late" start as one where the unit's real-time output reaches the economic minimum at some point after the hour indicated in the SCRA case. We defined a "failed" start as one where the real-time output did not reach its economic minimum at any time during the scheduled run.[17]

Q: What was your conclusion?

A: Over the 8.75 years studied, all except two of the studied units have been late or completely failed to start in at least 20% of scheduled RAA starts. Some have fared even more poorly; the worst performer failed in 13% of scheduled starts and was late for 31%, resulting in only 56% of its scheduled starts being on time. The worst four units were late or failed to start in over 30% of all scheduled starts.

Q: Is the problem static over the years studied?

A: No. The trend shows the problem worsening. In fact, the missing MWh from the units studied more than tripled between 2009 and 2013.[18]

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[16] On May 23, 2013, this time was moved forward from 10 p.m. to 5 p.m.

[17] This analysis compares the SCRA schedule with the unit's behavior in Real Time. The analysis will therefore miss any communication between the control room and the unit taking place after the SCRA results are created. For example, if, after the SCRA and during the operating day, the operators called a unit and asked it to come on two hours later than its SCRA schedule, this new start time would not be captured and the analysis would show the unit as being two hours late for its SCRA start time. These types of communications are not typical and I do not expect that they would materially affect the results of the study.

[18] We compute the missing MWh as (SCRA Sched MWh – RT Metered MWh).

Q: What is the impact of the "missing MWh"?

A: Very simply, when a unit starts late or fails to start, we need to replace the missing MWh. If we replace them with generation from a gas-fired unit, we run the risk that the unit will use up its allotted gas and transportation rights, rendering it unable to run later in the day. More broadly, use of gas can contribute to the systemic risk problem and the possibility of correlated outages.

To avoid the "missing MWh," operators often attempt to manage around these coal- and oil-fired units' performance problems by starting the units earlier than necessary or starting extra units to cover for the possibility that the most economic units do not start or are delayed. This contributes to uplift and reduces electricity prices through extra commitments, which generators have long noted distort the market and undermine the price signals that guide their investments and operation.

Q: Can you provide examples of late or failed starts?

A: Yes. In July, 2012, a dual fuel resource operating on oil failed to start in accordance with its offer, minimum notification and startup time parameters because it had to "sequence" its multiple onsite generators, both of which were close to a cold start. In another example, an oil unit offered into the markets but did not receive a day-ahead schedule. When it was called on to operate for reliability reasons within its notification time of twelve hours, the unit stated that it could not start "due to turbine issues" and asked for a delay. When the unit had

not shown up forty minutes after the ISO had been told it would be on "any minute," the ISO cancelled the startup order. The unit later explained that its startup times would be longer if the other onsite unit was not operating. In an example of a failed start, one oil unit tried for all six days of the July 2013 heat wave to start, and was never able to come online.

Q: Can you provide any examples of situations where these late or failed starts caused system problems?

A: Yes. On June 17, 2013, the system was tight on total thirty-minute operating reserves between 12:00 p.m. and 1:05 p.m., and was intermittently deficient in thirty-minute reserves for a total of 27 minutes during this time. The largest deficiency in this period was 130 MW. Two of the units investigated in this study were late to start during this period. Holding all other activities on the system constant, if these units had performed as expected, the deficiency would have been avoided. The failure of these units to start as requested resulted in a deficiency of operating reserves, leading to the implementation of Master/Local Control Center Procedure No. 2 ("Abnormal Conditions Alert").

C. <u>Outage Rates of Fossil Steam Generators</u>

Q: How are outage rates measured?

A: As part of determining the Installed Capacity Requirement, the ISO's System Planning Department computes an Equivalent Forced Outage Rate – Demand

("EFORd") for most units on the system. EFORd measures the portion of time that a unit is in demand but unavailable as a result of unplanned ("forced") outages. EFORd is expressed as a percentage of hours of unit failure as measured against total hours of availability when needed to serve load; as a result, a lower percentage indicates better performance and is desirable. EFORd values are computed for each FCM commitment period using five years of data from the Generator Availability Data System.

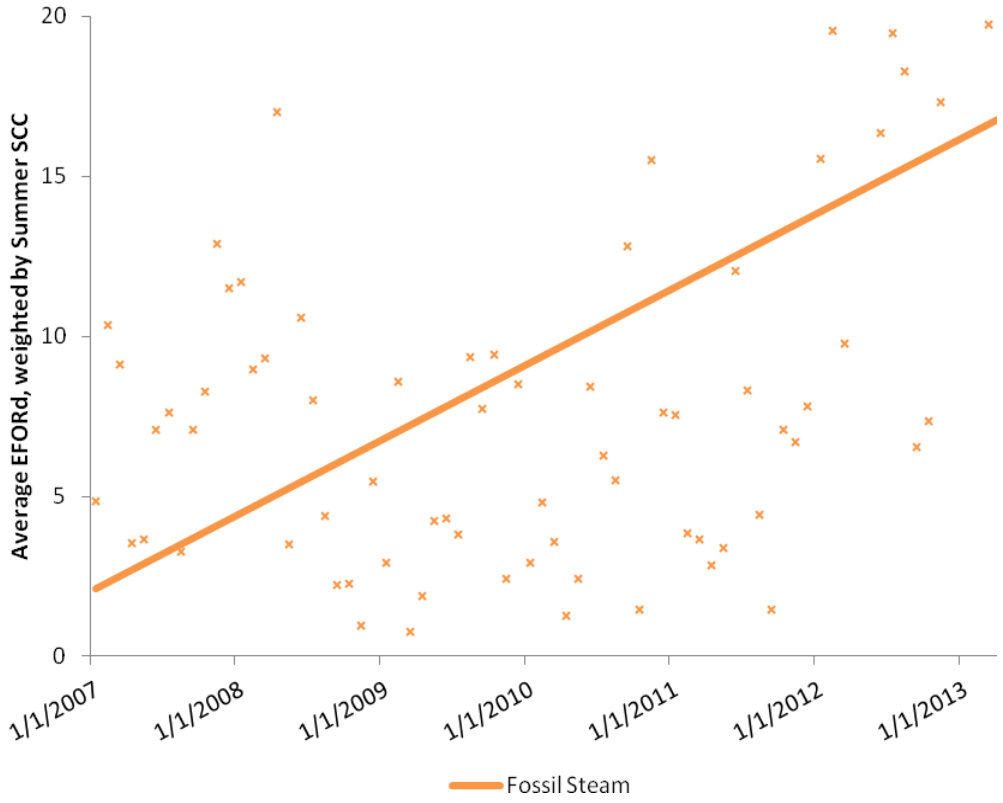
Q: What methodology did you use to review EFORd rates?

A: We studied monthly EFORd rates for those units submitting actual outage data into the Generator Availability Data System. We used the generation categories that correspond with System Planning's reports. These are: hydro; combustion turbines; combined cycle units; internal combustion units, including diesel-fired generators; nuclear; fossil steam; and "other" (including wood- and refuse-fired generators). To determine the outage rates of oil- and coal-fired generators, we reviewed the data for the fossil steam unit category.

Q: What were the EFORd rates of fossil steam units?

A: **Figure 6** includes a linear regression line that shows the EFORd rates of fossil steam units over time. The rest of the chart includes a scatter plot of these units' monthly average EFORd rates.

Figure 6: EFORd Rates of Fossil Steam Units Over Time



Q: Can you interpret these data?

A: The EFORd rates of fossil steam units indicate that, currently, more than 15% of the time when these units are needed, they have an unplanned outage. Moreover, these rates are far higher than they used to be, indicating worsening performance, and exceed the average EFORd rates of the whole fleet (which are discussed below). Despite this poor performance, these resources continue to serve as the region's primary alternative to gas-fired generation by offering capacity in the FCM at prices that clear in the auction.

D. Addressing Oil- and Coal-Fueled Generators' Performance Issues

Q: How could oil and coal units improve their performance?

A: Generators could make incremental investments to maintenance practices and operations that might improve their performance, leading to a decrease in unplanned outages and start times or an increase in ramp rates. It is also possible that, with the implementation of the Pay For Performance changes to the FCM, the region's resource mix could change, with some of the poorer-performing oil- and coal-fueled units replaced by lower-cost, more flexible resources with access to fuel.[19]

V. PERFORMANCE ISSUES THAT SPAN THE ENTIRE FLEET

Q: Are there additional performance issues?

A: Yes, unfortunately. Performance problems are not limited to the issues discussed above regarding gas-fired generators and oil- and coal-fueled generators. As discussed below, we've seen fleet-wide performance issues, as indicated in poor responses to the ISO's instructions following system contingencies, increasing

[19] See p. 5 of the Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives at http://www.iso-ne.com/key_projects/fcm_perf_incentives/index.html.

EFORd rates, inadequate staffing of units, and the failure of oil units to maintain fuel inventories.

A. Performance Issues Following System Contingencies

Q: Is there an issue with the performance of units providing reserves?

A: Yes. ISO system operators have observed issues with units underperforming in response to contingency dispatch instructions. One such episode occurred on September 2, 2010, when the ISO violated a NERC Reliability Standard as a result of poor unit response following the loss of the largest contingency.

Q: What happened on September 2, 2010?

A: September 2 was a high load day in New England. After a generation contingency (the largest contingency on the system), emergency dispatch signals were sent to 146 generators, requesting 1,922 MW. Within fifteen minutes of the event, generators had responded with only 1,267 MW. Although operators had requested more MW than necessary to return Area Control Error to pre-disturbance levels, the response was still 174 MW short of the quantity needed. As a result, the ISO violated NERC Reliability Standards.

The September 2, 2010 event led to an internal evaluation of the root causes of this specific event, and the commissioning of the Analysis Group to quantify historical unit performance after contingency dispatch.

Q: What did the analysis group review?

A: The Analysis Group examined unit response rates to contingency dispatch for 36 system contingencies that ranged in size from 500 MW to 1,840 MW and occurred between March, 2009 and February, 2011.[20] In those events, ISO operators requested additional energy from units providing reserves, with requests sent to as few as three and as many as 114 units, asking for total increases ranging from 258 MW to 1,835 MW. The performance of units was measured by computing a response rate for each unit for each contingency event. These response rates were measured as the unit's change in MW output ten minutes after the ISO issued the dispatch instruction in response to the contingency, divided by the change in output requested by the ISO. Response rates were weighted by the size of the requested change.

Q: What were the results?

A: The results of this study indicate that, on average, reserve units failed to provide all of the energy requested by the ISO. In fact, the average weighted response rate was just 71% (65% for online units, 81% for offline units). **Figure 7** shows generator response rates by resource fuel type.

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[20] *See* Analysis Group's Analysis of Reserve Resources: Activation Response following Contingency Events at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/analysis_group_reserve_resource_analyses_5_29_2012.pdf.

1 **Figure 7: Generator Response to Contingencies by Fuel Type**

Fuel Type	Requests	Units Requested	ΔDDP[21]	Avg MW/Req	Mean 10 min weighted response rate
Coal	57	11	808	14	57%
Distillate Fuel Oil	64	41	968	15	59%
Jet Fuel	11	10	258	23	67%
Kerosene	9	8	213	24	75%
Natural Gas	143	28	5,860	41	59%
Natural Gas and Distillate Fuel Oil	62	18	1,347	22	53%
Residual Fuel Oil	20	10	474	24	65%
Water	85	31	8,703	102	84%

2 **Q: What are the implications of these results?**

3 A: The analysis indicates that, on average, units do not deliver all of the energy
4 requested by ISO operators after a contingency. These results imply that many of
5 the MW of reserves counted toward meeting reserve requirements may not truly
6 exist when they are requested to be converted to energy; as a result of this
7 analysis, the ISO has taken steps to increase the amount of reserves procured and

[21] "Change in Desired Dispatch Point."

to make other changes in the reserve markets. Importantly, the data also indicates that these performance problems are not unique to any fuel type. Rather, nearly every segment of the fleet – including the non-gas fast-start units relied upon to provide reserves – is failing to perform in accordance with its stated capability.

B. Increasing EFORd Rates

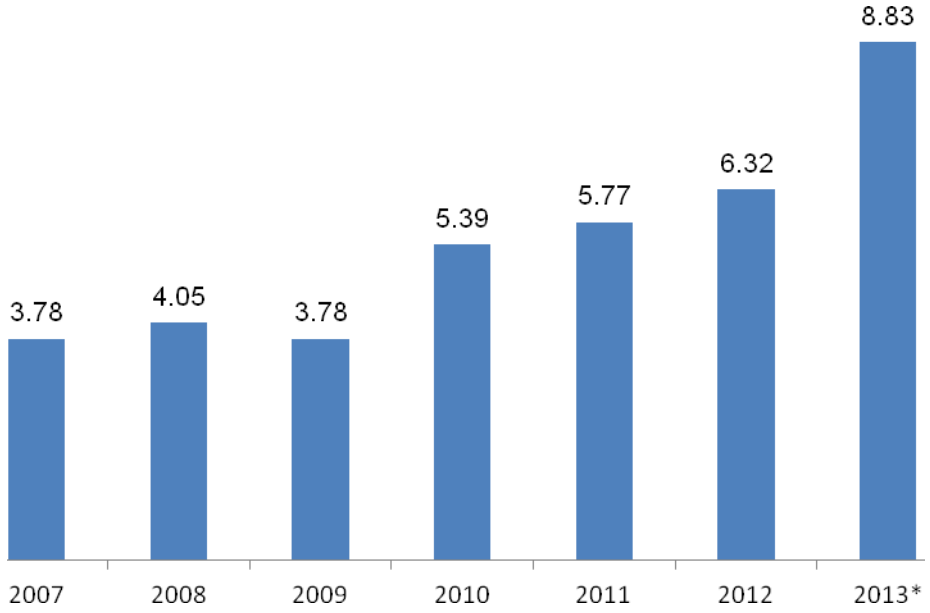
Q: Do fleet-wide outage rates indicate a problem?

A: Yes. As discussed above, EFORd values, which measure unplanned unavailability when generators are needed to serve load, are increasing fleet-wide. Increasing unplanned outages of generators can make it more difficult to operate the system reliably.

Q: Did you confirm and quantify the problem?

A: Yes. We looked at annual EFORd values for generators for the years 2006-2013, and confirmed that the average EFORd is rising. **Figure 8** displays the average annual EFORd values weighted by summer Seasonal Claimed Capability. Note that, although the values provided for 2013 include data only for the months January through August, the year-over-year increase is dramatic, as is the overall increase in EFORd rates, which are 2.33 times higher than they were in 2007.

Figure 8: Annual EFORd Rates



Q: Were you able to analyze EFORd rates by unit type?

A: Yes. We studied monthly EFORd rates for units submitting outage data into the Generator Availability Data System.[22] We grouped generators into technology categories in line with those used in the Installed Capacity Requirement reports. **Figure 9** shows the relative size of each technology category for those units considered in this analysis, and the GW represented by each. **Figure 10** is a scatter plot of monthly average EFORd rates by generation type, with linear regression lines to indicate how the EFORd of each generation type is trending over time.

[22] We excluded the relatively few MW of generation that submitted NERC class average data instead of actual outage data.

Figure 9: Relative Size of Generation Technology Types (Numbers are GW)

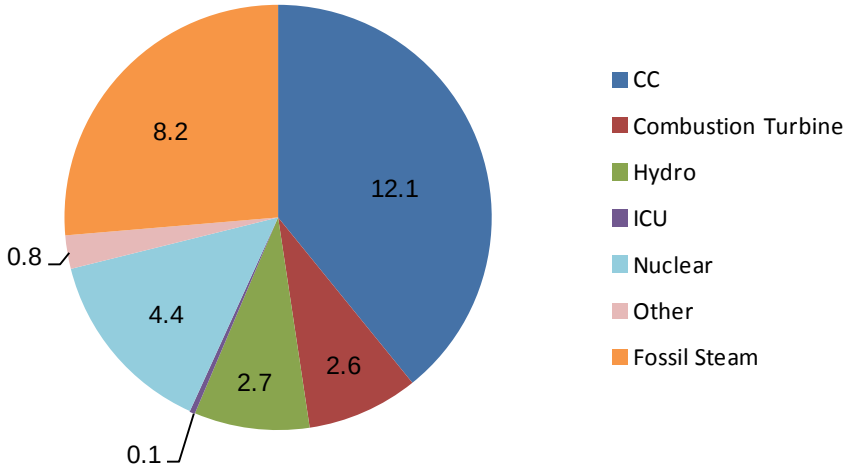
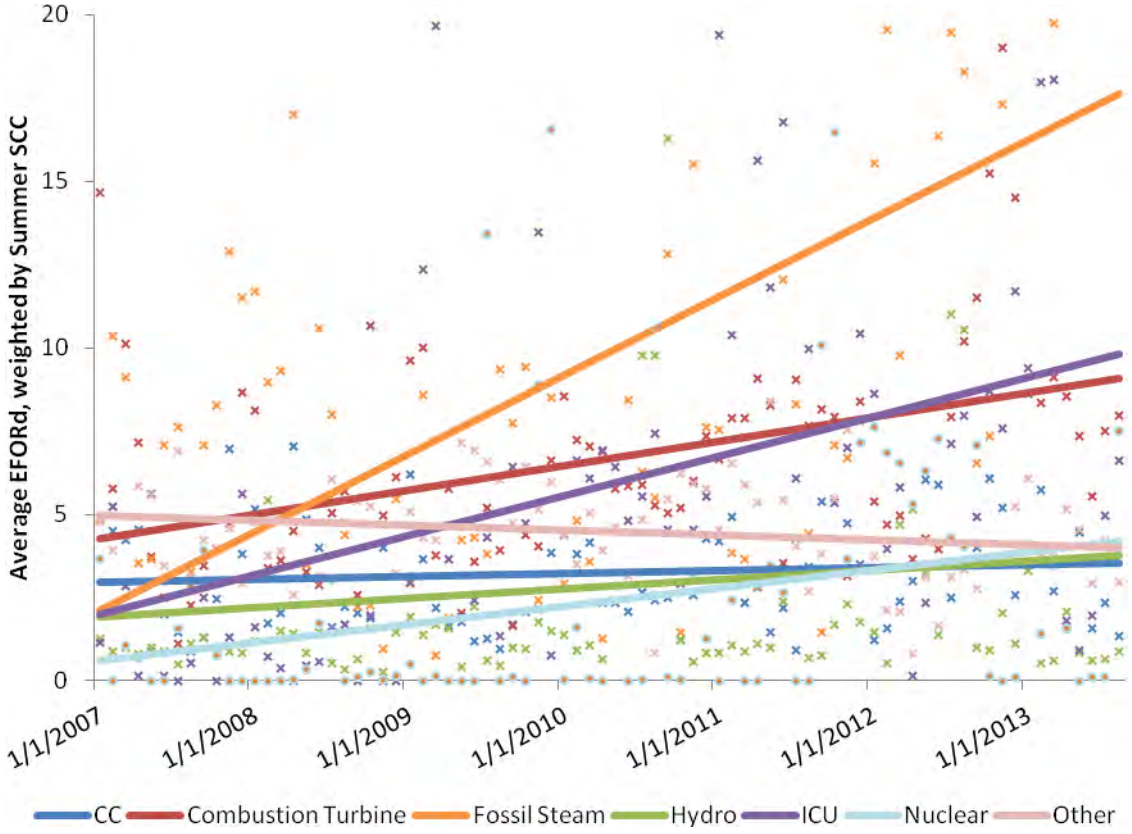


Figure 10: Average EFORd by Technology Type 2007-2013



Q: What is the significance of the analysis of EFORd by unit type?

A: Unavailability is trending upward in all categories except "other," and especially in the fossil steam category, as discussed above. Notably, the analysis also shows that the combustion turbine category has deteriorating availability. This category includes units fueled by oil, kerosene, jet fuel, and natural gas, and represents a large portion of New England's fast-start generation. We are also seeing deteriorating availability with the internal combustion units, which include diesel-fired peaking units that operate infrequently. Increasing outages among these combustion turbine and peaking units are of particular concern because we rely on these units to ensure reliable operations during stressed system conditions, whether to meet summer peak demand or to respond rapidly to system contingencies that can occur any time of the year.

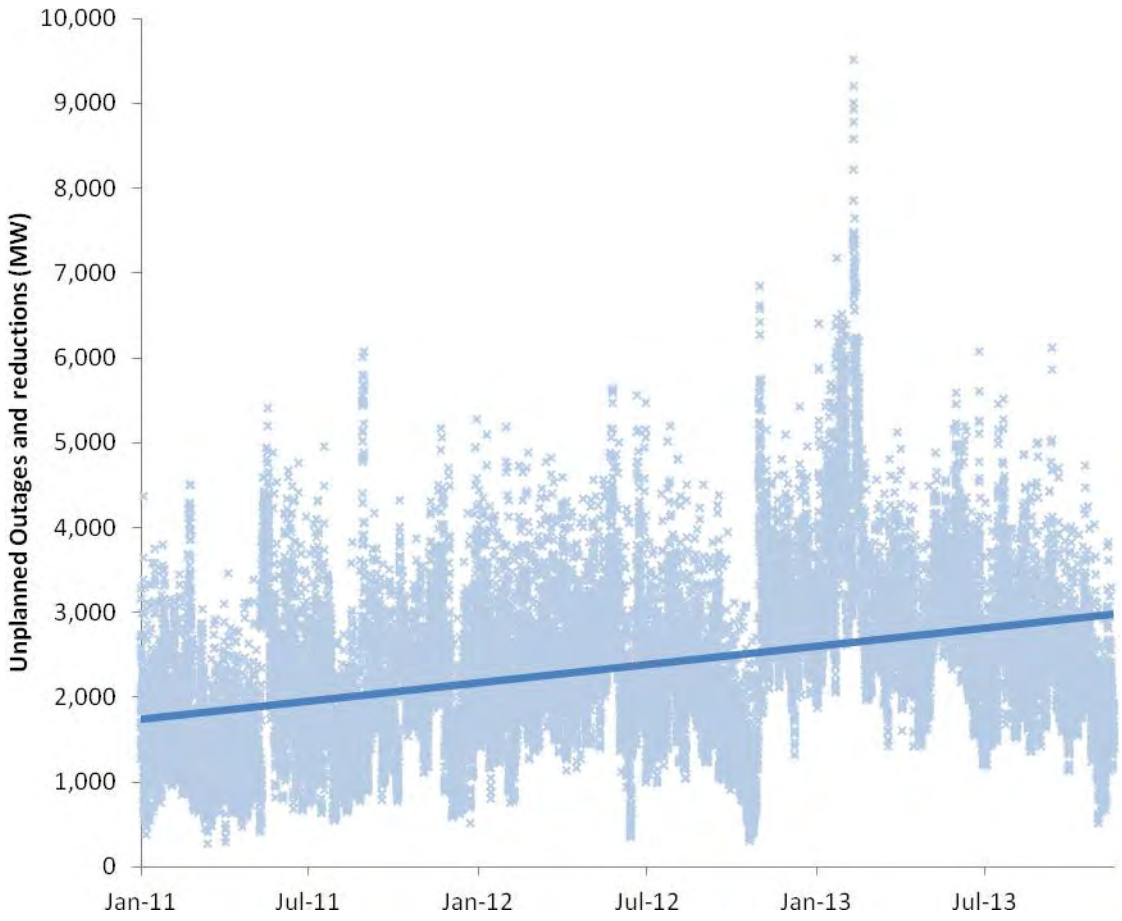
Q: Have you confirmed the EFORd data using other methodologies?

A: Yes. Increasing EFORd rates imply that the amount of capacity that is unavailable is increasing over time. To investigate further, we reviewed alternate data sources, including the ISO System Capacity Monitor ("CAPSYS") and the Control Room Operations Window ("CROW"). CAPSYS is a control room tool used by operators. Among its many functions, CAPSYS computes the net MW effect of current outages and unit reductions in reference to Capacity Supply Obligation for the ISO system as a whole. CROW is an internal ISO database in which detailed generation outage information is logged. CROW went into

production at the very end of 2010, so the data we show in this analysis spans January 2011 through November 2013.

For this analysis, we captured hourly outages and reductions from CAPSYS. We then reduced these hourly quantities by any planned generation outages and reductions logged in CROW. The result is a quantity of MW that the ISO had not expected to be unavailable in each hour. **Figure 11** below shows these hourly values over time. The linear trendline clearly demonstrates that the amount of MW forced offline and reduced from Capacity Supply Obligation levels is increasing over time.

Figure 11: Generator Unavailability Using CAPSYS and CROW



Q: What impact does the increasing frequency of outages have on reserve deficiencies?

A: Between January 2011 and November 2013, there were 78 hours in which there was a deficiency of either total ten minute reserves or total operating reserves (as measured by Energy Management System reserve requirements and designations) for some duration during the hour. In short, had generators with unplanned outages instead performed, they could have, in some cases, ameliorated or even eliminated reserve deficiencies.

Q: Can you give an example where outages led to a reserve deficiency?

A: Yes. July 19, 2013 was the sixth day of a heat wave during which temperatures exceeded 90°F on a daily basis in New England, with temperatures reaching 99°F in Boston on the 19th. The extended nature of the heat wave led to many generator reductions due to ambient air temperature and environmental issues. The load in the peak hour from 4:00 to 5:00 p.m. was 27,377 MW, which is the fourth highest peak load in ISO history. In this hour, 4,265 MW of generation (13% of the total Capacity Supply Obligation for the month) was unavailable as a result of unplanned outages or reductions.[23] Outages and reductions on this day resulted in an extended deficiency of operating reserves, which spanned six hours and peaked at around 700 MW of deficiency. ISO operators were required to implement Operating Procedure No. 4 ("Action During a Capacity Deficiency").

C. <u>Failure to Appropriately Staff Generators</u>

Q: Please discuss the issue with inadequate staffing.

A: The failure to adequately staff generators has, in some instances, prevented generators from coming online when dispatched by the control room. For example, on July 26, 2012, the control room attempted to dispatch a generator that had operated on the prior day but did not have a day-ahead schedule for the 26th. The generator failed to start, indicating that it did not have staff on hand to

[23] Another 346 MW were unavailable as a result of planned outages, totaling 4,611 out-of-service.

operate the facility. When asked why staff was not available, the generator explained that it did not staff the plant full-time; because the generator ran infrequently, it maintained only a single, on-call skeleton crew. That crew had been called to operate the plant on the previous day and was not available for the current day.

In another instance in August, 2012, the ISO attempted to bring a generator online in accordance with the generator's offer. A security guard answered the phone and reported that he was the only person onsite and he had no contact information with which to summon anyone else to the plant. (The generator ultimately made a self-report to the NPCC regarding the incident.) In two instances in the summer of 2012, a generator reported that it had "exhausted all staffing options" and was therefore unavailable.

Q: Why are generators not appropriately staffing their units?

A: In my opinion, generators take the chance that they won't be called and make an economic decision to cut costs by sending staff home. Quite simply, they do not have adequate incentives to keep their units fully staffed and ready to operate.

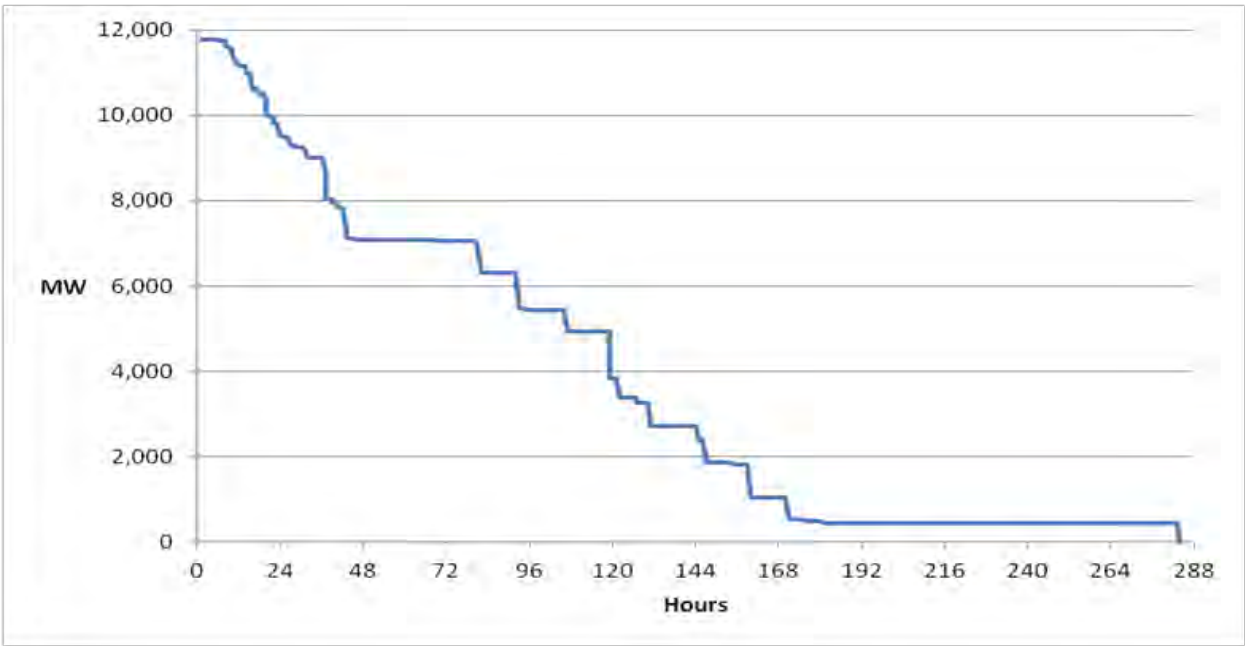
D. <u>Low Oil Inventories</u>

1 **Q: Please describe oil units' inventory practices.**

2 A: As noted above, the ISO has been enhancing its information-gathering on the
3 topic of fuel inventories. By surveying resource operators, we know that oil and
4 dual-fuel units have tanks that are kept, on average, only about one-third full.
5 This may be adequate for the limited hours that oil units are dispatched during the
6 year (oil-fired resources make up less than 1% of the electricity generated
7 annually), but it limits the availability of these resources when needed for
8 sustained periods. For example, if the nearly 12,000 MW of resources capable of
9 operating on oil were operated at full load, based on their reported inventories
10 almost half of those resources would become unavailable within a few days,
11 assuming no replenishment of fuel. See **Figure 12** regarding estimated oil-
12 generator output, which is based on information from generator fuel surveys.[24]

[24] For more information, *see* pp. 5-6 of Winter Operations Summary: January – February 2013 at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

Figure 12: Estimated Oil-Fired Generator Output Based on Reported Fuel Inventories



Q: Can you give an example of a generator failing to operate because of insufficient oil?

A: Yes. One oil-fired unit has repeatedly failed to produce at times of system stress. In February, 2013, during Storm Nemo, the unit offered in at a high price to avoid being committed and alternatively represented itself as unavailable, while later confirming that it was out of oil. In July of 2013, during a heat wave, the unit asked the ISO to reduce the unit's output "for environmental reasons," and later noted that its oil tanks were getting low. During the heat wave, the ISO contacted the unit every two hours to monitor its oil inventory and kept the generator at its Emergency Minimum Limit. The unit would have been dispatched at higher levels if it had fuel. Notably, despite the unit's report of its minimal fuel

inventory, the unit offered itself as fully available in the markets throughout the heat wave.

Q: What actions has the ISO taken to mitigate the risks created by low oil inventories?

A: As discussed above, during the 2012-2013 winter, the ISO learned that oil units were not keeping sufficient fuel on hand and gas units were having difficulty procuring gas. We grew concerned about operational difficulties in the upcoming winter (2013-2014). Ultimately, because the Pay For Performance changes and other market improvements would not be in place in time, we proposed a stop-gap "Winter Reliability Program" that, among other things, compensates oil-fired and dual fuel units for keeping oil in inventory. This is an out-of-market solution that was deemed necessary to ensure reliable operations in the event of a cold snap or other contingency. While it is too early to assess the Program's impact, my belief is that it will have proven to be critical to reliability this winter.

Q: Isn't this issue resolved by the Commission's order on the complaint filed by NEPGA on the topic of generator obligations?

A: I believe it is. The ISO interprets the Commission's order as requiring oil resources to have sufficient fuel in their tanks to meet their Capacity Supply

Obligations.[25] However, as discussed further below, these examples are included to illustrate that generators' existing incentives are leading them to make decisions that are consistent with their economic self-interest but do not facilitate regional reliability.

E. <u>Observations</u>

Q: Are there any commonalities among these performance issues?

A: Yes. There are two. First, a number of these performance issues indicate that the ISO is not receiving accurate information from generators about their resources' ability to operate. This is evident in cases where generators do not have gas or oil to operate, despite having offered into the markets. As we saw with oil and coal units, it is also clear that some generators' start and notification times may not be accurate. Finally, units are representing themselves as available when they do not have staff on hand to operate.

System operations – both operator actions and system dispatch software – are predicated on the ability to rely on the market and capability data submitted by resources. In general, these data have become less reliable, as detailed in my testimony. During times of system stress, the data become even more suspect.

[25] *See New England Power Generators Association, Inc. v. ISO New England Inc*., 144 FERC 61,157 (2013).

This requires the system to be operated conservatively where possible, increasing costs and distorting market outcomes, which further blunts the price signals sent to the market in response to problems. Where it is not possible to operate the system conservatively, we must live with the heightened risk of reliability problems.

Second, it is clear that many of the generators' actions – whether failure to keep oil in the tank or to staff their units – are consistent with their economic self-interest but are not aligned with regional reliability. In another example of this behavior, a number of generators regularly modify their start and notification times when they do not receive a day-ahead commitment. In fact, as recently as December 17, 2013, a fast-start unit changed its operating parameters to include a six-hour start time when in reality it is a ten-minute unit, and, on January 8, four fast-start units changed their start times to 90 minutes. Whether these changes are justified by a lack of staff at the plants or difficulty in getting fuel on short notice, the point is the same; unlike in the current paradigm, generators must have incentives that cause them to take actions that contribute to, rather than detract from, the reliability of the bulk power system.

VI. CONCLUSION

Q: How would you characterize the performance issues discussed above?

A: I would characterize them as pervasive. My testimony has shown that the problems are evident in each significant category of generation. Specifically, gas-fired generators are not procuring firm pipeline access to natural gas, of which there is simply not enough to supply both generators and the LDCs. These generators have limited access to alternatives like LNG. Although the ISO's system operators are actively managing these issues, we have seen some sudden, sizeable reductions in generators' output as a result of gas supply interruptions.

The oil and coal generators we rely on when gas-fired generators are unavailable have their own set of problems. They are the biggest contributors to underperformance relative to their Capacity Supply Obligations, reducing their ecomax during peak hours on peak days more than any other category of generator. They have trouble starting on time (or at all), and their rate of unplanned outages is the highest among the fleet, such that they are unavailable on an unplanned basis more than 15% of the time that they are needed.

While gas, oil and coal units are significant proportions of the fleet, they are not alone in experiencing performance problems. These problems are truly fleet-wide. When we have asked generators to respond to a contingency, the average

response rate is only 71%. Nearly every category of generator is experiencing increasing rates of unplanned outages, with the overall rate more than doubling since 2007. Generators of different types are failing to staff their units and, as a result, are unable to respond in a contingency. Absent out-of-market action, oil units are keeping their fuel tanks only about one-third full, and dual fuel units are mothballing their ability to switch fuels.

Q: Do these pervasive performance issues need to be addressed?

A: I believe that they do. Even if the region's gas supply problems were solved, we have a system that is dependent on gas and will be vulnerable to gas supply interruptions. This "systemic risk" may be realized in the event of one of a number of pipeline problems, which include maintenance, pressure problems, fuel quality problems, or operational flow orders during periods of high demand. During one of these events, multiple units that simultaneously draw from the pipeline could be affected, causing a correlated outage of multiple generators (including reserves). The scope of the potential problem is illustrated by the fact that a single pipeline can supply generators representing thousands of megawatts of electricity. In other words, given the systemic risk, all generators need to perform.

Q: How would these pervasive performance issues be addressed?

A: Gas-fired generators could invest in sufficient firm gas and/or back-up LNG. Generators of various types could invest in, maintain and test dual fuel capability

and keep their alternate fuels on hand. They could also adjust maintenance practices and operations. Ultimately, the region will need investment in new resources and we will need those resources to operate reliably. With the recent announcement of generator retirements, we are reaching that point now and the market needs to work to incent investment in the resources the region needs. These decisions are the generators' prerogative. The ISO's role, and that of the markets we administer, is to give these generators the appropriate incentives to ensure that decisions are made that are both profitable and conducive to the reliable operation of the bulk power system.

Q: Does this conclude your testimony?

A: Yes.

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

Executed on January 17, 2014.

Peter Brandien

Vice President – System Operations

Attachment I-1c

Testimony of Matthew White on behalf of the ISO

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-_____-000**
New England Power Pool	**)**	

TESTIMONY OF

MATTHEW WHITE

ON BEHALF OF ISO NEW ENGLAND INC.

Filed on: January 17, 2014

TABLE OF CONTENTS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-_____-000**
New England Power Pool	**)**	

TESTIMONY OF MATTHEW WHITE
ON BEHALF OF ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

Q: Please state your name, title, and business address.

A: My name is Matthew White. I am the Chief Economist for ISO New England Inc. (the "ISO"), One Sullivan Road, Holyoke, Massachusetts 01040-2841

Q: Please describe your responsibilities, work experience, and educational background.

A: My primary responsibilities at the ISO include the design and development of the ISO's suite of auction-based electricity markets. Prior to joining the ISO, I held faculty appointments at the University of Pennsylvania's Wharton School of Finance and Commerce (2002-2009) and Stanford University's Graduate School of Business (1995-2001). At these institutions I conducted research on electricity demand, pricing, and market design, and taught graduate-level courses in economics and decision analysis. My public service includes appointments as a senior staff economist at the Federal Energy Regulatory Commission, Office of Energy Policy and Innovation (2009-2010) and the Federal Trade Commission,

Bureau of Economics (2001-2002). My research studies have been published in peer-reviewed economics journals, and I have served as a referee and evaluator for the National Science Foundation and over twenty-five journals spanning economics, engineering, and political science. I received a M.S. in Statistics and a Ph.D. in Economics from the University of California, Berkeley.

II. PURPOSE AND ORGANIZATION OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to explain in detail the rationale for and the design of the Pay For Performance reforms to the Forward Capacity Market ("FCM").

Q: How is your testimony organized?

A: In Section III, I explain the economic rationale for improving resource performance incentives, and why stronger market-based incentives are essential to solve the reliability challenges facing the New England system today. I show that the current FCM design has a number of significant flaws that undermine performance incentives and that must be fixed. I also explain how a well-designed capacity market remedies these flaws, and that changes to the energy market alone will not.

In Section IV, I explain how the Pay For Performance design works. In particular, I show that Pay For Performance is simply a two-settlement system for forward capacity market obligations. I explain how this improvement satisfies economically-sound market design principles, which in key respects the current FCM does not. This section emphasizes the close connection between a resource's performance during periods of scarcity and its market compensation, a hallmark of well-designed markets.

In Section V, I provide a detailed explanation the Capacity Performance Payment[1] Rate, an important value in the design that corrects the FCM's price signal for resource investment and performance. I start from two simple economic principles, and derive an appropriate performance incentive rate that is consistent with the goals of the capacity market.

In Section VI, I show that with the Pay For Performance design, the Forward Capacity Auction selects a more reliable mix of capacity resources for the power system. I demonstrate how the FCM selects capacity resources cost-effectively under the Pay For Performance design, and I explain why the FCM does not select resource's cost-effectively under current rules. Moreover, with these

[1] Capitalized terms used but not otherwise defined in this testimony have the meanings ascribed thereto in the ISO New England Transmission, Markets and Services Tariff (the "Tariff"), the Second Restated NEPOOL Agreement, the Participants Agreement, or the Pay For Performance rules.

improvements there is less volatility than would occur if similar incentives were included in the energy market instead.

In Section VII, I enumerate and explain other important features of the Pay For Performance design. This includes the economic rationale for a number of detailed design elements, including Capacity Scarcity Conditions, the Capacity Balancing Ratio, and Capacity Performance Bilateral transactions.

In Section VIII, I describe the economic logic and the terms of the Pay For Performance "stop-loss" provisions, which will limit the downside consequences for a capacity supplier in the FCM.

III. RATIONALE FOR FCM CHANGES TO IMPROVE PERFORMANCE INCENTIVES

A. The Capacity Market Must Provide Incentives For Resources To Perform To Achieve Its Goals

Q: What are the central goals of New England's capacity market?

A: In New England's restructured electricity system, the capacity market has two central, related goals: (1) to ensure that there are adequate resources – the right amount, in the right locations, and able to perform as expected – to meet the

region's reliability objectives; and (2) to ensure that the first goal is achieved in a cost-effective manner.

Q: Is the ISO seeking to change these goals?

A: No. In implementing Pay For Performance in the FCM, the ISO is not proposing to alter these central goals. Rather, the ISO is proposing to fix existing flaws in the FCM design that hamper the capacity market's ability to achieve these goals.

Q: What do you mean that resources must be able to perform as expected?

A: It is tempting to think that the first goal stated above – adequate resources – is simply about having enough capacity installed in the right locations to serve demand. But the mere existence of those resources, even if ample in quantity and well-located, is meaningless if those resources do not provide energy or reserves. The ISO cannot reliably operate the system if the resources it depends on do not or cannot perform (that is, do not provide energy or reserves) as offered during periods of scarcity. A well-designed capacity market not only induces the existence of sufficient resources in the right locations, it also must play a role in ensuring that those resources are appropriately valued and compensated for the energy and reserves they provide when needed.

Q: What are the region's reliability objectives, and how is actual resource performance related to those objectives?

A: In New England, the reliability planning requirement for resource adequacy is based on system performance. Specifically, ISO New England Planning Procedure No. 3, "Reliability Standards for the New England Area Bulk Power Supply System"[2] Section 2, explains the resource adequacy criterion. It states, in substantive part, that to assure resource adequacy the system will be planned in such a manner that "the probability of disconnecting non-interruptible customers … will be no more than once in ten years."[3] In other words, the resource adequacy objective of the FCM is not defined by a target capacity reserve margin, but rather is defined by a loss-of-load probability standard. This is achieved by having a certain amount of capacity that operates with a certain level of performance.

If the system's resources do not perform adequately during periods of scarcity, the system's actual loss-of-load probability will not satisfy the resource adequacy criterion. So actual resource performance during scarcity conditions, and not just having a certain number of installed megawatts of capacity, is central to achieving the region's reliability objectives.

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[2] ISO New England Planning Procedure No. 3 is available at http://www.iso-ne.com/rules_proceds/isone_plan/pp03/pp3_r6_final.pdf

[3] *See id.* at 3.

Q: Does the FCM currently provide incentives for resources to perform during periods of scarcity?

A: The importance of ensuring resource performance during periods of scarcity was well recognized in the original FCM design. Yet, while there are provisions in the current rules that were intended to provide such incentives, they are both too weak and riddled with exemptions that excuse poor performance during scarcity conditions.

To remedy this problem and achieve the FCM's goals, the ISO is replacing the capacity market's flawed performance incentives with a performance incentive design that will compensate resources for investments that contribute to reliability and send price signals for performance during scarcity conditions.

Q: Why is the ISO making these changes at this time?

A: Although the flaws of the FCM's performance incentive mechanism have been present since the capacity market's inception, the practical consequences of these flaws have become significantly greater during the last few years.

As the testimony of ISO witness Brandien describes in detail, the New England power system faces significant and growing reliability risks. These include, in brief:[4]

- System operators' concern that the regions' gas-fired generating units, which rely on a frequently constrained, "just-in-time" pipeline supply system, lack the fuel supply arrangements and backup fuel capabilities necessary to assure they can deliver power during stressed system conditions.

- Growing risks of relying upon the region's existing oil- and coal-fired steam units because these units, as a class, are inflexible and exhibit substantially deteriorating performance and availability.

- Overall system trends in unit outage rates that are getting progressively worse over time, across many generation technology types, rather than improving.

- Recurring events in which a broad array of generation resources performs poorly when requested to deliver additional energy following major system contingencies.

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[4] *See* Testimony of Peter Brandien on behalf of the ISO, submitted with this filing as Attachment I-1b ("Brandien Testimony").

As the Brandien testimony indicates, these performance concerns span a wide array of resource types and technologies. They present new levels of reliability risk to the region because many of the underlying risk drivers can force output reductions from multiple generators concurrently, and the system operators are no longer confident that the remaining generators will perform as expected and as offered.

Q: Why is the ISO choosing to address these reliability risks through market incentives?

A: As agreed to by its stakeholders through the Participants Agreement and approved by the Commission, the ISO's mission is to assure the reliability of the region's bulk power system through open markets. In New England, vertical integration has been effectively eliminated and, as a result, only financial incentives can induce resource investment and performance. In light of diminishing performance under current FCM rules, greater financial incentives are needed to resolve these reliability risks. The logic is simple: Reducing these risks will require new investments and capital expenditures by the regions' capacity resource owners to improve the performance of their existing assets, and to develop replacement capacity resources. Private investors will undertake such investments if there is a sufficient financial return in the ISO's markets; they will not undertake them if the market's incentives do not reward investments in improved performance and reliability.

Q: Can you be more specific about the potential investments and capital expenditures that can resolve these risks?

A: The most cost-effective capital expenditures may take many different forms that vary with each resource's technology, location, and individual circumstance. Many types of technologies and contractual arrangements may be technologically feasible to reduce gas supply risks, such as adding and maintaining dual-fuel capability, securing back-up LNG supply, or contracting for firm gas transport. The fact that these may be technologically feasible, however, does not mean they are commercially feasible for generators in the absence of a higher expected financial return on these investments than the ISO's markets currently provide.

Similarly, business practice improvements – such as greater expenditures on maintenance and equipment, or improved facility staffing – may enable a resource to respond more reliably when needed. However, in a competitive market, these expenditures will not be incurred by profit-minded owners unless the return for delivering energy at those times covers the additional investment.

Moreover, entirely different types of capacity resources may help to address these reliability risks as well. Greater amounts of flexible generation, new storage technologies, or fast-responding demand-side resources that reliably deliver energy on short notice can help maintain reliability during stressed system conditions and unforeseen fuel supply disruptions. In some cases, it may simply be the most cost-effective outcome for resources with progressively deteriorating

reliability to retire, and be replaced with new capacity resources that provide reliable performance.

That said, our analysis indicates that only the most ineffectual capacity resources will be incented to retire under Pay For Performance. Many existing fossil-fired plants have low capacity costs and perform well enough during scarcity conditions to cover these costs. Thus, the economic analysis indicates that many can remain in the market. I explain this finding in greater detail in Section VI.A (pages 131-132) of this testimony.

Q: How will the ISO determine how much of each type of resource is needed to resolve these reliability risks cost-effectively?

A: The ISO will not make such determinations. In New England's competitive electricity markets, it is the role of private investors – who must place their own capital at risk – to determine the types of investments that are most cost-effective.

That point is important and fundamental. The ISO is in no position to determine what combination of investment in new resources, versus investment to improve performance and reliability of existing units, will prove to be most cost-effective. Nor can the ISO foresee what innovative developments in, say, storage technologies, contractual arrangements in the gas industry, physical plant performance capabilities, and so forth, will become commercially feasible if investors expect higher potential returns for the reliability benefits of their

investments. Indeed, perhaps more important than any of the specific potential investments noted in connection with this filing, are the potential technologies and investments that may emerge in the future the ISO has *not* yet identified. Put simply, the determination of what specific types and amounts of private investments are best suited to resolving New England's growing reliability risks is the central role for a competitive marketplace, not for the ISO.

In this environment, the capacity market must serve to reward investment decisions that address these reliability risks in cost-effective ways. Accordingly, resolving these reliability risks requires improving suppliers' financial incentives to undertake the investments *they* determine will best improve resources' performance during periods of heightened reliability risk.

Q: How can a capacity market achieve this goal?

A: By providing simple, strong, and direct financial incentives for suppliers to make investments that ensure they can perform during periods of scarcity. These incentives occur naturally in many types of markets, but as I will explain further below, they do not occur naturally in electricity markets. The FCM's current performance incentive mechanism was originally intended to redress this problem, but it is flawed in many ways – and, most importantly, fails to provide incentives for cost-effective investments that will resolve the region's reliability risks.

B. The FCM's Current Link Between Payments And Performance Is Broken

Q: What is the link between payments and performance in the current FCM design?

A: From its inception, the FCM has included provisions intended to motivate resource performance during scarcity conditions, when system reliability is at heightened risk. The current performance incentive provisions take the form of relatively small and infrequent penalties with many exemptions for non-performance, rather than broader performance incentives that provide both risk and reward.

Currently, the FCM measures resource performance during certain types of scarcity conditions called "Shortage Events." At a high level, a resource's performance is assessed based on its "availability" during Shortage Events. Resources that are not "available" during a Shortage Event receive reduced capacity payments.[5]

Q: Please describe the current Shortage Event mechanism in more detail.

A: In the current FCM, capacity payments are primarily determined by the quantity of the resource's Capacity Supply Obligation MW and the price at which that

[5] *See* current Tariff Section III.13.7.1.

Capacity Supply Obligation was assumed. During the Capacity Commitment Period, a resource with a Capacity Supply Obligation has its performance measured during Shortage Events. Stated simply, Shortage Events are scarcity conditions in which the supply of energy and reserves is insufficient to meet the demand for energy and the ISO's real-time reserve requirements for a duration of thirty minutes or more.

Pursuant to the current FCM rules, the ISO computes an "availability score" for each resource with a Capacity Supply Obligation for each Shortage Event. The availability score is the resource's "available" MW, divided by its Capacity Supply Obligation MW. As a general matter, a resource is assessed as being fully available if it is producing energy at the time, or if it self-reports at the time that it is ready to commence startup procedures. In addition, and notwithstanding the logical contradiction in terminology, a resource is treated as fully available if it is not running and cannot startup for a number of possible reasons listed in the Market Rules.

Q: At a high level, in what ways is this current Shortage Event mechanism flawed?

A: With the benefit, now, of years of practical experience with the FCM, it is clear that the linkage between payments and performance is broken. At best, the FCM's Shortage Event mechanism provides weak incentives for resources to undertake investments to improve resource performance. Indeed, in many ways

the current mechanism creates financial *disincentives* for resource owners to incur additional capital expenses that would improve performance and reliability, because those expenses would raise the resource's capacity cost and render it less likely to clear the capacity auction.

In terms of specific design elements, the current Shortage Event mechanism is flawed for two fundamental reasons. The first is that performance assessments are based on a resource's "availability." This is a flawed performance metric that undermines incentives for true resource performance and the investments that enable it. The second is that the FCM has numerous exemptions that remove almost all financial consequences for non-performance. Other important problems with the current Shortage Event mechanism are caps on potential penalties that turn capacity payments into a free option, and a penalty rate that is needlessly complex and too low to be effective. I will discuss each of these problems in turn.

1. Basing Capacity Payments On "Availability" Is Deeply Flawed

Q: Why do you say that availability is a flawed performance metric?

A: The primary problem with "availability" as a performance metric is that it results in resources with very different contributions to system reliability receiving the same capacity payment. That undermines the financial incentives to enhance

resources' capabilities to deliver during scarcity conditions, because the capacity payment is not directly tied to what is delivered during these conditions.

For example, consider unit flexibility – the ability to start or stop on relatively short notice, and to quickly ramp (up or down) to meet changes in demand or cover other supplier's output fluctuations. Suppose that a high operating-cost, inflexible unit delivers nothing during an extended scarcity condition, because it cannot get online in time to help. In contrast, a similarly high-cost but highly flexible unit, which is capable of responding to the scarcity condition, is asked to deliver as much energy (or reserves) as it can to help resolve the emergency. Both resources are treated as "available" and deemed performing under current FCM rules during the scarcity condition, and receive the same capacity payment.

Because both resources receive the same performance measure under current FCM rules, the FCM provides little incentive for suppliers to develop flexible units, or to undertake capital improvements to increase an existing unit's operational flexibility. Developing flexibility can be costly, and the improved service that flexibility enables is not remunerated in the current capacity market.

The general problem is that basing capacity payments on "availability" means that resources with different contributions to system reliability receive the same payment. The contribution to system reliability of a resource that consistently delivers energy and reserves during scarcity conditions is high, and it should be

rewarded accordingly by the market. In contrast, a high-cost, slow-start unit that delivers little energy or reserves during the scarcity conditions contributes little to system reliability. This resource has less value, and should be paid less – regardless of how it scores on an "availability" performance metric.

If the capacity market's compensation to a unit that consistently delivers during scarcity conditions was higher, and the compensation to a unit that does not deliver during scarcity conditions was lower, the market would produce stronger financial incentives to invest in these capabilities. That requires the capacity market to compensate resources based on their true performance during scarcity conditions – delivery of energy and reserves – rather than based on "availability."

At a high level, one way to think about the problem here is to observe that the term "availability" is a something of a misnomer. It does not measure whether a resource is able to deliver energy (or reserves) at times the system needs it most. Instead, it generally indicates whether a resource claims to be able to deliver energy (or reserves) at some *future* point in time, when the system may – or may not – need it. This leads to perverse market outcomes in which resources with very different contributions to system reliability receive the same capacity payment.

Q: What other sorts of investments might a supplier forego as a result of this flaw in measuring performance?

A: Making the same capacity payments to both poor and strong performers during scarcity conditions undermines incentives for suppliers to invest in the capabilities or technologies that are most valuable for delivering energy (or reserves) during scarcity conditions. Backup fuel or dual-fuel capability is another example.

One important operational concern is that a gas-fired unit that has no dual-fuel capability and has made no advance arrangements for fuel may find it difficult to obtain fuel on short notice. The unit may claim it is available even if it is uncertain that it could deliver energy if called. This is most beneficial to resources with high offer prices, as they are the less likely to be running in advance of a scarcity condition occurring, and so the least likely to have their claim of availability tested. An untested claim of availability allows a resource that cannot deliver during scarcity conditions to receive the same capacity payment as a resource that incurs additional capital costs to maintain backup fuel that ensures it can deliver.

More generally, resources that rarely expect to be called to perform during scarcity conditions have limited incentives to spend capital on firm fuel, dual-fuel capability, or other investments that may be needed only a few hours per year. Even if a resource does not have this capability and could not run if asked, it can list itself as available and know that because of its inflexibility or its high energy offer price, its claim of availability is unlikely to be tested – and therefore it is unlikely to be penalized. Hence, it is not an economic business decision for

many suppliers to invest in secure fuel or dual-fuel capability, because the financial benefit (in the form of reduced penalties) under the current FCM design is unlikely to occur, but the financial costs are up front and unavoidable even if the new investment is never used.

Q: Does using availability to measure performance create other problems?

A: Yes. If a resource can receive its full capacity payment without having to provide energy or reserves, then resources that are able to provide energy or reserves during scarcity conditions may actually be harmed by offering to do so. This is because resources that are more likely to be called during scarcity conditions are subject to more frequent potential penalties, under the flawed availability-based design.

For example, consider again two resources with equal operating costs and that differ with respect to unit flexibility. The better-performing resource, precisely because of its flexibility, is likely to be called on by the ISO far more frequently than the inflexible resource. Using round numbers for clarity, assume each resource has the same 10 percent chance of failing to start because of mechanical problems, and that the flexible resource is called to start ten times for each one time the inflexible resource is called during scarcity conditions.

In this situation, the flexible unit has 10 times the likelihood of being penalized, and 10 times the expected cost (in Shortage Event penalties) associated with

accepting a Capacity Supply Obligation. To cover these greater costs, the flexible unit would require a higher offer price in the forward capacity auction. In effect, its flexibility not only reduces its expected profits due to the FCM penalty mechanism, it reduces the resource's expected profit by making it less likely to clear in the forward capacity auction in the first place.

This truly perverse distortion of proper market incentives is an inherent flaw of the current FCM's availability-based performance metric. It constitutes a strong disincentive to build flexible resources of any kind – which are often the most valuable resources to manage an unanticipated period of heighted reliability risk.

Q: But isn't it unfair to older or less flexible resources to expect them to perform in ways that they were not designed for, and to expected them to deliver energy or reserves in scarcity conditions they cannot foresee?

A: No. Resources with long lead times or other limitations may not be able to provide energy or reserves in all scarcity conditions; and they are not asked to do so if their physical capabilities preclude them from being of any use. Rather, the problem is with how they are compensated.

Because of the FCM's flawed availability-based performance metric, these resources receive capacity revenue as if they are contributing to reliability in situations when they are not. Put another way, the ISO's dispatch instructions reflect a resource's capabilities. Resources that aren't capable of much are not

asked to do much. In a well-designed market, resources would be compensated based on what they do. That works in the energy markets, because units are paid for their performance (delivering energy or reserves) in those markets. It is a problem in the capacity market, however, because resources that are not capable of much get paid the same as units that are highly capable. This provides a disincentive for investors to develop units with greater capabilities, particularly if the additional capabilities entail capital costs that must be recovered through higher offer prices in the capacity market.

In this context, greater capabilities cover a broad range of resource attributes and technologies that share the common characteristic of enhancing the ability to provide energy and reserves during scarcity conditions. For example, such resources include higher-cost flexible resources, lower-cost resources that produce energy in essentially all hours, demand-response resources which characteristically perform well when called during scarcity conditions, and storage and new innovative technologies that can respond to scarcity conditions.

Q: Is that the extent of the problems associated with basing capacity payments on availability?

A: No. So far I have focused on the distorted incentives that individual resources face because capacity payments are based on availability. While the problems with respect to individual resources are bad, they are even worse when considering the New England generation fleet as a whole. The reason is that

basing capacity payments on availability instead of actual performance – energy and reserves provided – during scarcity conditions adversely affects the mix of resources that clear in the FCM.

The reasons for this problem are simple to see: The flawed availability-based performance metric makes it profitable for resources to remain in the capacity market that have: (1) low capacity costs, and (2) perform poorly during scarcity conditions (that is, when measured properly, by energy and reserves delivered). Moreover, by remaining in the market, the poorly-performing resources depress capacity prices and displace other potential suppliers with better performing resources that would do more to improve system reliability.

In effect, the current FCM has a structural bias to select less-reliable resources. In economic terms, the current FCM suffers from a phenomenon known as *adverse selection*: it tends to select resources in the capacity auction that have poor performance and poor reliability, because these characteristics enable resources to have lower capacity costs.

At root, this problem occurs because resources' capacity payments are not directly based on their performance during periods when they are needed the most. Put another way, the capacity market tends to select less-reliable resources because it fails to reward them like properly functioning markets do: based on what they deliver.

Q: In practice, does the FCM make capacity payments to resources that have chronically poor performance during scarcity conditions?

A: Yes. Here some statistics are informative. I examined the performance of the region's larger capacity resources (100 MW or more) since the start of the FCM, which covers the period from June 2010 through November 2013. Performance, for purposes of this calculation, is measured by the sum of the energy and reserves provided by a resource in all hours in which the system experienced a reserve deficiency for a portion or all of the hour, as indicated by the system's dispatch and pricing software.

In this analysis, more than a dozen resources, with combined average Capacity Supply Obligations of 4739 MW over this period, stand out. These resources' performance averages only 17 percent of their average Capacity Supply Obligation MW during scarcity conditions. In simple terms, they have delivered relatively little energy or reserves, as compared to their Capacity Supply Obligations, during scarcity conditions over the last three and one half years (since inception of the FCM). The combined average Capacity Supply Obligations of these resources comprises 15 percent of the Net Installed Capacity Requirement for the current (2013/2014) commitment period.

Over this same time period, these resources have received, in total, $674 million in Capacity Payments. On average, that amounts to $7,153 per MWh of energy and reserves provided by this group during scarcity conditions. That payment rate

makes this group of resources very expensive, relative to what they provide during periods of scarcity.

From these statistics I draw the following conclusions. First, the current FCM continues to retain, and compensate, resources that chronically perform poorly during scarcity conditions. This conclusion is also consistent with the facts documented in the Brandien Testimony concerning the deteriorating performance of the region's fossil-steam fleet, in general.[6] Second, these resources potentially displace entry by new resources that would have better performance, and do more to improve reliability, in the capacity market.

2. Exemptions For Non-Performance Are Incompatible With Sound Capacity Market Design

Q: You stated above that the current FCM design includes numerous exemptions that remove almost all financial consequences for non-performance. Please describe these exemptions.

A: The current FCM rules contain a variety of exemptions under which resources that are not able to provide energy or reserves during a Shortage Event are nonetheless deemed fully "available." As a result they are not subject to capacity

[6] Brandien Testimony at 26-36.

payment reductions, despite providing zero contribution to system reliability during the Shortage Event.

For example, a resource that is on a planned outage when a Shortage Event occurs will be deemed available up the MW amount submitted in the outage request.[7] A resource that is not committed due to an outage or derate of certain transmission equipment is considered fully available.[8] And an import capacity resource that is properly offered, but that cannot be delivered because the relevant external interface is constrained, is considered to be fully available.[9] Demand Resources are not subject to the same Shortage Event provisions, but are subject to other limited penalties.[10] Intermittent Power Resources are not subject to the Shortage Event provisions at all.[11] And, as already described, resources that are unable to help alleviate a scarcity condition due to lengthy startup times are considered fully available.[12] The economic effects of these exemptions will tend to distort the mix of capacity resources in undesirable ways, and are contrary to sound capacity market design.

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[7] *See* current Tariff Section III.13.7.1.1.4(b).

[8] *See* current Tariff Section III.13.7.1.1.3(f).

[9] *See* current Tariff Section III.13.7.1.2(d).

[10] *See* current Tariff Section III.13.7.1.5.

[11] *See* current Tariff Section III.13.7.1.3.

[12] *See* current Tariff Section III.13.7.1.1.3(c).

Q: Why are exemptions such as these contrary to sound capacity market design?

A: These exemptions break the link between resource performance and capacity payments. They enable resources that do not deliver energy or reserves during scarcity conditions to continue to receive full capacity payments, as if – counter to fact – they had actually contributed to system reliability during the event. This creates poor incentives, of two forms.

First, it undermines the financial reward for undertaking actions or operational-related investments that can improve resource performance during scarcity conditions, such as plant-level changes that might shorten lead times, making secure fuel arrangements or investing in a backup fuel system, or to incur greater expenses to return from planned maintenance outages faster (facing, say, a spring season with hotter-than-anticipated weather). In brief, when an exemption means that a supplier's capacity payment is not directly tied to what is delivered during stressed system conditions, the supplier does not face strong incentives to invest in ways that can improve the resource's ability to deliver during those conditions.

Second, exemptions enable resources with low capacity costs that expect to perform poorly during scarcity conditions (for any reason) to continue to profitably participate in the FCM. When poor performance is excused and exempt from financial consequences, a poorly performing resource does not need to raise its bid price in the capacity auction to account for any expected penalties

– but resources without the exemption do. This skews the bids in the auction in an especially problematic way: It lowers bid prices from resources that expect to perform poorly and to be exempt from the financial consequences for non-performance. As a result, the auction becomes more likely to clear these poor-performing, less-reliable resources.

At bottom, selling capacity becomes an 'empty' obligation when non-performance is exempt from any financial consequence. In the absence of broad, resource-neutral financial consequences for non-performance, it should come as no surprise that the New England system retains capacity resources that exhibit poor performance during stressed system conditions.

Q: But some of these exemptions are for things beyond the resource owner's control. Why should a resource's capacity payments be reduced if it cannot deliver energy or reserves for reasons beyond its control?

A: Markets must allocate risks that arise from circumstances beyond either the buyer or the seller's direct control. In the capacity market, the market design must either place these risks on suppliers or on consumers. While suppliers may argue that some causes of poor resource performance are 'not their fault,' it is incorrect to conclude that consumers – who are even less likely to be at fault for the supplier's non-performance – should bear the non-performance risk.

Moreover, the concept of 'not my fault' becomes difficult to apply in an economically sound manner in markets intended to motivate long-term resource investments. Creating exemptions changes the return to different capital investments, in potentially undesirable ways. A generator exemption for planned maintenance undermines the incentives to accelerate maintenance work. A long startup lead-time exemption reduces the incentive for a new combined cycle developer to use new technologies that enables the unit to come online quickly. Providing a force majeure exemption for lack of pipeline gas supplies lessens the incentives to install dual fuel or other backup fuel arrangements.

A common refrain is that it makes little economic sense for market design to place performance incentives, and therefore performance risk, upon a supplier for risk factors it cannot control. That common refrain is flatly incorrect, and reflects a fundamental misunderstanding of how markets work – and how the capacity market in particular should work. An important role of the capacity market is to award Capacity Supply Obligations to resources that can be expected to contribute to reliability during scarcity conditions. To do so, a well-designed capacity market should lead a supplier to incorporate into its capacity offer price *all factors* that affect its ability to deliver during scarcity conditions, regardless of whether these factors are within or beyond its control. No other entity is better-positioned to price these factors. In this way, the capacity market offer prices serve an essential role as price signals of both a resource's cost *and its reliability*. That property is crucial to efficient market design: It is what ensures that the

capacity market does not award capacity obligations to resources that expect to perform poorly.

Exemptions undermine this central role of prices as signals of resources' future performance and reliability. In a market designed in large part to help the region meet specific reliability objectives, exemptions are particularly damaging to the market's ability to achieve these objectives at least cost. For all of these reasons, exemptions are incompatible with sound capacity market design. They serve to destroy essential incentives, and inappropriately shift costs to those even less able to manage the risk.

3. Caps On Capacity Payment Reductions For Non-Performance Further Erode Performance Incentives

Q: Please describe the caps on availability penalties in the current FCM rules.

A: Presently, penalties are capped so a resource cannot lose money in the FCM.[13] Even if a resource were to accrue significant non-performance penalties during Shortage Events, the total penalties are limited so that they cannot exceed the resource's FCM revenue. That is, there is no way that a resource can lose money

[13] *See* current Tariff Section III.13.7.2.7.1.3.

in the FCM by accepting a Capacity Supply Obligation in the Forward Capacity Auction, and then failing entirely to perform.

Q: Why is that a problem?

A: This property is contrary to how markets for forward-sold goods should work. A resource that sells a good or service forward, that is, in advance of when delivery is required, takes on an obligation to deliver it. If the seller's cost of making good on delivery exceeds the forward price at which it sold the good, the seller must still make good on the delivery – or compensate the buyer for (the financial equivalent of) the damages it suffers as a result.

The potential for the seller to lose money in making good on its obligation serves two important economic purposes: (1) It motivates only reliable sellers to take on the obligation, and (2) it motivates sellers that do take on the obligation to fulfill it, up to the point where the cost of doing so exceeds the buyer's harm from default. That is how proper markets work, and it is a central property of forward-sold goods markets.

In stark contrast, the "can't lose money" provisions in the current FCM break this basic precept of forward markets. They effectively mean that poorly performing resources are not taking on a proper forward obligation. Rather, they are playing a game of "heads I win, tails I don't lose" with consumers' capacity payments. The "heads I win" scenario corresponds to a year in which the resource, say, is

not called during scarcity conditions, or manages to perform, or fails to perform but is exempt from any penalties; and, in any of these circumstances, has sufficiently small penalties that it has positive net capacity payments for the year. The "tails I don't lose" scenario is one in which poor performance is chronic and not excused, resulting in substantial penalties. In that scenario, the resource walks away without losing money in FCM settlement, even in the worst of circumstances.

Economists have a term for this game: It is called a *free option problem.* By clearing in the capacity market, poor performers have the option to keep the capacity money if they are able to perform. But if they do not perform, they end the commitment period no worse off for having taken on the obligation. Providing free options is exceptionally poor market design, because they undermine essential performance incentives. They make it a worthwhile gamble for suppliers who rarely expect to perform to take on obligations because they have nothing to lose. Worse still, the free option problem helps make it profitable for even the poorest performing resources to remain in the capacity market, potentially displacing entry by more reliable resources that would be able to perform when needed.

The free option problem in the current FCM rules must be fixed to achieve two objectives of a well-designed forward capacity market: (1) that only resources that expect to be able to perform during scarcity conditions take on Capacity Supply

Obligations, ensuring that the ISO can expect to obtain reliable service from capacity resources; and (2) that a supplier accepting a Capacity Supply Obligation is motivated to perform during scarcity conditions, even if the cost of doing so turns out to be greater than it anticipated at the time it accepted the obligation. The costs a supplier must be willing to incur should not be unlimited, but the free option problem with the current FCM must be corrected to improve resource performance and assure reliable service.

4. The Penalty Rate In The Current FCM Rules Is Needlessly Complex And Is Too Low To Be Effective

Q: Please describe the penalty rate for non-performance in the current FCM rules.

A: The penalty rate in the current FCM rules has a structure that defies economic logic. Simplifying slightly, the penalty rate during a Shortage Event is based on a formula in the FCM rules that can be interpreted as:[14]

$$\textit{Annualized FCA Payment} \times \textit{Percent Factor} \times \textit{Availability Score}$$

[14] *See* current Tariff Section III.13.7.2.7.1.2.

In simplified terms, the *Annualized FCA Payment* is what the resource is paid for its capacity for the year (before applying the penalty). As explained earlier in Section III.B.1, the availability score is the resource's "available" MW, divided by its Capacity Supply Obligation MW. The *Percent Factor,* abbreviated PF in the Tariff, is a number equal to 5 percent for Shortage Events of five hours or less, and that increases by 1 percentage point for each additional hour a Shortage Event lasts, with a limit of 10 percentage points for the day.

The penalty rates that result under this rule have an odd structure: They *decrease* the longer is the scarcity condition. Moreover, they decrease quite rapidly. For example, assume a 1 MW resource receives a capacity clearing price of $3 per kW-month, which is indicative of the level of capacity clearing prices in Forward Capacity Auctions to date. If the resource is unavailable (*i.e.,* a score of zero) for a Shortage Event that lasts only one-half hour, its effective penalty rate is $3,600 per MWh. However, if the Shortage Event lasts for two hours, the effective penalty rate falls by 75%, to $900 per MWh. If there is a severe deficiency lasting five hours, the effective penalty rate is lower still, at $360 per MWh.

Generally, scarcity conditions with longer durations can be expected to occur when the system faces more severe challenges meeting system energy and reserve requirements, and longer periods of heightened reliability risk. Under the current FCM penalty structure, however, the penalty rate *falls* significantly the longer the scarcity condition. In effect, as scarcity conditions continue, the price signal for

resources to perform plummets. This perverse property is difficult to reconcile with economic logic.

Q: Is that the only problem with the current penalty structure?

A: No. In addition to its odd structure, the current penalty structure is needlessly complex. That makes the current FCM performance incentives lack transparency. It hampers the ability of investors to gauge whether additional capital expenditures to improve performance during scarcity conditions would be a profitable investment.

For example, even if a resource owner has a reasonably informed view on how many hours, in total, the system may experience Shortage Events each year, that information is not enough to gauge its expected penalty for non-performance. The resource owner must also estimate the particular duration of *each* non-contiguous Shortage Event during the year – likely an impractical task. Moreover, errors in performing this task can result in mis-estimates of the effective penalty rate by a factor of *ten* (for instance, there is a factor of ten change in the penalty rate between $360 per MWh and $3,600 per MWh in my preceding example).

This needless complexity impedes the ability for a resource owner to quantify whether investments that would improve the resource's performance during Shortage Events would yield a positive return, in the form of reduced penalties.

In effect, its complexity undermines the very goals that these performance incentives are intended to serve.

Q: Are there other problems with the penalty rate in the current FCM rules?

A: Yes. Overall, the current Shortage Event penalty rate is generally low, and far too low to mirror the central principle of well-designed capacity market performance incentives. Over a broad range of possible Forward Capacity Auction clearing prices and scarcity condition durations, the effective penalty rate under the current mechanism is on the order of several hundred dollars per MWh. As I explain in detail in Section V of this testimony, to provide appropriate incentives for cost-effective investments, the marginal incentive to perform during scarcity conditions should be larger than this by an order of magnitude.

The low rate that presently applies to non-performance in the FCM directly undermines the financial incentives for resources to undertake capital investments to improve performance during scarcity conditions.

C. There Is A Simple Logic to Well-Designed Capacity Market Performance Incentives

1. How Competitive Markets Provide Incentives for Performance

Q: The performance incentives in the current energy and capacity markets seem quite different. From an economic standpoint, does that make sense?

A: No, it does not. Performance incentives in the energy and in the capacity markets should work similarly and in harmony. In fact, there is a simple logic to how performance incentives are achieved in markets, and it applies to both the ISO's energy and capacity markets. Specifically, during scarcity conditions, a supplier's payments should depend on what it actually delivers at the time. The logic of this simple idea is readily evident by considering how markets other than electricity provide performance incentives during scarcity conditions.

Q: How do markets, other than for electricity, generally provide performance incentives?

A: The essential features of how markets normally provide performance incentives are simplest to explain by looking at two market scenarios. The first of the two scenarios arises when demand is less than the market's total supply. In this situation, the competitive market price will be set at the incremental production cost of the most expensive supplier serving demand. This is the oft-cited property that in a competitive market, price equals marginal cost.

The second scenario occurs when demand reaches the market's supply limit. In this situation, the competitive market-clearing price rises above suppliers' incremental production costs. At such times, the clearing price set in a properly functioning market is based on demand – not on suppliers' incremental costs.

Specifically, the market-clearing price is determined by the value that consumers place upon the last unit produced. At that price, no demand goes un-served: total supply equals the total amount consumers choose to purchase.

This market-clearing process works smoothly in many different settings. For example, think of industries that have both short-run supply constraints and provide a service, or a good that is not easily stored, such as delivered natural gas, hotels, or airline flights. In those industries, when demand reaches the market's short-run supply limit, price rises to what the market will bear. When demand is lower and sellers find they have idle gas transportation capacity, un-booked hotel rooms, or unsold airline tickets, price falls closer to marginal cost.

Q: How does this provide performance incentives?

A: During periods when the market is tight, suppliers earn revenue in excess of their variable costs. In economics parlance, this is called *scarcity revenue* (or sometimes scarcity "rent"). It is revenue that a properly functioning, competitive market provides during scarcity conditions, when demand reaches the market's short-run capacity constraints. Because price falls close to marginal cost during non-scarcity conditions, suppliers in many markets must cover their total costs and earn the return on their investments based on what they deliver during scarcity conditions.

The opportunity to earn scarcity revenue at these times plays two important roles in markets. First, it motivates sellers to pursue investments that ensure they will be able to deliver their goods and services during scarcity conditions. That is, a seller has strong financial incentives to make sure that it can provide as much of its goods or services as possible when supply is tightest. Second, the scarcity revenues are an important determinant of the overall amount of capacity a market installs.

Q: How do businesses respond to these incentives?

A: By making cost-effective investments to assure they can deliver when market conditions are tight. For example, an airline should take all possible cost-effective steps to make sure all of its planes are in service and flying during busy travel seasons. It would make sure that all of its planes have been properly maintained and serviced so that they require no down-time during that peak period. It would likely have forward fuel procurement arrangements in place, and might pay extra to fuel suppliers to guarantee its availability and the delivered price. It might hire additional staff to ensure smooth operations at the point of service, such as gate personnel and baggage handlers. So long as these expenses cost less than the incremental revenue they can be expected to generate, they will be made.

2. Flawed Incentives To Perform In Electricity Markets

Q: How do electricity markets differ from the competitive market model you describe above?

A: Electricity markets generally behave like other markets when supplies are ample, but when supplies are tight, things are different. When electricity demand reaches the energy market's short-run capacity limit, the market price for energy is not determined by the value that consumers place on the last unit produced – it does not rise to the price that the market will bear – as in the other markets that I described above. Instead, it continues to be set based on sellers' offers and the ISO's administrative pricing rules.

Q: Why in times of scarcity is the energy price not set by what the market will bear?

A: Energy market prices do not rise to the price that the market will bear in times of scarcity for a number of reasons, but the root cause is that the demand side of electricity markets remains under-developed. For a host of technological, political, and regulatory reasons, the vast majority of electricity consumers are not exposed to real-time electricity prices. That is, consumers have neither the information (about real-time prices) nor the incentive to reduce their electricity consumption in response to scarcity conditions in the wholesale market. Without a natural demand-side response mechanism by consumers, there is no means for suppliers in the wholesale market to determine what price the market is willing to bear for the limited supply available during scarcity conditions.

Cognizant of this problem, wholesale energy markets such as New England's have alternative mechanisms to set price during scarcity conditions. Specifically, during periods of scarcity the energy market price is determined by the offer price of the marginal supplier, plus an administratively-determined price adder. The adder, which is informally called a scarcity price (and in our Tariff is referred to as a Reserve Constraint Penalty Factor or "RCPF"), helps to replace the energy market's missing scarcity revenue during tight market conditions.

Unfortunately, this scarcity pricing mechanism is not flexible enough to equilibrate electricity supply and electricity demand during scarcity conditions. That is, the energy market's administrative price adders do not – and cannot – adjust the total energy price to ensure no demand goes un-served during scarcity conditions, as naturally occurs in other markets. The ISO cannot do this because it does not have the information this requires (there are insufficient demand-side bids in the Real-Time Energy Market), and because the absence of natural demand-side response by consumers means electricity demand may not react as required.

These shortcomings mean that even with administrative scarcity pricing in the energy market, electricity markets still face a reliability problem and an investment problem.

Q: What is the reliability problem?

Because the energy market cannot adjust price in real-time to equilibrate supply and demand, it cannot assure that no demand will go un-served at the prevailing market price under all circumstances. To limit the frequency with which this occurs, the ISO adheres to an administrative rule that determines, in part, the level of reliability consumers should receive. Reliability, in this context, refers to the chance that (some) demand would go un-served at the prevailing energy market price. In New England, this administrative rule takes the form of the resource adequacy criterion noted earlier in this testimony.

Q: What is the investment problem?

A: The investment problem occurs because the energy market's scarcity revenue is too low to attract the level of investment necessary to achieve the reliability objective. If the scarcity revenue is too low, marginal suppliers will not expect to recover their total costs and will not enter the market (or will soon exit). In that case, additional demand will go un-served, undermining reliability further.

Importantly, the scarcity revenue a seller may earn by producing at these times motivates the seller to do more than just install capacity; it motivates the seller to undertake cost-effective investments to ensure its capacity will perform reliably when demand is high or alternative sources of supply are scarce. Without these investments, the power system will also have poor reliability.

3. The Role Of Capacity Markets

Q: How does the capacity market address this, and how does this relate to performance incentives?

A: At a fundamental level, capacity markets exist to remedy these shortcomings of the energy market. There is no realistic fix to the energy or capacity market that will obviate the need for an administratively-determined reliability criterion, at least for the foreseeable future. A well-designed capacity market can simply and effectively enable suppliers to earn the scarcity revenue that the energy market does not provide and that is necessary to achieve this reliability objective.

However, the capacity market cannot pay out this revenue irrespective of resource performance. Doing so would eliminate the natural mechanism that scarcity revenue provides to guide investments that enable resources to perform reliably during scarcity conditions. Instead, the capacity market must pay out the scarcity revenue that the energy market fails to provide in the same way normal markets do – based on what resources provide during scarcity conditions. If that incentive structure is not replicated, then suppliers will not have the incentive to make the investments necessary to ensure that they are able to perform when needed most – during periods of scarcity.

Q: Does that imply a resource's capacity revenue should depend on its performance during scarcity conditions?

A: Absolutely. In fact, the logic for how a well-designed capacity market provides performance incentives is simple, as it mirrors how markets normally operate. A resource's capacity revenue should depend on the energy and reserves it delivers during scarcity conditions – that is, when there are no additional resources to turn to in order to meet total electricity demand and reserve requirements.

At a high level, this principle works similarly to, and in harmony with, how the energy market provides performance incentives. Suppliers earn the energy market's scarcity revenue during scarcity conditions, and only to the extent they are performing – delivering energy or reserves – at the time. Similarly, suppliers should earn the scarcity revenue that the energy market fails to provide, and that the capacity market is intended to replace, according to the same principle – based on the energy or reserves they deliver at the time.

In this way, the energy and capacity markets jointly provide the strong resource performance incentives that well-designed markets supply. Linking payments to performance is how properly functioning markets work, and rewards cost-effective capital expenditures in assets or capabilities that help ensure resources can perform during scarcity conditions, when reliability is at heightened risk.

Q: What are the hazards of not linking payments to performance in this manner?

A: There are two primary, and related, problems with failing to link capacity payments to performance during scarcity conditions. First, an individual supplier will face the wrong incentives. In many situations, capital investments that improve resource performance during scarcity conditions can cost more than the incremental net energy revenue from the investment. That fact comes as no surprise by itself; because of the demand-side limitations of the energy market, energy market net revenue does not cover all of suppliers' capital investments.

In principle, additional capacity revenue can make the investment profitable. However, this requires the capacity market to recognize, and reward, the resource's improved performance during scarcity conditions. Without strong performance incentives, the capital investment will produce little, if any, additional capacity revenue for the supplier. This provides a disincentive for resources to incur the fixed expenses associated with backup fuel or secure fuel arrangements, or undertake capital improvements that increase resource flexibility, or pursue other capital investments that can materially improve resource performance and system reliability.

Second, without capacity payments strongly linked to performance, a capacity market will have a structural 'bias' to clear less reliable resources. To illustrate why, consider two cases. In the first case, consider a capital expense such as adding backup fuel capability. Capital investments of this sort improve resource performance but can be costly and, in particular, can increase the resource's

capacity cost. To obtain a return on the investment, the resource must raise its bid in the Forward Capacity Auction. That makes the resource less likely to clear. As a result, the capacity market is less likely to select resources that invest in improved reliability.

For the second case, consider now an older resource with declining performance that no longer starts reliably and generates little energy market revenue. By reducing its fixed operations and maintenance expenses the resource becomes less reliable still, but lowers its capacity cost. This enables it to profitably submit a lower bid in the capacity auction – particularly if there is little risk that the resource's capacity payments will be reduced when it fails to perform. Such decisions reduce reliability, but make the resource more likely to clear in the capacity auction. As a result, the capacity market is more likely to select resources that choose not to invest in improved reliability.

Taken together, these two cases imply that a capacity market with poor performance incentives will tend to select less reliable resources. Resources that undertake capital investment to improve performance are less likely to clear, and resources that forego expenses that would improve performance are more likely to clear. Under the current rules, the FCM has a structural bias toward selecting resources that have poor performance and poor reliability, because these characteristics enable them to have lower capacity costs. This structural bias occurs because resources' capacity payments are insensitive to their performance

during periods when they are needed the most. As explained previously, a capacity market with weak performance incentives tends to select less reliable resources precisely because it fails to reward them based on performance during scarcity conditions, as a properly functioning market would.

Q: Do strong capacity market performance incentives remedy this problem?

A: Yes. Linking capacity payments to resource performance during scarcity conditions addresses these problems directly. More reliable, better performing resources can afford to submit lower bids in the capacity auction because of the additional performance-based revenue they obtain, making them more likely to clear in the capacity auction. Less reliable, poorly performing resources cannot afford to submit lower bids in the capacity auction because the reduced capacity payments they receive will no longer cover their capacity costs. This makes poor performers less likely to clear in the capacity auction.

In sum, improving the capacity market's performance incentives will change which resources clear, selecting a better performing, more reliable fleet, rather than being biased toward less reliable resources.

D. The Reliability Problems Actually Observed In New England Are Exactly What You Would Expect As A Result Of The Current Flawed Capacity Market Design

Q: Given all of the problems that you have identified with the current FCM design, what sorts of outcomes would you expect to see after running seven Forward Capacity Auctions?

A: Given the flawed incentives that I have described, and the systematic bias towards clearing less reliable resources in the Forward Capacity Auctions, I would expect to see a deterioration of the reliability of the New England fleet over time, rather than the gradual improvement that would result from sound market design.

Q: In practice, is that what has been observed in New England?

A: Yes. As detailed in the testimony of ISO witness Peter Brandien, the system's resources overall exhibit declining performance by a number of different measures.[15] Moreover, the system's operators no longer have confidence that resources will be able to perform when needed. This uncertain performance is manifest in many different ways and across a broad array of resource types and technologies. Moreover, a portion of the system's capacity resources have exhibited chronically poor performance during scarcity conditions, collecting capacity payments while doing little to assist with reliability during these periods of heightened risk. And it does appear that these problems are getting worse, not better, as time passes.

[15] *See generally,* Brandien Testimony.

Q: Before moving on to explain the Pay For Performance design, please summarize your main points so far.

A: The current FCM provides weak incentives for performance and investment. In a well-designed capacity market, resources would earn the scarcity revenue it provides based on what they deliver during scarcity conditions. The current FCM design does not satisfy this property, and therefore fails to achieve the central objectives of the capacity market. In particular, it provides insufficient incentives for investments that improve resource performance and reliability during scarcity conditions, when the system is at heightened risk. It also results in capacity payments to resources that do little to help meet the system's resource adequacy criterion, which is not a cost-effective use of consumers' capacity payments.

IV. HIGH-LEVEL DESCRIPTION OF THE PAY FOR PERFORMANCE DESIGN

A. Pay For Performance Is Based On Sound Principles For Capacity Market Design

Q: What are the central market design principles of Pay For Performance?

A: The Pay For Performance design adheres to three fundamental market design principles that characterize efficient, competitive markets:

- *Pay for performance.* The first principle is in the design's very name: a well-designed market must pay more for better performance, and pay less for worse performance. This provides the strong performance incentives – at the right times, in the right amounts – that the current FCM lacks.

- *Incentives entail risk.* Second, suppliers – and not consumers – bear the risk and the rewards associated with their resources' performance. This places risk in the right place, in order to incent investment by suppliers and to enable the capacity market's price signal to select a reliable, cost-effective resource portfolio. This risk will need to be priced in each resource's bid in future capacity auctions.

- *Resource neutrality.* Third, the proposal is resource neutral. All suppliers receive the same compensation if they provide the same performance, regardless of their technology.

Q: Please explain the first principle – pay for performance – and how the capacity market must change to incorporate it.

A: The pay for performance principle means that resources that perform well should earn more capacity revenue, and resources that perform poorly should earn less capacity market revenue. By following this principle, the capacity market will incorporate the central features of how properly functioning markets work. Specifically, for all of the reasons discussed above, a resource should earn its

capacity market revenue based on the amount it delivers when demand approaches the market's short-run capacity limit.

To implement this principle, the Pay For Performance design changes the performance-based component of the FCM in two central ways. First, it changes the FCM performance metric to the amount of energy or reserves that a resource delivers. This differs from the FCM's current availability-based performance metric, which is deeply flawed as described previously in Section III.B.1 of this testimony. Second, the capacity market's performance incentive applies during scarcity conditions, which occur when the ISO is unable to satisfy the combined energy demand and operating reserve requirements of the power system. In this way, the design ensures that suppliers face strong financial incentives for investments that enable their resources to perform at the right times and in the right amounts. They are compensated based on what they contribute to system reliability, in the form of energy or reserves, at times when the energy market's incentives are too low and, simultaneously, the system is at heighted reliability risk.

Q: Please explain the second principle – that incentives entail risk – and its consequences for the allocation of risk.

A: A hallmark of competitive markets is that suppliers bear the risk if their assets fail to perform. In the present context, a prominent risk is that if a supplier is frequently unable to deliver during scarcity conditions, it may not be able to cover

its cost and generate a return on its investment. Placing that risk on suppliers is precisely how properly functioning markets work, in order to provide strong financial incentives for resource performance and cost-effective investment.

The Pay For Performance design places resource performance risk on suppliers, which is where that risk belongs. Suppliers are in the best position to manage their performance risk, whether through undertaking new investments to reduce their performance risk, or by making arrangements with other suppliers or entities to cover their obligations during periods they may be unable to perform.

Q: But won't this unfairly penalize suppliers when their non-performance is due to reasons beyond their control?

A: Markets must allocate risks that arise from circumstances beyond either the buyer or the seller's direct control. The costs of those risks must be borne somewhere. In the capacity market, that means that the market design must either place these risks on suppliers, or on consumers. While suppliers may argue that some causes of poor resource performance are 'not their fault,' it is incorrect to conclude that consumers – who are likely much less at fault – should bear the non-performance risk. There is no efficiency gain in doing so.

In fact, markets work best when each supplier bears its own non-performance risks, even when the causes for non-performance are not clearly within the suppliers' control. There are two primary reasons for this. First, the notion of

1 "fault" and "control" when discussing the reasons for non-performance are rarely
2 black and white. A supplier that decides to mothball its dual-fuel capability
3 becomes more susceptible to being unable to provide energy and reserves if there
4 is a disruption on the gas pipeline network. The pipeline disruption may stem
5 from causes beyond the generator's purview, but the generator' inability to
6 perform is also result of its longer-term decision to not maintain backup fuel
7 capability.
8
9 Second, even where the reasons for non-performance are arguably beyond the
10 supplier's control, the capacity market will serve its central goals of achieving
11 reliability cost-effectively when suppliers – not consumers – bear their non-
12 performance risks. By putting the risks of non-performance on the supplier,
13 regardless of the reason, a supplier is incented to incorporate all information it
14 possesses about its expected performance into the offer price at which it is willing
15 to accept a Capacity Supply Obligation. In this way, capacity market offer prices
16 serve an essential role as price signals of both a resource's cost *and its reliability*.
17
18 A high offer price signals that a resource either has very high capacity costs, or
19 has a high likelihood of not performing during scarcity conditions, or perhaps
20 both. The capacity auction will not select such a resource if another resource
21 offers a lower price. This proper function of market price signals works only if
22 the market design leads each supplier to incorporate into its offer price its best
23 assessment of all factors that may result in its non-performance – regardless of

whether those factors are within or outside its immediate control. That property is crucial to efficient market design; it is what ensures that the capacity market does not award capacity obligations to resources that expect to perform poorly.

In sum, in a well-designed market, compensation does not depend upon why a supplier is not producing, or whether the reason(s) are within, or beyond, its control. Its performance is a business risk that suppliers must manage, and their entry and exit decisions – and expected capacity market offer prices – should reflect these risks. The Day-Ahead and Real-Time Energy Market designs already honor this central market design principle, in that they provide no excuses, and no exemptions, for non-performance; in those markets, competition and the market design mean the risks of an individual supplier's non-performance are borne by that supplier. A well-designed capacity market must do the same.

Q: Please explain the third principle – resource neutrality – and why it is important.

A: The third important principle of well-designed markets is that two suppliers that provide the same good or service receive the same price. Their compensation is not dependent on whether or not they use the same technology to produce it. The Pay For Performance design honors this principle by providing all resources with the same compensation for the same performance, regardless of resource type or technology. This is important for several reasons. First, it helps to assure that

compensation is non-discriminatory, with payment terms that do not depend in any way upon the class of resource being compensated.

Second, it frees suppliers to identify and develop the most cost-effective means to improve resource performance. There should be no limits on the technologies eligible to receive FCM revenue. This harnesses the full strength of markets to identify new, innovative ways in which current and future suppliers can improve performance and reliability. The span of these cost-effective investments is difficult to foresee, and might include innovative fuel arrangements for intra-regional gas storage with local distribution companies, backup fuel supplies, greater price-responsive demand practices, new energy storage technologies, and so forth. The central point is that the most cost-effective solutions to the region's reliability challenges will surely come from the innovative results of supplier-selected solutions. Providing the same compensation for the same performance enables healthy, strong competition that will reward cost-effective investments as new technologies emerge and the wholesale markets continue to evolve over time.

B. Pay For Performance Is A True Two-Settlement Market Design

Q: What are the characteristics of a two-settlement market design?

A: Two-settlement systems are widely used for forward-sold goods, whether in centralized markets or in bilaterally-arranged forward contracts. They have three principal characteristics:

- *Forward price*. In a two-settlement system, the buyer and seller establish a forward transaction price at the time the buyer accepts the seller's offer. Payment of this forward price represents the first of two financial settlements.
- *Forward position.* In consideration, the seller takes on an obligation that must be satisfied at a future date. This obligation is commonly called a seller's *position* in a forward market. For commodities and other physical goods, this future obligation has three standard elements: The time at which the good is to be delivered; the location at which the good is to be delivered, and the amount to be delivered. Importantly for present purposes, any of these three elements may be specified as contingent upon other conditions, or determined by formula, rather than be specified as a fixed value at the time of the forward sale.
- *Settlement for deviations.* If the time, place, or quantity delivered by the seller deviates from that specified in the contract, the deviation is credited or charged between buyer and seller in accordance with the terms of the forward contract. This is the second of the two financial settlements. When there is a liquid spot market for the forward-sold good, the second settlement price for deviations is typically the spot price, which reflects the cost the buyer incurs due to the seller's non-performance. In forward-sold goods markets that do not have liquid spot markets at the time of delivery, the settlement price for deviations is stipulated in advance in the forward contract terms.

These three characteristics are the essential 'building-blocks' of well-designed

forward markets.

When organized wholesale energy markets initially emerged, they appropriately developed following these three principles. This is most evident in the design of the Day-Ahead Market, which is a forward market for energy. Specifically, a supplier that clears an energy supply offer in the Day-Ahead Market receives the day-ahead price for the amount of energy it sells forward, which comprises the first settlement. This forward transaction creates a financial obligation for the seller to deliver the amount of energy it sold forward, at a specific location in the network, during a specific hour (or hours) of the next day. If the amount, times, or location of the energy that the seller delivers differ from the terms of the forward transaction, there is a second settlement for the deviation at delivery.

For example, if the supplier delivers more than its forward obligation, it is paid the deviation settlement price for the additional amount it delivers; if the supplier delivers less than its forward obligation, it is charged the same price for the quantity it did not deliver. Importantly, there are no excuses or exemptions associated with the second settlement; the reason a supplier delivers more or less than its forward obligation is independent of the settlement.

Q: What are the benefits of using a two-settlement design for a forward market?

A: The two-settlement market design has numerous virtues. First, it provides a clear product definition. The product transacted in the forward market is an obligation to deliver a particular good at a specific future time and place.

Second, it is conceptually simple. Resources take on a forward obligation to supply at a future point in time, and then cover that obligation either by delivering or through purchases from other suppliers.

Third, the two-settlement design ensures transparency. Everyone knows their obligations, knows the price to be paid if they do not fulfill their obligations, and knows the reward if they are asked and able to deliver above and beyond their obligations.

Fourth, and perhaps most importantly for present purposes, a two-settlement design provides strong performance incentives in both the short-run and in the long-run. It motivates suppliers to take any and all cost-effective investments that will enable them to deliver on their future obligations. It also results in strong incentives for only the most reliable, cost-effective resource to take on obligations in the first place.

Last, a two-settlement system helps to reduce financial risk on both sides of the market. Buyers' expenditures and suppliers' revenues exhibit less volatility over

time using a two-settlement design than if suppliers faced the same performance incentives in a spot market alone.

Q: Is Pay For Performance a true two-settlement market design?

A: Yes. Pay For Performance is a true two-settlement design based on the same logic of forward markets described above. In particular, it has the following three principal characteristics:

- *Forward price*. The Forward Capacity Auction establishes the forward price for Capacity Supply Obligations.
- *Forward position.* A supplier that clears a capacity offer in the Forward Capacity Auction acquires a physical obligation and a forward financial position in the capacity market. Under the Pay For Performance design, a resource's forward financial position is a *share* of the system's energy and reserve requirements in scarcity conditions during the Capacity Commitment Period.
- *Settlement for deviations.* A resource that delivers more or less energy and reserves than its share of the system's energy and reserve requirements during scarcity conditions will receive a performance payment. The performance payment is based on the deviation between a resource's actual performance and its forward financial position. Because deviations can be positive or negative, the performance payment may be positive or negative. The

deviations are credited or charged at a fixed rate specified in the Tariff, called the Capacity Performance Payment Rate.

In this way, a resource's performance is evaluated relative to a pro-rata share of the system's total energy and reserve requirements during scarcity conditions. The settlement for deviations means that resources that perform well, relative to their pro-rata share, will earn more total capacity market revenue. Resources that perform worse than their pro-rata share will earn less capacity market revenue.

These performance payments during scarcity conditions replace the existing FCM Shortage Event penalty structure in its entirety.

Q: You state that under Pay For Performance, the forward position is both a physical obligation and a financial position. Can you please explain that in more detail?

A: Yes. When a resource clears in a Forward Capacity Auction, it assumes a Capacity Supply Obligation for the associated Capacity Commitment Period. As in the current capacity market, the Capacity Supply Obligation represents a physical obligation to offer the MW amount of the Capacity Supply Obligation in both the Day-Ahead Energy Market and the Real-Time Energy Market during the commitment period. Those offer requirements are unchanged under Pay For Performance. A resource's Capacity Base Payment – which represents the first of the two financial settlements – is based on its Capacity Supply Obligation amount and the relevant capacity clearing price.

Under Pay For Performance, a capacity resource's obligations include a forward financial position as well: The financial obligation to cover a pro-rata share of the system's total energy and reserve requirements during scarcity conditions. This financial obligation is covered by delivering energy and reserves, or by purchasing energy and reserves from other suppliers at the time. The purchase from (or sale to) other suppliers is the basis for the second of the two financial settlements, the settlement for deviations. This second settlement for deviation is a resource's Capacity Performance Payment.

Q: Please explain the pro-rata share financial obligation. Can you provide an example?

A: The pro-rata share financial obligation concept is simple, and easily explained by example. When a resource acquires a Capacity Supply Obligation, its share of all capacity obligations is equal to its Capacity Supply Obligation MW divided by the total Capacity Supply Obligation MW of all capacity suppliers. For example, imagine a resource acquires a 300 MW Capacity Supply Obligation, and that the total of all suppliers' Capacity Supply Obligation MW is 30,000 MW. The resource's forward financial position is a 1 percent share of the system's requirements, calculated as 300 Capacity Supply Obligation MW / 30,000 Total MW = 1 percent.

During any period when scarcity conditions occur during the Capacity Commitment Period, the resource's financial obligation is a 1 percent share of the

system's total energy and reserve requirements at the time. For example, suppose a scarcity condition occurs during an off-peak period when the system's total load is 16 GW and the reserve requirement is 2 GW. This gives a total system energy and reserve requirement of 18 GW. The resource's pro-rata share of the system's requirements during this scarcity condition is its 1 percent share applied to the system's requirements of 18 GW. Its pro-rata share is therefore 1 percent × 18 GW = 180 MW.

Q: How does this resource's 180 MW share of the system's requirement relate to its 300 MW Capacity Supply Obligation?

A: At a high level, because the resource has a 300 MW Capacity Supply Obligation, it has an obligation to offer 300 MW into the energy markets. Its Capacity Base Payment – the first of the two financial settlements – is based on its 300 MW Capacity Supply Obligation.

Continuing the example, assume for simplicity that there is only the single scarcity condition described above during the commitment period. The resource's Capacity Performance Payment – the settlement for deviations, the second of the two financial settlements – will be based on its performance relative to 180 MW, which is its pro-rata share of the system's requirements during the scarcity condition. Its Capacity Performance Payment will be positive if the resource delivers more than 180 MW of energy and reserves during the scarcity condition, and its Capacity Performance Payment will be negative if it delivers less than 180

MW of energy and reserves during the scarcity condition. In other words, deviations at delivery are determined by comparing the actual performance of the resource, measured by the energy and reserves it provides, to its share of the system's requirements during the scarcity condition.

Q: Please illustrate the possible outcomes with respect to the Capacity Performance Payments.

A: Assume again only a single scarcity condition event, and that the resource has a 300 MW Capacity Supply Obligation and a 180 MW pro-rata share of the system's requirements at the time of the scarcity condition. Three cases illustrate the possible outcomes. First, imagine that the resource delivers exactly 180 MW of energy and reserves (combined). In that case, its Capacity Performance Payment is zero. The resource's performance exactly matches its share of the system requirements. In this case, there is zero deviation to settle from its forward financial position, and its monthly capacity payment is equal to the Capacity Base Payment.

Now suppose instead that the resource delivers more than its share of the system's requirements. Specifically, suppose the resource performs at its full output of 300 MW. In this case, the first 180 MW that it delivers satisfies its forward financial position. The additional 120 MW of energy or reserves that it delivers above that is a positive deviation from its forward financial position. This will result in a positive Capacity Performance Payment, calculated as 120 MW multiplied by the

Capacity Performance Payment Rate for the duration of the scarcity condition. I discuss the Capacity Performance Payment Rate in detail below.

Last, imagine instead that the resource performs at 100 MW during the scarcity condition – 80 MW less than its share of the system's requirements. In this case, the 80 MW deviation will result in a negative Capacity Performance Payment, calculated as 80 MW multiplied by the Capacity Performance Payment Rate for the duration of the scarcity condition. The Capacity Performance Payment will only be negative if the supplier performs at a level less than the share associated with its obligation.

Q: Doesn't this mean the resource is being penalized for its 80 MW underperformance?

A: No. In the Pay For Performance design, a negative Capacity Performance Payment is in no respect a "penalty." In a two-settlement forward market design, the settlement for deviations, whether positive or negative, is simply the second of the two settlements, as agreed to and understood by the parties upon initiating the transaction (in this case, upon the supplier acquiring a Capacity Supply Obligation).

As a simple analogy, if a grain supplier agreed to deliver ten tons of grain in six months, and then only delivered eight, its under-performance would be settled at the spot price. Even if the spot price happens to be higher than the six-month-ago

forward price, the grain supplier is not being penalized. The transaction is simply being settled as previously agreed.

Pay For Performance, like all two-settlement designs, works the same way. A supplier that under-performs its financial obligation covers its obligation by purchasing from other suppliers, at the agreed upon settlement rate for deviations from forward obligations.

Q: If a resource's Capacity Performance Payment is based on its physical performance, why do you say it is a "financial" position?

A: As with the Day-Ahead Energy Market, under Pay For Performance a resource is not specifically asked, or expected, to physically operate at a MW level equal to its forward position. Rather, it is expected to operate as dispatched. During scarcity conditions, the system dispatch software directs resources to produce at a level that maximizes the sum of the energy and reserves they can provide during each interval, subject to the resource's offered capabilities (such as its ramp rate) and the transmission network's capabilities. A supplier's financial incentives under Pay For Performance – which are to maximize its resource's capabilities to provide energy and reserves – are fully aligned with the system's dispatch objectives to make maximum use of those capabilities during scarcity conditions.

The share-of-system forward financial position, then, is not a physical dispatch target. It is a financial arrangement that links payments to performance, and

thereby creates stronger economic incentives for resources to enhance their capabilities to perform during scarcity conditions.

Q: You stated above that the Day-Ahead Energy Market also follows the principles of sound two-settlement market design. Are there notable differences between the two-settlement design in the Day-Ahead Energy Market and under Pay For Performance in the capacity market?

A: Yes. While both the Day-Ahead Energy Market and the capacity market under Pay For Performance represent true two-settlement designs, there are some notable differences. First, the definitions of the forward positions differ. In the Day-Ahead Energy Market, the forward position is associated with a fixed quantity (for example, a resource might clear 50 MW day-ahead), while in the capacity market under Pay For Performance, the forward position is a percentage share (for example, 1 percent) of the system's requirements, but the MW requirements are not known until the scarcity condition occurs.

Second, the deviation settlement prices in the Day-Ahead Energy Market and the capacity market under Pay For Performance are different. As I stated earlier, when there is a liquid spot market for a forward-sold good, the second settlement price for deviations is typically the spot price, which reflects the cost the buyer incurs due to the seller's non-performance. The Real-Time Energy Market serves this role with respect to Day-Ahead Energy Market positions. As there is no spot market for capacity, under Pay For Performance, deviations are settled at an

administratively-determined rate specified in the Tariff. This rate, called the Capacity Performance Payment Rate, plays the role of an additional scarcity price following the economic logic I described earlier in my testimony in Section III.C. I will discuss the Capacity Performance Payment Rate in detail below.

The third notable difference follows directly from the second. In the Day-Ahead Energy Market, the supplier faces uncertainty over the price at which the deviation will settle, because the real-time price is not known beforehand. Under Pay For Performance, the supplier knows in advance the price at which the deviation will settle, because the Capacity Performance Payment Rate is specified in the Tariff.

This eliminates one element of uncertainty. In the energy market, the supplier faces both quantity risk and price risk in the settlement of forward energy positions, while in the capacity market, the supplier will face only quantity risk, as the price will be known.

Q: Who actually pays the Capacity Base Payments and the Capacity Performance Payments to suppliers?

A: Load pays the Capacity Base Payments to suppliers, while the Capacity Performance Payments are purchases by under-performing suppliers from over-performing suppliers. This is an important property of the Pay For Performance design. A resource that performs below its share of the system's requirements is

buying, anonymously and through the pool, energy (or reserves) from resources that perform above their share of the system's requirements at the same time. The price of these transactions through the pool is the Capacity Performance Payment Rate.

Because all of the Capacity Performance Payments are transfers among suppliers, consumers are fully hedged. That is, consumers continue to pay the capacity clearing price determined by the Forward Capacity Auction three years in advance. They are not at risk for unexpectedly high Capacity Performance Payments to suppliers that perform well during scarcity conditions over the course of the Capacity Commitment Period.

Q: Can resources without a Capacity Supply Obligation receive Capacity Performance Payments?

A: Yes. For a resource with a Capacity Supply Obligation, its performance payment is based on the deviation between its actual performance and its share of the system's requirements. For a resource without a Capacity Supply Obligation, its share of the system's requirements is zero. This means any energy or reserves that it delivers during a scarcity condition event is technically a positive deviation from its share of the system requirements, and should be credited – like all positive deviations – at the same Capacity Performance Payment Rate. A resource without a Capacity Supply Obligation cannot under-perform relative to

its share of the system requirements, and so it cannot have negative Capacity Performance Payments.

A useful way to think about the role of a resource that does not have a Capacity Supply Obligation is that it is a counter-party to (one or more) transactions, through the pool, with resources that have Capacity Supply Obligations but are under-performing at the time. For example, suppose that during a scarcity condition, a capacity resource has a negative 10 MW deviation from (that is, under-performs) its share-of-system obligation. At the same time, a non-Capacity Supply Obligation resource over-performs its share-of-system obligation – which is zero – by delivering 10 MW. The resource with the Capacity Supply Obligation will be charged for is negative deviation of 10 MW at the Capacity Performance Payment Rate; the resource without the Capacity Supply Obligation will be credited for its positive deviation of 10 MW at the same rate. In this situation, the resource with the Capacity Supply Obligation is buying, anonymously and through the pool, 10 MW of energy and reserves from the resource without the Capacity Supply Obligation. It is in this respect that a resource that under-performs relative to its share of the system requirement covers its financial forward position with purchases from other suppliers in the pool.

This design feature is important for two reasons. First, it enables Pay For Performance to be a true two-settlement design. Resources with Capacity Supply Obligations cover their forward financial position either with output of their own,

or with purchases from other suppliers. When a resource covers its position with purchases from others, the purchase payment is due to the relevant counterparty regardless of the counterparty's financial position (if any) in the capacity market. In practice, this feature implies that resources without a Capacity Supply Obligation will receive performance credits only to the extent they deliver energy and reserves that help reduce the severity of a reserve deficiency.

The second reason this design feature is important is reliability. It provides strong performance incentives to *all* resources, of whatever type, to deliver energy and reserves during scarcity conditions when system reliability is at heightened risk. During scarcity conditions, the pool of potential resources that might be able to relieve the reserve shortage should be as broad as possible, and from a reliability standpoint there is no reason to limit that pool to resources with Capacity Supply Obligations.

Q: What would happen if there were no scarcity conditions at all during the Capacity Commitment Period?

A: This is unlikely, given how Capacity Scarcity Conditions are defined, as I will explain below. But if there were no scarcity conditions, then each resource would receive its Capacity Base Payments with no performance adjustments up or down. This helps to assure that suppliers would recover the cost of the investments they make to enable improved resource performance in the event that suppliers'

performance, in the aggregate, is so good that when system conditions are tight scarcity conditions do not occur.

In that case, over time, the ISO's Installed Capacity Requirement may fall while still achieving the region's reliability objectives. Thus, a complete absence of scarcity conditions would not be a persistent market outcome.

Moreover, the two-settlement design of Pay For Performance has important risk-reducing properties in additional ways. For example, it provides suppliers with a degree of insurance for a portion of their total revenue (the capacity market revenue) in a year where there are few scarcity conditions due to mild weather or unusually few major system contingencies.

C. How Capacity Performance Payments Are Calculated Under Pay For Performance

Q: Please explain in more detail how a resource's capacity payments are determined under Pay For Performance.

A: As mentioned above, under Pay For Performance, a supplier's FCM revenue comprises two parts: A Capacity Base Payment and a Capacity Performance Payment.

- The Capacity Base Payment is determined by multiplying the resource's Capacity Supply Obligation (in MW) by the relevant prices. For obligations assumed in the Forward Capacity Auction, that price would be the auction clearing price. For obligations assumed in reconfiguration auctions, that price is the reconfiguration auction price. For obligations assumed bilaterally, that price is the bilateral price. This component of the capacity payment is largely the same as under the current FCM rules.[16]

- The Capacity Performance Payment is determined by a resource's actual performance – the MW amount of energy and reserves provided – during scarcity conditions. This component of the capacity payment is different from how the FCM works today, and is the heart of the Pay For Performance mechanism.[17]

I will explain in detail how scarcity conditions are defined later in my testimony, but generally, scarcity conditions occur when total energy and reserves supplied are insufficient to meet the load and reserve requirements, either zonally or system-wide. During a scarcity condition, a resource's performance payment is determined by its Capacity Performance Score. The Capacity Performance Score is a quantity in MW that corresponds to the resource's deviation from its share of

[16] *See* revised Tariff Section III.13.7.1.

[17] *See* revised Tariff Section III.13.7.2.

the system's requirement, as I discussed above. A resource's Capacity Performance Score may be positive or negative, depending on whether the resource provided more or less than its share of the system's requirements during the scarcity condition.

Q: Please explain the calculation of a resource's Capacity Performance Score in more detail.

A: Again, the Capacity Performance Score is simply the MW amount by which a resource over-performs or under-performs relative to its share of the system's requirements at the time of a scarcity condition.[18] A Capacity Performance Score is calculated for each resource, whether or not it has a Capacity Supply Obligation, for each 5-minute interval in which a scarcity condition occurs. The Capacity Performance Score is the difference between the amount of energy and reserves actually provided by the resource during the interval and the resource's share of the system's requirements during that interval, as shown in the following formula:

$$\textit{Capacity Performance Score} = \textit{Actual MW} - (\textit{Balancing Ratio} \times \textit{CSO MW})$$

[18] *See* revised Tariff Section III.13.7.2.4.

The term *Actual MW* simply reflects the average amount of energy and reserves that the resource actually provided during the interval. For example, a resource supplying 100 MW of power continuously for a 5-minute interval, and an additional 50 MW of reserves during the interval, would have an *Actual MW* value of 150 MW. The value *Actual MW* explained here corresponds to a new defined term in the Tariff, Actual Capacity Provided, which I will address in more detail later.

The term *(Balancing Ratio × CSO MW)* reflects the resource's share of the system's requirements, in MW, during the interval. I explained above that a resource's share of the system's requirements is equal to its Capacity Supply Obligation MW divided by the total Capacity Supply Obligation MW of all capacity suppliers. That calculation yields the resource's percentage share of the system's requirements, which would then be multiplied by the amount of those system requirements (measured in MW) to generate the resource's share of the system requirements in MW. The term *(Balancing Ratio × CSO MW)* captures all of these concepts.

The term *CSO MW* in the *(Balancing Ratio × CSO MW)* term is simply the resource's Capacity Supply Obligation. The *Balancing Ratio* term, called the Capacity Balancing Ratio in the Tariff, is the system's total load and reserve requirement at the time of the scarcity condition divided by the total Capacity

Supply Obligation MW of all capacity suppliers. This concept is expressed mathematically as follows:

$$\textit{Capacity Balancing Ratio} = (\textit{Load} + \textit{Reserve Requirement}) \ / \ \textit{Total CSO MW}$$

For instance, suppose a scarcity condition occurs during an off-peak period when load is 16 GW and the reserve requirement is 2 GW. Assume for simplicity that the *Total CSO MW* (total Capacity Supply Obligation MW of all capacity suppliers) is 30 GW. Then the Capacity Balancing Ratio would be (16 + 2) / 30 = 60 percent. As another example, suppose that a scarcity condition occurs during a hot summer day when load is 27 GW and the reserve requirement is 2.4 GW. Then the Capacity Balancing Ratio for that scarcity condition interval would be (27 + 2.4) / 30 = 98 percent.

Q: Please provide an example of how the Capacity Performance Score would be calculated.

A: Assume that the resource has a Capacity Supply Obligation of 300 MW, and that the total Capacity Supply Obligation MW of all capacity suppliers is 30,000 MW. Also assume that the scarcity condition occurs in an off-peak period where load is 16,000 MW and the reserve requirement is 2,000 MW. Assume that during the scarcity condition interval in question, the resource actually provides 200 MW of energy and reserves.

Using the balancing ratio formula above, the Capacity Balancing Ratio for the interval in question is (16,000 + 2,000) / 30,000 = 60 percent.

Using the performance score formula above, the resource's Capacity Performance Score for the interval is 200 MW – (.60 x 300) = +20 MW. Although the resource has a Capacity Supply Obligation of 300 MW, in this interval, by providing 200 MW of energy and reserves, it has over-performed (relative to its share of the system's requirements) by 20 MW. This represents a 20 MW positive deviation from its share of the system's requirements during the interval, and the resource will receive a positive Capacity Performance Payment for the interval of 20 MW multiplied by the five-minute Capacity Performance Payment Rate.

Q: Please provide another example, showing that the Capacity Performance Score can be negative.

A: The performance score will be either positive or negative, as a resource's actual performance may be greater or less than its pro-rata share of the system's requirements during the scarcity interval.

Using all of the same assumptions in the example above, except that in this case, instead of actually providing 200 MW of energy and reserves during the interval, assume that the resource actually provides 150 MW of energy and reserves during the interval.

In this case, the Capacity Balancing Ratio will not change. The Capacity Balancing Ratio for the interval will still be (16,000 + 2,000) / 30,000 = 60 percent.

Again using the performance score formula above, the resource's Capacity Performance Score in this case will be 150 MW – (.60 x 300) = –30 MW. By providing 150 MW of energy and reserves, it has under-performed (relative to its share of the system's requirements) by 30 MW. This represents a 30 MW negative deviation from its share of the system's requirements during the interval, and the resource will receive a negative Capacity Performance Payment for the interval of 30 MW multiplied by the five-minute Capacity Performance Payment Rate.

Q: Does this mean that a resource will receive a Capacity Performance Payment for each five-minute interval?

A: The ISO will only calculate Capacity Performance Scores and Capacity Performance Payments for five-minute intervals in which there is a scarcity condition. But for each interval having a scarcity condition, each resource will get a distinct Capacity Performance Score and an associated Capacity Performance Payment. As stated above, for each five-minute interval having a scarcity condition, the resource's Capacity Performance Payment will be the product of its Capacity Performance Score for the interval and the Capacity Payment Performance Rate. Again, because the Capacity Performance Score may

be positive or negative, the Capacity Performance Payment may also be positive or negative.

From a settlements perspective, capacity payments will be made monthly, and each resource's Monthly Capacity Payment for a month will be the sum of the resource's Capacity Base Payment for the month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the month. Again, the sum of the resource's Capacity Performance Payments for the month may be positive or negative. And if the sum of those payments is negative, it is possible they could exceed the Capacity Base Payment, making the resource's Monthly Capacity Payment negative.

The Pay For Performance design does include limits on how negative a resource's net capacity payment can get, in aggregate. These limits are referred to as the monthly and annual "stop-loss" provisions, which I discuss in detail in Section VIII.

Q: Is a resource's average performance during scarcity conditions in a month relevant to the Monthly Capacity Payment calculation?

A: In a sense, yes. As a technical matter, Monthly Capacity Payments will be determined by totaling a resource's Capacity Performance Payment for each five-minute interval in which there is a Capacity Scarcity Condition – without regard to the resource's average performance. However, there is a mathematically

equivalent way to calculate a resource's Monthly Capacity Payment based on average resource performance during scarcity conditions in a month. This exercise is useful because it can help in understanding the Pay For Performance construct, how the capacity market settlements work, and how the stop-loss mechanisms function.

Q: Please explain this alternative approach to calculating a resource's Monthly Capacity Payment based on average performance.

A: This is best accomplished by example. Assume that in a month, several scarcity conditions occur that last, cumulatively, for 18 five-minute intervals. That is a total of 1.5 hours. It does not matter whether some or all of those intervals are consecutive. Assume that over those 18 intervals, the average Capacity Balancing Ratio is 60 percent. Finally, assume that the resource in question has a Capacity Supply Obligation of 300 MW, and over the 18 intervals of scarcity conditions, provides on average 200 MW of energy and reserves.

We can calculate this resource's average Capacity Performance Score using the same formula as described above: *Actual MW – (Balancing Ratio × CSO MW)*. Substituting the values in this example, we get (200 MW – (60% × 300 MW)) = +20 MW. In other words, the resource provided, on average, 20 MW above its share of the system requirements across the scarcity condition intervals in the month.

As in the examples above that only included a single interval, this MW deviation amount must be multiplied by the Capacity Performance Payment Rate to arrive at the Capacity Performance Payment amount for the month. Note, however, that the Capacity Performance Payment Rate is measured in Megawatt-hours. Since in the current example there were 1.5 hours of scarcity conditions, the 20 MW average over-performance amount must be multiplied by 1.5. So the resource's average Capacity Performance Score for the month is 20 MW × 1.5 hours = 30 MWh.

The resource's total Monthly Capacity Payment is its Capacity Base Payment plus its monthly Capacity Performance Payment. This is:

(*FCA Price* × CSO MW) +

(30 MWh *Total Monthly Score* × *Capacity Performance Payment Rate*).

The first term in parenthesis is the Capacity Base Payment. The second term in parenthesis is the monthly Capacity Performance Payment.

To calculate the total Monthly Capacity Payment, we need the *FCA Price* and the Capacity Performance Payment Rate. Both of these values are established prior to the Capacity Commitment Period. For purposes of this example, I will use simple round numbers and assume the FCA Price is $3.00 per kW-month and the

Capacity Performance Payment Rate is $2,000 per MWh. We can then calculate the resource's total monthly payment as follows:

- An *FCA Price* of $3 per kW-month is equivalent to $3,000 per MW-month. The resource's Capacity Base Payment is therefore ($3,000 / MW-month × 300 MW CSO) = $900,000 per month.

- The resource's total monthly performance payment is its total monthly score, 30 MWh in this example, multiplied by the Performance Payment Rate of $2,000 / MWh assumed for this example. This yields a monthly Capacity Performance Payment of (30 MWh × $2,000 / MWh) = $60,000.

On average, this resource performed above its share of the system's requirement during the month's scarcity conditions. Its performance increases its total FCM payment for the month by $60,000, to $960,000.

Q: In what way is this mathematically equivalent to the approach to calculating the resource's Monthly Capacity Payment that you described previously?

A: In the approach I described previously, which is reflected in the Tariff provisions implementing Pay For Performance, a resource's total monthly Capacity Performance Payment will be determined by summing the Capacity Performance Payments for each individual five-minute interval having a scarcity condition, without reference to the average Capacity Balancing Ratio or the average

Capacity Performance Score across those intervals. Using those average values, however, as part of a single calculation for the month, will yield exactly the same value. Again, understanding this will facilitate later discussions about monthly settlements and the stop-loss mechanism.

Q: You stated above that under Pay For Performance, resources without a Capacity Supply Obligation are eligible for positive Capacity Performance Payments if they provide energy or reserves during scarcity conditions. How will Capacity Performance Payments be calculated for such resources?

A: Capacity Performance Payments for resources without a Capacity Supply Obligation will be calculated in the same manner as described above, using the same calculations. Where the resource's Capacity Supply Obligation is used in a formula, a zero will apply.

Such a resource's Capacity Performance Score can only be positive, and will equal its actual performance during the scarcity condition. This is evident by using the value zero for a resource's Capacity Supply Obligation MW value in the Capacity Performance Score formula:

$$\textit{Actual MW} - (\textit{Balancing Ratio} \times \textit{CSO MW}).$$

Because the Capacity Supply Obligation is zero, there is nothing to subtract from the *Actual MW*, regardless of the value of the Capacity Balancing Ratio. Note,

importantly, that a resource without a Capacity Supply Obligation will have a Capacity Base Payment of zero.

Again, this is an important design feature because it provides strong performance incentives to all resources, of whatever type, regardless of Capacity Supply Obligation, to deliver energy and reserves during scarcity conditions when system reliability is at heightened risk. During scarcity conditions, the pool of potential over-performers that might be able to relieve the shortage should be as broad as possible, and there is no reason to limit that pool to resources having a Capacity Supply Obligation.

D. Capacity Performance Payments Are Transfers Among Suppliers

Q: You stated above that Capacity Performance Payments are transfers of money from under-performing suppliers to over-performing suppliers. Please explain this further.

A: Under the Pay for Performance design, consumers only pay for the Capacity Base Payments, which are fixed at the time of the Forward Capacity Auction. Hence, the costs to consumers are hedged once the Forward Capacity Auction is complete. They do not bear the financial risk of unexpectedly high Capacity Performance Payments earned by suppliers that perform well during the commitment period. Instead, it is the suppliers whose resources perform poorly – below their share of the system's requirements – that bear the risk of covering the

Capacity Performance Payments. During a scarcity condition, some resources will perform well (above their share of the system's requirements) and others will perform poorly (below their share of the system's requirements). The negative Capacity Performance Payments from the latter will go to pay the positive Capacity Performance Payments to the former. Effectively, the FCM performance incentives amount to financial transfers from under-performing to over-performing capacity resources during scarcity conditions.

Q: Please provide an example of how this works.

A: Imagine a two hour scarcity condition event occurs when load and reserve requirements equal 60 percent of the total Capacity Supply Obligation MW – that is, the applicable Capacity Balancing Ratio is 60 percent.

Unit A has a Capacity Supply Obligation of 140 MW. Units B and C each have a Capacity Supply Obligation of 80 MW. During the scarcity condition, Unit A fails to deliver any energy or reserves, so its Actual Capacity Provided is zero. Units B and C each provide a full 80 MW of energy and reserves during the event. Recalling that the Capacity Performance Score formula is *Actual MW – (Balancing Ratio × CSO MW)*:

- Unit A's average Capacity Performance Score is (0 – (.60 x 140)) = – 84 MW.
- Unit B's average Capacity Performance Score is (80 – (.60 x 80)) = +32 MW.
- Unit C's average Capacity Performance Score is (80 – (.60 x 80)) = +32 MW.

For purpose of this example, assume a Capacity Performance Payment Rate of $2,000/MWh, as in prior examples. Then:

- Unit A has a negative Capacity Performance Payment (that is, a charge in the FCM settlement), calculated as: – 84 MW × 2 hours × $2,000/MWh = – $336,000.
- Units B and C each have a positive performance payment (that is, a credit in the FCM settlement), calculated as: 32 MW × 2 hours × $2,000/MWh = +$128,000 each.

The charge of $336,000 to Unit A is used to pay the credits of $128,000 each to Unit B and Unit C. No additional funds are needed or collected from consumers to settle the Capacity Performance Payments to suppliers.

Q: In your example, why is the amount collected from Unit A for its under-performance greater than the total amount paid to Units B and C for their over-performance?

A: In general, there will always be a net surplus when all the performance credits and charges are tabulated. In this example, the net surplus is the difference between total performance charges collected from Unit A and the credits paid to Units B and C is $80,000, calculated as: ($336,000 – ($128,000 + $128,000)).

This net surplus occurs because, by definition, there are more under-performing resources than over-performing resources during a scarcity condition. If there were not more under-performing resources than over-performing resources, then there would not have been a scarcity condition. Stated more precisely, the system experiences a scarcity condition if and only if the total MW of capacity resources performing below their share of the system's requirements exceeds the total MW of capacity resources that are performing above their share of the system's requirements. Logically, if that were not the case, the system's requirements would be met, and there would be no scarcity condition.

In fact, the magnitude of this net surplus is directly related to the magnitude of the reserve deficiency during the scarcity condition. The greater the deficiency, the greater the amount by which under-performing MW will exceed over-performing MW. So long as there are more under-performing MW than over-performing MW (which again, must be the case or there would be no reserve deficiency), and so long as under-performing MW and over-performing MW are charged at the same Capacity Performance Payment Rate, there will be a surplus collected.

At a high level, this over-collection is not unlike what occurs in the Day-Ahead Energy Market as a result of congestion. And it is a useful feature in that it ensures the ISO's revenue adequacy in the pool-wide settlement of all Capacity Performance Payments. That is, the total of all performance-related charges will

always be sufficient to cover the total of all performance-related credits due to others, across the pool.

Q: What will be done with the net surplus?

A: I mentioned earlier, and will describe in detail below, a "stop-loss" mechanism is included in the Pay For Performance design to limit, in extreme cases, the total losses that a supplier might face as a result of negative Capacity Performance Payments. The stop-loss mechanism can be thought of as a mutual insurance plan among suppliers exposed to that risk. The total net surplus resulting from Capacity Performance Payments will be used as a part of that stop-loss insurance mechanism. The stop-loss mechanism is described in detail below, in Section VIII.

V. THE CAPACITY PERFORMANCE PAYMENT RATE

Q: What is the Capacity Performance Payment Rate?

A: As I explained above, Pay For Performance is a two-settlement forward market. In two-settlement systems, when there is a liquid spot market for the forward-sold good, the second settlement price for deviations is typically the spot price, which reflects the cost the buyer incurs due to the seller's non-performance. For example, the Real-Time Energy Market serves this role with respect to Day-Ahead Energy Market positions. As there is no spot market for capacity, under

Pay For Performance, deviations are settled at an administratively-determined rate specified in the Tariff called the Capacity Performance Payment Rate.[19]

A. The Capacity Performance Payment Rate Determines Incentives to Perform

Q: How does the Pay For Performance design improve performance incentives?

A: The primary element is the Capacity Performance Payment Rate. During scarcity conditions, a resource's performance above or below its share of the system's requirements will be settled at the Capacity Performance Payment Rate. As explained earlier in this testimony, the Capacity Performance Payment Rate is the price at which suppliers transact, through the pool, when an under-performing capacity supplier covers its share-of-system obligation with purchases from other suppliers.

Because the Capacity Performance Payment Rate is a price, it affects suppliers' incentives. In real-time, the sum of the Capacity Performance Payment Rate and the Locational Marginal Price comprise a resource's marginal incentive to deliver energy during scarcity conditions. In this sense, the Capacity Performance Payment Rate serves as a 'scarcity price premium' above the real-time energy and reserve prices. It works in addition to, and takes effect under the same conditions as, the ISO's energy scarcity price adder in the Real-Time Energy Market.

[19] *See* revised Tariff Section III.13.7.2.5.

More importantly, the Capacity Performance Payment Rate affects resources' longer-term investment incentives. Over time, resources that perform well during scarcity conditions accrue positive performance payments and greater net FCM revenue. Resources that perform poorly (or not at all) during scarcity conditions earn comparatively less net FCM revenue. Through this mechanism, Pay For Performance creates financial incentives for the system to evolve toward a resource mix that performs well when the power grid experiences operating reserve deficiencies and faces heightened risk to reliability.

Q: What is the value of the Capacity Performance Payment Rate?

A: When fully phased-in, the Capacity Performance Payment Rate will be $5,455 per MWh. I will refer to this value as the "Full PPR" in my testimony. However, this value will not apply upon the initial implementation of Pay For Performance. Instead, the ISO will phase-in the Capacity Performance Payment Rate such that a lower value will apply to upcoming Forward Capacity Auctions, and their corresponding Capacity Commitment Periods, before reaching the Full PPR value. I refer to this period prior to reaching the Full PPR as the "phase-in period." I will discuss the determination of the Full PPR next, and the phase-in period subsequently.

B. The Capacity Performance Payment Rate Is Based On Sound Economic Principles

Q: How did you determine the Full Capacity Performance Payment Rate?

A: I determined the Full PPR value using a three-step process. First, I identified two economic principles to guide the development of the Full PPR. Second, from these two principles I derived a formula that the Full PPR value must satisfy in order to honor the two principles. Third, I used data for the New England system from several sources to calculate a numerical value for the Full PPR, based on the formula derived in step two. I will discuss each of these three steps in turn.

Q: What are the economic principles used to determine the Full PPR?

A: Two specific economic principles guide the determination of the Full PPR. These are:

1. *Entry occurs when needed.* The Full PPR must be set at a level such that a new capacity resource is willing to enter the market if new entry is needed to satisfy the Installed Capacity Requirement.

2. *Zero revenue for zero performance.* A resource that expects to have zero performance (that is, it expects to supply zero energy and reserves) during all scarcity conditions should expect zero net capacity revenue.

Both of these principles are crucial to a successful capacity market. The first principle requires that when new entry is necessary to satisfy the Installed Capacity Requirement, the *sum* of the prospective entrant's Capacity Base

Payment (determined by the capacity clearing price) and the prospective entrant's expected Capacity Performance Payments is at least as large as the net cost of new entry (also known as "net CONE"). This is essential to ensure that the capacity market serves its objective of attracting new investment in cost-effective resources that can meet the region's reliability requirements.

In this context, the cost of new entry includes, among many things, the cost of permitting, interconnecting, constructing, and financing the new capacity resource. To obtain the 'net' cost of new entry, from the foregoing costs one deducts (the present value of) the net operating revenue the resource expects to earn from its participation in the energy and ancillary service markets. The result – net CONE – represents the costs (including a return on capital) the new entrant must expect to cover from capacity market revenue to be willing to enter the market.

Conceptually, net CONE corresponds to the scarcity revenue that the energy market fails to provide, but that a new entrant would require in order to be willing to invest (when the system requires new entry). The capacity market must remunerate this amount, in expectation, when new capacity is needed to induce investment and satisfy the Installed Capacity Requirement. For present purposes, net CONE does not include any Capacity Performance Payments, which we will describe separately from net CONE for the sake of clarity.

The second principle requires that if a resource's expected performance is zero during scarcity conditions over the entire Capacity Commitment Period, its total expected negative Capacity Performance Payments should fully offset the Capacity Base Payments. In that way, a resource that expects its performance to be zero during all scarcity conditions will not find it profitable to acquire a Capacity Supply Obligation. This principle assures that the region does not pay for, and rely upon, capacity resources that do not expect to perform – at all – during scarcity conditions.

The second principle mirrors, in part, the performance incentives that exist in the energy market: A resource that never provides energy (or reserves) earns zero expected energy market revenue, and would soon exit. Similarly, to provide economically appropriate incentives for such a resource to exit capacity the market, the resource should also expect zero net FCM revenue. A resource that expects to provide zero energy (or reserves) during scarcity conditions is not worth buying in the capacity market.

C. A Simple Capacity Performance Payment Rate Formula Satisfies These Sound Principles

Q: How did you determine a formula that the Full PPR value must satisfy in order to honor these two economic principles?

A: Each of these two economic principles can be represented by precise formulas governing a capacity resource's revenues and costs. I first translated these principles into corresponding formulas. I then combined them logically (which is to say, algebraically) to determine a new formula that the Full PPR must satisfy to honor the two economic principles. Although the final result is a simple formula for the Full PPR, deducing it from the two principles requires many logical steps. I will describe these steps next.

Q: How do you translate the first principle into precise formulas?

A: The first principle – that the Full PPR must be set at a level such that a new capacity resource is willing to enter the market if new entry is needed to satisfy the Installed Capacity Requirement – applies to new entry. In terms of revenues and costs, it is equivalent to stating that a new entrant's expected net FCM revenue must be equal to, or exceed, the sum of its net costs to enter the market and a risk premium (if any) to be willing to accept the obligations that a resource accepts with a Capacity Supply Obligation.

This statement of revenues and costs can be represented more succinctly by the following formula, where all terms are expressed on a per Capacity Supply Obligation MW-year basis:

(A) $$Capacity\ Price_{new} + Expected\ PP_{new} \geq net\ CONE + RF_{new}.$$

I will refer to this formula as Condition (A).

The first term, *Capacity Price*$_{new}$, is the (annual) capacity clearing price when new entry clears. This is also the resource's Capacity Base Payment rate under the Pay For Performance design, represented in dollars per MW-year in this context.

The second term, *Expected PP*$_{new}$, is a new resource's expected (annual) Capacity Performance Payments. It is represented in dollars per MW-year in this context. I explain this term in more detail below.

The third term, *Net CONE*, is the new entrant's (annualized) net cost of new entry, as described earlier. It is represented in dollars per MW-year.

The last term, RF_{new}, is the new entrant's *risk factor*. The risk factor represents the amount of expected profit, if any, the entrant would be willing to forego by not acquiring a Capacity Supply Obligation and deploying its capital in its next-best alternative use. While it might seem odd for a profit-seeking entity to be willing to forego expected profit, acquiring a Capacity Supply Obligation under Pay For Performance presents the possibility that a resource – if it performs very poorly – could have negative Capacity Performance Payments that exceed its Capacity Base Payments. In that case, it would incur a loss in capacity market settlements. Because of this possibility, a market participant that has positive expected profits from acquiring a Capacity Supply Obligation, but is sufficiently

risk averse, may nonetheless choose to forego those expected profits in order to avoid the possibility that it could incur a loss in capacity market settlements. The risk factor represents the additional premium a new entrant requires, expressed here in dollars per MW-year, above its net cost of new entry, in order to be willing to accept the Capacity Supply Obligation.

To make further use of Condition (A), it is helpful to explain the second term, *Expected* PP_{new}, in more detail. A new resource's *Expected PP* value is determined by the Capacity Performance Payment Rate multiplied by the resource's expected annual average Capacity Performance Score. Stated as a formula, and again with all terms represented on a per Capacity Supply Obligation MW-year basis, this is:

(B) $Expected\ PP_{new} = PPR \times [Actual_{new} - Balancing\ Ratio] \times Scarcity\ Hours_{new}$

I will refer to this formula as Condition (B).

In Condition (B), the terms on the right-hand side of the equal sign have the following precise interpretations:

- The symbol *PPR* represents the Capacity Performance Payment Rate, in dollars per MWh;

- $Actual_{new}$ is the new resource's expected <u>average</u> performance per MW of capacity during scarcity conditions annually (a number normally between zero and one);

- The *Balancing Ratio* as represented here is the expected annual average Capacity Balancing Ratio during all scarcity hours annually; and

- The term $Scarcity\ Hours_{new}$ is the expected annual hours of scarcity conditions when the system is at planning criteria and new entry is required.

As a simple example, suppose a new resource has a capacity of 1 MW, its expected average annual performance is $Actual_{new}$ = .9 MW during scarcity hours, the expected average annual Capacity Balancing Ratio during scarcity hours is 60 percent (or 0.6), and the expected number of scarcity hours annually is 20. Assume for the purposes of this example only that the PPR value is $2,000 per MWh. In this simple example, the new resource's expected annual Capacity Performance Payment is:

$$Expected\ PP_{new} = \$2{,}000 \text{ per MWh} \times [.9 - .6] \times 20 \text{ hours per year}$$

$$= \$12{,}000 \text{ per MW-year.}$$

In this example, the resource's expected annual Capacity Performance Payments are positive. They are positive because its expected annual performance rate is 90 percent (calculated as 0.9 MW per MW of Capacity Supply Obligation), and this performance rate exceeds its annual expected Capacity Balancing Ratio of 60 percent. Stated equivalently, the new resource in this example expects that, over the course of the year, it will perform during scarcity conditions at a rate of 90 percent, which exceeds the expected share-of-system financial performance obligation during scarcity conditions of 60 percent.

Q: How do you translate the second economic principle into precise formulas?

A: The second economic principle requires a resource's expected net FCM revenue to be zero if the resource's owner expects it to have zero annual performance during scarcity conditions. To translate this principle into a formula, we can apply the same logic used in Condition (B) above. Note, however, that in this case the application of Condition (B) must also apply to existing resources because a 'zero performer' could be an existing resource whose performance has deteriorated to where it no longer expects to perform.

Specifically, we can re-state Condition (B) without the 'new' qualifier as the following formula:

$$\textit{Expected PP} = \textit{PPR} \times [\textit{Actual} - \textit{Balancing Ratio}] \times \textit{Scarcity Hours}$$

The interpretation of each term in this formula is just as before.

To use this formula in the context of the second economic principle, note that if a resource expects never to perform during scarcity conditions, then – by definition – its value of *Actual* in this formula is zero. Accordingly, if we zero-out the *Actual* term above, we find that a resource that expects to have average annual performance of zero during all scarcity conditions has a negative *Expected PP* value per Capacity Supply Obligation MW-year of:

$$PPR \times [0 - Balancing\ Ratio] \times Scarcity\ Hours$$

which can be simplified to:

(C) $$-PPR \times Balancing\ Ratio \times Scarcity\ Hours.$$

I will refer to this as Condition (C).

The *Expected PP* value in Condition (C) is a negative number. In words, it equals the Capacity Performance Payment Rate for the resource's share of system requirements (given by the Capacity Balancing Ratio), applied in all expected scarcity hours during the year. In terms of the Pay For Performance design, this negative number represents the expected deviation settlement (per Capacity

Supply Obligation MW) for a resource with zero performance under the Pay For Performance two-settlement system.

Q: Why is this particular formula, Condition (C), important?

A: There is a key relationship between the expected deviation payment and the capacity clearing price. Consider a resource that expects to perform at zero during all scarcity conditions, in a year when new entry is required and new entry sets the capacity price. The second economic principle described above requires that if a resource's expected performance is zero, its expected negative Capacity Performance Payments must offset its Capacity Base Payment revenue from the capacity clearing price.

This requires, in expectation, that

$$\text{(D)} \qquad PPR \times Balancing\ Ratio \times Scarcity\ Hours_{new} = Capacity\ Price_{new}$$

I will refer to this as Condition (D).

Excepting the sign change, the left hand side is the same formula obtained in Condition (C). It is the expected annual performance payment (per Capacity Supply Obligation MW) for a resource with zero expected performance in all scarcity conditions. In this scenario, however, we are considering a year in which

new entry occurs, so the appropriate number of scarcity hours is that when new entry occurs, or *Scarcity Hours*$_{new.}$

Moreover, in this scenario, the capacity clearing price is set by the new entrant. The capacity clearing price when new entry occurs is the value of *Capacity Price*$_{new}$. We used this same term earlier, in our explication of Condition (A).

Condition (D) is necessary for the second economic principle to be satisfied. To see this, suppose that, counter to fact, Condition (D) did not hold and (say) the capacity price exceeds the value of *PPR* × *Balancing Ratio* × *Scarcity Hours*$_{new}$. Then a resource with zero expected performance has positive expected net FCM revenue, violating the second economic principle of zero expected revenue for zero performance.

Q: How did you combine these formulas to arrive at the final Full PPR formula?

A: The first and last conditions, Conditions (A) and (D) above, jointly determine the set of Capacity Performance Payment Rate values that satisfy the two main economic principles.

To see this, first determine the set of possible values for *PPR* that simultaneously make Conditions (A) true and Condition (D) true. We can do this by inserting Condition (D) into the left-hand side of Condition (A). That yields the following new formula:

$$PPR \times Balancing\ Ratio \times Scarcity\ Hours_{new} + Expected\ PP_{new}$$
$$\geq\ net\ CONE\ +\ RF_{new}$$

We can also use Condition (B), which is our definition of the term *Expected* PP_{new}, to write the previous formula in an equivalent way. Specifically, inserting the full expression for *Expected* PP_{new} from Condition (B) in place of the single term *Expected* PP_{new} in the left-hand side of the previous formula yields the following equivalent formula:

$$PPR \times Balancing\ Ratio \times Scarcity\ Hours_{new}$$
$$+ PPR \times [Actual_{new} - Balancing\ Ratio] \times Scarcity\ Hours_{new}$$
$$\geq\ net\ CONE\ +\ RF_{new}.$$

In this expression, there are several terms on the left-hand size of the inequality sign that add and subtract the same quantities. They therefore cancel each other out and can be removed from that expression. The terms that remain are shown in the following equivalent formula:

$$PPR \times Actual_{new} \times Scarcity\ Hours_{new} \geq\ net\ CONE\ +\ RF_{new}.$$

Re-arranging these terms yields the formula for the Capacity Performance Payment Rate that satisfies the two starting economic principles. This formula is:

$$PPR \geq \frac{Net\ CONE + RF_{new}}{Scarcity\ Hours_{new} \times Actual_{new}}$$

I will refer to this as the Full PPR formula. In summary, this analysis shows that to satisfy the foundational economic principles underlying the Capacity Performance Payment Rate, the rate must satisfy this Full PPR formula.

Q: Can you interpret the Full PPR formula, in words?

A: Although the mathematical derivation of this formula takes many steps, the conclusion is economically sensible and simple to interpret. Stated succinctly, the Capacity Performance Payment Rate spreads the total capacity revenue that a new entrant requires over its expected annual output during scarcity conditions.

To see why, let's look at the pieces. The sum in the numerator of the Full PPR formula ($Net\ CONE\ +\ RF_{new}$) is the new entrant's total cost, including a risk premium (if any), that it must expect to recover from the capacity market in order to be willing to enter. The amount in the denominator ($Scarcity\ Hours_{new} \times Actual_{new}$) is the new entrant's expected total annual performance during scarcity conditions. Performance, in this context, is measured in MWh delivered in the form of energy or reserves, per Capacity Supply Obligation MW, during scarcity conditions. In this way, a new capacity resource earns its capacity revenue by performing during scarcity conditions.

Similarly, an existing capacity resource – one that clears in the auction, whether or not new entry sets price – earns greater net FCM revenue to the extent that it delivers more energy and reserves during scarcity conditions. These resources all have positive expected profit in the capacity market (with the possible exception of the marginal resource that sets the capacity clearing price, who expects zero profit).

Q: What if the Capacity Performance Payment Rate is set at a lower value than the Full PPR formula specifies? Would a new entrant still be willing to enter when new entry is required in order to satisfy the Installed Capacity Requirement?

A: Yes. If new entry is required, the Forward Capacity Auction will clear at a high enough price to clear the new entrant, and ensure the region meets the Installed Capacity Requirement. Because of this, even if the Capacity Performance Payment Rate was set at a low value that does not satisfy the Full PPR formula, the first economic principle would not be violated.

However, if the Capacity Performance Payment Rate is set at a lower value that the Full PPR formula specifies, the second economic principle – zero expected revenue for zero performance – would be violated. A zero performer would have positive expected profits, and may submit a capacity offer price less than that of a new entrant. Because of this, the zero performer could displace the new entrant.

Q: Please explain why a zero performer would not clear in the Forward Capacity Auction, whether or not new entry is required to satisfy the Installed Capacity Requirement, if the Capacity Performance Payment Rate is set according to the Full PPR formula?

A: If a capacity resource expects to have zero performance when the system is at criteria, its expected negative net Capacity Performance Payments will equal the offer price of the new entrant. That means its net expected FCM revenue will be zero, and therefore it will not find it profitable to acquire a Capacity Supply Obligation.

A different perspective on this property is to observe that, in order for a zero expected performer to cover its expected negative Capacity Performance Payments, the Capacity Base Payment it requires is *greater* than the Capacity Base Payment that a new entrant requires to be willing to enter. This means the zero expected performer will not clear in the forward auction, because a new entrant would instead. The fact that the zero expected performer will not clear when new capacity is required is by design; moreover, it implies that a zero expected performer will not clear if the capacity market has excess supply, because the Capacity Base Payment would be lower than when the capacity price is set by new entry.

That property is important from both an economic standpoint and from a reliability perspective. The Full PPR formula ensures that a zero expected performer cannot profit by displacing a reliable new entrant.

Q: What about resources that are in between, that is, neither new entrants nor zero expected performers? Does this Capacity Performance Payment Rate select these resources cost-effectively?

A: Yes. Because all resources are compensated at the same rate on the basis of their performance, better performers earn higher net FCM revenue; poor performers earn less. All resources that clear in the Forward Capacity Auction either have low capacity costs, high expected performance, or both. Conversely, the resources that fail to clear in the Forward Capacity Auction have high costs, poor expected performance, or both.

This differs from how the capacity market clears today, where resource may have low capacity offers and clear because they have minimized the capacity costs by not undertaking capital expenses that would improve their performance during scarcity conditions, when reliability is at heightened risk.

D. Determinants of the Full PPR Value

Q: Is it important for the numerical value of the Capacity Performance Payment Rate to be specified prior to the Forward Capacity Auction, even

though performance payments are not realized until three years later, during the Capacity Commitment Period?

A: Yes. From a commercial standpoint, it is important for the Capacity Performance Payment Rate value to be specified well in advance of the Forward Capacity Auction. A fixed value for the Capacity Performance Payment Rate avoids uncertainty over the deviation settlement price that will apply when a capacity supplier's performance is below or above its share of system requirements during scarcity conditions. This means that when a supplier evaluates its expected Capacity Performance Payments prior to bidding in the Forward Capacity Auction, the supplier faces only *quantity* risk – the MWh of its over- or under-performance during commitment period scarcity conditions – but it does not face *price* risk regarding the Capacity Performance Payment Rate at which its deviations are settled. For these reasons, the Capacity Performance Payment Rate is set forth in the Tariff, based on the foregoing principles and analysis.

Q: How did you determine the $5,455 per MWh numerical value for the Full PPR?

A: To determine the numerical value for the Full PPR, I used the Full PPR formula described above:

$$PPR \geq \frac{Net\ CONE + RF_{new}}{Scarcity\ Hours_{new} \times Actual_{new}}$$

For this purpose I evaluated each term that appears on the right-hand side of the Full PPR formula, using various sources of data for the New England system. I will explain each term and the value used for each term next.

Net CONE. This parameter is the net cost of entry for the most cost-effective generation type. Based on the recently-completed Offer Review Trigger Price analysis for New England, this is a combined cycle with an estimated annualized net cost of entry of $8.87 per kw-month, or $106,394 per MW-year.[20]

Risk Factor. For purposes of establishing the Capacity Payment Performance Rate, we assume the risk factor term RF_{new} is zero. This is appropriate under the assumption that a potential new entrant's next best alternative to acquiring a Capacity Supply Obligation is not materially more risky than acquiring it. This would be the case if a potential new entrant's next best alternative to acquiring a Capacity Supply Obligation is not to acquire one and to collect the Capacity Performance Payment Rate for the same performance, for example. Under that putative next best alternative, for a resource with high expected performance (*i.e.,* a value of $Actual_{new} = 0.92$), the volatility of its cash flows from year to year under the Pay For Performance design is *lower* by acquiring a Capacity Supply Obligation than if the resource relied solely on Capacity Performance Payments.

[20] *See* 2013 Offer Review Trigger Prices Study by The Brattle Group, submitted in *ISO New England Inc.*, Revisions to Forward Capacity Market Offer Review Trigger Price Provisions, Docket No. ER14-616-000 (filed December 13, 2013). The filing is currently pending at FERC.

I explain this property of cash flow volatility under Pay For Performance in greater detail in Section VI.B below.

In general, the ISO has no certain means by which it can ascertain the specific next best alternative use of a proxy new entrant's capital if it chooses not to acquire a Capacity Supply Obligation. Assuming a different (that is, positive) value for the risk factor term for purposes of establishing the Capacity Performance Payment Rate would result in a *higher* Capacity Performance Payment Rate than the numerical value proposed below.

Scarcity Hours at Criteria. The term $Scarcity\ Hours_{new}$ represents the expected number of scarcity hours annually when the system is at criteria, and new entry is required. To determine an appropriate value for $Scarcity\ Hours_{new}$, we employ the ISO's system planning model used to determine the Installed Capacity Requirement and related values. This model indicates that at planning criteria, the expected value of the number hours of operating reserve deficiencies is 21.2 hours per year.

In obtaining this value, we used the same inputs and assumptions as are employed in the ISO's probabilistic simulation model to set the Installed Capacity Requirement, with one exception. Other than that exception, these inputs and assumptions are detailed in the ISO's January 2013 report, *ISO New England Installed Capacity Requirement, Local Sourcing Requirement, and Maximum*

Capacity Limit for the 2016/2017 Capability Year,[21] and the principal results are filed with the Commission.[22] The exception is that we assumed that all Real-Time Demand Response ("RTDR") resources are able to supply reserves, or are available to supply energy, prior to a reserve deficiency. This is consistent with the Commission-approved ISO plans for the full integration of active demand response resources into the energy markets in 2017, but it differs from current RTDR dispatch practices as an action under Emergency Operating Procedures (OP-4 Load Relief), which generally occurs subsequent to an operating reserve deficiency.

The value of the number of scarcity hours used to determine the Capacity Performance Payment Rate is the ISO's system planning model's result when the system is at planning criteria. This value does not change materially from one year to the next. In particular, the estimates of scarcity hours when the system is at planning criteria is robust to annual variation in the amount of excess supply, or lack thereof, from one year to the next.

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[21] Available at: http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/index.html.

[22] *See ISO New England Inc. and New England Power Pool*, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2016/2017 Capability Year, Docket No. ER13-334-000 (filed November 6, 2012), accepted by letter order dated December 31, 2012.

As the overall mix of capacity resources in New England evolves and resource performance improves, the estimated number of scarcity hours when the system is at criteria may change slowly over time. However, this value is unlikely to drift significantly lower than current estimates, even as performance improves, because as performance improves (other things assumed equal) the Installed Capacity Requirement necessary to satisfy the region's resource adequacy criterion will also adjust downward.

Average Annual Performance. The term $Actual_{new}$ represents the average annual performance, per Capacity Supply Obligation MW, of a cost-effective new entrant. This is a number that ranges between zero (no performance) and, normally, one (perfect Capacity Supply Obligation performance). Performance above a resource's Capacity Supply Obligation MW is possible, in which case this value may exceed one.

Importantly, $Actual_{new}$ is not the Year 1 value of the new entrant's performance, but rather its expected average annual performance over the project owner's investment horizon when new entry occurs. We determine an appropriate value for $Actual_{new}$ based on the following:

- *Units and ages.* To determine an appropriate value for $Actual_{new}$ empirically, we examined the observed performance of 31 combined cycle generating facilities constructed in New England over the past 20 years. This sample

mirrors the 20-year investment horizon employed in the ISO's Offer Review Trigger Price analyses for the cost of new generation entry.

- *Actual performance during scarcity conditions.* For each facility, we calculated its average actual scarcity condition performance during the months of June, July, and August for the three-year period from 2010-2012. We use summer months' scarcity conditions performance because when the system is at criteria (requiring new entry), ISO planning models indicate nearly all expected scarcity hours are anticipated to occur during the summer months.

We then determined a trend line, via linear regression, that best explained the 31 facilities' observed performance rates as a function of the units' ages. The data show that average performance (the trend line) of these resources is a relatively flat function of facility age, declining from average performance of approximately 94 percent per MW for new (age 1 year) facilities to approximately 89 percent per MW for facilities at age 20. We use the midpoint of this range, or a value of $Actual_{new}$ = 0.92 per MW, as an appropriate value for a new combined cycle facility's average performance during scarcity conditions of over the project's investment horizon.

Q: How do you combine the values obtained from these data sources to obtain the Full PPR?

A: Using these values as inputs to the Full PPR formula derived previously, we obtain

$$PPR \geq \frac{Net\ CONE + RF_{new}}{H_{new} \times Actual_{new}} = \frac{\$106{,}394\ /\ \text{MW-year}}{21.2\ \text{hours/year} \times 0.92} = \$5{,}455\ /\ \text{MWh}.$$

While values above $5,455per MWh would also satisfy the inequality, the ISO will set the Full PPR at the smallest value that satisfies this requirement, or $5,455 per MWh.

Q: Did you make any adjustments for the cost of the FCM's Peak Energy Rent deduction in evaluating the Full PPR formula?

A: No. Since the Peak Energy Rent provisions were revised in December 2010, the value of the monthly Peak Energy Rent deduction has fallen substantially from prior years. Over the last three years, from 2011 through 2013, the cost of the Peak Energy Rent deduction has averaged four cents per kW-month. Accounting for this cost would not make a material difference in the value of the Full PPR.

E. The PPR Phase-In Period

Q: Please summarize the phase-in of the Capacity Performance Payment Rate.

A: The Pay For Performance changes incorporate a phase-in, over several years, of the Capacity Performance Payment Rate. Specifically, it will start at a lower

value for the ninth Forward Capacity Auction (conducted in February of 2015 for the Capacity Commitment Period beginning on June 1, 2018), and rise over time to reach the Full PPR value after a phase-in period of six Forward Capacity Auctions.

The proposed phase-in period is structured in two discrete steps, each of three years' duration, before the Full PPR is applied. Specifically:

- For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2,000/MWh. This corresponds to the 9th, 10th, and 11th Forward Capacity Auctions to be conducted in 2015, 2016, and 2017, respectively.

- For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. This corresponds to the 12th, 13th, and 14th Forward Capacity Auctions to be conducted in 2018, 2019, and 2020, respectively.

- For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5455/MWh. This corresponds to the 15th Forward Capacity Auction, to be conducted in 2021, and thereafter.

During the first step, the Capacity Performance Payment Rate is set at $2,000 per MWh, which is (slightly more than) one-third of the Full PPR of $5,455 per MWh. During the second step, the Performance Payment Rate increases to (approximately) two-thirds of the Full PPR rate of $5,455 per MWh. The full rate would be in effect for the 2024-2025 Capacity Commitment Period, so the complete design takes effect approximately 10 years from now.

Under this phase-in schedule, the second step provides a three year 'overlap' period in which market participants would observe the system's operating experience under the Pay For Performance design, as well as their individual resources' performance. This occurs at a Capacity Performance Payment Rate less than the Full PPR.

Q: Why does Pay For Performance incorporate a phase-in period for the Capacity Performance Payment Rate?

A: The ISO understands that Pay For Performance represents a major shift in the Forward Capacity Market design that will significantly impact the capacity revenue streams for some suppliers and impact costs to consumers. It is reasonable to smooth the transition to the new paradigm, and phasing in the Capacity Performance Payment Rate will help to accomplish that. The lower initial value will tend to reduce the financial risk and uncertainties that capacity sellers face under the Pay For Performance design while participants gain

1 experience with the design prior to the full Capacity Performance Payment Rate
2 becoming effective.
3
4 During the phase-in periods, market participants will acquire greater information
5 and experience about the frequency, timing, and duration of scarcity conditions on
6 the system. They will also acquire years of additional experience with how their
7 individual resources perform during these conditions. This additional information
8 will help suppliers better gauge the risks and rewards they face under the new
9 design, provide additional time for new bilateral arrangements to develop in the
10 marketplace that can help manage and spread risk, and enable the region to better
11 assess the likely impacts of incremental changes in the Capacity Performance
12 Payment Rate on Forward Capacity Auction prices prior to reaching the full
13 Capacity Performance Payment Rate.
14
15 **Q: Are there any trade-offs or concerns associated with using a lower Capacity**
16 **Performance Payment Rate during the phase-in period?**
17 A: There are some performance trade-offs that come with the lower Capacity
18 Performance Payment Rate. A lower rate will result in lower marginal incentives
19 for performance during scarcity conditions. However, here it is paramount to
20 observe that the primary role of the Capacity Performance Payment Rate, and the
21 capacity market generally, is to induce cost-effective long-run investments in
22 resources' capabilities. An investment decision is not made on the basis of the
23 Capacity Performance Payment Rate during any single year; it is based on the

present value of the revenue streams the investment will generate over its useful life. This means that resource owner's investment decisions in response to the Pay For Performance design will be determined in significant part, if not primarily, by the Full PPR value that will apply for most of the life of the investment.

In fact, the phase-in period is likely to affect investments largely by shifting the timing of investment. Suppose, for instance, that a resource owner could undertake a particular capital expense that would improve the resource's performance and that the expense would be a profitable undertaking, in present value terms, if paid the Full PPR value of $5,455 per MWh for its performance. Conceivably, this capital expense might not be a profitable investment if the owner is paid a lower Capacity Performance Payment Rate of $2000 per MWh for performance indefinitely. However, since the lower value is transitory, and the investor would undertake the new investment eventually when it faces the Full PPR (by assumption), the decision of whether to undertake this investment during the phase-in period is a financing question – that is, a matter of the time value of money.

Specifically, a profit-minded owner would undertake the capital investment during the phase-in period as long as the incremental performance payment revenue it brings during the phase-in period exceeds the foregone interest on deferring the capital expense until the Full PPR value arrives. That is, a profit-

maximizing resource owner will not seek to recover the total cost of the investment based on the lower rate, but only the interest cost of accelerating the investment before the Full PPR value arrives. This standard financial logic implies that, because investors know the Full PPR value in the Tariff and the date when it will take effect, the phase-in period may have only a small impact in deferring new investments that can improve resource performance.

VI. PAY FOR PERFORMANCE WILL IMPROVE RELIABILITY IN A COST-EFFECTIVE MANNER

A. Pay For Performance Yields Cost Effective Resource Selection, While The Current FCM Does Not

Q: You have stated above that Pay For Performance produces a cost-effective and more reliable resource mix. What do you mean by cost-effective?

A: The logic of cost-effective resource selection is simple. Cost-effectiveness is the ratio of cost to performance. If two resources have the same capacity cost, but one resource has better performance during scarcity conditions, then a well-designed capacity market should select the better performing resource. More generally, if the capacity market selects resources cost-effectively, then the resources that clear will either have low capacity costs, high reliability, or both. In contrast, the flawed aspects of the current FCM have the undesirable result that

the capacity market may clear resources that have little or no contribution to reliability.

Q: Can you illustrate cost-effectiveness with a simple example?

A: Yes. Suppose a resource has capacity of 10 MW and a capacity cost of $3 per kw-month. This means its owner would require a net expected capacity payment of at least $3 per kw-month to be willing to acquire a Capacity Supply Obligation. Let's assume it is a moderately poor performer, with average annual performance of 2 MW (in the form of energy and reserves) during scarcity conditions.

Now consider a better-performing competing resource, also with capacity of 10 MW but with average annual performance of 8 MW during scarcity conditions. This resource has a higher capacity cost of $4 per kw-month.

Which resource is more cost-effective? Using round numbers for purposes of this example only, assume there are 20 scarcity hours per year. Then:

- The moderately poor performer has an annual capacity cost of $3 per kw-month × 10 MW × 12 months/year × 1000 = $360,000 per year. It has expected annual performance during scarcity conditions of 2 MW × 20 hours per year of scarcity = 40 MWh per year.

Its cost / performance ratio is therefore: $360,000 / 40 MWh = $9,000 per MWh.

- The better performer has an annual capacity cost of $4 per kw-month × 10 MW × 12 months/year × 1000 = $480,000 per year. It has expected annual performance during scarcity conditions of 8 MW × 20 hours per year of scarcity = 160 MWh per year.

  Its cost / performance ratio is therefore: $480,000 / 160 MWh = $3,000 per MWh.

In this example, the better performer is more cost-effective by a factor of three. However, the current FCM design is more likely to clear the less cost-effective resource. Assuming each resource bids competitively, the worse-performing resource's bid of $3 per kw-month is lower than the better-performing resource's bid of $4 per kw-month. In this way the current FCM tends to obtain a resource mix that is biased toward resources that deliver less energy and reserves during scarcity conditions, when reliability is at heightened risk.

Q: From an economic perspective, why does cost-effectiveness matter?

A: Recall the discussion of scarcity revenue from Section III.C above. From an economic perspective, the capacity market serves to provide suppliers with the additional scarcity revenue that the energy market fails to provide and that is

1 necessary to achieve the region's reliability criteria. A resource's cost-
2 effectiveness has the useful interpretation as the minimum additional scarcity
3 price "premium" that it must be paid in the capacity market in order for the
4 resource to cover its total costs and be willing to operate.
5
6 To see this, consider the better-performing resource in the previous example. To
7 cover its capacity cost, it requires average capacity market revenue of $3,000 for
8 each MWh it expects to deliver during scarcity conditions. This capacity market
9 revenue is in addition to the scarcity revenue that it receives in the energy market
10 for delivering the same MWh. Thus, the energy and capacity markets jointly will
11 enable this resource to cover its total costs if, and only if, it receives the energy
12 market's existing scarcity price *plus* a scarcity price premium of $3,000 per MWh
13 via the capacity market.
14
15 Stated differently, if New England had no capacity market at all, it could retain
16 the better-performing resource only if the energy market's scarcity price was
17 increased by $3,000 per MWh. Similarly, it could retain the worse-performing
18 resource in the previous example only if the energy market's scarcity price was
19 increased by three times as much, or $9,000 per MWh. Put simply, a resource's
20 cost effectiveness has a simple and important economic interpretation: it is the
21 scarcity price premium the resource requires from the capacity market in order to
22 operate profitably.
23

Q: What does the interpretation of cost-effectiveness as a scarcity price premium imply for capacity market design?

A: The concept of cost-effectiveness is important to capacity market design for two reasons. First, it means that the scarcity price premium that consumers are in effect paying, through the capacity market, will be minimized if and only if the capacity market selects the most cost-effective set of resources. In a pure energy market with enough resources to meet the region's resource adequacy criterion, scarcity prices would have to be much higher than today but the energy market would naturally select the most cost-effective set of resources. Similarly, under Pay For Performance, resources will be selected by the Forward Capacity Auction on the basis of their cost effectiveness. Under the current FCM, however, resources are not selected on the basis of cost effectiveness. That means that consumers, implicitly, are frequently paying an unnecessarily high scarcity price premium for the level of service they obtain during scarcity.

The second reason cost-effectiveness matters is for what it reveals about implicit pricing. The current FCM design is effectively a system of price discrimination, but this is masked by the current FCM's flawed performance metric. To see this, suppose both of the resources in the previous example clear in the capacity market under the current rules, at a capacity clearing price of $4 per kw-month. As shown previously, the capacity market will pay the better performer $3,000 per MWh for the energy (and reserves) it delivers during scarcity conditions. But in this scenario the worse-performing resource receives the same total capacity

revenue of $480,000 as the better-performer, while delivering fewer MWh during scarcity conditions. That gives it an effective scarcity price premium of $480,000 / 40 MWh = $12,000 per MWh delivered. The poor-performer is paid an effective scarcity price premium that is four times greater than that paid to the better-performer.

The use of scarcity prices in the energy market would never produce this type of price discrimination, because in the energy market both resources receive the same price per MWh delivered during scarcity conditions. However, in the current capacity market they receive quite different effective scarcity prices. Moreover, this type of price discrimination works in an especially problematic way: It pays higher effective prices to resources that perform poorly. In fact, the worse a capacity resource performs, the *higher* the effective scarcity price it receives under the current capacity market design.

It should come as no surprise then that poorly performing resources find it profitable to remain in the current capacity market and that New England has deteriorating performance across the fleet.

Q: How does the Pay For Performance design select resources on the basis of cost-effectiveness in the Forward Capacity Auction to solve that problem?

A: Unlike the current FCM design, with Pay For Performance the FCM will clear a more cost-effective set of resources. This works because resources are incented

to account for their expected performance when they bid in the Forward Capacity Auction, and each resource's capacity offer price will reflect the resource owner's own estimate of its cost-effectiveness.

This is one of the most important economic features of the Pay For Performance design. I will therefore walk thru how this works in some detail, using an extended example.

Consider two different 100 MW resources. Resource 1 is a moderate performer, with an annual average performance of 0.6 per MW during scarcity conditions and a capacity cost of $2.25 per kw-month. Resource 2 is a poor performer, with an annual average performance of 0.1 per MW during scarcity conditions and a lower capacity cost of $0.75 per kw-month.

Because Resource 1 has higher expected performance than Resource 2, there are different reliability consequences if the Forward Capacity Auction awards a Capacity Supply Obligation to Resource 1 or Resource 2. Resource 1 has expected performance during scarcity conditions of:

Resource 1: 100 MW × 0.6 *performance rate* = 60 MW.

By contrast, Resource 2 has expected performance during scarcity conditions of:

Resource 2: 100 MW × 0.1 *performance rate* = 10 MW.

Although both resources are assumed qualified to acquire a Capacity Supply Obligation of 100 MW, the expected amount of energy and reserves delivered during scarcity conditions is six times greater if the Forward Capacity Auction awards the obligation to the moderately-performing Resource 1 instead of the poorly-performing Resource 2.

First, let's examine the outcome of the Forward Capacity Auction under the Pay For Performance design. For this, a few additional market assumptions are necessary. First, assume the Full PPR of $5,455 per MWh. Next, assume – for purposes of this example only – that there are 10 hours of scarcity conditions annually, an annual average balancing ratio of $BR = 0.9$, and the Capacity Clearing Price is $4 per kW-month.

Though I use this particular set of assumptions strictly for example purposes here, these assumptions correspond (approximately) to the conditions of the "Near Term Equilibrium" FCM scenarios estimated by the Analysis Group Inc. in its in the report entitled "Assessment of the Impact of ISO-NE's Proposed Forward

Capacity Market Performance Incentives" dated September 2013 and provided in Attachment I-1g of this filing (the "Impact Assessment").[23]

Using the previous formula for *Expected PP* (expected Capacity Performance Payments) shown in Condition (B) earlier in my testimony (*see* Section V.C), we can calculate each resource's expected profit from acquiring a Capacity Supply Obligation. The table below shows each resource's base capacity price, expected performance payment, capacity cost, and expected profit, all shown on a per kw-month basis.

	Capacity Price	*Expected PP*	*Capacity Cost*	*Expected Profit*
Resource 1	$4	– $1.36	– $2.25	$0.39
Resource 2	$4	– $3.64	– $0.75	– $0.39

The calculation to obtain the expected performance payment for Resource 1 is

Expected PP for Resource 1 = $5,455 × [60 MW – 90% × 100 MW CSO] × 10 hours

This equals –$1,636,500 per year, or –$1.36 per Capacity Supply Obligation kW-month as shown in the table. Similarly, for Resource 2,

[23] Impact Assessment at 30 (Table 4).

Expected PP for Resource 2 = $5,455 × [10 MW – 90% × 100 MW CSO] × 10 hours

This equals –$4,364,000 per year, or –$3.64 per Capacity Supply Obligation kW-month as shown in the table.

Assuming both resources bid competitively (and in an expected profit-maximizing manner), Resource 1 would clear in the Forward Capacity Auction. Using the values shown in the table, Resource 1's competitive bid is the sum of its capacity cost and expected performance payment (which is in this case negative, representing a net charge), which is $1.36 + $2.25 = $3.61 per kw-month. This is less than the market-clearing capacity price of $4 per kw-month, so it clears. Resource 1 then has an expected net profit of $0.39 per kw-month.

Resource 2 would *not* clear in the Forward Capacity Auction. Its bid would need to cover its expected costs of $3.64 + $0.75 = $4.39 per kw-month in order to break even, given its expected performance charges. This break-even bid exceeds the clearing price of $4 per kw-month. Resource 2 is better off not clearing, because at a capacity price of only $4 per kw-month the resource would have a negative expected profit of –$0.39 per kw-month as shown in the table

Note further that, in this scenario, the Forward Capacity Auction clears the better-performing Resource 1, and does not clear the poorer-performing Resource 2.

That is, at the full proposed Capacity Performance Payment Rate, the market selects the correct resources from the standpoint of expected resource performance. Although Resource 1's capacity cost is three times larger than Resource 2's, Resource 1 delivers *six* times the expected energy and reserves during scarcity conditions – making Resource 1 a more cost-effective way to meet the system's requirements for energy and reserves during scarcity conditions.

Now, let's turn to the market outcome under the current FCM design. Under the current design, there is no Capacity Performance Payment Rate. For purposes of this example, I will assume that without Pay For Performance the market clears at a lower Capacity Clearing Price of $1.75 per kw-month.

Proceeding similarly to the previous scenario, we can calculate each resource's expected profit from acquiring a Capacity Supply Obligation. The table below again shows each resource's base capacity price in the scenario without Pay For Performance, expected performance payment (now zero), capacity cost, and expected profit, all shown on a per kw-month basis.

	Capacity Price	*Expected PP*	*Capacity Cost*	*Expected Profit*
Resource 1	$1.75	$0	– $2.25	– $0.50
Resource 2	$1.75	$0	– $0.75	$1.00

Without Pay For Performance, the market-clearing resources are reversed. The poor-performing Resource 2's competitive bid in the auction is its capacity cost of

$0.75. This bid would clear in the Forward Capacity Auction at a clearing price of $1.75, giving the poor-performing Resource 2 an expected profit of $1.00 per kw-month.

The moderately-performing Resource 1 would *not* clear, however. Its Forward Capacity Auction bid would need to cover its capacity cost of $2.25 per kw-month in order to break even, which exceeds the market-clearing price of $1.75 per kw-month. In effect, without Pay For Performance, the FCA *fails* to select the correct resources from the standpoint of resource performance.

Q: What are the main implications of this example?

A: This example reveals that without Pay For Performance, there are three potential adverse outcomes:

- resources with poor performance may clear in the Forward Capacity Auction, displacing competing resources with substantially better performance;
- the market produces a worse-performing resource mix, which lowers the amount of energy and reserves the ISO can expect to obtain during tight system conditions when reliability is at heightened risk; and
- perversely, suppliers find poor performance may be *more* profitable than better performance.

The ISO's proposed Capacity Performance Payment Rate is designed to reverse all three problems. The less reliable and less cost-effective resources will tend to de-list (not clear) in the Forward Capacity Auction, rather than displace resources with more cost-effective performance.

Q: How do the potential outcomes illustrated in this example relate to the concept of cost-effectiveness that you discussed previously?

A: The Capacity Performance Payment Rate enables the Forward Capacity Auction to select the set of resources that most cost-effectively meet the system's needs during scarcity conditions. That is, it selects resources with the lowest capacity costs *relative to* the expected amount of energy (and reserves) that the resources will deliver.

To see this in the context of Resources 1 and 2, the table below summarizes the attributes of each resource in the example above. The final column tabulates each resource's cost-effectiveness, that is, the ratio of its annual capacity cost to its annual performance.

	Capacity (MW)	*Performance per Scarcity*	*Expected Scarcity*	*Annual Performance*	*Capacity Cost*	*Cost / Performance*
Resource 1	100	60	10	600	$ 2.25	$4,500
Resource 2	100	10	10	100	$ 0.75	$9,000

The far-right column shows that Resource 1's capacity costs $4,500 for each MWh expected during scarcity conditions. Resource 2 is *more* costly in these terms. It has a capacity cost of $9,000 for each MWh expected during scarcity conditions.

The Capacity Performance Payment Rate clears Resource 1 instead of Resource 2 because it leads profit-maximizing resources to bid into the FCA on the basis of their cost effectiveness. In terms of the scarcity price premium explained earlier, Resource 1 requires a minimum scarcity price premium in the capacity market of $4,500 per MWh that it expects to deliver during scarcity conditions over the Capacity Commitment Period. This minimum scarcity price premium that it requires is less than the full Capacity Performance Payment Rate of $5,455 per MWh that it receives in the FCM. Since the capacity market's payment rate exceeds the minimum scarcity price premium at which it is willing to sell, Resource 1 is profitable in the capacity market and will clear in the Forward Capacity Auction.

Resource 2 requires a minimum scarcity price premium in the capacity market of $9,000 per MWh that it expects to deliver during scarcity conditions over the Capacity Commitment Period. This minimum scarcity price premium is *greater* than the full Capacity Performance Payment Rate of $5,455 per MWh that it would receive in the FCM for what it delivers during scarcity conditions. Since the capacity market's payment rate is less than the minimum scarcity price

premium at which it is willing to sell, Resource 2 is not profitable in the capacity market. Its minimum bid, as shown earlier, will not clear in the Forward Capacity Auction under Pay For Performance.

The central insight of the two-settlement design used in Pay For Performance is that at the Full PPR, it leads any competitive expected profit-maximizing resource to bid into the capacity market *as if* it was offering the minimum scarcity price premium it requires to be willing to accept a Capacity Supply Obligation and deliver its expected energy and reserves during scarcity conditions. By clearing the lowest-priced bids in the Forward Capacity Auction under Pay For Performance, the capacity market is selecting the set of capacity resources that are most cost effective: that is, that have the lowest capacity cost per MWh delivered during scarcity.

As this example illustrates, these properties enable the Pay For Performance design to select cost-effective resources and to produce a resource mix with superior performance than the existing FCM.

Q: What happens if there are insufficient existing resources with offers that correspond to a scarcity price premium of less than $5,455 per MWh?

A: In this case, the Forward Capacity Auction will clear new entry. In market equilibrium, when the capacity clearing price reflects the cost of new entry, all existing resources that have cost-effectiveness less than the Full PPR can clear

and profit in the FCM by bidding competitively. A resource that has cost-effectiveness in excess of the Full PPR will not clear, because the auction will clear a cost-effective new entrant instead.

Q: What about when the Capacity Performance Payment Rate is $2,000 per MWh, during the phase-in period?

A: During the phase-in period, some existing resources that are not cost-effective, in comparison to a cost-effective new entrant, may still clear in the Forward Capacity Auction. The extent to which this will occur will be less than occurs today under the current, flawed FCM design. Moreover, the extent to which it occurs will dissipate as the Capacity Performance Payment Rate increases to its full value.

Q: Is the explanation that the capacity market will clear a better-performing resource mix under Pay For Performance corroborated by empirical or simulation evidence for the New England system?

A: Yes. As I noted previously, the Analysis Group performed a study of the impacts of the Pay For Performance design. Part of their work involved prospective simulations of resource bids and what resources would clear under Pay For Performance, relative to a continuation of the existing FCM rules.

The resource-level results of their prospective simulations are reported in the Impact Assessment.[24] The points illustrated in my preceding example are corroborated in the empirical findings from the Analysis Group's study. For example, consider the region's oil-fired units, for which performance ranges widely (across units) historically during scarcity conditions.

- In the Analysis Group's findings without Pay For Performance, Table 6 (page 38) estimates 1,047 MW of these resources fail to clear in the Forward Capacity Auction. These de-listed resources have an average performance of 39 percent during scarcity conditions.

- With Pay For Performance and a Capacity Performance Payment Rate of $5,455 per MWh, the total de-listing resources in this group increases to 2,282 MW. However, there is a dramatic change in *which* resource de-list. These 2,282 MW delisting do not include (all of) the 1,047 MW that delist without Pay For Performance. Rather, the 2,282 MW are among poorest performers of this resource group, exhibiting average annual performance of only 14 percent during scarcity conditions.

[24] Impact Assessment at 38 (Table 6).

This indicates that without Pay For Performance, the FCM will tend to produce a poorer performing resource mix. With Pay For Performance and the full Capacity Performance Payment Rate, the FCM obtains a resource mix with superior performance.

B. Placing Performance Incentives in the Capacity Market Produces Less Volatility in Suppliers' Revenue and Consumers' Expenditures than Placing Comparable Performance Incentives in the Energy Market

Q: You stated above that the Capacity Payment Performance Rate can be interpreted as a scarcity price premium. At a high level, what are the economic differences if this premium was instead incorporated into the scarcity price in the energy market?

A: By design, the Capacity Performance Payment Rate applies to a resource's performance only during scarcity conditions. Similarly, the ISO's existing administrative scarcity price adder in the energy market also applies to the real-time energy price only during scarcity conditions.

In theory, the ISO's market design could place the full marginal incentive (that is, incorporate the full Capacity Performance Payment Rate) into the energy market's scarcity price. However, doing so would have different implications for some market outcomes. The most important difference concerns market volatility.

Specifically, the Pay For Performance design will produce more stable total revenues for suppliers over time. Incorporating the same scarcity price premium entirely in the energy market's price would yield more volatile net revenues for suppliers over time. This is true even though the combined scarcity price – that is, the magnitude of the marginal incentive to perform – is the same in both alternatives.

In addition, and for similar economic reasons, there would be greater volatility in total market expenditures for buyers. Wholesale market buyers, and potentially consumers, would face greater volatility of total costs if the scarcity price premium is placed into the energy market, instead of being implemented as an element of the capacity market using the Pay For Performance design.

Q: Why does the Pay For Performance design have this stabilizing effect, relative to the placing the performance incentive in the energy market?

A: The difference in net revenue stability reflects an important economic principle. As explained in Section IV.A earlier in my testimony, Pay For Performance is based on a two-settlement market design involving a forward sale, with subsequent performance payments based on deviations from a forward financial position. This two-settlement design reduces a seller's exposure to revenue fluctuations that arise from uncertainties *beyond* its individual performance.

In particular, a supplier's total annual scarcity revenue is sensitive to fluctuations in weather, which can cause the total number of scarcity hours to vary from year to year. Whether a scarcity price premium is vested in the energy or in the capacity market, most suppliers' scarcity revenues will depend on the actual number of scarcity hours during the Capacity Commitment Period. However, the two approaches differ significantly with respect to how *much* a supplier's net revenue will vary with the number of scarcity hours.

This is easiest to see in the special case where a capacity resource has average performance (per Capacity Supply Obligation MW) that is equal to its average share of system obligation over the Capacity Commitment Period. In this case, under Pay For Performance, an increase in the number of actual scarcity hours during the Capacity Commitment Period has *zero* effect on its FCM revenue. This resource covers it obligations perfectly with its own performance, so has no deviation payments in FCM settlement under Pay For Performance regardless of the number of scarcity hours.

The same insight is useful for resources with average performance that is higher, or lower, than the annual average balancing ratio. The smaller a resource's average deviation from the Capacity Balancing Ratio under Pay For Performance over the course of the year (where positive and negative deviations offset), the more the Pay For Performance design will smooth out the swings in a supplier's

total revenue when the number of scarcity hours during the Capacity Commitment Period turns out to be either higher, or lower, than it anticipated.

By contrast, imagine the same scarcity price premium was instead incorporated into the energy market. One more scarcity hour would increase the supplier's total scarcity revenue, by the product of the total scarcity price and the amount of energy (and reserves) it provides at the time. One fewer scarcity hour each year would reduce the resource's annual revenue in the same way. The resource is completely financially exposed to the full effect of fluctuations in the number of hours in which scarcity conditions occur each year. With the high scarcity price premium that is necessary to induce economically sound performance incentives, a resource in this situation could face considerable volatility in its total earnings each year.

In effect, the two-settlement design of Pay For Performance provides a capacity supplier with a three-year forward partial hedge against fluctuations in its total scarcity revenue. The hedge is only partial because it helps hedge against underlying risk drivers that are systematic (such as weather) and lead to changes in the number of total scarcity hours per year. It does not hedge against fluctuations in an *individual* resource's performance, however. That would dilute the resource's performance incentives, contrary to the intent of the design. Placing the scarcity price premium in the energy market alone provides no such

hedge, and results in greater volatility in a suppliers' total revenue from year to year.

Q: **Why is this revenue stabilizing property important?**

A: A central practical concern with placing the performance incentive solely, or even largely, in the energy market is that it is more likely to precipitate boom-and-bust cycles for suppliers. It leaves capacity suppliers with less insulation from the financial consequences of uncertainty in the number of scarcity hours each year. This quantity could vary significantly for a number of reasons, including a mild versus a severe weather year, a significant disruption to the region's fuel supply infrastructure, and the amount of excess capacity on the system in future years.

The ISO's Pay For Performance design provides the typical capacity resource with a greater level of insulation against the revenue swings than would occur due to these uncertainties. In general, this is desirable because net revenue stability is likely to facilitate new entry and reduce the cost of financing capital investments. As shown above, the Pay For Performance design works to provide more stable net revenues for the typical capacity resource over time, relative to placing the performance incentive in the energy market.

Q: **You indicated earlier that placing the performance incentive in the energy market, rather than in the capacity market using the Pay For Performance**

design, would also increase the volatility of consumers' costs. Why is that the case?

A: A hallmark of the Pay For Performance design is that consumers pay just the Forward Capacity Auction clearing price, determined three years ahead of the commitment period. Consumers do not bear the short-run risk of paying unexpectedly high Capacity Performance Payments after the capacity auction. This is achieved because the performance incentives under the Pay For Performance are structured as transfers among suppliers.

In contrast, in the energy market, the analogous performance incentive component is provided by the administratively-determined scarcity price adder in the real-time energy market. This means market participants that buy in the real-time market directly assume the costs of the performance incentive (*i.e.,* the scarcity price). If the high scarcity price is of similar magnitude to the full Capacity Performance Payment Rate, or $5,455 per MWh, then wholesale buyers could face real-time prices that are an order of magnitude greater than what they have experienced during similar stressed system conditions in the past.

Moreover, because participants in the Day-Ahead Energy Market have strong incentives to anticipate (and profit from) real-time price spikes – by bidding up day-ahead prices – it should be expected that some of the real-time market's increased volatility will result in higher prices in the Day-Ahead Energy Market.

In effect, placing the scarcity price premium in the energy market changes the traditional 'hedge' that the capacity market provides to buyers and, ultimately, consumers. It would expose load serving entities to greater volatility in their total procurement costs from year to year, as compared to the Pay For Performance approach. The underlying logic is that because suppliers incorporate their expected performance payments into their Forward Capacity Auction bids, the cost of these incentives to consumers is based on the *expected* number of scarcity hours during the Capacity Commitment Period. In contrast, the cost that consumers would bear if the same scarcity price premium is incorporated into the energy market is determined by the *actual* number of shortage hours that occur. Total costs are more predictable using the Pay For Performance design because the expected number of scarcity hours is more stable than the actual number of shortage hours that occur each year. That is, while on average there may be 20 shortage hours each year, in any given year there could be many more or far fewer.

In summary, the Pay For Performance design is able to achieve the same financial performance incentives for suppliers, while providing more stable total costs to buyers over time.

VII. OTHER IMPORTANT FEATURES OF THE PAY FOR PERFORMANCE DESIGN

1 **A. Capacity Scarcity Conditions Complement Scarcity Pricing In The Energy**
2 **Market**
3
4 **Q: What is a "Capacity Scarcity Condition"?**
5 A: So far in my testimony, I have referred to "scarcity conditions" generally. In the
6 Pay For Performance design, the scarcity conditions in which performance will be
7 measured are well defined, and are referred to as "Capacity Scarcity
8 Conditions."[25]
9
10 **Q: Can Capacity Scarcity Conditions occur at a zonal level, or only at the**
11 **system level?**
12 A: The New England system is partitioned into a set of Capacity Zones. A Capacity
13 Scarcity Condition can occur in all Capacity Zones at the same time, indicating
14 that, at the system level, reserves are insufficient (in a precise sense that I will
15 describe below). A Capacity Scarcity Condition can also occur in a single
16 Capacity Zone that has a zonal real-time reserve requirement.
17
18 At present, there are two import-constrained Capacity Zones associated with
19 contiguous Reserve Zones: The Connecticut Zone, and the NEMA/Boston Zone.
20 It is possible for a scarcity condition to occur in one or the other of these two

[25] *See* revised Tariff Section III.13.7.2.1.

zones (or both) at a time when there is ample supply in the rest of the system, and therefore the system as a whole does not experience a scarcity condition.

If a scarcity condition occurs in only a portion of the New England system, it is important for the strong performance incentives created by Pay For Performance to apply to resources that can alleviate it. This is consistent with the overall objective of Pay For Performance to provide greater financial incentives for investments that will improve resource performance in the times – and in the locations – that supply is scarce and the system faces heightened reliability risk.

Q: What is the trigger for a Capacity Scarcity Condition?

A: At a high-level, Capacity Scarcity Conditions occur when the supply of energy and real-time reserves is insufficient to meet the applicable load and reserve requirements. This applies to the system as a whole, as well as to the individual zones explained above. The scarcity conditions during which a resource's performance is assessed under Pay For Performance correspond to the conditions in which the ISO's existing scarcity price adders are incorporated into the energy price.

Scarcity pricing in the energy market is based on the supply of real-time reserves relative to real-time reserve requirements. The ISO has several distinct reserve requirements, and different types of real-time reserves. There are three primary real-time reserve requirements, and a Capacity Scarcity Condition will be based

on whether the real-time energy price incorporates a scarcity price adder (indicating the supply of reserves is less than the required level of reserves) for one or more of the following reserve requirements:

(i) The *system minimum 30-minute reserve* requirement, which is satisfied with offline or online generation capability available in thirty minutes or less. The supply of reserves that helps satisfy this requirement includes all resources' thirty-minute operating reserves ("TMOR"), ten minute non-spinning reserves ("TMNSR"), and ten-minute spinning reserves ("TMSR").

(ii) The *system 10-minute reserve* requirement (sometimes called the system's *contingency reserves* requirement), which is satisfied with offline and online generation capability available in ten minutes or less. The supply of reserves that helps satisfy this requirement includes all resources' TMNSR and TMSR.

(iii) The *zonal 30-minute reserve* requirements, for the zones described above. The supply of reserves that helps satisfy this requirement includes the resources within the zone providing TMOR, TMNSR, and TMSR.

This list does not include a zonal 10-minute reserve requirement, because the New England system does not have a 10-minute reserve requirement at the zonal level.

Q: If the supply of real-time reserves is deficient, does that always trigger a Capacity Scarcity Condition?

A: No, there are circumstances in which it may not. These circumstances arise in the same way, and are treated in the same way, under scarcity pricing in the energy market and under Pay For Performance. That is, a Capacity Scarcity Condition occurs under the same circumstances in which a deficiency of one of these three types of real-time reserves results in its scarcity price adder being incorporated into the energy price.

To explain these circumstances precisely, it is helpful to explain more specifically how scarcity pricing is triggered in the real-time energy and reserves markets. If the system's real-time dispatch software indicates there is a deficiency (that is, the supply of reserves is less than the required level of reserves) in one or more of these reserve requirements, then the price in the real-time reserve market is set by the ISO's administratively-determined reserve scarcity prices. As mentioned above, these reserve scarcity prices are called Reserve Constraint Penalty Factors ("RCPFs") in the Tariff.

Generally, if the real-time reserve market price is set by a RCPF, then the energy market price will incorporate this RCPF. In simple terms, that means that the real-time LMP for energy is determined by the energy market offer price of the marginal resource supplying reserves, *plus* the value of the RCPF (for the reserve requirement that is deficient). In this way, an RCPF serves as the energy market's scarcity price 'adder' when there is a deficiency of real-time reserves.

There are exceptions to the general process just described. Specifically, in the real-time energy and reserves markets, there are certain circumstances in which the reserve market price may be set by the RCPF value but no reserve scarcity price adder is incorporated into the energy market price. For example, if the system is ramping total energy production up to match rapidly climbing load, the system may have a transitory violation of a reserve requirement that could not be reduced even if the system had one less MW of energy demand. In this case, the real-time LMP for energy does not incorporate the reserve market's scarcity price. That is, the reserve market has an RCPF-based price, but there is no scarcity price adder incorporated into the energy price. In technical terms, this is known as a situation in which the system's resource ramping limitations are not binding on the system's energy dispatch.

Capacity Scarcity Conditions apply in the same way. In general, they are triggered whenever the system's real-time dispatch software indicates that there is a deficiency (that is, the supply of reserves is less than the required level of

reserves) for one or more of the three reserve requirements listed above. However, a Capacity Scarcity Condition is not triggered if the reserve market has an RCPF-based price, but there is no scarcity price adder incorporated into the energy price. In the Tariff, this provision is addressed in the definition of a Capacity Scarcity Condition, which specifically excludes the circumstance in which RCPF-based pricing occurs in the reserve market only because of resource ramping limitations that are not binding on the energy dispatch.

In Section III.C earlier in this testimony, I explained that a well-designed capacity market should provide performance incentives based on resource performance during scarcity conditions. I further indicated that these performance incentives should be complementary to, and in harmony with, scarcity pricing in the energy market. As explained here, the close correspondence between a Capacity Scarcity Condition and the conditions that result in scarcity pricing in the energy price (that is, the real-time LMP) mean that the Pay For Performance design honors these characteristics of a well-designed capacity market.

Q: Does scarcity pricing in the energy market occur at the same five-minute frequency with which Capacity Scarcity Conditions are measured for determination of Capacity Performance Payments?

A: Yes. In the real-time energy and reserve markets, the ISO calculates energy and reserve prices at a five-minute frequency. It is possible for scarcity pricing in the energy and reserve markets to occur for a time period as brief as five minutes.

Because Capacity Scarcity Conditions are based on the same system dispatch conditions that result in scarcity adders being incorporated into the energy market price, Capacity Scarcity Conditions are therefore measured on the same frequency. It is similarly possible for a Capacity Scarcity Condition to be as brief as five minutes.

There is an important practical reason why energy market scarcity pricing and Capacity Scarcity Conditions are calculated at a five-minute frequency. Periods of heightened reliability risk can occur abruptly, such as following a major system contingency, when the ISO may need to dispatch a large number of resources to increase output immediately – and counts on these resources to perform as dispatched in order to recover the Area Control Error within proscribed time limits (*e.g.*, 15 minutes). During these situations, a resource's marginal incentive to perform should reflect the importance of meeting this reliability standard. If the contingency is sufficiently large to deplete reserves, then assessing resource performance during these post-contingency conditions – for purposes of both Capacity Performance Payments and energy market payments – assures that resources that contribute to reliability the most at these times are rewarded for service they provide, and resources that do not deliver energy and reserves in these conditions are not. In keeping with the overall design objectives of Pay For Performance, resources are thereby compensated in accordance to what they provide during periods of heightened reliability risk.

B. Performance Measurement Reflects Contributions That Alleviate Scarcity Conditions

1. Actual Capacity Provided During a Capacity Scarcity Condition

Q: At a high-level, how is a resource's performance measured under Pay For Performance?

A: A resource's performance is assessed based on the energy and reserves it provides during a Capacity Scarcity Condition. In general, the measurement of energy and reserves for this purpose is the same as that used to compensate resource performance in the energy market. For demand resources, the measurement of resource performance is based on its reduction in energy consumption and, if applicable, any reserves it provides.

In the Tariff, the measure of resource performance during a Capacity Scarcity Condition is referred to as the resource's Actual Capacity Provided.[26] Note, importantly, that a resource does not need to have a Capacity Supply Obligation in order to perform and to receive Capacity Performance Payments. Thus, whether or not a particular resource has a Capacity Supply Obligation, its Actual Capacity Provided is calculated in the same way.

[26] *See* revised Tariff Section III.13.7.2.2.

The Pay For Performance design provides for a few adjustments in the measurement of Actual Capacity Provided of note, particular with respect to transmission limitations and external transactions. These I explain presently.

Q: If a generator's dispatch instruction is limited because of a transmission system limitation, can the generator increase its Capacity Performance Payment if it produces more energy than instructed?

A: No, it cannot. If a resource's dispatch instruction is limited by the transmission system's capability, the resource's Actual Capacity Provided is limited as well. This is provided for expressly in the Tariff. In this way, the design precludes a financial incentive for a resource to produce at a level that exceeds the transmission system's capabilities, at its location, during a scarcity condition.

Although the details differ, the effect of this treatment is similar to the effect of scarcity pricing in the energy market. In both cases, a resource whose dispatch is limited by a transmission constraint does not improve its profit by increasing its energy production above its dispatch point.

Q: **Please explain how performance is measured for Import Capacity Resources and external transactions generally.**

A: An Import Capacity Resource's performance is determined by the net energy delivered during the Capacity Scarcity Condition. For example, if a Market Participant with an Import Capacity Resource schedules a single external

transaction for 100 MW continuously all day into New England, and a Capacity Scarcity Condition occurs for one hour during the transaction, its Actual Capacity Provided would be 100 MWh for this event.

The reference to "net" energy delivered in the calculation of Actual Capacity Provided recognizes the possibility that a Market Participant may have both import and export external transactions during a Capacity Scarcity Condition. In this case, the import MWh and the export MWh during the scarcity condition are netted to determine the Market Participant's net import MWh. It is the Market Participant's net import MWh (but not less than zero) that is the basis for the Capacity Performance Payment. For example, if a Market Participant has a 50 MWh export external transaction and a 200 MWh import external transaction both scheduled during a Capacity Scarcity Condition, the Capacity Performance Payment will be based on Actual Capacity Provided equal to the net import of 200 MWh – 50 MWh = 150 MWh. This netting is performed at the participant level, across all external interfaces, to determine the performance eligible for Capacity Performance Payments.

Recall that, under Pay For Performance, a resource's performance is measured in the same way whether or not it has a Capacity Supply Obligation during the scarcity condition. Accordingly, if a Market Participant without an Import Capacity Resource schedules external transactions that flow during a Capacity Scarcity Condition, its Actual Capacity Provided will be determined in the same

way. That is, it is determined by the net import energy (but not less than zero) during the Capacity Scarcity Condition. Similarly as before, the netting is performed at the participant level, across all external interfaces, to determine the performance eligible for Capacity Performance Payments.

There are two reasons for this netting treatment of external transactions. The first is that it compensates a Market Participant based on the actual physical energy scheduled to be delivered *into* New England (if any) during the Capacity Scarcity Condition. To see why, suppose a Market Participant has a 50 MWh export external transaction and a 50 MWh import external transaction both scheduled during scarcity condition. The actual flow of power scheduled into New England to accommodate these two offsetting external transactions is, in fact, zero. In this situation, the Market Participant's two external transactions do not help alleviate the Capacity Scarcity Condition at all. Accordingly, the netting rule means that, in this situation, the Market Participant will receive a performance payment for its external transactions based on its net scheduled external transactions, which in this case is zero.

The second reason for the netting rule is to appropriately address wheeling transactions across the New England system that may continue to flow during a Capacity Scarcity Condition. Wheeling transactions simultaneously import power and export power, in equal amounts, across different external interfaces. They do not help resolve scarcity conditions, and for this reason their appropriate Capacity

Performance Payment is zero. The netting rule that applies to external transactions achieves this appropriate treatment.

There is an additional provision for capacity-backed exports *from* the New England system. This circumstance applies to generators within New England that are nominally serving load outside of the New England control area, through associated capacity-backed export external transactions (in the Tariff, these are called "External Transaction sales"). Because such a generator is not serving load in New England during the Capacity Scarcity Condition, the amount of its export is not credited to the applicable generating unit's Actual Capacity Provided.

Q: Does Pay For Performance require changes in how performance is assessed for demand response resources?

A: The way that performance is measured for demand response resources (including Real-Time Emergency Generation Resources) in the current FCM construct does not need to be changed in order to determine Capacity Performance Payments under Pay For Performance. In simple terms, they will continue to be assessed based on the reductions in load they achieve, and are eligible for Capacity Performance Payments in the same way as all other resources for their performance during Capacity Scarcity Conditions.

It is worth noting that, prior to the first Capacity Commitment Period (2018/2019) under Pay For Performance, the ISO plans to implement its Commission-

1 approved design to fully integrate demand response resources into the energy
2 markets.[27] This means that, unlike today, there may be demand response
3 resources that participate in the real-time energy and ancillary services markets
4 without a Capacity Supply Obligation. Such a resource will be compensated for
5 its performance (in the form of load reductions and, if applicable, reserves
6 provided) during Capacity Scarcity Conditions at the Capacity Performance
7 Payment Rate, consistent with the treatment of all resources under the Pay For
8 Performance design.
9
10 **Q: How do energy efficiency resources demonstrate performance?**
11 A: In the Tariff, energy efficiency resources are included in the On Peak Demand
12 Resource and Seasonal Peak Demand Resource categories. Currently, these
13 resources demonstrate performance by submitting data to the ISO substantiating
14 their energy load reduction (analogous to energy 'delivered' for a supply
15 resource) during the peak hours as defined for each resource type. For an On Peak
16 Demand Resource, for example, performance is the amount of energy load
17 reduction it provides during defined on-peak hours, and zero in all other hours. In
18 the Tariff, the Actual Capacity Provided of an energy efficiency resource during a
19 Capacity Scarcity Condition is determined based on its average load reduction in

[27] *See ISO New England Inc*., 138 FERC ¶ 61,042 (2012) (accepting rules that fully integrate demand response resources (price-responsive demand or "PRD") into the energy market); *ISO New England Inc.*, 142 FERC ¶ 61,027 (2013) (accepting, in part, changes to the FCM rules to be consistent with the price-responsive demand fully integrated rules and accepting an effective date of June 1, 2017 for the fully integrated rules).

the applicable hour. For an On Peak Demand Resource or Seasonal Peak Demand Resource other than energy efficiency, the Actual Capacity Provided is determined based on its average output in the applicable hour.

Hence, for these resources, the timing of the Capacity Scarcity Condition will, to a large degree, affect the resource's performance measurement. A Capacity Scarcity Condition during low-load periods would, in general, occur when the amount of energy reduction or output from these resources is lowest (*e.g.,* zero). Conversely, a scarcity condition during a peak period occurs when these resources are likely to have their highest load reductions or output, leading to high performance.

Under Pay For Performance, every resource is eligible for Capacity Performance Payments, whether or not the resource has a Capacity Supply Obligation. This means that an energy efficiency resource that does not acquire a Capacity Supply Obligation will still be compensated for its performance. Its performance would be substantiated through compliance with the measurement and verification procedures applicable to comparable energy efficiency resources that do acquire a Capacity Supply Obligation. In addition, under the Pay For Performance design, if an energy efficiency resource with a Capacity Supply Obligation substantiates performance during hours other than peak periods, its performance during off-peak scarcity conditions would increase its Capacity Performance Payment as well. In other words, energy efficiency resources will be compensated for their

performance under Pay For Performance similarly to other resources in the system.

2. Capacity Balancing Ratio Measurement

Q: **How is the Capacity Balancing Ratio determined?**

A: Recall that the Capacity Balancing Ratio,[28] in concept, measures the system's load and reserve requirements relative to total Capacity Supply Obligations. In Section IV.C of this testimony, I explained the Capacity Balancing ratio using the following formula:

Capacity Balancing Ratio = (*Load* + *Reserve Requirement*) / *Total CSO MW*

The product of the Capacity Balancing Ratio and a resource's Capacity Supply Obligation MW determines the resource's share-of-system financial forward position and, when compared to its Actual Capacity Provided, its Capacity Performance Score.

To calculate the Capacity Balancing Ratio, the ISO does not directly measure the sum of consumers' electrical loads – at least, not at the retail point of

[28] *See* revised Tariff Section III.13.7.2.3.

consumption. Rather, the ISO determines the system's electrical load (including losses) based on measurement of total supply. Accordingly, in the Tariff, the numerator of the Capacity Balancing Ratio is determined, in part, from the same inputs used to determine Actual Capacity Provided.

Specifically, the load value appearing in the numerator of the Capacity Balancing Ratio is calculated as the sum of the Actual Capacity Provided, less the reserves supplied, for all resources during each interval of the Capacity Scarcity Condition. This appropriately accounts for the amount of 'load' served by demand-side resources at the time. The numerator in the Capacity Balancing Ratio is determined by adding to this sum the applicable reserve requirement value at the time.

Q: Do the reserve requirements used in the Capacity Balancing Ratio depend on the type of reserve requirement that is violated during a Capacity Scarcity Condition?

A: Yes. The value of the reserve requirement in the Capacity Balancing Ratio reflects the required amounts of the types of reserves that can help alleviate the Capacity Scarcity Condition. For example, if the system dispatch software indicates a deficiency in the system minimum 30-minute reserve requirement (*i.e.,* offline or online generation capability available in 30 minutes or less), then the reserve requirement in the Capacity Balancing Ratio includes the required levels of 10-minute reserves and 30-minute reserves. This is because 10-minute capable

reserves can substitute for, and contribute to, the 30-minute reserve needs. However, if the system dispatch software indicates a deficiency in the system 10-minute reserve requirement, but not a deficiency in the 30-minute reserve requirement, then the reserve requirement in the Capacity Balancing Ratio includes the required levels of 10-minute reserves, but not the required levels of 30-minute reserves (as the latter do not help alleviate the Capacity Scarcity Condition, and are in sufficient supply, in this situation).

If the system dispatch software indicates a reserve deficiency in a Capacity Zone, but not in the system overall, then the calculation uses zonal-level information to provide a Capacity Balancing Ratio applicable the resources in the relevant Capacity Zone.

Q: Please explain further. If a scarcity condition occurs in a Capacity Zone, but not in the system overall, how is the Capacity Balancing Ratio calculated differently?

A: At a high level, the Capacity Balancing Ratio is determined similarly whether the scarcity condition occurs at the system level or at a zonal level. In particular, if the scarcity condition occurs in a Capacity Zone, but not in the system overall, the Actual Capacity Provided is determined from the resources in that Capacity Zone. Similarly, the reserve requirement value is based on the zonal, not the system-level, reserve requirement.

There are two additional adjustments made when a scarcity condition occurs in a Capacity Zone (but not in the system overall). First, for the measure of load in the numerator of the Capacity Balancing Ratio, which is determined from Actual Capacity Provided within the Capacity Zone, we must add in the load served by energy flowing into the Capacity Zone across an external interface. In the Tariff, there is an adjustment for the net amount of energy imported directly into the Capacity Zone from outside the New England Control Area in this situation.

Second, during a scarcity condition in a zone, part of the reserve requirement in the zone is generally supplied through the unloaded portion of the internal transmission interfaces into the zone. The amount of the Capacity Zone's reserve requirement satisfied through reserve support across these internal interfaces is subtracted from the zonal reserve requirement in the numerator of the Capacity Balancing Ratio. In this way, the Capacity Balancing Ratio reflects the reserves that are required from resources *inside* the Capacity Zone at the time. In the Tariff, there is an adjustment that subtracts the reserve support coming into the Capacity Zone over the internal transmission interface in this situation.

This treatment means that a resource located in a Capacity Zone experiencing a zonal scarcity condition, at a time when the system as a whole is not in a scarcity condition, has its performance evaluated relative to its share of the *zone's* energy and reserve requirements, rather than its share of the system's requirements (which are not experiencing a scarcity condition at the time).

Q: Are there different Capacity Balancing Ratios applicable if there is a simultaneous violation of a system-level and a zonal reserve requirement?

A: Yes. Resources located in a Capacity Zone that is deficient its zonal reserve requirement have Capacity Performance Scores calculated using the zonal Capacity Balancing Ratio, as described in my preceding response. Resources outside the Capacity Zone(s) that are deficient their zonal requirements (*i.e.,* the resources located in the rest of the system) have Capacity Performance Scores calculated using the system-level Capacity Balancing Ratio.

In this way, a resource located in a Capacity Zone experiencing a zonal scarcity condition remains evaluated relative to its share of the zone's energy and reserve requirements. A resource in the rest-of-system has its performance evaluated relative to its share of the system's requirements (which are also experiencing a scarcity condition at the time).

In the Tariff, this treatment is delineated by whether or not there is scarcity pricing in a Capacity Zone based on a deficiency of the *local* Thirty-Minute Operating Reserves requirement. If so, the resources in that zone have the zonal Capacity Balancing Ratio calculation. If not, they are located in the rest-of-system, and have the system-wide Capacity Balancing Ratio calculation.

Q: Can the Capacity Balancing Ratio exceed 100 percent?

A: Yes, that is possible, in theory. To see why, recall that the FCM procures an Installed Capacity Requirement designed to meet the 1-event-in-10-years resource adequacy criterion (as noted earlier in this testimony in Section III.A). This means that, as a matter of statistics, it is possible that New England could experience a future peak load level sufficiently high that it (plus the reserve requirement) could exceed the total of all Capacity Supply Obligations on the system.

If the Capacity Balancing Ratio exceeds 100 percent for an interval, then even a capacity resource that performs exactly at its Capacity Supply Obligation MW would receive a negative Capacity Performance Payment for the interval. That is because under Pay For Performance, resources are accepting a share-of-system requirements financial performance obligation – even if the system's energy and reserve requirements during scarcity conditions turn out to be higher, or lower, than expected over the course of the Capacity Commitment Period.

If a supplier views the likelihood of the Capacity Balancing Ratio exceeding 100 percent to be material, this possibility should be factored into its capacity offer price in the Forward Capacity Auction. To determine a competitive capacity offer price, any capacity resource should calculate its annual expected Capacity Performance Payment (as explained, in greater detail, in the examples provided earlier in this testimony in Section VI.A). The possibility of a negative Capacity Performance Payment due to a Capacity Balancing Ratio in excess of 100 percent,

if it is material, simply becomes part of that financial calculation to determine a resource's capacity offer price.

C. Capacity Performance Bilaterals

Q: What is a Capacity Performance Bilateral?

A: A Capacity Performance Bilateral is a financial transaction between two resource owners. In a Capacity Performance Bilateral, a resource that performs above its share of the system's requirements during a scarcity condition agrees to transfer (some or all of) its positive Performance Score to the benefit of another resource.[29] The principal purpose of this type of transaction is to enable a capacity supplier to reduce its financial exposure to negative Capacity Performance Payments during a period when it may expect to perform poorly.

Q: How does it work?

A: The concept is simple, and easily explained by example. Imagine that one resource owner expects to perform well during scarcity conditions, and another resource owner's unit is out of service. A one-hour scarcity condition occurs during the month. Assume Resource S ('S' is for Seller) performs well, and has a positive deviation from its share of system requirements (a positive Capacity

[29] *See* revised Tariff Section III.13.5.3.

Performance Score) of +100 MWh. Resource B ('B' is for Buyer) is out of service, and has a negative deviation from its share of system requirements (a negative Capacity Performance Score) of –60 MWh.

For purposes of this example only, assume the Capacity Performance Payment Rate is $2,000 per MWh. We can calculate each resource owner's Capacity Performance Payment as the product of its Capacity Performance Score and the Capacity Performance Payment Rate:

Capacity Performance Payment to S = +100 MWh × $2,000 per MWh = $200,000

Capacity Performance Payment to B = –60 MWh × $2,000 per MWh = –$120,000

Now suppose that the two parties agree to a Capacity Performance Bilateral. Specifically, assume their Capacity Performance Bilateral is an agreement to transfer 60 MWh of Resource S's Capacity Performance Score to Resource B. Once the two parties submit the Capacity Performance Bilateral to the ISO, the ISO adjusts each resource's Capacity Performance Score and Capacity Performance Payment accordingly. With a Capacity Performance Bilateral for 60 MWh, the seller is debited 60 MWh of its Capacity Performance Score and the

buyer is credited 60 MWh of Capacity Performance Score. This results in adjusted Capacity Performance Payments, as follows:

Capacity Performance Payment to S = (+100 – 60) MWh × $2,000 per MWh = $80,000

Capacity Performance Payment to B = (– 60 + 60) MWh × $2,000 per MWh = $0

The buyer no longer has a negative Capacity Performance Payment, in this example.

Q: Why would a resource owner use a Capacity Performance Bilateral?

A: From an economic perspective, there is little purpose in the two parties agreeing to a Capacity Performance Bilateral *after* a scarcity condition occurs. Rather, a Capacity Performance Bilateral creates economic value to the transacting parties if it is arranged before a Capacity Scarcity Condition occurs. There are two reasons why the transacting parties may find it valuable to enter into a Capacity Performance Bilateral:

- Differences in their expectations about the number of scarcity hours that will occur during a specified period of time; and

- risk aversion with respect to potential negative Capacity Performance Payments during a period when a supplier expects its resource may perform poorly.

For example, a resource owner that plans to take a two-week maintenance outage of its resource may wish to enter into a Capacity Performance Bilateral, as a buyer, to reduce the potential for negative Capacity Performance Payments if scarcity conditions occur while the unit is out of service. In this way, a Capacity Performance Bilateral is a simple means for it to manage non-performance risk: In effect, it is acquiring (a degree of) financial insurance against the possibility, and the magnitude, of a negative Capacity Performance Payment while it is out of service.

Note that, in consideration of the transfer of Capacity Performance Score from the seller to the buyer under a Capacity Performance Bilateral, the seller would be remunerated by the buyer. The terms of this remuneration are arranged between the parties to the Capacity Performance Bilateral, and this component of the bilateral transaction is not settled (nor observed) by the ISO.

Q: Why might a resource owner enter into a Capacity Performance Bilateral, instead of shedding its Capacity Supply Obligation entirely for the period it is out of service?

A: The shortest timeframe for which a resource can assume or shed a Capacity Supply Obligation is an entire month. There are monthly Capacity Supply Obligation bilateral transactions and monthly reconfiguration auctions. It is plausible that Market Participants may seek to shed a Capacity Supply Obligation when it is known prospectively that the resource will (or may) be out of service (or perform poorly) for much of the month. For example, a participant that plans to conduct a four-week maintenance outage may shed the resource's Capacity Supply Obligation during the month affected. By shedding the Capacity Supply Obligation the resource would avoid any possibility of a negative Capacity Performance Payment should scarcity conditions occur during the month.

Of course, not all outages can be anticipated, and not all periods in which a resource may have poor performance last for a month. Capacity Performance Bilaterals are a highly flexible instrument that enables a resource owner to mitigate the risk of negative Capacity Performance Payment during periods shorter than a month, or on shorter notice than a Capacity Supply Obligation can be shed. A Capacity Performance Bilateral will adjust a resource's Capacity Performance Score during a scarcity condition, without affecting either resource's Capacity Supply Obligation.

Q: Are there restrictions on the types of resources that may enter into a Capacity Performance Bilateral?

A: Under Pay For Performance there is no need, nor reason, to exclude any resource type from entering into a Capacity Performance Bilateral. Nor are any zonal restrictions necessary, other than that the two resources must be subject to the same Capacity Scarcity Condition. This is because a Capacity Performance Bilateral transfers credit for demonstrated performance, above the transferring resource's share of the system's requirements, which substitutes for the same MWh of performance not provided by the receiving resource (during the same Capacity Scarcity Condition).

Note that if a resource is in a Capacity Zone that is not experiencing a scarcity condition, it would not have any Capacity Performance Score to transfer. Resources can only transfer positive Capacity Performance Scores.

Q: How does a Capacity Performance Bilateral fit within the set of ISO-administered processes with which a capacity resource can cover its financial performance obligation under Pay For Performance?

A: Capacity Performance Bilaterals fit within a range of ISO-facilitated transactions that can help a Market Participant with a Capacity Supply Obligation to manage its non-performance risk. These span a range of different time horizons. For instance:

- Prior to the Capacity Commitment Period, a resource owner that learns its resource may perform more poorly than anticipated can shed its Capacity Supply Obligation, either in an annual reconfiguration auction or bilaterally;

- during the Capacity Commitment Period, on a monthly basis, a supplier whose resource may be out of service, or that may perform poorly for any other reason, can shed its Capacity Supply Obligation in a monthly reconfiguration auction or bilaterally;

- within the month prior to a Capacity Scarcity Condition, a supplier whose resource may perform poorly can cover its financial performance obligation (in whole or in part) by entering into a Capacity Performance Bilateral with a bilaterally-arranged counter-party.

Last, during a Capacity Scarcity Condition, a resource that performs poorly covers its financial performance obligation through the Pay For Performance two-settlement system. As I explained in Section IV.B earlier in this testimony, it covers its under-performance with purchases, at the Capacity Performance Payment Rate, from suppliers that over-perform at the same time.

In sum, Capacity Performance Bilaterals provide a highly flexible means for participants to manage potential non-performance risk, and fit within a range of mechanisms with which a supplier can cover a resource's financial performance obligation under Pay For Performance.

D. Peak Energy Rent and Import Capacity Offer Price Thresholds

1. Applicability Of The Peak Energy Rent Deduction

Q: How does the Peak Energy Rent deduction of the FCM change with Pay For Performance?

A: The existing Peak Energy Rent provisions of the FCM deduct a portion of each capacity resource's monthly payment if, during the month, the real-time energy price exceeds a specified threshold price.[30] The design intent of this Peak Energy Rent deduction is to provide a disincentive for a pivotal supplier in the Real-Time Energy Market to physically withhold supply during tight market conditions, and thereby increase the energy price paid to its other resources at the time.

The Pay For Performance design does not change, as a substantive matter, the function or design of the Peak Energy Rent deduction of the FCM. That is, the Peak Energy Rent deduction will continue to apply, in the same way as today, if the real-time energy price exceeds the specified threshold price.

Q: You explained earlier, in Section VI.A, that the Capacity Performance Payment Rate plays the role of a scarcity price premium to the energy market's scarcity price. Given that, should the Capacity Performance Payment be counted as part of a resource's Peak Energy Rent?

A: No. The revenue that a resource receives in the form of Capacity Performance Payments is not included in the calculation of the Peak Energy Rent. To do so would eviscerate the performance incentives that Pay For Performance is

[30] *See* revised Tariff Section III.13.7.1.2.

designed to provide. The effect would be to increase the Peak Energy Rent deduction as the resource's Capacity Performance Payments increase. If the positive Capacity Performance Payments that are earned by good-performing resources were then removed from the resource's net FCM revenue each month, the incentive disappears. This is not consistent with the design objectives of Pay For Performance.

At a more sophisticated level, the two-settlement nature of the Pay For Performance design intrinsically provides incentives for competitive behavior in the capacity market, similar to the role played by the existing Peak Energy Rent deduction in the Real-Time Energy Market. To see this, it helps to consider the economic structure of the Peak Energy Rent provisions in more detail.

From an economic perspective, the Peak Energy Rent provisions of the FCM are structured as a financial call option on the real-time energy price. Stated in simplest possible terms, a capacity resource receives a financial charge in FCM settlement equal to a *portion* of the scarcity revenue that it earns in the energy market during tight market conditions. The portion is based, approximately, on the resource's pro-rata share of system's energy requirements at the time. (In the Peak Energy Rent provisions of the Tariff, this portion is determined by a term called the Scaling Factor, which plays a role in the Peak Energy Rent provisions that is analogous to the Capacity Balancing Ratio under Pay for Performance.) In this way, under the Peak Energy Rent, a resource retains the Real-Time Energy

Market's scarcity revenue only if its performance exceeds its share of the system's requirements during scarcity conditions.

A similar effect is achieved with respect to the additional scarcity revenue that the capacity market provides under the Pay For Performance design. Specifically, a capacity resource is subject to a financial charge in FCM settlement, in the form of a negative Capacity Performance Payment, if it performs below its share of the system's requirements during scarcity conditions. In this way, under Pay For Performance, a resource retains the capacity market's scarcity revenue only if its performance exceeds its share of the system's requirements during scarcity conditions.

Taken together, the Peak Energy Rent deduction and the Pay For Performance design provide powerful *dis*incentives for a resource intentionally to exhibit poor performance (that is, for a resource to withhold its supply) during scarcity conditions. However, while these disincentives are structured similarly, they are not strictly duplicative of one another. Accordingly, Pay For Performance does not remove the existing Peak Energy Rent provisions of the FCM. Moreover, for all of the reasons explained above, a resource's Capacity Performance Payments will not be subject to subsequent deduction under the Peak Energy Rent provisions of the FCM.

2. Import Capacity Resource Offer Obligations

Q: How do Import Capacity Resources' offer obligations change under Pay For Performance?

A: Generally, an Import Capacity Resource with a Capacity Supply Obligation must offer energy associated with the resource into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions. Presently, these energy offers must be at, or below, an administratively-determined daily offer price threshold. Pay For Performance makes the requirement for Import Capacity Resources to offer energy at, or below, this daily offer price threshold economically unnecessary. Accordingly, this unnecessary administrative requirement is being removed from the Tariff.[31]

The intent of the requirement for Import Capacity Resources to offer at, or below, an administrative daily offer price threshold is to ensure the ISO can dispatch the energy associated with the resource during scarcity conditions. At the time this requirement was implemented, the ISO's scarcity price adders in the energy market were much lower than today, and the system experienced energy prices during scarcity conditions well below $1,000 per MWh (the value of the energy market's offer price cap). As a result, if an Import Capacity Resource offered into the Real-Time Energy Market an external transaction below the energy market's offer price cap, but at a higher offer price than the prevailing energy price during

[31] *See* revised Tariff Section III.13.6.1.2.1.

the scarcity condition, the external transaction could not be economically dispatched. By requiring external transactions associated with Import Capacity Resources to offer at, or below, a much lower administrative daily offer price threshold, the ISO was able to ensure it could economically dispatch the external transactions associated with an Import Capacity Resource during scarcity conditions.

Under Pay For Performance, this same objective is achieved in a simpler manner. During any scarcity condition, an Import Capacity Resource faces a marginal incentive to deliver energy that equals the sum of the energy market's real-time price plus the Capacity Performance Payment Rate, less the price of energy in the neighboring Control Area that is the source of the import. This marginal incentive is likely to exceed the Capacity Performance Payment Rate of $2,000 per MWh during the phase-in period, and to exceed $5,000 after the Full PPR takes effect. These marginal incentives are much stronger than the incentives that exist under today's administrative daily offer requirement for Import Capacity Resources.

Given the magnitude and applicability of the marginal incentives under Pay For Performance, for purposes of assuring that an Import Capacity Resource's energy will be accessible and delivered into the New England system during scarcity conditions, the existing administrative daily offer requirement becomes moot.

Accordingly, under Pay For Performance, this unnecessary administrative requirement is being removed.

VIII. STOP-LOSS PROVISIONS OF THE PAY FOR PERFORMANCE DESIGN

Q: What is a stop-loss limit?

A: Under the Pay For Performance design, it is possible for a capacity resource to incur a negative Capacity Performance Payment that exceeds its Capacity Base Payment. In that circumstance, the resource incurs a net financial loss in capacity market settlement. The Pay For Performance design includes provisions that limit a capacity supplier's potential net financial losses. I will refer to this limit as a "stop-loss limit," and the associated design elements as the "stop-loss mechanism."[32]

The Pay For Performance design includes both monthly and annual stop-loss limits.

Q: What is the purpose of the stop-loss mechanism?

A: Under the Pay For Performance design, a resource may incur a net financial loss in the FCM settlement if its performance is sufficiently poor, relative to its share

[32] *See* revised Tariff Section III.13.7.3.

of the system's requirement, in a month with a sufficiently high number of scarcity hours. As I explained in Section III.B.3 in this testimony, this potential for a capacity resource to have a net loss on its forward financial position in the capacity market plays an economically important role in solving the existing FCM's free option problem.

Nonetheless, it is not commercially reasonable for a capacity supplier to face potentially unlimited losses for non-performance. Accordingly, the Pay For Performance design includes the stop-loss mechanisms to limit a capacity supplier's potential loss exposure in the capacity market settlement.

A. A High-Level Explanation Of The Stop-Loss Mechanism And Its Design Principles

1. Design Principles

Q: What are the central design principles of the stop-loss mechanism?

A: The stop-loss mechanism design is guided by four central principles. These are: (1) simplicity, (2) transparency, (3) incentive distortions should be minimized, and (4) loss-limit events should occur infrequently. The stop-loss mechanism of the Pay For Performance design represents a balanced trade-off among these design principles.

Q: Please explain the first principle – simplicity – and why it is important.

A: Simplicity allows market participants to understand readily how the stop-loss mechanism works. This enables it to serve its intended purpose well as a means to limit a supplier's maximum exposure to financial loss in the capacity market. Simplicity helps a supplier to incorporate the risk-reducing role of the stop-loss mechanism into quantitative risk models and prospective financial calculations, facilitating the evaluation of its financial risk of poor performance.

In addition, keeping the stop-loss mechanism simple helps to minimize potentially complex tracking and assignment issues when suppliers trade Capacity Supply Obligations among one another, and provides clarity to market participants regarding how stop-loss limits apply when bilateral trades are contemplated.

Q: Please explain the second principle -- transparency – and why it is important in a stop-loss design.

A: Transparency enables a potential capacity supplier to know its maximum loss exposure *prior to* its participation in the Forward Capacity Auction. This enables the supplier to account for its maximum loss exposure when preparing its capacity supply offer in each auction. In addition, transparency enables a potential capacity supplier to communicate its maximum loss exposure to third parties with which it may do business, such as external entities providing financing to a capacity resource, prior to the decision to acquire a Capacity Supply Obligation.

Q: Please explain the third principle – why is it important that the stop-loss mechanism minimize incentive distortions?

A: Any stop-loss mechanism has the potential to attenuate a capacity supplier's incentive to perform (or invest to improve future performance), once a resource has reached (or expects to reach) the stop-loss limit.

Of particular concern is that the stop-loss limit presents an alternative to investing in tangible resource improvements or operating practices that would reduce poor performance. If the stop-loss limit is set so there is a small maximum loss, then simply paying that limited performance charge may be a more financially attractive option than undertaking operational-related investments to improve resource performance. This undermines the Pay For Performance design, which is based on the principle that resources should be paid for the energy (or reserves) they deliver during scarcity conditions.

A well-designed mechanism should minimally distort a supplier's incentives (a) to perform during scarcity events, and (b) to trade-out or replace a non-performing capacity resource during periods when it expects to perform poorly.

Q: Please explain the fourth principle -- why must loss-limit events occur infrequently?

A: The stop-loss limit also imposes costs on other capacity suppliers, who may receive lower FCM revenue to ensure that performance payments balance across

the pool. I explain this in greater detail below. In addition, a frequently-reached stop-loss limit also weakens the incentives of poorly-performing resources to make investments that improve performance, which would adversely affect the capacity market's ability to achieve the region's reliability objectives.

2. Economic Framework of the Stop-Loss Mechanism: Mutual Insurance Among Capacity Suppliers

Q: At a high-level, what is the conceptual logic of the stop-loss mechanism?

A: Conceptually, the stop-loss mechanism is a mutual insurance system among all resources with a Capacity Supply Obligation. Each capacity supplier receives insurance against the possibility of a large negative Capacity Performance Payment – that is, in excess of the stop-loss limit – in the event that its capacity resource performs poorly in a month with many scarcity hours.

The set of all capacity resources eligible to receive this insurance benefit also pay for it. Specifically, if one (or more) capacity resources reaches the stop-loss limit, the other capacity resources in the pool will receive reduced net FCM payments. In effect, capacity suppliers are insuring one another, in part, against the adverse financial consequences of very poor resource performance.

Q: How does that work in relation to the two-settlement design of Pay For Performance?

A: Under the two-settlement Pay For Performance design, a resource that performs worse than its share-of-system requirement during scarcity conditions has a negative Capacity Performance Score. This results in a negative Capacity Performance Payment for the resource. The stop-loss mechanism limits the magnitude of the resource's negative performance payment.

When this occurs, it affects the net surplus that results from settlement of all Capacity Performance Payments across the pool. This net surplus is described in Section IV.D earlier in this testimony. Specifically, without a stop-loss mechanism, the Pay For Performance design results in a net surplus each time scarcity conditions occur. There is a net surplus because the total amount of resource under-performance (in MW) exceeds the total amount of resource over-performance (in MW) during any scarcity condition (if this were not the case, there would have been no scarcity condition).

As part of the stop-loss mechanism design, the net surplus that accrues each Obligation Month will be allocated among the pool of capacity suppliers. However, if there is a capacity resource with sufficiently poor performance that its negative Capacity Performance Payment reaches the stop-loss limit, that fact will decrease the net surplus that remains to be shared with all other capacity suppliers. In this way, if one (or more) capacity resources reaches the stop-loss limit, other capacity suppliers will receive reduced net FCM payments.

This is a very simple mutual insurance system. Moreover, it ensures that all FCM performance payments balance across the pool of all suppliers.

Q: Can you provide a simple example that illustrates this concept?

A: Let's consider an example that I used earlier in my testimony, which appears in Section IV.D on pages 83-84. I will use that example to illustrate how a stop-loss limit reduces the net surplus and, as a result, reduces the final payments to capacity suppliers that do not reach the stop-loss limit.

In that example, there was one scarcity condition during a month. Unit A performed below its share of system requirement and incurred a negative Capacity Performance Payment of –$336,000. This is greater (in magnitude) than the positive Capacity Performance Payments of Units B and C, which are +$128,000 each. The settlement of all Capacity Performance Payments in that example yields a net surplus of $80,000, calculated as: $336,000 – ($128,000 + $128,000).

Now let's consider how a stop-loss limit changes this net surplus. The stop-loss mechanism limits a resource's negative Capacity Performance Payment if, and only if, its value reaches (in magnitude) the stop-loss limit. For purposes of the present example only, assume that the stop-loss limit applicable to unit A is $280,000. That means Unit A's negative Capacity Performance Payment will be limited to –$280,000, instead of being charged a negative Capacity Performance Payment of $336,000 in the FCM settlement.

This reduces the net surplus. Units B and C still have positive Capacity Performance Payments of +$128,000 each. Unit A has a negative Capacity Performance Payment limited by the stop-loss to –$280,000. The net surplus when all Capacity Performance Payments are settled across the pool is then $24,000, calculated as $280,000 – ($128,000 + $128,000). This net surplus is less than the $80,000 net surplus in the example without the stop-loss mechanism.

Q: How is the net surplus allocated?

A: Each Obligation Month, the net surplus from the settlement of all Capacity Performance Payments is allocated, on a Capacity Supply Obligation pro-rata basis, to capacity suppliers that did not reach the stop-loss limit.

In the context of the previous example, both Unit B and Unit C have the same Capacity Supply Obligation of 80 MW each. This means they will receive an equal allocation of the net surplus at the end of the Obligation month. With the stop-loss limit, the net surplus is $24,000, and so their allocation of the net surplus is $12,000 each.

Note that, in the example *without* the stop-loss limit, the net surplus is $80,000, and Units B and C would receive larger allocation of the net surplus. To see this, recall that the total capacity of all three suppliers in this example is 300 MW. Thus, in the case without a stop-loss, a pro-rata allocation of the net surplus would allocate to B and to C each a pro-rata share equal to (80 MW / 300 MW) = 26.33% of the total net surplus, or $21,333, calculated as 26.33% of $80,000. In

sum, *without* the stop-loss limit, Unit B and Unit C's allocation of the net surplus would have been $21,333 each. This is more than their allocation of $12,000 each with the stop-loss. In general, in this way, if a capacity resource reaches the stop-loss limit, the other capacity suppliers will receive reduced net FCM payments.

There are two important features to note about this simple example. First, FCM performance payments balance, exactly, across the pool of capacity suppliers. The net surplus after settlement of all Capacity Performance Payments is allocated back to capacity suppliers.

Second, the net surplus will be lower if one (or more) capacity supplier's Capacity Performance Payments reach the stop-loss limit. This reduces the amount to be shared among all capacity suppliers after all Capacity Performance Payments are settled each month. In that sense, capacity suppliers are insuring one another, in part, against the adverse financial consequences if one of them experiences very poor resource performance. Each capacity supplier receives financial protection against the possibility of an excessively negative Capacity Performance Payment – that is, in excess of the stop-loss limit – in the event that its capacity resource performs poorly in a month with many scarcity hours. The other capacity suppliers share in the allocation of this risk, in the sense that if this occurs, they receive a lower allocation of the net surplus.

Q: Is it possible for the net surplus to be negative due to the stop-loss mechanism?

A: Yes, that is possible. If there are a large number of capacity suppliers that perform very poorly in a month with many scarcity hours, it is possible that application of the stop-loss limit will produce a negative net surplus (that is, a net deficiency). In this case, each capacity supplier that does not reach the stop-loss limit will still be allocated a pro-rata share of the negative net surplus.

For example, imagine that in the preceding example we changed the stop-loss limit applicable to unit A. Specifically, instead of assuming a stop-loss limit of $280,000, suppose we assume a stop-loss limit of only $250,000. In that case, Unit A's negative Capacity Performance Payment is limited to –$250,000. The net surplus when all Capacity Performance Payments are settled across the pool is then –$6,000, calculated as $250,000 – ($128,000 + $128,000). As before, the net surplus (here, a deficiency) of –$6,000 is allocated on a Capacity Supply Obligation pro-rata basis to the units that do not reach the stop-loss limit. This means that Units B and C share in the net surplus allocation at the end of the obligation month in the form of a charge of –$3,000 each.

Because of the possibility that the net surplus to be allocated at the end of an Obligation Month may be either positive or negative, in the Tariff this allocation

is referred to as the "Allocation of Deficient or Excess Capacity Performance Payments."[33]

Q: Conceptually, how is that like mutual insurance?

A: Whether the net surplus is positive or negative, the stop-loss design amounts to a mutual insurance system among an 'insured pool' of all capacity suppliers. Each capacity supplier is protected, financially, against extreme losses if its resource performs very poorly during a month with many hours of scarcity conditions. This protection is likely to be most important if a capacity resource is out of service during a period when significant scarcity conditions occur, and the resource did not trade its Capacity Supply Obligation to another resource (or otherwise cover its share-of-system obligation).

In this context, there is no pre-specified insurance premium assessed to participants in this insurance pool. Instead, the net surplus plays the role of the financial reserves available to cover insured losses. Like insurance generally, the net surplus may be greater than the 'insured losses' incurred by poorly performing resources, if no (or few) capacity resources losses exceed the stop-loss limit. This is the case when the net surplus is positive. In this situation, the net surplus that remains is returned to the other capacity suppliers in the insurance pool.

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[33] *See* Tariff Section III.13.7.4.

This distribution is precisely analogous the conventional mutual insurance dividend in a mutual insurance system. The conventional mutual insurance dividend is a variable amount that is returned to the mutually-insured parties if – and only if – covered losses are less than the surplus premiums.

Also like insurance generally, the net surplus is not guaranteed to cover total 'insured losses' if there are many poorly performing resources in a period with many scarcity hours. This is the case when the net surplus is negative. The stop-loss mechanism then reduces the net FCM payments to all other capacity suppliers in the pool, on a pro-rata basis, to offset the 'stopped' losses incurred by poorly performing capacity resources. This is analogous to a mutual insurance practice of increasing the financial reserves after the fact (via additional levies on the insurance pool members) after a period of excessive insured losses.

In these respects, the stop-loss mechanism design is not a novel concept. Rather, it is modeled on the key elements of a risk-sharing, or mutual insurance, system among a pool of unaffiliated commercial entities that face similar, but imperfectly correlated, verifiable loss events.

Q: Do resources without a Capacity Supply Obligation participate in the stop-loss mechanism?

A: Only resources with a Capacity Supply Obligation participate in the stop-loss mechanism. This is not a stop-loss design decision per se, but rather a direct

consequence of the Pay For Performance two-settlement design overall. Specifically, a resource without a Capacity Supply Obligation cannot incur financial losses in the capacity market because it does not have a share-of-system financial performance obligation. It receives no Capacity Base Payment, and cannot receive a negative Capacity Performance Payment.

This means a resource without a Capacity Supply Obligation has no potential financial losses in FCM settlement, and nothing to 'insure' through the stop-loss mechanism. Accordingly, these resources do not have stop-loss limits, and are not included in the allocation of the net surplus (whether positive or negative).

B. The Monthly Stop-Loss Limit

Q: Over what time periods are a capacity resource's losses limited by the stop-loss mechanism?

A: The stop-loss mechanism has two separate stop-loss limits, which apply to different time periods. One limits a resource's net financial losses in each month of the commitment period. The other further limits a resource's net financial losses over the entire annual commitment period (which runs from the beginning of June until the end of the following May).

The monthly stop-loss limit and the annual stop-loss limit are applied separately. That means a resource that has reached *either* the monthly stop-loss limit, or the

1 annual stop-loss limit, will have its negative Capacity Performance Payment
2 limited by the binding stop-loss limit in an Obligation Month.
3
4 I will discuss the monthly stop-loss limit next, and the annual stop-loss limit in
5 Section VIII.C subsequently.
6
7 **Q: What is the monthly stop-loss limit?**
8 A: The monthly stop-loss limit caps a resource's Capacity Performance Payment, if
9 negative, to an amount equal to the product of its Capacity Supply Obligation
10 MW and the applicable Forward Capacity Auction Starting Price.[34]
11
12 For example, assume a capacity resource has a 10 MW Capacity Supply
13 Obligation, and that the Forward Capacity Auction Starting Price is $15,000 per
14 MW-month. This resource will have a monthly stop loss limit of $150,000,
15 calculated as $15,000 per MW-month × 10 MW = $150,000 per month.
16
17 **Q: Why is this monthly stop-loss limit reasonable?**
18 A: This monthly stop-loss limit is consistent with the four stop-loss design principles
19 listed previously, each of which is consistent with the overall Pay For
20 Performance design. These properties are (1) simplicity, (2) transparency, (3) the

[34] *See* revised Section III.13.7.3.1.

1 economic incentives of the Pay for Performance design are maintained, and (4)
2 loss-limit events should occur infrequently. In addition, this monthly stop-loss
3 limit is consistent with a capacity resource's maximum potential net loss under
4 other Tariff provisions that are not being changed with Pay For Performance, and
5 that the Commission has previously found to be reasonable. I will discuss each of
6 these points in turn.
7 **Q: Please explain why the monthly stop-loss limit satisfies the first principle –**
8 **simplicity?**
9 A: The monthly stop-loss limit caps a resource's Capacity Performance Payment
10 based on the product of its Capacity Supply Obligation MW and the Forward
11 Capacity Auction Starting Price (which is $15,819 per MW-month for the
12 upcoming eighth Forward Capacity Auction), regardless of the Capacity Base
13 Payment. This monthly stop-loss limit value can be easily calculated by market
14 participants prior to the auction and incorporated into their valuation of a Capacity
15 Supply Obligation.
16
17 **Q: Please explain why the monthly stop-loss limit satisfies the second principle –**
18 **transparency?**
19 A: The monthly stop-loss limit ensures that a resource can determine, based on the
20 price of its capacity offer, the maximum net loss exposure it may face each month
21 under Pay For Performance. This means it can account for, and thereby limit, its
22 maximum monthly net loss based on its capacity offer price.
23

If the Capacity Clearing Price is greater than the resource's capacity offer price, the resource will clear in the Forward Capacity Auction. In this case, its maximum monthly net loss, on a per Capacity Supply Obligation MW basis, equals the difference between the Capacity Clearing Price and the Forward Capacity Auction Starting Price. This difference is smaller than the difference between the resource's capacity offer price and the Forward Capacity Auction Starting Price – both of which are known quantities to the resource prior to the Forward Capacity Auction.

In this way, the resource's maximum monthly loss exposure under Pay For Performance is known to the resource owner prior to the Forward Capacity Auction.

Q: Please explain why the monthly stop-loss limit satisfies the third principle – the economic incentives of Pay For Performance are maintained?

A: The most important reason is that it is reasonable to anticipate that resources will reach the monthly stop-loss limit infrequently. This indicates that, with infrequent exception, a resource's incentive to perform is not affected by the monthly stop-loss limit.

In addition, two other important features of the Pay For Performance design should result in the monthly stop-loss limit being reached infrequently. These are the ability of a resource to cover its obligation through a bilateral transaction with

another market participant, either through the new Performance Score Bilateral mechanism (*see* Section VII.C) or through a trade of the Capacity Supply Obligation to another resource. Resources that expect to have zero performance have an incentive to arrange such transactions at a cost to them of (at most) the Forward Capacity Auction Starting Price if they expect a high number of scarcity hours during, say, a summer month.

Moreover, a resource that performs at zero for many scarcity hours early in a month may not reach the stop-loss limit by the end of the month, if its performance improves during later scarcity conditions. That is, a resource can "come back above" the stop-loss limit through good performance. This preserves incentives to perform even in the presence of the stop-loss limit. I discuss this property in greater detail further below.

Q: Please explain why the monthly stop-loss limit satisfies the fourth principle – that loss-limiting events should occur infrequently?

A: The monthly stop-loss limit is set sufficiently high so that even poorly performing resources are likely to reach this limit infrequently.

This can be seen by considering how many hours of scarcity conditions in a month are necessary for a resource that performs poorly to reach the monthly stop-loss limit. The following calculation here is informative, which considers the case of a resource with zero performance.

The number of scarcity hours until a resource's Capacity Performance Payment reaches the monthly stop-loss limit depends on a number of factors, including the Capacity Performance Payment Rate, the Forward Capacity Auction Starting Price, the resource's average performance, and the average Capacity Balancing Ratio. Assume, for purposes of this calculation only, the Full PPR value of $5,455 per MWh, a Forward Capacity Auction Starting Price of $15,000 per MW-month, and an average Capacity Balancing Ratio of 0.75. The Capacity Performance Payment for a 1 MW Capacity Supply Obligation resource with zero performance is:

Capacity Performance Payment = $5,455 × [0 – 0.75 × 1 MW] × *Scarcity Hours*

This Capacity Performance Payment will reach the monthly stop-loss limit when it equals 1 MW × Forward Capacity Auction Starting Price, or $15,000. Equating the stop-loss limit to the Capacity Performance Payment in the formula above yields the following formula for *Scarcity Hours:*

Required Scarcity Hours = $15,000 / ($5,455 × [0 – 0.75 × 1 MW]) = 3.7 hours

This calculation means that, under these assumptions, a zero-performing resource's Capacity Performance Payment will not reach the monthly stop-loss limit unless there are 3.7 hours of scarcity conditions, or more, in an Obligation Month.

It is possible for the New England system to have 3.7 hours of scarcity conditions or more in a month. However, that is not common. For example, the ISO has analyzed the number of hours of scarcity conditions from 2010 to present (through December 2013), based on the ISO's current energy market scarcity pricing rules. This analysis includes the actual number of hours of scarcity conditions after the current RCPF values took effect in June 2012, and a case-by-case dispatch simulation 'backcast' analysis of the number of hours that would have occurred prior to that date had the current RCPF values been in place from 2010 through 2012. This analysis indicated an average number of hours *annually* of only 7.66. Until July 19, 2013, the most that occurred in any single month is 4 hours. Thus, while it is possible for the New England system to have 3.7 hours of scarcity conditions in a month, that is not common in the data since the FCM's inception.

Moreover, even under conditions where the total system capacity equals the Installed Capacity Requirement, and the system is at planning criteria, the ISO's planning model predicts an expected number of scarcity hours of 21.2 *annually.* (*See* Section V.D, p. 107, earlier in this testimony). The finding that the expected number of scarcity hours annually is 21.2 at criteria suggests that a realization of 3.7 or more scarcity hours may occur in a hot summer month, but it is not likely to recur regularly over the course of the year.

Note that, in this example, differences in the numerical values of the assumptions could yield a higher or lower number of scarcity hours. Of primary interest is the

fact that during the phase-in period, when the Capacity Performance Payment Rate is lower, a higher number of scarcity hours must occur before a poorly-performing resource would reach the stop-loss limit. This implies that loss-limiting events would be even less frequent during the phase-in periods. To see this, note that the Full PPR of $5,455 is 2.73 times larger than the initial Capacity Performance Payment Rate of $2,000, which I calculate as 2.73 = 5,455 / 2,000. Using the same assumptions as in the preceding example, this means a zero performer would not reach the monthly stop-loss limit unless there are 2.73 times as many scarcity hours as the 3.7 shown in the previous example. That amounts to 2.73 × 3.7 hours = 10.1 hours of scarcity conditions in a month. Thus, it is not anticipated that poorly-performing resources would reach the monthly stop-loss limit frequently.

Q: You stated above that this stop-loss limit is consistent with a capacity resource's maximum loss exposure under other, existing Tariff provisions. Please explain further.

A: From an economic perspective, the monthly stop-loss limit is analogous to a capacity resource's maximum loss exposure under the existing significant decrease provisions of the Tariff.[35] Stated in simplified terms, if a capacity resource suffers a significant decrease in expected performance before the third

[35] *See* Tariff Section III.13.4.2.1.3(b).

annual reconfiguration auction (held approximately four months before the capacity commitment period begins), the ISO would submit a bid on behalf of the capacity resource in that reconfiguration auction for its capacity reduction at the Forward Capacity Auction Starting Price.

In this situation, the resource would effectively be required to 'buy out' of its non-performing Capacity Supply Obligation MW at a price up to the Forward Capacity Auction starting price. However, the resource still continues to receive the Capacity Base Payment, based upon its original Capacity Clearing Price. In this situation, the resource's maximum loss exposure is equal to the difference between the Capacity Clearing Price and the Forward Capacity Auction Starting Price for each affected Capacity Supply Obligation MW. Stated as a formula, it faces a maximum loss exposure of:

Maximum loss exposure = *Clearing Price* × CSO MW – *FCA Starting Price* × CSO MW.

This maximum loss exposure, if applied on a monthly basis, is equivalent to the resource's maximum potential net loss under the monthly stop-loss mechanism. The reason is simple: On the right-hand side of the equality in the formula above, the first product is also equal to the resource's Capacity Base Payment. The second product is equal to its Capacity Performance Payment when it reaches the monthly stop-loss limit. This means that, in a worst-case scenario, a resource's

Monthly Capacity Payment under Pay For Performance equals the same formula as above.

This equivalence is apparent using a few simple formulas. Under Pay For Performance, a resource's Monthly Capacity Payment is the sum of its Capacity Base Payment and its Capacity Performance Payment. In the worst-case scenario for a resource, its Capacity Performance Payment is equal to the (negative of the) monthly stop-loss limit. This means the Monthly Capacity Payment provides a maximum potential net loss given by the following formula:

Monthly Capacity Payment = Capacity Base Payment – Monthly Stop-Loss Limit

Recall now that the Capacity Base Payment is calculated as *Clearing Price* × CSO MW, and the monthly stop loss limit is calculated as *FCA Starting Price* × CSO MW. Inserted into the preceding formula for the Monthly Capacity Payment, we find that under Pay For Performance a resource's maximum monthly loss exposure is:

Maximum loss exposure = Clearing Price × CSO MW–*FCA Starting Price* × CSO MW.

Stated in simple terms, a resource's maximum loss under the existing significant decrease provisions of the Tariff is equivalent, if applied on a monthly basis, to the resource's

maximum loss under the Pay For Performance stop-loss mechanism. This is not a coincidence; the monthly stop-loss mechanism is intended to maintain this equivalence.

In summary, the monthly stop-loss mechanism takes an existing liability limit on a capacity resource's net financial loss prior to the start of the Capacity Commitment Period, and extends that existing liability limit to apply, on a monthly basis, throughout the Capacity Commitment Period under the Pay For Performance design.

It is important that the monthly stop-loss limit harmonize with the existing liability limit built into the existing significant decrease provisions. Both of these provisions provide resources with financial incentives to trade out of their obligations or to enter into the reconfiguration auction if they are unable to perform. And if the monthly stop-loss limit were set below the existing liability limit in the significant decrease provisions, it could undermine those incentives. Imagine, for instance, that a resource discovers after the Forward Capacity Auction that its operating circumstances have changed for the worse, such that it expects to have poor performance throughout the Capacity Commitment Period. If the monthly stop-loss limit was materially lower (in magnitude) than the existing liability limit in the existing significant decrease provisions, the resource may have a perverse financial incentive to not trade out of its Capacity Supply Obligation and instead simply pay the stopped financial losses. This perverse financial incentive would be present if, for example, the bilateral market in which participants trade their obligations during the commitment period is tight and

obligations trade at close to the Forward Capacity Auction Starting Price. To ensure that the monthly stop-loss limit works in harmony with this existing Tariff provision, it is important that the Capacity Performance Payment not be limited to less than the Forward Capacity Auction Starting Price.

Q: Can a resource that has reached the monthly stop-loss limit early during an Obligation Month "come back above" the stop-loss limit by the end of the month?

A: Yes. A resource that reaches the monthly stop-loss limit early in the month can, with strong performance in scarcity conditions that occur subsequently during the same month, finish the month with a net financial position better than the monthly stop-loss limit. This design element is consistent with the third and fourth principles of the stop-loss design. Specifically, it helps to reduce the frequency with which resources may reach the stop-loss limit. In addition, it provides a resource with an incentive to perform in the event that its losses have reached the monthly stop-loss limit. It is also consistent with the first principle, simplicity, because it means that the order of a resource's performance within a month does not affect its Capacity Performance Payment at the end of the month.

Q: Can you provide a simple example of this possibility?

A: Assume the Capacity Clearing Price is $5,000 per MW-month, the Full PPR of $5,455 per MWh, and there is a scarcity event that lasts 4 hours with an average Capacity Balancing Ratio of 0.75. Without a monthly stop-loss, a resource with a

1 MW Capacity Supply Obligation that has zero performance would accrue the following contribution to its monthly Capacity Performance Payment:

$$\$5{,}455 \times [0 - 0.75 \times 1 \text{ MW CSO}] \times 4 \text{ hours} = -\$16{,}365$$

In this example, the resource's Capacity Performance Payment to date exceeds the monthly stop-loss limit of $15,000. If there were no further scarcity conditions in the month, its final monthly Capacity Performance Payment would therefore be –$15,000.

Now suppose there is a second scarcity event that also runs 4 hours, again with an average Capacity Balancing Ratio of 0.75. The resource provides its full 1 MW during the second event. For the second event, it would accrue the following contribution to its monthly Capacity Performance Payment:

$$\$5{,}455 \times [1 - 0.75 \times 1 \text{ MW CSO}] \times 4 \text{ hours} = +\$5{,}455$$

The resource's total Capacity Performance Payment for the month is the sum of the two contributions, or –$16,365 + $5,455 = –$10,910. The resource's strong performance during the second scarcity condition means it does not reach the monthly stop-loss limit, and it increased its Capacity Performance Payment by $4,090, calculated as: $15,000 – $10,910.

Q: Are there any other adjustments to a resource's performance in calculating its monthly stop-loss limit?

A: Yes. There is an adjustment if a capacity resource has actual performance during scarcity conditions that exceeds its Capacity Supply Obligation. The stop-loss limit applies to a resource's performance *up to* its Capacity Supply Obligation. If a resource's performance exceeds its Capacity Supply Obligation, the performance above its obligation is treated separately from the monthly stop-loss calculation. Specifically, performance above a resource's Capacity Supply Obligation MW is credited in a resource's monthly Capacity Performance Payment, but is excluded from the stop-loss calculations.

This treatment of the non-obligated MW of a resource with a Capacity Supply Obligation provides comparability to the non-obligated MW of a resource without a Capacity Supply Obligation. It addition, in some circumstances, it further helps improve a resource's incentives to perform. In the Tariff, this treatment is provided for within the calculation of the monthly stop-loss, if a resource's Capacity Performance Payment is negative.

Q: How is the treatment of performance in excess of a resource's Capacity Supply Obligation equivalent to the treatment of performance by a resource that does not have a Capacity Supply Obligation?

A: Performance during scarcity conditions by a resource without a Capacity Supply Obligation falls outside the stop-loss design, and is simply compensated at the

Capacity Performance Payment Rate according to the Pay For Performance two-settlement design. Performance during scarcity conditions by a resource's non-obligated MW, above its Capacity Supply Obligation, are treated in the same way. Thus, the difference between a resource's performance and its Capacity Supply Obligation, if positive, is treated equivalently under the stop-loss mechanism regardless of the numerical value of its Capacity Supply Obligation, or if it has no Capacity Supply Obligation at all (that is, if its Capacity Supply Obligation is zero).

Q: Is application of the stop-loss mechanism to performance only up to a resource's Capacity Supply Obligation consistent with the objectives of the Pay For Performance design?

A: Yes. This design characteristic strengthens a resource's incentives to perform. Consider a resource that has performed poorly and has already exceeded the monthly stop-loss limit by a quantity such that, even with a strong performance late in the month, it cannot improve its monthly Capacity Performance Payment above (the negative value of) its monthly stop-loss limit. If all performance, including that beyond its Capacity Supply Obligation, is subject to the stop-loss, the resource has (by assumption) no financial incentive to perform. However, if performance above a resource's Capacity Supply Obligation is excluded from the monthly stop-loss limit calculations, the resource can earn additional FCM revenue for superior performance during the remainder of the month. This feature strengthens a resource's incentive to perform, although it is applicable only to

resources with the capability to deliver energy and reserves above their Capacity Supply Obligation.

Q: How do the rules for Capacity Performance Bilaterals under Pay For Performance relate to the monthly stop-loss?

A: As discussed in Section VII.C, the rules for Capacity Performance Bilaterals are simple, as a resource can only trade away positive Capacity Performance Scores. Because of this simple framework, there are no ways for a poorly performing resource to "game" the monthly stop-loss limit by trading behaviors such as acquiring additional negative score through Capacity Performance Bilaterals (and receiving compensation in the trade for doing so) that it would otherwise not pay for if it had reached the monthly stop-loss limit.

C. The Annual Stop-Loss Limit

Q: What is the purpose of the annual stop-loss limit?

A: The purpose of the annual stop-loss limit is to reduce a capacity resource's annual maximum potential net financial loss that could otherwise occur in exceptional circumstances, such as a Capacity Commitment Period with a large number of

annual scarcity hours, spread over many months, in which the capacity resource experiences ongoing poor performance.[36]

Q: At a high level, please explain the annual stop-loss limit.

A: Recall that under the monthly stop-loss limit, a capacity resource's maximum monthly potential net loss is the difference between its Capacity Base Payment and the monthly stop-loss limit. Expressed as a formula:

Maximum monthly potential net loss = Capacity Base Payment – Monthly Stop-Loss Limit

Under the annual stop-loss mechanism, a capacity resource cannot be worse-off, on an annual basis, than three times its maximum monthly potential net loss.

As a simple example, imagine a capacity resource has a monthly Capacity Base Payment of $50,000 and a monthly stop-loss limit of $150,000. Its maximum monthly potential net loss is the difference, which is $50,000 – $150,000 = – $100,000.

[36] *See* revised Tariff Section III.13.7.3.2.

The resource's annual stop-loss limit prevents the resource's net financial loss, over the course of the Capacity Commitment Period, from exceeding three times this maximum monthly potential net loss, or 3 × (–$100,000) = –$300,000.

At a high level, this is a very simple annual stop-loss design. It means that, on an annual basis, a capacity resource's maximum potential net loss is not as large as would be the case in the absence of the annual stop loss limit. Specifically, the annual stop-loss limit reduces a capacity supplier's maximum annual potential net loss by 75 percent, relative to the twelve monthly stop-loss limits alone.

Q: How is the annual stop-loss limit applied to determine a resource's monthly capacity payments?

A: The value of the annual stop loss limit is applied to a resource's cumulative Capacity Performance Payments over the course of the Capacity Commitment Period.

Let's continue the previous simple example. First, recall that a resource's total capacity revenue for the Capacity Commitment Period is the sum of its twelve monthly Capacity Base Payments and its twelve monthly Capacity Performance Payments. To simplify the explanations, I will refer to each of these twelve monthly sums as an annual amount; that is, I'll refer to the sum of the resource's twelve monthly Capacity Base Payments as its annual Capacity Base Payment, and so forth. Expressed as a formula:

annual capacity payment = annual Capacity Base Payment

+ annual Capacity Performance Payment

As explained in the previous example, the annual stop-loss mechanism is designed so that the resource's annual capacity payment is limited to a maximum annual potential net loss of –$300,000. Next, note that this occurs if, and only if, the resource's negative Capacity Performance Payments reach the annual stop-loss limit. Inserting these terms in the previous formula, we obtain:

Maximum annual potential net loss = annual Capacity Base Payment

– annual stop-loss limit

Last, we can now evaluate the terms in this formula to determine the annual stop-loss limit. Continuing with the example, as I assumed in the previous answer, the resource has a monthly Capacity Base Payment of $50,000. Its annual Capacity Base Payment is therefore 12 × $50,000 = $600,000. If we insert the value for its annual Capacity Base Payment of $600,000, and the previously-obtained value for this resource's maximum annual potential net loss of –$300,000, into the preceding formula, we find:

–$300,000 = $600,000 – *annual stop-loss limit*

It is convenient to re-arrange the terms in this formula to obtain:

$$\textit{annual stop-loss limit} = \$300{,}000 + \$600{,}000 = \$900{,}000$$

This means the means the resource's annual stop-loss limit is $900,000. Over the commitment period, the resource's net Capacity Performance Payments will be limited, in its worst-case scenario, to –$900,000.

Q: Is the annual stop-loss limit applied to limit negative Capacity Performance Payments on an ongoing basis during the commitment period, or is it only applied at the end of the Capacity Commitment Period?

A: Importantly, the annual stop-loss limit is applied to a resource's cumulative Capacity Performance Payments on a rolling basis during the Capacity Commitment Period. That is, each Obligation Month, the ISO will check whether the resource's cumulative year-to-date Capacity Performance Payments (after application of the monthly stop-loss limit each month) exceed the annual stop-loss limit. If this occurs, the Capacity Performance Payment for the current Obligation Month will be limited so that the resource's cumulative negative Capacity Performance Payments do not exceed the annual stop-loss limit. The resource will continue to receive its monthly Capacity Base Payment even if its Capacity Performance Payment is limited by the annual stop-loss limit prior to the end of the commitment period.

Q: Please explain how the annual stop-loss limit is determined in further detail. How will the ISO calculate the annual stop-loss limit on a rolling basis each Obligation Month?

A: There is a general formula for determining the annual stop-loss limit. This general formula is used in the Tariff. It is:

$$[\,3 \times (\textit{Clearing Price} - \textit{Starting Price}) - 12 \times \textit{Clearing Price}] \times \text{max CSO MW}$$

The first set of terms in the square brackets, 3 × (*Clearing Price – Starting Price*), corresponds to three times the resource's maximum monthly potential net loss, on a per Capacity Supply Obligation MW basis.

The second set of terms in the square brackets, or 12 × *Clearing Price,* corresponds to the resource's annual Capacity Base Payment per Capacity Supply Obligation MW.

The final term in this expression, max CSO MW, is the largest value of resource's Capacity Supply Obligation MW during the capacity commitment period to date. This adjustment is necessary for resources that have different values of their Capacity Supply Obligation MW in different months of the year. I explain this adjustment in more detail further below.

Q: Is the annual stop-loss mechanism consistent with the four design principles you identified above?

A: Yes, the annual stop-loss mechanism satisfies the four stop-loss design principles listed previously. These properties are (1) simplicity, (2) transparency, (3) the economic incentives of the Pay for Performance design are maintained, and (4) loss-limit events should occur infrequently.

Q: Please explain why the annual stop-loss limit satisfies the first principle – simplicity.

A: The annual stop-loss mechanism's relationship to the monthly stop-loss limit is simple and intuitive: It limits a resource's maximum annual potential net loss to three times its maximum monthly potential net loss. The annual stop-loss limit value can be easily calculated by market participants using the formula above, and incorporated into their valuation of a Capacity Supply Obligation prior to the Forward Capacity Auction or in their determination of whether to trade a Capacity Supply Obligation during the commitment period.

Q: Please explain why the monthly stop-loss limit satisfies the second principle – transparency.

A: Under this annual stop-loss design, a resource can determine its maximum annual net loss exposure *prior to* participation in the Forward Capacity Auction, as a function of its Forward Capacity Auction offer price. For example, suppose a capacity supplier intends to offer a 10 MW resource into the Forward Capacity

Auction at an offer price of $5 per kw-month. Using the formula and example above, if the resource clears in the Forward Capacity Auction, its maximum annual net loss exposure is at most –$300,000 per MW-year. If the Forward Capacity Auction clears at a higher price than $5, the resource's bid would be accepted and its maximum annual loss exposure would be closer to zero, *i.e.,* its worst case annual losses decrease if the Forward Capacity Auction clearing price exceeds its offer of $5. Alternatively, if the Forward Capacity Auction clears at a lower price than $5 per kw-month, the resource's offer does not clear and its maximum annual net loss exposure is zero in the FCM settlement.

This transparency property enables a resource owner to assess, based on a planned capacity price offer, the maximum annual potential loss it may face under Pay For Performance for its Capacity Supply Obligation MW. This enables it to communicate its maximum potential annual loss, as a function of its capacity price offer and Capacity Supply Obligation MW, to entities such as credit committees, risk management teams, or other parties providing financing to a capacity supplier. It also means a capacity supplier can account for, and thereby limit, its maximum potential annual net loss based on its capacity offer price.

Q: Please explain why the monthly stop-loss limit satisfies the third principle – the economic incentives of Pay For Performance are maintained.

A: The annual stop-loss mechanism is based on a multiplier of three: A resource's maximum annual potential net loss is three times larger than its maximum

monthly net loss. This element of the annual stop-loss design has an important property. Mathematically, this ensures that a capacity supplier cannot reach its maximum potential net loss, on an annual basis, prior to completion of the first three summer months of the capacity commitment period – regardless of the Forward Capacity Auction clearing price.

The ISO's planning models suggest that, in most years, a majority share of all scarcity conditions are expected to occur during these three months. It is particularly important that the annual stop-loss mechanism not attenuate performance incentives prior to the completion of these first three summer months of the capacity commitment period, and this design ensures that.

For these reasons, it is reasonable to anticipate that resources will reach the annual stop-loss limit infrequently. This indicates that, with infrequent exception, a resource's incentive to perform is not affected by the annual stop-loss limit.

Q: Please explain why the monthly stop-loss limit satisfies the fourth principle – that loss-limiting events should occur infrequently.

A: In order for a resource to reach the annual stop-loss limit, its Capacity Performance Payments must reach the monthly stop-loss limit in at least three months (or reach the equivalent sum over a longer time period). As noted previously, the monthly stop-loss limit is set sufficiently high that events in which it is reached should occur infrequently. Therefore, events in which it is reached

three times will occur even less frequently. Moreover, after a resource has performed sufficiently poorly to reach the monthly stop-loss limit twice, it may have strong incentives to shed its obligation to another resource that can perform; by doing so, the poorly performing resource would not incur sufficient losses in the FCM settlement to reach the annual stop-loss limit. In sum, it is reasonable to anticipate that a resource reaching the annual stop-loss limit will be an infrequent event.

Q: Does the resource's maximum potential net loss depend on *when* it hits the annual stop-loss limit – that is, at what point during the commitment period?

A: No. Because a resource receives its Capacity Base Payment in each month even after its negative Capacity Performance Payments have reached the annual stop-loss limit, it will receive the same total capacity payment for the commitment period regardless of when (that is, in which month) it reaches the annual stop-loss limit.

Q: Can a resource that reaches the annual stop-loss limit early in the year "come back" above the annual stop-loss with strong performance later in the year?

A: Yes. A resource that reaches its annual stop-loss limit before the end of the commitment period can complete the year better off than at the annual stop-loss limit, if it performs well later in the year. This design ensures that when a

resource reaches the annual stop-loss limit, it still has an incentive to perform because it may earn additional revenue for its additional performance.

The mechanics surrounding how a resource "comes back" above the annual stop-loss are similar to those for the monthly stop-loss, as explained earlier. If a resource that has reached the annual stop-loss limit provides more energy and reserves during subsequent scarcity conditions than its share of the system obligation, it receives positive monthly Capacity Performance Payments. If these positive monthly Capacity Performance Payments raise the resource's cumulative (negative) Capacity Performance Payments above the annual stop-loss limit, it will receive additional net revenue for its additional performance.

Q: You stated earlier that in determining a resource's annual stop-loss limit, the calculation will be based on the maximum of its Capacity Supply Obligation MW during the Capacity Commitment Period to date. Please explain further.

A: The Pay For Performance design permits trading of Capacity Supply Obligations between months. This flexibility allows resources to adjust to changing expectations surrounding their future performance and system conditions. However, the annual stop-loss limit is calculated on a per Capacity Supply Obligation MW basis, which requires a single annual Capacity Supply Obligation value. We use the maximum year-to-date Capacity Supply Obligation MW for two reasons: it is simple, and it preserves a resource's economic incentives to

perform – and to only acquire additional Capacity Supply Obligation MW if it expects to perform.

Specifically, if a resource acquires additional Capacity Supply Obligation MW through a bilateral trade or reconfiguration auction at any time during the commitment period, it increases its annual stop-loss limit. This provides a strong disincentive for a resource to acquire additional Capacity Supply Obligation MW if it expects it may perform sufficiently poorly to reach the annual stop-loss limit.

Q: Are there any other adjustments to a resource's performance in calculating its annual stop-loss limit?

A: Yes. As with the monthly stop-loss calculation, and for the same reasons, the annual stop-loss limit applies to a resource's monthly performance *up to* its Capacity Supply Obligation. If a resource's performance exceeds its Capacity Supply Obligation, the performance above its obligation is treated separately from the annual stop-loss calculation. Specifically, performance above a resource's Capacity Supply Obligation MW is credited in a resource's monthly Capacity Performance Payment, but is excluded from the stop-loss calculations.

D. Treatment of Resources with Multi-Year Commitments

Q: How are resources treated that recently cleared as new, and that elected multiple-year commitments?

A: The New England system has some capacity resources that cleared as new resources before the implementation of Pay For Performance, and elected to have the relevant Capacity Clearing Price apply for multiple Capacity Commitment Periods that include (one or more) years after Pay For Performance is implemented.

For these resources, there is a slightly different stop-loss treatment. Specifically, these resources will have a monthly stop-loss limit based on their applicable Forward Capacity Auction price, rather than the auction starting price, for the duration of their multiple-year commitment. This means their maximum potential net loss, each month and annually, is limited to zero and is therefore analogous to their current FCM loss limit.[37]

The reason for this differing treatment is that resources that cleared as new prior to the ninth Forward Capacity Auction and elected multiple-year treatment had no knowledge of the rewards and risks to which they would be subject under Pay For Performance, which will apply to at least some portion of their multiple-year commitment. Such resources did not have the opportunity to price those factors into their original Forward Capacity Auction offers (when they cleared as new resources). Their stop-loss treatment will limit the risk under Pay For

[37] *See* revised Tariff Section III.13.7.3.1.

Performance for such resources in a manner consistent with their original offers in the Forward Capacity Auction.

Q: Can such a resource elect different treatment?

A: Some of these resources may prefer the greater rewards, and be willing to accept the greater performance risks, afforded by full participation in Pay For Performance. For this reason, the Pay For Performance rules allow resources that cleared as new prior to the ninth Forward Capacity Auction and that elected multiple-year treatment to opt out of the remaining years of its multiple-year election.[38] This option can be exercised at any point in the resource's remaining multiple-year commitment, but is irrevocable. A resource choosing to so opt out will participate in subsequent Forward Capacity Auctions in the same manner as other Existing Capacity Resources.

E. Treatment Of The Net Surplus Each Obligation Month

Q: You indicated earlier that, because of the stop-loss mechanism, the net surplus after all Capacity Performance Payments are settled each month may be positive or negative. Please explain further how the net surplus is allocated in each case.

[38] *See* revised Tariff Section III.13.7.3.3.

A: Consistent with the mutual insurance conceptual framework discussed earlier in this section of the testimony, the net surplus will be allocated, in its entirety, among capacity suppliers each month.[39] Specifically:

If the net surplus is positive, the net surplus is allocated to all capacity suppliers on a pro-rata (per Capacity Supply Obligation MW) basis, excepting resources with Capacity Performance Payments that are limited by either the monthly or the annual stop-loss limits that month. If a resource has reached (either) stop-loss limit, its pro-rata share of the net surplus is reduced (down to a minimum of zero), dollar for dollar, by its 'insured losses.' In effect, this treatment requires a stopped-out resource to reimburse, from its pro-rata share of the net surplus, the insurance pool of all other capacity suppliers for covering its stopped-out losses *before* the stopped-out resource receives any allocation of the net surplus.

If the net surplus is negative, the net surplus is similarly allocated to all capacity supply resources on a pro-rata (per Capacity Supply Obligation MW) basis, excluding resources with Capacity Performance Payments that are limited by either the monthly or the annual stop-loss limits that month. The reason for the exclusion is that to do otherwise would exceed these resources' stop-loss limits, which is contrary to the stop-loss mechanism design objective.

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[39] *See* revised Tariff Section III.13.7.4.

In the special case that a resource does not reach a stop-loss limit during the month, but a pro-rata allocation of a negative net surplus would yield financial losses in excess of its maximum potential net loss for the month, the stop-loss limit will be honored and the balance of the net surplus allocated to the remaining capacity suppliers.

These calculations are performed separately for each type of Capacity Scarcity Condition and for each Capacity Zone. (In the Tariff, each of the three types of reserve deficiencies that I described in Section VII.A is called a type of Capacity Scarcity Condition). Here's what that means. If, for example, Capacity Scarcity Conditions occur in only one zone during a particular Obligation Month, then the net surplus is allocated, following the pro-rata rules, among the capacity resource in that zone. Alternatively, if all Capacity Scarcity Conditions apply to all Capacity Zones during a particular Obligation Month, then the net surplus is allocated, following the pro-rata rules, among all capacity resources in the system. And, last, if there are some Capacity Scarcity Conditions that apply to all Capacity Zones, and other Capacity Scarcity Conditions that apply to only one Capacity Zone, both during the same Obligation Month, then the net surplus is first divided in proportion to the duration of each type of Capacity Scarcity Condition, and then each portion is allocated as in the two previous cases. This process ensures that the resources whose performance contributes to the net surplus due to a Capacity Scarcity Condition in their Capacity Zone are also the

resources that primarily bear the benefit (if the net surplus is positive) or cost (if it is negative) of the insurance that the stop-loss mechanism provides.

Q: When the net surplus is allocated among the capacity suppliers in (one or more) Capacity Zones, why is the allocation on a pro-rata per Capacity Supply Obligation MW basis?

A: Note that whether the net surplus is positive or negative, *pro-rata* means in equal dollar amounts per Capacity Supply Obligation MW. Other things equal, if one capacity resource has twice the Capacity Supply Obligation MW of another, the larger of the two resources would receive twice the net surplus allocation of the smaller resource (in dollar terms), but they would each receive the same allocation in dollars per Capacity Supply Obligation MW terms.

This pro-rata rule means the allocation of the net surplus is not a function of individual resources' performance during the month, only their Capacity Supply Obligation MW each month. That is by design, and minimizes distortions to a resource's marginal performance incentives during scarcity conditions. That is consistent with the stop-loss design principle to minimize incentive distortions.

Taken together, these allocation rules are consistent with the mutual insurance concept for the stop-loss design. When the net surplus is positive, the allocation rule means that all capacity resources that do not incur insured losses receive (a portion of) the surplus, which may offset (to some degree) the negative net

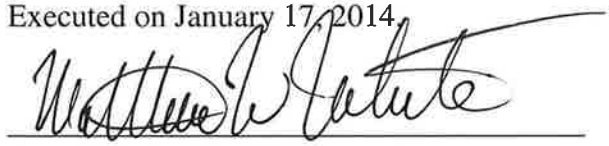
surplus allocation they periodically experience. When the net surplus is negative, the allocation rule means that each capacity supplier bears (a portion of) the financial consequences when a capacity resource performs poorly enough to exceed the stop-loss limit. That is the central purpose of a risk-sharing mutual insurance pool. Regardless of whether there is a positive or negative net surplus in a particular month, however, all capacity suppliers' total FCM compensation is reduced (from what it otherwise would be) whenever a capacity resource performs poorly enough to reach the annual or monthly stop-loss limit.

Q: Does that conclude your testimony?

A: Yes.

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

Executed on January 17, 2014.



Matthew White

Chief Economist

Attachment I-1d

Testimony of Peter Cramton on behalf of the ISO

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-_____-000**
New England Power Pool	**)**	

TESTIMONY OF PETER CRAMTON
ON BEHALF OF ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

Q: Please state your name, title, and business address.

A: My name is Peter Cramton. I am a Professor of Economics at the University of Maryland. My business address is Economics Department, University of Maryland, College Park, MD 20742.

Q: Please describe your work experience and educational background.

A: I am a Professor of Economics at the University of Maryland. Since 1983, I have conducted research on auction theory and practice. This research appears in the leading economics journals. The main focus is the design of auctions for many related items. Applications include spectrum auctions, electricity auctions, and treasury auctions. On the practical side, I am Chairman of Market Design Inc., an economics consultancy founded in 1995, focusing on the design of auction markets. I have advised numerous governments on market design and I have advised dozens of bidders in high-stake auction markets. Since 1997, I have

advised ISO New England Inc. ("ISO") on electricity market design and was a lead designer of New England's Forward Capacity Market ("FCM"). I led the design of electricity and gas markets in Colombia, including the Firm Energy Market, the Forward Energy Market, and the Long-term Gas Market. Since 2001, I played a lead role in the design and implementation of electricity auctions in France and Belgium, gas auctions in Germany, and the world's first auction for greenhouse gas emissions held in the UK in 2002. I led the development of innovative auctions in new applications, such as auctions for airport slots, wind rights, diamonds, medical equipment, and Internet top-level domains. I received my B.S. in Engineering from Cornell University and my Ph.D. in Business from Stanford University.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to comment on the ISO's proposed Pay For Performance ("PFP") reforms to its FCM.

Q: Can you summarize your main points?

A: Yes. I wish to emphasize four main points about the PFP design. First, PFP is an economically sensible design based on sound market principles, appropriately applied to capacity markets. Second, PFP fixes important shortcomings of the current FCM. Third, a high performance payment rate is appropriate and is

economically well-justified. Fourth, PFP induces a FCM with desirable long-run properties. My testimony will explain each of these points in detail.

III. PFP IS AN ECONOMICALLY SENSIBLE DESIGN BASED ON SOUND PRINCIPLES FOR CAPACITY MARKETS

Q: What are the key principles of the PFP design?

A: The most basic principle of the PFP design is in its name: *pay for performance*. Resources earn the capacity payment based on performance during scarcity conditions. This is accomplished through the definition of the capacity product, which includes an obligation to supply during hours of reserve shortage. Resources are paid based on the service provided. If a resource meets its performance obligation, it receives its full capacity payment; if the resource underperforms, it receives a smaller payment; and if the resource over-performs, it receives a larger payment.

The supply obligation is load-following, so that consumers are fully-hedged, but not over-hedged. In any scarcity hour the total supply obligation equals total demand—load plus reserve requirements.

Q: Why is it economically sensible to put stronger performance incentives in the capacity market?

A: The motivation for the capacity market is to address a demand-side flaw, the absence of demand response. This causes the energy price to be set too low during periods of scarcity, creating missing money. One could restore the missing money with an "energy only" design by setting a high scarcity price during hours of reserve shortage. The scarcity price would be set in the ISO Tariff to induce the desired level of reliability. The PFP design in the FCM works in the same way as the "energy only" design, but with a forward contracting model that addresses several problems of the "energy only" design. Specifically, the forward contracting coordinates investment at the desired reliability level, reduces payment risk for both consumers and generators, and mitigates market power in the energy market during periods of scarcity.

PFP provides the same strong performance incentives as in the "energy only" market with an appropriately set scarcity price. This is accomplished by paying resources based on performance during reserve shortages.

Q: Are there other key principles of the PFP design?

A: Yes. A second principle is *resource neutrality*. A resource should receive the same compensation for the same performance, regardless of technology. This "equal pay for equal work" is grossly violated in the current design. Unreliable resources that fail to provide energy or reserves in shortage situations often receive the same compensation as reliable resources that do provide services during shortages.

A third principle is to *reward outputs, not inputs*. In most markets, consumers pay for the goods and services delivered. Payments are based on outputs of production, not inputs. The PFP design works in the same way. Consumers pay for what they value. PFP also simplifies the market, since there is just a single product and a single price, or one per zone in the event zonal constraints bind. All suppliers and technologies compete on the same basis. Suppliers that can more efficiently convert inputs to outputs are rewarded.

Q: Doesn't the PFP design cause suppliers to bear performance risk?

A: Yes. With PFP, suppliers do bear performance risk. This is both intended and appropriate. Performance risk must be borne by consumers or suppliers. Putting performance risk on suppliers is desirable, since suppliers make a variety of decisions that impact performance. It is this performance risk that motivates good supplier decisions. A supplier will not invest in performance improvements if the supplier does not bear the risk and receive the rewards for its performance. The performance incentives cause the supplier to see and feel the economic consequence of decisions that impact performance. Furthermore, having consumers bear the performance risk is wholly inappropriate; they can neither control that risk nor change suppliers' behavior to manage the risk. Likewise, it is equally inappropriate to socialize the risk among all resources. Incentives and consequences need to be placed directly upon the resources that can control them.

Q: But some events that impact performance are not within the supplier's control. Is it still desirable to base payments on outputs?

A: Yes. There are two main reasons why this is desirable. First, risks not subject to a supplier's control must be borne either by consumers or the supplier. Consumers have no control of these risks either, so there can be no incentive benefit in placing this risk on consumers.

Second, placing the risk on the supplier affects what clears in the capacity market in ways that are desirable from both an economic and a reliability standpoint. Specifically, a supplier that is less likely to perform, even if due to reasons beyond the supplier's control, will place a higher offer into the FCA to account for this risk. As a result, the less reliable supplier will be less likely to clear. This mechanism—placing risk on suppliers, rather than on consumers, for factors outside of either party's control—enables the capacity price mechanism to work in an economic manner to clear the resources that are most likely to deliver when they are needed.

This approach also simplifies the market, because it is unnecessary to assign blame for failures to perform. The market simply measures output during scarcity.

Q: Can you describe the mechanics of the PFP design at a high level?

A: PFP is a two-settlement design—a forward sale that is then settled based on deviations at delivery. There is nothing novel or complicated about this design. It

is equivalent to the structure of the energy market and many other forward contracts. Each supplier takes on a forward obligation and then covers that obligation with its own supply or purchases supply from others. The principal difference between PFP and a forward energy contract is that with PFP it is necessary to set the settlement price (the performance payment rate) in the ISO Tariff, since in a shortage situation there are no competitive offers with which to determine a market price.

The PFP design shares the same key benefit of other two-settlement systems: efficient performance. The capacity supplier faces strong marginal incentives to perform during shortages and any deviations from forward obligations are automatically settled at delivery. Poor performance is not "penalized." Rather, deviations both positive and negative are settled at the performance payment rate. A negative deviation is simply a purchase of supply through the pool from another resource at the time of delivery.

Q: Are there exemptions in the two-settlement design for non-performance?

A: There are no exemptions. This is a critical feature in simplifying and improving the market. A policy of no exemptions provides strong and uniform performance incentives. It is a hallmark of two-settlement designs. Deviations from forward obligations are settled at delivery. No exemptions.

This is just like in the day-ahead energy market. When a supplier fails to deliver on its day-ahead sale, the deviation is made up with a real-time purchase. There is no debate about why the supplier was short and whether the deviation was justified. This lack of exemptions is what makes the two-settlement design so effective. Obligations and remedies are clear.

As another example, consider the forward grain market. Suppose the farmer sells a quantity of grain forward at a fixed price. He bears all the risk of factors—either positive or negative—that impact his performance. If there is a drought and his harvest is poor, he covers any shortfall with a spot purchase at the higher market price caused by the drought. If the farmer's yield is especially high, any surplus beyond the forward obligation is sold at the spot price. If the farmer's grain is destroyed in transit, the forward obligation is met with a spot purchase. All deviations, whatever the cause, are settled at the spot price.

A supplier of course likes exemptions consistent with the chief weaknesses of its fleet. Slow-start resources want to be exempt unless given sufficient advance notice of a shortage; resources with long maintenance outages want an exemption for planned maintenance; resources in locations vulnerable to transmission problems want transmission exemptions; resources with fuel delivery challenges want a no-fuel exemption. The list is endless.

However, in each of these cases, despite the chorus of "it's not my fault," some of the resource's reliability weakness is the supplier's fault. The supplier can invest in more responsive resources; the supplier can shift its obligation to another during scheduled maintenance; the supply can locate where transmission is more robust; and the supplier can invest in dual-fuel capability to protect against gas delivery problems.

Introducing exemptions distorts incentives, favoring some suppliers at the expense of others. For example, a transmission exemption encourages resources to locate in areas with transmission problems. These resources are paid for more reliability than they deliver.

A policy of no exemptions creates a level playing field. Responsibilities are clear and settlement is straightforward. Suppliers do bear greater performance risk, but it is precisely this risk that motivates performance-improving investments.

Q: But in many cases the relevant decisions that impact performance were made long ago. Why should these resources face high marginal incentives to perform?

A: It is important to remember that the FCM is a long-run market. The market must provide incentives that work well in the long run, both before and after investments are made. Indeed, a primary goal of the capacity market is to motivate efficient investment in the right resources. High marginal incentives

reward long-run investments that improve performance and reliability. Without these strong incentives, costly investments to improve performance would not be made. Moreover, these strong incentives must be maintained throughout the life of the project for this is the assumption on which the investment is initially made.

Even after long-run investments have been made, strong performance incentives are needed to foster medium and short-term investments in reliability. Investors, seeing the price incentive, can respond creatively to offer consumers reliable supply at least cost. For example, by lining up replacement supply during a long outage or investing in more reliable fuel delivery. Suppliers are not told what to do; they are simply rewarded based on the output delivered. This is the chief advantage of using prices to motivate behavior and is the hallmark of a market-based system.

Q: But don't these strong performance incentives make supplier revenues highly volatile?

A: No. An important feature of the PFP design is to reduce the volatility of supplier revenues and consumer expenditures from year to year relative to an "energy only" market design. The risk reduction stems from the way the capacity payment substitutes for the energy rents that otherwise would be earned during scarcity hours. Specifically, the capacity payment reflects the *expected* energy rents during scarcity (a constant), rather than the *actual* energy rents during scarcity, which vary greatly from year to year as a result of many random events. A supplier that

meets its share of the system performance obligation on average over the year has a net performance payment of zero, and receives its full capacity payment. Suppliers on average do meet their obligations, aside from the small quantity of MWh unserved during reserve shortages. The supplier's capacity and fuel contracts serve to hedge the risk stemming from the capacity supply obligation. Consumers meanwhile pay a fixed amount for energy during scarcity hours. Risk is reduced on both sides of the market.

Variation in supplier payment is limited to deviations in performance. The only way to further reduce supplier risk would be to weaken performance incentives. But this would compromise the good investment incentives that PFP creates. Instead, in the PFP design, suppliers reduce risk through investments that improve the reliability of their resources. Thus, PFP reduces supplier risk to the extent possible without damaging the incentives to invest in reliability.

Q: Won't this make capacity expensive for consumers?

A: No. In fact, over the long-run the PFP design will reduce the total cost of reliable energy supply. This is because the PFP design identifies the most cost-effective resources to meet the Installed Capacity Requirement, as I explain below.

Q: Can a supplier also mitigate risk through its bidding in the Forward Capacity Auction ("FCA")?

A: Yes. To minimize risk, a supplier adjusts its bids in the FCA based on the cost of providing reliable performance. For example, consider a 100 MW resource that expects to have a net performance payment of zero with a 60 MW capacity obligation, in other words no performance deviations at the 60 MW level. It would be risky for the resource to take on a capacity obligation greater than 60 MW. Thus, the resource can offer its first 60 MW of capacity into the FCA at a low price and then offer the remaining 40 MW at a higher price, reflecting the greater risk of these additional MWs. Such a bidding strategy is economically sensible. Taking on a capacity obligation consistent with the unit's expected performance reduces risk—the resource provides an excellent hedge for the obligation. But selling additional capacity beyond a unit's expected performance increases risk and needs to be priced higher to account for the additional risk. The supplier's increasing offer schedule reflects the increasing risk of higher levels of capacity obligation. A simple example of this would be the highest block for a combined cycle gas plant. To get the highest megawatts out of the unit will be both much more costly and subject to higher risk. Thus, this last block will be offered at a higher price and will only clear if no other, less expensive resource can take on the obligation.

Q: Doesn't PFP sometimes penalize suppliers for following ISO dispatch instructions?

A: No. Resources are not penalized for following instructions; rather, payments are reduced for failing to meet an obligation to deliver energy or reserves during a

shortage. In fact, the ISO would like the resource to run to help meet energy and reserve needs, but the ISO dispatch instructions reflect a variety of constraints that prevent the unit from running. This could be because of unit limits (start time, ramping rate, etc.) or transmission system limits (inadequate capability). In any event the dispatch instructions reflect what the unit is able to do, not just what the ISO would like the unit to do. This is just another version of the argument that resources should receive exemptions from circumstances allegedly outside of their control, in this case the operational constraints included in the ISO's commitment and dispatch software, and that is false.

As an example, a high-cost resource with a long lead time may not be committed and therefore the resource is not able to supply energy or reserves during a shortage. Its failure to perform means that the resource did not contribute to reliability. The resource therefore should be paid less, even though it followed dispatch instructions. It was not asked to run, because it could not get online in time to reduce the shortage.

The folly of paying non-performing resources is easy to see with an extreme example. Consider a resource with a lead time and marginal cost that are so high that the resource is never committed. Were resources paid for following dispatch instructions then this resource would receive full payment: it never is asked to run and never does so. But this resource clearly makes zero contribution to reliability. It should be paid zero. Following dispatch instructions is not a measure of a

resource's contribution to reliability. Supplying energy or reserves during scarcity hours is.

IV. PFP FIXES IMPORTANT SHORTCOMINGS OF THE CURRENT FCM

Q: Please describe some of the problems of the current FCM and explain how the PFP design addresses these problems.

A: There are several problems with the current FCM. The problems stem from performance incentives being too weak. I will consider each of the problems in turn.

One of the biggest problems is the use of "availability" to measure performance. Currently, there is little consequence for non-delivery during reserve shortages. The reason is the large number of exemptions that crept into the FCM settlement. Resources are credited for being "available" even when they provide no energy or reserves during scarcity conditions.

Availability-based obligations have proven to be a poor design. The availability approach results in the same compensation for different levels of service. High cost, long lead-time resources receive the same payment as low cost, quick start units, even if the latter contribute much more to reliability by providing energy and reserves during scarcity hours. This undermines incentives to invest in short

lead times and other resource attributes that improve performance during shortages.

A further problem with availability-based obligations is that a resource can claim to be available even when it is unlikely it will perform if called. The availability claim is successful when the resource is not called to provide energy. Thus, it is high-cost slow-start resources that are less apt to have their availability tested. The availability metric perversely rewards resources for being less desirable (*e.g.* expensive or slow to start) since they are less apt to have their performance tested.

As an example, consider a resource that does not have dual fuel capability and has not made advance arrangements for fuel and, as a result, faces considerable uncertainty as to whether it could acquire fuel during the operating day. The availability approach gives this resource the incentive to report it is available up until the point when the resource is needed and is called to deliver energy at which point the resource is unable to start for lack of fuel. From a reliability perspective, this is the worst possible outcome. The system operator is relying on the resource to be available if needed, and then the ISO discovers this is not the case. But now it is too late to avoid a scarcity condition.

Q: Are there other problems with the current FCM?

A: Yes. Another problem in the current market is the inadequate incentive suppliers have to invest in reliability-enhancing capabilities that are useful only a few hours

per year. Dual fuel supply is a lead example. New England's heavy reliance on gas and its position at the end of the gas network makes New England especially vulnerable to inadequate gas supply. Backup fuel supply could resolve this systemic reliability risk. However, the current FCM provides little incentives for such investment.

The PFP design greatly improves incentives for investment in resource capabilities that are needed only a few hours per year when the system's reliability is at a heightened risk. By rewarding performance during scarcity hours, PFP targets exactly those investments that improve performance during scarcity events.

Q: In the current market does a non-performing resource receive capacity revenues?

A: Yes. This is the "money for nothing" problem. The current FCM pays capacity resources that do not perform. As a result, it is profitable for a resource that only operates for its annual capability audit to take on a Capacity Supply Obligation ("CSO"). The resource may contribute little, or even zero, to reliability and yet enjoys capacity revenues.

Q: What is the implication of overpayment for poor performers in the current market?

A: As a result of overpaying poor performers, the current FCM suffers from adverse selection. Rather than clearing those resources that achieve the reliability objective at least cost, the market favors less reliable resources. Units with low going-forward costs and poor performance clear before more cost-effective resources that have higher going-forward costs and better performance. The reason is that the performance rewards in the current FCM are inadequate. Weak performance incentives bias the market in favor of less reliable resources. Over time, this bias erodes reliability in New England.

An implication of this adverse selection is the "effective capacity" problem. Effective capacity is the quantity of energy and reserves that the resource delivers during scarcity conditions. Effective capacity may be worse than one would expect based on the Equivalent Forced Outage Rate (EFORd) currently used to set the Installed Capacity Requirement in the FCM. The reason is that weak performance incentives adversely select resources that perform poorly during scarcity hours. Available resources are often not accessible in time to deliver during scarcity conditions. EFORd ignores this, since it only downgrades a resource's performance when it fails to operate when called with adequate lead-time. This introduces a systemic bias in the measurement of effective capacity that reduces system reliability.

The PFP design addresses this problem by clearing resources that expect to perform, rather than systematically selecting underperformers.

Q: Do you see any other flaws in the current market?

A: Yes. Another issue with the current market is the "free option" problem. The current FCM has penalty caps that prevent a net loss on FCM obligations. This means poor performers are playing a game of heads-I-win, tails-I-don't lose. As a result, poor performing suppliers are encouraged to participate in the market when they should exit. This is similar to but distinct from the "money for nothing" problem. The free option problem relates to the downside truncation of any losses when faced with uncertain performance.

Under PFP, resources can have a loss in the capacity market if they perform poorly in a year with a large number of scarcity hours. There is still a limit to losses, but not a complete elimination of the possibility of a loss. The stop-loss limit under PFP is specifically designed to rarely bind and therefore to only rarely harm incentives.

Q: As an expert in market design, is there a root cause that underlies the flaws you have identified in the current FCM?

A: Yes. The basic problem with the current capacity market is the absence of a coherent capacity product definition. Good product definition is essential to all markets. The current FCM product lacks clarity as a result of exemptions and a questionable availability metric. The product is needlessly complex. Furthermore, the too-weak performance incentives create the wrong investment incentives. Unreliable resources are encouraged. The product provides poor incentives for

investments that would contribute to system reliability by improving performance during scarcity.

In contrast, the PFP design has a simple and coherent product definition: physical capacity together with a financial obligation to cover a share of demand during hours of reserve shortage. The physical component guarantees that adequate physical resources will be available. The financial component provides the performance incentives. Since the financial component is a standard two-settlement forward contract, it is easy to create and trade a matching financial security that hedges performance risk. Suppliers anticipating underperformance, say as the result of an extended outage, can purchase the hedge from suppliers anticipating over-performance. Thus, the coherent product motivates efficient performance and enables suppliers to better manage performance risk.

V. A HIGH PERFORMANCE PAYMENT RATE IS NEEDED FOR EFFECTIVE PERFORMANCE INCENTIVES

Q: On what basis is the performance payment rate determined?

A: The performance payment rate ("PPR") follows directly from two basic economic principles. The first is that new capacity must be willing to enter the market when new entry is needed to meet the Installed Capacity Requirement. The second is that a resource that provides zero performance should expect to receive zero revenue. Thus, a resource's expected payment increases linearly from zero with

zero performance to 100% of the net cost of new entry (net "CONE") for an efficient new resource that performs as expected.

Ignoring risk for the moment, new capacity that performs as expected is willing to take on the supply obligation if the capacity price, which in equilibrium must be net CONE, is equal to the expected scarcity rents that are earned in the scarcity hours:

Capacity price = Net CONE = PPR × Expected scarcity hours × Expected scarcity performance.

Thus, PPR = Net CONE / (Expected scarcity hours × Expected scarcity performance). The performance payment rate simply amortizes the net cost of new entry over the expected production of energy and reserves in scarcity hours.

The ISO has estimated the three parameters that determine the performance payment rate as follows:

PPR = Net CONE / (Expected scarcity hours × Expected scarcity performance)

PPR = ($106,394 / MW-year) / (21.2 hours/year × 0.92) = $5,455 / MWh.

The PPR reflects the reliability criterion through the expected number of scarcity hours in the year. The ISO's planning model shows that when the system satisfies

the reliability criterion the expected number of scarcity hours is 21.2. A lower level of reliability would lead to more scarcity hours and a reduced PPR.

The PPR also depends on the expected performance rate, which currently is 0.92 for the type of new generation that the ISO has estimated to be the most cost-effective entrant (a combined cycle unit). Improvements in a new entrant's expected performance would result in a lower PPR, and lower FCM clearing prices; however, given that performance cannot exceed 1.0, there is little scope for improvements in expected performance to have much impact on PPR. Thus, it is unlikely the PPR would need to be modified in future years for this reason.

Finally, the PPR directly depends on net CONE. Net CONE can change in two ways. First, there might be a change in costs. Second, rents in the energy and reserve markets may change. Either of these factors may change over the long term, as technology changes and the energy market evolves.

The PPR should be updated every few years so that it stays at the level consistent with the two basic principles of: (1) supporting entry when needed; and (2) zero pay for zero performance.

Q: What are the advantages of setting the PPR at this level?

A: There are several. The first is good incentives. PPR calculated in this way closely aligns the reward for performance during times of system stress with the region's

desired level of reliability. This reward motivates suppliers to make reliability enhancing investments such as dual-fuel capability. Suppliers also properly consider the reliability tradeoffs when investing in new resources.

A second advantage is that it is cost-effective. The FCA clears the lowest-cost set of resources necessary to satisfy the reliability standard. Resources that are not cost-effective exit the auction because the capacity payment provides insufficient revenues to cover costs. I explain this further below.

A third advantage is transparency. Fixing the PPR in the Tariff helps guide long-term investment decisions and facilitates contracting to hedge performance risk, for example during extended outages.

VI. THE PFP DESIGN HAS DESIRABLE LONG-RUN PROPERTIES

Q: What are the long-run properties of the PFP design?

A: Perhaps the most important property of the PFP design is that it clears the most cost-effective set of resources to meet the ISO's reliability planning requirements. Cost-effectiveness is measured as cost / performance. Resources clear in the FCA based on the capacity cost per MWh delivered in scarcity conditions. The most cost-effective resources clear first.

The reason that under PFP the market clears the most cost-effective resources is simple. Since resources are paid based on performance, better performers earn higher net FCM revenue and poorer performers earn less. All resources that clear have positive expected net FCM revenue, because they are sufficiently cost effective. Resources that do not clear in the FCM are not profitable either because they have high costs, poor expected performance, or both.

In contrast, the current market clears on capacity cost alone, regardless of what performance consumers get for the money. This adversely selects less reliable resources. Consumers are somewhat compensated with a lower capacity price, but overall consumers today end up paying more relative to what they get for their money. This is because many poor performing resources are selected even though they are not as cost effective as some high performing resources that do not clear. Without strong performance incentives, high performing resources are inadequately rewarded for their performance and choose not to participate.

Consumers "get what they pay for" with PFP, since resources are compensated based on their contribution to reliability—the supply of energy and reserves during periods of reserve shortage. Resources that expect to contribute nothing expect to receive nothing.

Q: Will some resources decide to operate in the market without a CSO?

A: The vast majority of operating resources will operate with a CSO. Existing resources typically are cost-effective because a large portion of their investment costs are sunk. Moreover, taking on the obligation at a level consistent with the unit's expected performance reduces risk. The unit receives a fixed payment for providing its share of performance during shortages and the unit's capacity provides a physical hedge for the obligation.

Nonetheless, there may be a few resources that prefer to operate in the energy market without a CSO. These typically will be resources with high cost, poor performance, or both. Consumers do not pay more as a result of these non-CSO resources. These resources are paid for any reliability they contribute at a rate consistent with the region's desired level of reliability, but they are not relied upon. Rather, the FCM will acquire efficient new capacity to replace the non-participating resources. Over the long-term, assuring reliability in this way still costs net CONE, since we assume the new entry market is contestable.

Q: How will the capacity price vary from year to year under PFP?

A: The capacity market under PFP is expected to have a more stable capacity price than today's market. The reason is that the market will clear at the expected cost of covering the share-of-system obligation during scarcity hours. The obligation has both real benefits for consumers and real costs for suppliers. The clearing price reflects these costs. The costs may change somewhat from year to year, but

are largely invariant to whether there is excess supply in a particular year. Supply will exit or enter at the expected cost of the obligation.

In contrast, without PFP, the capacity price careens from near zero with excess supply to a high price when new entry clears. This increases risk and makes the market vulnerable to the exercise of market power on both sides of the market. As a result, without PFP the capacity price is a much less robust signal for investment incentives. Capacity price volatility has been and remains an important problem that has plagued capacity markets.

Q: Will the PFP design lead to excess entry?

A: No. The capacity market will select the most cost-effective resources up to the target that meets the Installed Capacity Requirement. Additionally, less cost-effective resources could decide to operate in the energy market despite not clearing in the FCA. These resources would be rewarded at the performance payment rate for energy or reserves supplied during scarcity hours. However, since they are less cost-effective than the cleared resources, they would lose money in expectation and decide to exit. Were they to stay in the market, then their contribution to reliability would reduce the number of scarcity hours, thereby further damaging their profitability. This market response to excessive entry drives the market back to the equilibrium where supply equals the Installed Capacity Requirement demand.

Q: How will PFP affect investment incentives?

A: With PFP, all resources face a strong marginal incentive to contribute to reliability by providing energy or reserves in scarcity hours. These strong incentives favorably influence all capital investments that improve performance during stressed system conditions, both in the short run and long run. Suppliers are motivated to make any cost-effective investment in reliability.

Q: How will PFP impact the mix of resources?

A: Favorably. PFP supplements the investment incentives provided by the energy and reserve markets with capacity payments that reflect a resource's contribution to reliability. These combined revenue streams motivate investment in a least-cost portfolio of resources system-wide. The portfolio will consist of a mix of resource types. When there are too few fast-start units, the value of a fast-start unit will be high and more fast-start units will enter. When there are too few baseload units, baseload units will have a high value and enter. Similarly, excessive reliance on one fuel type, such as gas, will increase the possibility of shortages from inadequate gas. This makes units that do not rely solely on gas more valuable and they will enter.

Without PFP, the resource mix suffers from adversely selecting less reliable resources, since contributions to reliability are not rewarded. As such, there are too few fast-start units and other resources that perform well in scarcity hours. The equilibrium result is a less reliable system that does not satisfy the reliability

standard. The reliability shortfall could conceivably be addressed by purchasing additional capacity, but the purchase is not cost effective and might not actually address the problem if the new resources experience the same reliability shortcomings as the existing fleet (*e.g*. dependence on natural gas).

The correct solution is to adopt PFP. This properly rewards contributions to reliability, and thereby motivates investment in the least-cost portfolio for satisfying demand reliably.

VII. CONCLUSION

Q: Can you summarize the main elements of the PFP design and its implied long-run equilibrium properties?

A: Yes. PFP is based on two key elements. The first is a share-of-system supply obligation to provide energy or reserves during shortages. The second is a performance payment rate to settle deviations from the obligation. The performance payment rate is set equal to the net cost of new entry amortized over the expected number of scarcity hours that the resource provides energy or reserves. From these two elements we have the following long-run properties:

- The most cost-effective resources clear in the FCA; that is, the market selects the resources with the lowest cost per MWh of supply in scarcity hours.

- Entry occurs if capacity is needed to satisfy the Installed Capacity Requirement; exit occurs if there is surplus.

- The capacity price does not depend on whether there is excess supply. It remains at the net cost of new entry, which is equal to the expected cost of covering the supply obligation.

Q: Does this conclude your testimony?

A: Yes. This concludes my testimony.

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

2 Executed on January 17, 2014.

3 Peter Cramton

4 Peter Cramton

Attachment I-1e

Joint Testimony of David LaPlante and Seyed Parviz Gheblealivand

on behalf of the ISO

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)**	**Docket No. ER14-_____-000**
and New England Power Pool	**)**	

JOINT TESTIMONY OF DAVID LAPLANTE AND SEYED PARVIZ GHEBLEALIVAND ON BEHALF OF ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

Q: Mr. LaPlante, please state your name, title, and business address.

A: My name is David LaPlante. I am the Vice President of Market Monitoring for ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: Mr. LaPlante, please describe your work experience and educational background.

A: I have a Bachelor's degree in statistics from Princeton University and a Master's Degree in City and Regional Planning from Harvard University. I have over 30 years of experience in the energy and utility industry. Between 1989 and 1994, I spent five years supervising and conducting power system reliability studies at the New England Power Pool. I have been working on the deregulation of the wholesale electric industry in New England since 1994. When serious discussions about deregulation of the wholesale electricity market in New England began, I was part of the team that negotiated the contract between the ISO and the New

England Power Pool ("NEPOOL") that led to the creation of the ISO in 1997. I then led the ISO team that worked with NEPOOL to develop and implement the region's first set of wholesale markets in 1999. Following that, I was responsible for the market design portion of the Standard Market Design implemented by the ISO in March 2003. I was integrally involved in the Forward Capacity Market ("FCM") settlement agreement and in the development of the capacity market rules that implement the settlement agreement. In July 2008, I was promoted to Vice President of the Internal Market Monitor (the "IMM") at the ISO.

Q: Dr. Gheblealivand, please state your name, title, and business address.

A: My name is Seyed Parviz Gheblealivand. I am an Economist with Market Development for the ISO. My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: Dr. Gheblealivand, please describe your work experience and educational background.

A: I have a Bachelor's degree in civil engineering and an MBA from Sharif University of Technology in Tehran, Iran and a Master's Degree and a PhD in Economics from The University of Texas at Austin. The focus on my PhD studies was on Industrial Organization, primarily the theory and empirical study of firm entry and exit, contracts, regulation, and auctions. I joined the ISO's IMM in January of 2011 as Senior Analyst. I was promoted to the position of Economist in October 2013 and transferred to the Markets Development Department in

January, 2014. Prior to joining the ISO, I was a visiting lecturer at the University of Wisconsin-Parkside, during which I taught courses in Industrial Organization and Regulation, and Financial Markets and Institutions.

Since my arrival at the ISO, I have worked on numerous projects in the ISO administered markets, including the energy market, Forward Reserve Market and the FCM. I was the IMM's lead on development of the FCM Pay For Performance project.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q: What is the purpose of this testimony?

A: The purpose of this testimony is to explain why we believe it is imperative that Pay For Performance be implemented and to describe the rule changes related to market monitoring and mitigation that are required to implement it.

Q: Please provide an overview of your testimony.

A: In Section III of our testimony, we explain why we believe that Pay For Performance is a much-needed and essential improvement to the FCM. In Section IV of our testimony, we detail the four main changes to market monitoring and mitigation in the FCM required by the implementation of Pay For Performance. First, under Pay For Performance, only de-list bids from resources associated with

Lead Market Participants[1] that are pivotal may be mitigated by the IMM. For this purpose, the revised rules include a new test to determine if a Lead Market Participant is pivotal. Second, the IMM's de-list bid analysis is being revised to remove the risk adjustment from the calculation of net going-forward costs. As a result, the current "net risk-adjusted going forward costs" bid component is being simplified to "net going forward costs," and the risk premium will be included as a separate component of the de-list bid. It is important to the success of Pay For Performance that resources price the risks they perceive from Pay For Performance in their offer. By making the risk premium a separate component, resource owners will be able to fully describe their risk analysis to the IMM. Third, expected Capacity Performance Payments under Pay For Performance are being added as a distinct de-list bid component. Fourth, the threshold below which resources may leave the capacity market without cost review by the IMM (the "Dynamic De-List Bid Threshold") is being increased from $1.00/kW-month to $3.94/kW-month beginning with the ninth Forward Capacity Auction. Each of these changes, as well as some smaller conforming changes, is discussed in detail below.

III. WHY PAY FOR PERFORMANCE IS A MUCH-NEEDED IMPROVEMENT TO THE FCM

Q: Why do you believe Pay For Performance is necessary?

[1] Capitalized terms used but not otherwise defined in this testimony have the meanings ascribed thereto in the ISO New England Transmission, Markets and Services Tariff (the "Tariff"), the Second Restated NEPOOL Agreement, the Participants Agreement, or the Pay For Performance rules.

A: We believe that the Pay For Performance design is necessary because the current set of wholesale markets will not maintain reliability in New England over the next decade. If Pay For Performance is not adopted, the region is much more likely to suffer a loss of load event, or events, for two reasons. First, the current set of wholesale markets do not send sufficient price signals for owners of resources with Capacity Supply Obligations to make the investments needed to assure their resources can operate reliably when needed. Second, the current capacity market pays resources that do not perform when most needed for reliability, keeping them in the market and preventing new, efficient, and reliable units from entering. Pay For Performance must be put in place now – as some of the region's units reach the end of their lives – so that the wholesale markets send price signals that force poor performing units to exit the market and replace them with new, reliable units. If Pay For Performance is not put in place, the region will struggle to maintain reliability with a generating fleet comprising gas-fired generation that has not invested in means to reliably perform in tight gas situations and poorly maintained, aging, inflexible fossil fueled generation that frequently does not perform when reliability problems arise. As we discuss later, recent events provide strong evidence that the price signals from the current set of wholesale markets are not sufficient to maintain reliability over the next decade.

This is not a new problem. In the 2010 Annual Markets Report, the IMM recommended that changes be made to the definition of a Shortage Event in the current market to strengthen the incentives for capacity resources to perform. The

problems with resources failing to follow dispatch instructions began in 2009 and resulted in the IMM referring to the Federal Energy Regulatory Commission ("FERC" or "Commission") nearly 200 instances of resources failing to follow dispatch instructions. In the 2012 Annual Markets Report, the IMM also recommended reinstating provisions in place during the transition period that take back some or all of a resource's capacity payment if it fails to meet its obligations as a capacity resource. Pay For Performance addresses these problems and recommendations in a comprehensive manner and will result in resources making efficient investments that assure reliability.

Q: Why do you believe that the current set of wholesale markets do not support the investment needed to assure resources with Capacity Supply Obligations operate when needed to maintain reliability?

A: In his testimony, Mr. Brandien describes the wide variety of performance problems that the ISO has been experiencing over the past several years and expresses his concerns about system reliability.[2] The IMM reviews many of these situations to determine whether Tariff violations have occurred and whether rule changes are needed to address the problems. Thus, we are well aware of the problems with the system. The most compelling evidence that the current market signals are inadequate to maintain reliability are the extensive and intrusive regulatory, administrative, and out-of-market actions that the ISO has had to take to track, and understand, the fuel supply of existing resources, to increase the

[2] *See* Testimony of Peter Brandien on behalf of the ISO, submitted with this filing as Attachment I-1b ("Brandien Testimony").

incentives for resources to make their fuel supply reliable, and to enforce the Tariff obligations for resources to have the fuel to follow dispatch instructions if it is physically available.

In the winter of 2009 – 2010, natural gas fired resources began failing to respond to dispatch instructions because of a lack of fuel or an unwillingness to purchase fuel at prevailing prices. In response to this and other problems with natural gas units, the ISO Operations Department was forced to hire experts in the natural gas area, develop the analytical tools to track the natural gas supply coming into New England and to monitor the nominations of natural gas by gas-fired units to determine whether it is reasonable to assume that those units will be able to follow dispatch instructions, especially if they are dispatched beyond their day-ahead schedules or do not have any day-ahead schedule. This detailed knowledge of the gas system is needed so that the ISO can commit oil fired units, out of merit order, if it appears that natural gas resources will not be able to follow dispatch instructions or to start up if committed. These out-of-merit commitments of oil units, while necessary to maintain reliability, undermine and distort the price signals in the Real-Time and Day-Ahead Energy Markets.

As oil prices rose and natural gas prices fell, the region's oil units reduced their on-site oil inventory. The reductions were so severe that the ISO was forced, on several occasions, to operate the resources to manage their fuel supply, rather than according to the economics of the resources or reliability needs. After

experiencing these problems, the ISO started a process of surveying all oil units to know how much oil is in the tanks so that unit commitment and dispatch instructions could be followed. That survey showed that oil inventories were low, that resupply of oil would take weeks rather than days, and that extended operation of most of the oil units in the region would cause them to run out of fuel. All of this confirms the lack of incentives to maintain a reliable fuel supply for resources that take on a Capacity Supply Obligation.

In response to these problems with natural gas and oil availability, the ISO and IMM issued a memo in November of 2012 making clear that generators were required to follow dispatch instructions and to secure the fuel required to follow the dispatch instructions. This memo resulted in a complaint to the FERC by the New England Power Generators Association ("NEPGA") arguing that the view of generator obligation under the Tariff expressed in the memo was incorrect. That complaint started a regulatory process that ultimately ended with a FERC order making clear that generators had an obligation to obtain fuel if it was physically available.[3] The order also made clear that fossil fueled units had an obligation to maintain sufficient on-site inventory so that they would be able to follow dispatch instructions.[4] If market signals were working, the ISO would not have needed to issue the November memo since generators would have found it in their economic interest to secure the fuel needed to follow dispatch instructions.

[3] *New England Power Generators Association, Inc. v. ISO New England Inc.*, 144 FERC 61,157 (2013).

[4] *Id.* at PP 47, 58.

While the regulatory process associated with the obligations memo was ongoing, the blizzard of February 2013 exposed the fuel supply problems facing the region as a result of inadequate market signals. To prevent these problems from re-occurring, in the winter of 2013 – 2014, the ISO implemented an out-of-market program that subsidized the purchase of oil for the region's oil units and paid for the testing of dual-fuel units. It was only in response to this program that many of the region's dual-fuel capable units have become available for dispatch on oil.

Importantly, all of this happened during a period when the New England system had more capacity than needed to meet its Installed Capacity Requirement. In other words, although the ISO easily met its capacity adequacy standards, it experienced significant enough problems maintaining reliability that it was necessary to take a hands-on approach to managing fuel in the region and to take out-of-market actions to assure reliability.

Pay For Performance is necessary to send price signals that will result in generators managing their own fuel supply and making the investments needed to assure system reliability. If Pay For Performance is not implemented, we will see increased intervention, similar to that described above, by the ISO into the market to assure reliability. And even these actions may not be enough to assure reliability when the system runs out of surplus capacity.

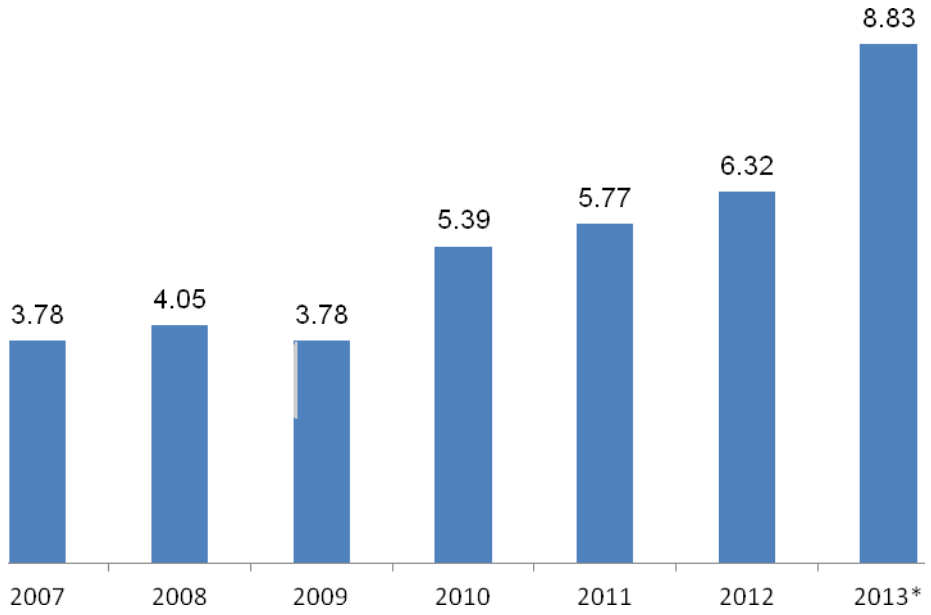
Q: Would these actions have been necessary if the wholesale market design and price incentives were sufficient to assure reliability?

A: No. The ISO does not own these units and should not have to track and influence fuel procurement decisions that are properly the sole province of the resource owner. If the markets were properly designed, the ISO would not have found it necessary to issue a memo to remind generators that they had an obligation under the Tariff to procure fuel and follow dispatch instructions and resource owners would have made the investments to assure that each resource would operate anytime it was dispatched. In short, Market Participants' incentives would be aligned with the ISO's objectives. For example, if the market design was efficient and the proper price signals were in place, then oil units would have found it profitable to maintain sufficient fuel on site to operate whenever needed and natural gas fired units would have had the incentive to make investments in dual-fuel capability or improved gas contracting to assure that they could operate anytime they received a dispatch instruction. The testimony of ISO witnesses Matthew White and Peter Cramton describes in detail the failings of the current market design and how Pay For Performance will remedy them to assure reliability.[5]

Q: What evidence do you have that the current market design is not sending the proper price signals to resource owners to assure that their resources operate reliably when needed?

[5] Testimony of Matthew White on behalf of the ISO, submitted with this filing as Attachment I-1c ("White Testimony") at Sections III and IV; Testimony of Peter Cramton on behalf of the ISO, submitted with this filing as Attachment I-1d ("Cramton Testimony") at 3-18.

A: The most compelling evidence that the current market signals are inadequate to maintain reliability is the increase in forced outage rates over the past several years. This is illustrated by the increase in forced outage rates shown in the chart below, which is also included in Mr. Brandien's testimony.[6] The increase in forced outage rates is evidence that poorly performing resources have not taken actions to maintain their ability to operate reliably. It stands to reason that they did not perceive investments to improve reliability as profitable. If they did, then such actions would have been taken.



Q: What is causing this increase in forced outage rates?

A: This increase in forced outage rates is likely driven by two factors. First, many of the region's oil and coal units are being operated differently than they were designed to operate. These units were designed to be operated all of the time, as

[6] Brandien Testimony at 41.

baseload units, or for five weekdays in a row, in the case of intermediate units. The decrease in natural gas prices and the run up in oil prices that started in 2009 has changed oil units from being operated as baseload or intermediate units to being operated as peaking units. As Mr. Brandien points out in his testimony, these units are large thermal units that perform best when operated for long periods of time.[7] Starting the boilers and heating the units puts stress on the unit. Once the unit is operating it can remain operating and be reasonably reliable, but getting the unit up to its Economic Maximum Limit takes time, especially if the unit has not been operated for weeks or even months. Second, because these units operate infrequently, it is unlikely that resource owners are investing significantly in these units to make them more reliable. At least one representative has stated at NEPOOL Markets Committee meetings that their company has reduced maintenance spending as the unit's capacity factor has fallen. The only investments they are likely to make are those required to meet environmental standards.

Q: Why doesn't the current capacity market design cause resource owners to make investments to make these resources more reliable when they are most needed?

A: Two features of the current FCM design cause resource owners to continue to sell into the market units that perform poorly when they are most needed, rather than making the investments needed to make them reliable. First, under today's FCM rules, a resource cannot lose more through poor performance in the capacity

[7] Brandien Testimony at 26-30.

market than it earns. In other words, without any possible net loss, they have "no skin in the game." Second, their revenue does not depend significantly on performing during the times when resources are needed the most. Consequently, they have no incentive to make investments to improve performance when most needed for reliability.

Q: **When is the probability of a loss of load event the greatest?**

A: There are two periods when the risk of a loss of load event is highest. The first is during periods of high temperatures and high loads in the summer and the second is during winter cold snaps, when usage of natural gas for space heating and electric loads is greatest. In summer, the region is at risk because the high outage rates of the existing fleet of generators will leave the region without enough operating generation to meet its load and operating reserve requirements. On July 19, 2013, the ISO was short of its approximate 2,375 MW operating reserves requirement by about 550 MW, despite having over 2,500 MW more "available" resources than the Installed Capacity Requirement. If there was no surplus above the Installed Capacity Requirement, the IMM has calculated that under the most conservative assumptions, the ISO would have been short of operating reserve by about 1,900 MW before calling on demand resources, forcing the system to operate with about 450 MW of reserves. This is much less than the ISO's first contingency and could lead to the ISO taking emergency actions to maintain system reliability.

In the winter, the ISO may be unable to meet load when the weather is cold and there is a significant, unexpected loss of supply. This causes problems because in cold conditions a high level of uncertainty exists as to whether natural gas availability will support the start up of additional natural gas resources, and many of the region's oil units take at least 12 hours to start. These problems were illustrated in Storm Nemo (in February 2013) and more recently on Saturday, December 14, 2013 when the ISO had to enter OP-4 when non-firm imports to New England were cut by the supplier during the peak load period of the day. Mr. Brandien's testimony explains the problems that the combination of limited natural gas supplies and inflexible resources pose for system operation.[8] In each of these situations, the inability of otherwise "available" generation to get fuel or to respond to stressed system conditions created reliability problems.

Q: Please explain how you determined that, if the ISO had no surplus capacity above the Installed Capacity Requirement, the system would have been 1,900 MW short of its operating reserve requirement of 2,375 MW on July 19, 2013 before calling on its Demand Resources.

A: As noted above, on that day there were about 2,500 MW of capacity above the Installed Capacity Requirement. This consisted of 31,366 MW of installed generation,[9] 1,655 MW of Demand Resources with a Capacity Supply Obligation, and 1,039 MW of Import Capacity Resources with a Capacity Supply Obligation. Comparing this supply with the net Installed Capacity Requirement of 31,552

[8] *See* Brandien Testimony at 6-24.

[9] Based on the total Summer Claimed Capability ratings of generating resources.

MW results in a surplus of 2,508 MW. To estimate what would have happened on that day if there was no surplus, it is necessary to remove approximately 2,500 MW of resources. In this analysis, we removed Salem Harbor, Brayton Point, and Norwalk Harbor stations from the resource mix because they have submitted Non-Price Retirement Requests, which means they will be retiring in the near future. These stations together have a total summer claimed capability of 2,445 MW, thus leaving 28,921 MW of generating capacity when removed. Generator reductions were then calculated based on actual performance over the July peak hour for the remaining resources on the system. Accounting for these outages resulted in 25,184 MW of available generating capacity for the peak hour. For this analysis, it was assumed that the same level of imports from external areas would be available to New England. Therefore, after accounting for the 2,652 MW of imports that were flowing at the time of peak, there were 27,836 MW available on the system prior to accounting for Real Time Demand Resources. As the peak load on this day was 27,379 MW, there were 457 MW available to meet the reserve requirement of 2,375 MW, thus leaving the system with an estimated shortage of approximately 1,900 MW.

Q: Do you believe this analysis understates or overstates the risk to reliability without the Pay For Performance program?

A: We believe it understates the risks because outages, especially outages for the older fossil steam units, have been increasing in the past several years. NERC GADS data show that the fossil steam (including nuclear) Equivalent Forced

Outage Rated demand (EFORd) for resources in New England has increased from 4.27 percent in 2007 to 16.35 percent in 2013 (data through November 30, 2013). If Pay For Performance is not implemented and the performance incentives remain the same, we see little reason for these resources to make investments, or to increase their maintenance budgets, to lower their outage rates since as ISO witnesses Matthew White and Peter Cramton explain in their testimony, the current capacity market provides weak incentives for investments in improved performance because its penalty structure is ineffective in sending the price signals that provide the incentives to invest in improved performance.[10] Thus, without Pay For Performance, outage rates are likely to continue to increase. If outage rates increase, then the analysis shown above becomes optimistic and the risk of having to use rolling blackouts to maintain system reliability also increases.

Q: Why is it especially important to provide improved price signals in New England's wholesale markets to maintain reliability?

A: According to U.S. Energy Information Administration data,[11] less than 3% of the generation in New England is owned or under contract to vertically integrated utilities, which means that 97 percent of the energy comes from merchant-owned generators. These generators make investment and expenditure decisions based on

[10] White Testimony at Section III.B; Cramton Testimony at 14-15.

[11] The data is available at http://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,1,0&fuel=g&geo=00fvvvvvvvvvo&sec=8&linechart=ELEC.GEN.ALL-CT-1.A&columnchart=ELEC.GEN.ALL-CT-1.A&map=ELEC.GEN.ALL-CT-1.A&freq=A&start=2001&end=2012&ctype=map&ltype=pin&maptype=0&rse=0&pin=

whether or not they will realize a return on their investments. Consequently, merchant generators will not make investments or expenditures unless the wholesale markets provide returns on them. If there were more vertically integrated utilities in New England, the fact that the price signals in the current markets are insufficient to maintain reliability might be able to be swept under the rug without consequence since vertically integrated utilities have an obligation to keep the lights on and face a variety of non-market pressures that ensure they will put high value on avoiding outages during peak demand periods; merchant generators do not face these pressures to nearly the same degree. Vertically integrated utilities are likely to react in ways that mask the reliability impact of these market inefficiencies, but merchant generators react in ways that fully reflect the inefficiencies of the market. Because of New England's lack of vertical integration, it is especially important that the details of the market design be constructed well and it is no surprise that flaws in the market design appear more quickly in New England than in other regions.

Q: How will Pay For Performance address the problem of increased forced outage rates and increase resource flexibility?

A: As ISO witness Matthew White discusses in more detail, Pay For Performance will address outages and reliability in two ways.[12] Pay For Performance will provide the revenue stream that resources can use to fund the maintenance and investments such as dual fuel equipment to increase the probability that resources will be available when needed. Since revenues from Pay For Performance are

[12] White Testimony at Sections III and IV.

earned in hours in which scarcity conditions occur, Pay For Performance will change the mix of generation in the region to one that is more likely to perform during scarcity conditions. In practical terms, Pay For Performance will encourage resources that are low-cost, flexible, or both, and will discourage resources that are both high-cost and inflexible. It does so because low-cost units are likely to be running most of the time and therefore providing energy during scarcity conditions, while flexible units can be called on when system conditions worsen and more capacity is needed to supply energy and reserves. Both low-cost and flexible resources are likely to earn a high percentage of the Pay For Performance revenues. Inflexible, high-cost resources are the least likely to be running during scarcity conditions and consequently will earn the least amount of revenues under Pay For Performance.

Over time, this re-allocation of revenue will change the resource mix. Resources that earn a high percentage of Pay For Performance revenues will be able to stay in the capacity market at lower capacity prices than resources that earn a low percentage of Pay For Performance revenues. Because their actual capacity revenue will be higher, they will be able to offset any going forward costs not covered by energy market rents. Resources that earn a low percentage of Pay For Performance revenues need higher capacity prices so that the low percentage they actually receive will be able to offset their going forward costs. Thus, the high-cost, inflexible resources will leave the market sooner and they will be replaced by lower-cost or more flexible resources.

In addition, because of the performance revenues earned during scarcity conditions, resources will have incentives to invest to improve their ability to perform in scarcity conditions and lowering their costs, two very desirable attributes.

Q: What do you believe will happen if Pay For Performance is not adopted?

A: System reliability will further deteriorate and more out-of-market ISO intervention will be needed to manage the physical risks to the system. The ISO will be forced to commit oil units out of merit to provide reserves and the likelihood of rolling blackouts will increase due to resources not performing during reserve shortages when they are most needed.

IV. DETAILED DISCUSSION OF PAY FOR PERFORMANCE RULE CHANGES RELATED TO MARKET MONITORING AND MITIGATION

A. Under Pay For Performance, The IMM May Only Mitigate De-List Bids From Pivotal Suppliers

Q: Under the current FCM rules, which de-list bids may be mitigated by the IMM?

A: Under the current FCM rules, Static De-List Bids, Permanent De-List Bids, and Export Bids submitted at prices equal to or above $1.00/kW-month (the current threshold for submission of Dynamic De-List Bids) are reviewed by the IMM to

determine whether the bid is consistent with the resource's net risk-adjusted going forward costs and opportunity costs. Any such bid that is found inconsistent with the resource's net risk-adjusted going forward and opportunity costs is subject to mitigation.

Q: How will this change under Pay For Performance?

A: Under the new Pay For Performance mechanism, the IMM may only mitigate de-list bids at prices above the Dynamic De-List Bid Threshold from resources associated with Lead Market Participants that are found to be pivotal suppliers. (We discuss the change in the Dynamic De-List Bid Threshold from the current $1.00/kW-month to a new value of $3.94/kW-month in Section IV.C below. In this section, we focus on limiting IMM mitigation to de-list bids submitted by pivotal suppliers.)

Q: Why is it appropriate to limit IMM mitigation to pivotal suppliers only?

A: In principle, a Lead Market Participant is pivotal if the applicable capacity requirement cannot be met without some capacity from that Lead Market Participant. A Lead Market Participant is not pivotal if none of its capacity is necessary to meet the applicable capacity requirement (assuming all resources other than those controlled by the Lead Market Participant competitively offer their capacity into the market). Since the market can clear without any of a non-pivotal supplier's capacity, a non-pivotal supplier cannot exercise unilateral market power and profitably set the price at a non-competitive level. Thus, IMM

review of the de-list bids of non-pivotal suppliers is not necessary to assure competitive market outcomes, and it is appropriate to apply mitigation only to the de-list bids of pivotal suppliers whose offers are inconsistent with their going forward costs.

Q: Please explain the process by which de-list bids will be reviewed by the IMM under Pay For Performance.

A: As under the current rules, all de-list bids will be required to include documentation allowing the ISO to review the de-list bid and determine whether it is consistent with the resource's going forward costs. If the resource's Lead Market Participant is pivotal, and the IMM's review of the de-list bid finds the bid consistent with its going forward costs (inclusive of the cost of "taking on the capacity obligation and its associated risks), then the de-list bid will be entered into the Forward Capacity Auction as submitted.

If the IMM's review of a de-list bid from a pivotal Lead Market Participant finds the bid not consistent with its going forward costs, the bid will be rejected. In this case, a revised de-list bid based on the IMM-determined values can be accepted by the participant and used in the auction. While the process for a rejected de-list bid varies somewhat depending on whether the bid is a Static De-List Bid, a Permanent De-List Bid, or an Export Bid, these processes are not being changed from the currently effective rules.

Q: How will the IMM determine if the Lead Market Participant submitting a de-list bid is pivotal?

A: Conceptually, a Lead Market Participant will be considered pivotal if any of the capacity from the existing resources controlled by that Lead Market Participant is needed to satisfy the capacity requirements either system-wide or in an import-constrained Capacity Zone.

Q: Please explain how the pivotal supplier determination will work system-wide.

A: As stated in the revised FCM rules, a de-list bid will be associated with a pivotal supplier if at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area minus the Installed Capacity Requirement (net of HQICCs) is less than or equal to the greater of: (a) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and (b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW.

Expressed mathematically, a Lead Market Participant is pivotal system-wide if the following inequality is true:

$$(\text{Total Capacity} - \text{NICR}) \leq \max[(\text{LMP Capacity} \times 1.1), (\text{LMP Capacity} + 200)]$$

Where:

- Total Capacity is the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area;
- NICR is the Installed Capacity Requirement (net of HQICCs) for the applicable Capacity Commitment Period; and
- LMP Capacity is the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant.

These terms are subject to adjustments as described in further detail below.

Q: Why is it the difference between the total amount of existing capacity minus the Installed Capacity Requirement (net of HQICCs) that is compared to the Lead Market Participant's capacity?

A: If the total amount of existing capacity is greater than the Installed Capacity Requirement (net of HQICCs), then the difference between the two will be a positive value that represents the amount by which the system is "long." In that case, for a supplier to be pivotal, it would have to control an amount of capacity equal to or greater than the excess amount in order for some of its capacity to be needed to satisfy the requirement. Otherwise the resource is not pivotal. If the amount of existing capacity is less than the Installed Capacity Requirement (net of HQICCs), the difference between the two is the amount by which the system is "short." In that case, all capacity is needed to satisfy the requirement and all suppliers are pivotal.

Q: Will any adjustments be made to the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area?

A: Yes. The total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area will be reduced by an amount equal to the total of all pending Non-Price Retirement Requests and Permanent De-List Bids other than those submitted by the Lead Market Participant for the resource being evaluated. Pending Non-Price Retirement Requests and Permanent De-List Bids represent capacity that is highly likely to be removed from the capacity market in the Capacity Commitment Period, and hence is properly excluded from the total amount of capacity in making the pivotal supplier determination. However, this exclusion will not apply to Non-Price Retirement Requests and Permanent De-List Bids submitted by the Lead Market Participant for the resource being evaluated. It is appropriate to include such amounts in the quantity of total existing capacity because its removal is within the control of the Lead Market Participant and exclusion of such amounts could lead to situations where the IMM fails to identify a pivotal supplier with potential market power.

Q: Please provide an example of how a pivotal supplier would be found non-pivotal if its Non-Price Retirement Requests are excluded from the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area.

A: Assume that the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area is 25,250 MW and that the net Installed Capacity Requirement is 22,000 MW. Lead Market Participant A has 3,000 MW of summer Qualified Capacity. Using the formula provided above, this participant is pivotal at the system level because the following expression is true:

$$(25{,}250 - 22{,}000) \leq \max[(3{,}000 \times 1.1), (3{,}000 + 200)].$$

Assume next that Participant A decides to submit Non-Price Retirement Requests in the amount of 2,000 MW. If the pivotal supplier test excludes this amount from the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area (that is, if the IMM assumes that the Non-Price Retirement Requests are accepted by the ISO), then the total summer Qualified Capacity is reduced from 25,250 MW to 23,250 MW. Participant A's summer Qualified Capacity is reduced from 3,000 MW to just 1,000 MW. Under these assumptions, Participant A would not be pivotal at the system level because the following expression is *not* true:

$$(23{,}250 - 22{,}000) \leq \max[(1{,}000 \times 1.1), (1{,}000 + 200)].$$

This becomes problematic if Participant A's Non-Price Retirement Request is subsequently rejected by the ISO, which would make this participant again pivotal. To address this problem, in determination of Participant A's pivotal supplier status, the IMM will assume that its Non-Price Retirement Requests are rejected in determining the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area. If this is not done,

and the Non-Price Retirement Requests are accepted, then Participant A's other resources may become pivotal and set the price at non-competitive levels.

Q: Please provide an example of how a pivotal supplier might be found non-pivotal if Non-Price Retirement Requests from other Lead Market Participants are included in the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area.

A: Assume again that the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area is 25,250 MW and that the Net Installed Capacity Requirement is 22,000 MW. As in the example above, assume that Participant A has 3,000 MW of summer Qualified Capacity, and submits Non-Price Retirement Requests in the amount of 2,000 MW. Another Lead Market Participant, Participant Z, has 1,500 MW of summer Qualified Capacity. In evaluating whether Participant Z is pivotal, it is appropriate to assume that Participant A's Non-Price Retirement Requests are accepted (that is, the amount of Participant A's Non-Price Retirement Requests is not included in the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area). Using the formula provided above, this participant Z is pivotal at the system level because the following expression is true:

$$(23{,}250 - 22{,}000) \leq \max[(1{,}500 \times 1.1), (1{,}500 + 200)].$$

If, on the other hand, the IMM assumed that Participant A's Non-Price Retirement Requests are rejected, then the IMM's pivotal supplier test would incorrectly identify Participant Z as non-pivotal at the system level because the following expression is *not* true:

$$(25{,}250 - 22{,}000) \leq \max[(1{,}500 \times 1.1), (1{,}500 + 200)].$$

These examples demonstrate that, to identify all potentially pivotal suppliers, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area must exclude the amount of capacity subject to Non-Price Retirement Requests, other than those of the Lead Market Participant being reviewed, which must be included in the total.

Q: Why is it appropriate to treat Permanent De-list Bids in the same manner as described above for Non-Price Retirement Requests?

A: Pursuant to Section III.13.1.2.3.1.5.2 of the Tariff, a Permanent De-List Bid that has been rejected by the IMM may be resubmitted as a Non-Price Retirement Request after such rejection. So any pending Permanent De-List Bid has the same potential impact on the total capacity amounts as a Non-Price Retirement Request. For this reason, it is appropriate to apply the same treatment to Permanent De-list Bids.

Q: How will the IMM determine the Installed Capacity Requirement (net of HQICCs) to use in the pivotal supplier analysis?

A: The IMM shall use the best available estimates of those values available at that time it conducts the pivotal supplier analysis, which is in the third quarter of each year. The IMM shall publish those estimated values on the ISO website no later than the date that the qualification determination notifications are issued. The determination of the Installed Capacity Requirement and related values go through the stakeholder process and are ultimately approved by the Commission. Final approval of the Installed Capacity Requirement and related values by the Commission occurs after the issuance of the qualification determination notifications in which the IMM must notify resource owners of the determinations regarding their de-list bids. Consequently, the IMM must perform the pivotal supplier test before the Installed Capacity Requirement and related values are approved.

Q: Will any adjustments be made to the total amount of existing capacity controlled by the Lead Market Participant?

A: Yes. For purposes of the system-wide pivotal supplier determination, the IMM will use the greater of: (a) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and (b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW. This is expressed mathematically by the max operator in the formula above.

Q: Why is the IMM increasing the capacity controlled by the Lead Market Participants in this manner?

A: It is important to ensure that all bids from potentially pivotal suppliers are subject to mitigation. Because the Installed Capacity Requirement (net of HQICCs) and related values in the pivotal supplier determination will not be not approved by the Commission at the time the pivotal supplier determination must be completed, it is reasonable to err on the conservative side by building into the design a small buffer or margin of safety to ensure that de-list bids from Lead Market Participants "near the line" – that could potentially be pivotal once the Installed Capacity Requirement (net of HQICCs) is final – will also be subject to mitigation. This is accomplished by adding a small amount to the Installed Capacity Requirement (net of HQICCs). If this buffer were not included, and the final Installed Capacity Requirement (net of HQICCs) were higher than previously estimated, then a pivotal supplier might incorrectly appear non-pivotal at the time of the IMM's evaluation.

Rather than increase the Installed Capacity Requirement, the pivotal supplier test increases the amount of capacity controlled by the Lead Market Participant. Increasing the amount of capacity controlled by the Lead Market Participant is mathematically equivalent to increasing the Installed Capacity Requirement (net of HQICCs) by the same amount. This approach allows the adder to be somewhat tailored to the amount of capacity controlled by the Lead Market Participant. The adder is the greater of: (a) the Lead Market Participant's existing capacity

multiplied by 1.1; and (b) the Lead Market Participant's existing capacity plus 200 MW. For Lead Market Participants with less than 2,000 MW, the 200 MW adder will control (that is, it will be the greater of the two values, and hence will be used in the pivotal supplier determination). For Lead Market Participants with more than 2,000 MW, the 1.1 multiplier will control.

The specific values chosen (multiplying by 1.1 or adding 200 MW, respectively) appropriately balance the uncertainties with respect to the Installed Capacity Requirement (net of HQICCs) at the time the pivotal supplier determination must be made and the IMM's objective to avoid mitigating resources that are unlikely to possess market power.

Q: Please explain how the pivotal supplier determination will work in an import-constrained Capacity Zone.

A: In an import-constrained Capacity Zone, the pivotal supplier determination will work largely in the same manner as it does system-wide, except that zonal values are used instead of system-wide values for the total amount of existing capacity, the capacity requirement, and the amount of existing capacity controlled by the Lead Market Participant. Specifically, as stated in the revised FCM rules, a de-list bid from a resource in an import-constrained Capacity Zone will be associated with a pivotal supplier if at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the import-constrained Capacity Zone minus the Local Sourcing Requirement for the

import-constrained Capacity Zone is less than or equal to the greater of: (a) the amount of capacity from all of the Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and (b) the amount of capacity from all of the Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant for the resource submitting the bid plus 100 MW.

Expressed mathematically, a Lead Market Participant is pivotal in an import-constrained Capacity Zone if the following inequality is true:

$$(\text{Zonal Capacity} - \text{LSR}) \leq \max[(\text{LMP Capacity} \times 1.1), (\text{LMP Capacity} + 100)]$$

Where:

- Zonal Capacity is the total amount of summer Qualified Capacity of all Existing Capacity Resources in the import-constrained Capacity Zone;
- LSR is the Local Sourcing Requirement for the import-constrained Capacity Zone for the applicable Capacity Commitment Period; and
- LMP Capacity is the amount of capacity from all of the Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant.

These terms are subject to the same adjustments as described above with respect to the system-wide pivotal supplier determination.

Q: Other Than Using Applicable Zonal Values, Does The Pivotal Supplier Determination In An Import-Constrained Capacity Zone Differ From The System-Wide Approach?

A: The only other difference is that system-wide, the amount of capacity from the Lead Market Participant is increased to the greater of the Lead Market Participant's existing capacity multiplied by 1.1 and the Lead Market Participant's existing capacity plus 200 MW, while in an import-constrained Capacity Zone, the adder in the second alternative is 100 MW instead of 200 MW. This smaller value reflects the smaller amount of variation in capacity in an import-constrained Capacity Zone than system-wide. The IMM believes that this smaller value is reasonable because each import-constrained Capacity Zone is only a portion of the system and uncertainty about the Local Sourcing Requirement is only a portion of that about the Installed Capacity Requirement.

Q: Why are new capacity resources excluded from consideration in both the system-wide and import-constrained Capacity Zone pivotal supplier determination?

A: In principle, a MW of power from a new capacity resource is a perfect substitute for a MW of power from an Existing Capacity Resource. There is no reason to include new capacity in the pivotal supplier determination, however, because

including capacity from new resources would not change the pivotal status of the Lead Market Participant of the new resource from pivotal to non-pivotal. But it could change the pivotal status of *other* participants from pivotal to non-pivotal. In other words, some participants that are in fact pivotal might be flagged as non-pivotal if the capacity from new resources is included in the determination of pivotal suppliers.

Q: Please explain why including new capacity of a pivotal Lead Market Participant does not make that participant appear non-pivotal?

A: In its simplest form, a participant's pivotal status depends on whether the capacity requirement can be met without that participant's capacity. A participant is pivotal if the difference between total quantity supplied and the quantity supplied by that participant is smaller than the quantity demanded. An additional MW of capacity by a participant increases both the total quantity supplied, and quantity supplied by that participant, leaving the difference intact. Hence, if a pivotal participant adds new capacity, it adds to the total quantity supplied as well as the quantity supplied by that participant at the Forward Capacity Auction Starting Price. The difference between these two variables, and as a result, the participant's pivotal status, will not change after including new capacity in the calculations.

Q: **Please explain how including new capacity of a participant could make other, potentially pivotal Lead Market Participants, appear non-pivotal in the test?**

A: Lead Market Participants submitting new capacity offers can withdraw their offers between the qualification deadline and the Forward Capacity Auction. Consider a situation where total existing capacity in the system is 50 MW short of the Installed Capacity Requirement. In this situation, all resources are pivotal. Now consider two participants, one that has 100 MW of existing resources (Participant A), and another one with only 20 MW of existing capability (Participant B). Participant A also has 400 MW of new capacity, which can be withdrawn after the pivotal supplier determination is made.

If the IMM includes Participant A's new capacity in determining whether Participant B is pivotal, the system will be long 350 MW and Participant B will appear to be not pivotal. As non-pivotal, Participant B would be exempt from mitigation by the IMM. If Participant A then later withdraws its new capacity, Participant B is indeed pivotal, but could proceed to the auction with an unmitigated offer that could set the market price.

Q: Is it possible that the IMM's pivotal supplier test results in "false positives," that is, Lead Market Participants that are in fact non-pivotal, but are identified as pivotal by the IMM?

A: Yes. In the scenario above, for example, if Participant A does not withdraw its 400 MW of new capacity, Participant B would have been identified as pivotal, but would have been in fact non-pivotal. The pivotal supplier test necessarily involves this tradeoff, however, and in its effort to guard against the exercise of market

power, the IMM believes there is far less risk to competitive outcomes and market integrity in flagging some non-pivotal suppliers as pivotal than in failing to flag some actually pivotal suppliers. The harm to the owner of the resource in the case of such "false positives" is minimal. Such a resource is not automatically mitigated; it is simply subject to potential mitigation if the submitted de-list bid is inconsistent with its going forward costs. If the de-list bid is consistent with its costs, there is no mitigation. The potential harm from failing to identity an actually pivotal supplier is far more serious. Unmitigated de-list bids from truly pivotal suppliers can inappropriately set the auction price significantly higher than it would have been if all offers are competitive. For these reasons, the pivotal supplier test is calibrated to identify virtually all potentially pivotal suppliers, even at the (minimal) risk of a false positive.

Q: Does the pivotal supplier test apply to a Lead Market Participant controlling only a single resource or only controlling a small amount of capacity?

A: Yes. The number or size of the resources controlled by a Lead Market Participant is not relevant to the pivotal supplier determination. A Lead Market Participant can be pivotal if only a small amount of its capacity is needed, regardless of the overall number and size of resources controlled. Furthermore, an exception based on the number or size of resources could provide an incentive to spin-off a pivotal generation asset for the purpose of exercising market power. When the amount of existing capacity is smaller than or equal to the applicable capacity requirement,

all Lead Market Participants, large or small, and irrespective of the number of resources they control, are pivotal.

B. Changes to the IMM's Review of De-List Bids

Q: At a high level, how is the IMM's review of de-list bids changing under Pay For Performance?

A: Under the current rules, there are two main components of a de-list bid that are reviewed by the IMM: net risk-adjusted going forward costs, and opportunity costs. The rule revisions presented here instead break the de-list bid into four distinct components for IMM review: net going-forward costs, expectations about the resource's Capacity Performance Payments, risk premium assumptions, and opportunity costs. Each of these four components will be discussed below, but the notable changes here are: (i) the removal of the risk adjustment from the net going-forward cost calculation and the creation of a distinct risk premium component, because risk assessment is an important piece of developing an offer under Pay For Performance; and (ii) the addition of a new component for expectations about Capacity Performance Payments.

Q: Will resources continue to have the ability to submit de-list bids that vary by block for a single resource?

A: Yes. Presently, resources can submit bids in the Forward Capacity Auction with different prices for one portion of the resource's capacity, or "block," than for

additional portions of the resource's capacity. For example, a generator with 100 MW of capacity can submit one bid price for the first 90 MW block of its capacity, and a second, higher bid price for the upper 10 MW block of its capacity. In the capacity auction, a resource that bids in this way may clear neither block, only the first 90 MW block, or both blocks, based on its bids and the relevant Capacity Clearing Price.

Under Pay For Performance, it is more important for a resource to be able to submit bids by block, since factors affecting the resource's performance during the Capacity Commitment Period may vary by block. For example, if a resource owner is risk averse, and believes that there is a greater risk that higher output blocks are not able to perform as reliably as lower blocks, it can price this higher risk into the upper blocks. That is economically desirable, as it means the auction is less likely to clear, and the region less likely to rely upon, the blocks of resources that owners believe are less reliable. In addition, the going forward costs of higher blocks may be greater than lower blocks. Allowing de-list bids to be broken into blocks permits this to be reflected in a resource's offer.

1. Net Going Forward Costs

Q: Why is the risk adjustment being removed from the net going-forward costs calculation and instead being reflected in a distinct risk premium bid component?

A: Under Pay For Performance, risks faced by resources are very different that those in the current market. Risks under Pay For Performance vary greatly depending on several factors, including the size of a participant's portfolio, its risk tolerance, and uncertainty about the number of hours with Capacity Scarcity Conditions during the Capacity Commitment Period three years in the future. A risk adjustment is included in the current net risk-adjusted going forward cost formula, but that formula is overly simplistic for use under Pay For Performance since it only reflects unit availability. Additionally, since each participant's risk tolerance and its method for assessing risk are likely to be different, it is not possible to develop a single formula that would enable all Lead Market Participants to accurately reflect their risk preferences. Therefore to permit each participant to thoroughly represent and fully explain their risk premium, under Pay For Performance the risk adjustment is being removed from the net going-forward costs formula, and is being replaced by a separate risk premium component of the bid. Using a formula for calculating the risk premium would force all participants to use the same methodology for calculating their risk premium; this seems an unwarranted intrusion into an area that should be the prerogative of the resource owner.

Q: How will the net going-forward cost calculation change?

A: The current net risk-adjusted going forward cost calculation in the Tariff is:

$$NRAGFC = \frac{\left[\frac{GFC}{1-EFORd} + RF - (IMR - PER)\right] \times InflationIndex}{Q_{summer} \times 12}$$

Where:

- GFC is the annual going forward costs (in dollars);
- EFORd is the Equivalent Forced Outage Rate of the unit;
- RF is the risk factor of the unit (in dollars);
- IMR is the annual infra-marginal rents (in dollars);
- PER is the resource-specific annual peak energy rents (in dollars); and
- InflationIndex is the inflation index. InflationIndex = $(1 + i)^4$ where i is the 1-Year Constant Maturity Treasury Rate at the beginning of the qualification period.

The variables in and application of this formula are defined in more detail in Section III.13.1.2.3.2.1.2 of the Tariff. The terms in this formula reflecting the risk adjustment are (1-EFORd) and RF. The term (1-EFORd) is the percentage of time that a unit that is in demand is in forced outage. A higher EFORd for a resource means that it is available during fewer hours in the Capacity Commitment Period and is more likely to be exposed to the Shortage Event penalties (under the current Tariff provisions). Risk Factor, RF, takes several risk-related factors such as cost of replacing a Capacity Supply Obligation if a resource having that obligation experiences a significant decrease in its capability.

As explained above, these two variables are being removed from the going-forward costs formula, and instead all risk related calculations will be included in a separate risk-premium de-list bid component, which is discussed below. The net going-forward costs formula after removal of the risk-related terms is:

$$NGFC = \frac{GFC - (IMR - PER) \times InflationIndex}{Q_{summer} \times 12}$$

Except for removal of the risk adjustment terms, the other variables will remain largely unchanged. These other variables have been in place and calculated successfully by participants for several years.

Q: You said that the remaining variables in the net going-forward costs formula will be "largely unchanged." Other than removal of the formula terms related to risk adjustment, are there any other changes to the net going-forward costs calculation?

A: The revisions also include a minor change to the "Inflation Index" term in the net going-forward costs calculation. That term is currently based on the 1-Year Constant Maturity Treasury Rate. After reviewing issues with the current inflation index and studying several historical and forward looking indices, the IMM has determined that the expected 4-year inflation prediction published monthly by the Federal Reserve Bank of Cleveland is the most comprehensive forward looking index for changes in the costs of capacity suppliers. Otherwise, there are no further changes to the net going-forward cost formula or the definitions of the formula terms.

2. Risk Premium

Q: How does the IMM view the risk premium in general?

A: The IMM views the risk premium as an essential part of each participant's offer. The future number of scarcity hours, the Capacity Balancing Ratio, and a resource's performance during the commitment period are all uncertain when a resource owner submits a new supply offer or a de-list bid. In making decisions about future investments and expenditures, we expect that resource owners will consider that uncertainty. Therefore, it is necessary for their de-list bids to also include that uncertainty so that the bids accurately reflect the price that resources require to participate in the market and meet the associated obligations.

More technically, the IMM defines the risk premium as the amount of expected profit a participant would be willing to forego in order to avoid some of the "downside" risk of losing money in the capacity market. Participants form their expectations about relevant market variables, calculate their expected profit-maximizing bid, and then add a premium depending on how much of the downside they want to avoid. Adding any risk premium to an expected-profit maximizing bid lowers the probability of clearing in the Forward Capacity Auction by enough that it will reduce the resource's expected profit. However, if the resource still clears in the auction, it may increase the resource's Capacity Base Payment – and therefore lowers its risk of losing money during the Capacity Commitment Period.

Q: What are the possible noncompetitive behaviors that can be concealed using the risk premium?

A: Adding a risk premium to an expected profit-maximizing bid is consistent with competitive behavior. However, a resource with significant market power that is unconcerned about a portion of its portfolio *not* clearing in the Forward Capacity Auction could use a risk premium on that portion of its portfolio to increase the market clearing price and benefit its resources that remain in the auction. For this reason, the IMM will review the information supporting the risk premium component of the de-list bid of pivotal suppliers.

Q: What are some of the risks faced by participants under Pay For Performance?

A: Under Pay For Performance, resources face a number of uncertainties that could result in losing money by acquiring a Capacity Supply Obligation and, under the same outcomes, not losing money if they did not acquire a Capacity Supply Obligation. For example, resources face risks regarding system conditions. Most importantly for Pay For Performance, the number of hours of scarcity conditions and the average Capacity Balancing Ratio during the Capacity Commitment Period are uncertain future conditions when de-list bids are due. The more Capacity Scarcity Conditions that occur and the higher the Capacity Balancing Ratio, the more money will flow through the Pay For Performance mechanism. All resources, but especially poorly performing ones, will want to account for this uncertainty in formulating their bids. In formulating its bid, a resource owner is likely to start with an expected number of Capacity Scarcity Condition hours and an expected Capacity Balancing Ratio and calculate its "base bid" on the basis of

those expectations. However, all resources will recognize that there could be more or fewer Capacity Scarcity Conditions, and a higher or lower Capacity Balancing Ratio than they expect.

A poorly performing resource is likely to be particularly concerned that it may experience performance charges that are greater than its "base bid" – that is, experience a net loss in FCM settlement – if there are more scarcity conditions or a higher Capacity Balancing Ratio that expected. To compensate for this risk, such resources are likely to add a risk premium to their bid. Resources also face risks with respect to their individual performance. If, for example, a resource has a significant decrease in its capability during the commitment period, it would have to either pay another resource to cover its obligation, or face the potential for additional losses during Capacity Shortage Conditions. It is to be expected that poorly performing resources, in particular, will include a risk premium in their bids; that is consistent with competitive pricing given the performance risk they face, and is economically appropriate because it leads the Forward Capacity Auction to be less likely to clear resources that the owners' expect may perform poorly.

Q: Please describe the new risk premium component of a de-list bid.

A: With the risk adjustment removed from the net going-forward cost calculation, the Tariff revisions implementing Pay For Performance include a new Section III.13.1.2.3.2.1.4 that details the separate risk premium component of a de-list bid.

That section states that the Lead Market Participant for a resource submitting a de-list bid that is to be reviewed by the IMM shall also provide documentation separately detailing any risk premium included in the bid. Such documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during scarcity conditions. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs may be included in the risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the FCM is consistent with the participant's corporate risk management practices. The IMM will review the affidavit and the risk analysis, compare it to those submitted by other participants, and ask for additional information if necessary.

Q: Why is this approach preferable to the formula-based approach in the currently effective version of the FCM rules?

A: The formulaic approach in the current rules is based on the risks in the current market design. Implementation of Pay For Performance changes the risks, making the current formula no longer adequate. The calculation of risk under Pay For Performance is more complex and is affected by several factors. The IMM believes that each company should evaluate their risks based on their own

methodology rather than requiring companies to use the same method prescribed by the IMM.

Q: How will the IMM evaluate the risk premium component of a de-list bid?

A: The IMM will evaluate each de-list bid in two ways. First, for units that are part of a multi-unit portfolio, the IMM will ascertain whether the risk premium requested for each of the units in the portfolio reflect consistent assumptions on key parameters affecting risk across the portfolio, including the expected number of hours of Capacity Scarcity Conditions. This may require the IMM to ask for information from a participant about other resources it owns for which it has not submitted de-list bids to determine if applying the assumption used in the submitted bids to other units would result in going forward costs higher than the Dynamic De-List Bid Threshold. If this occurs, the IMM will likely discuss these results with the participant to understand why de-list bids were submitted for the selected units and not others.

The second way in which the IMM will evaluate the risk premium portion of de-list bids is by comparing the risk premia across participants. If all of the risk premia are within the same range, then that would support a finding of a reasonable risk premium consistent with competitive market behavior. Participants with risk premium submittals that are noticeably outside of the range of reasonableness established by all of the risk premia taken together will likely be asked for further explanation.

The results of these analyses will be used by the IMM to determine if the risk premium is reasonable and consistent with the resource's net going-forward costs.

3. Expected Capacity Performance Payments

Q: Aside from the changes to the risk adjustment, you stated that another change to the IMM's review of de-list bids under Pay For Performance is the addition of a new component for expectations about Capacity Performance Payments. Please describe this change.

A: Pursuant to the revised rules, the Lead Market Participant for a resource submitting a de-list bid shall also provide documentation separately detailing its expected Capacity Performance Payments for the resource. This documentation must include assumptions regarding the Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

Q: Why is the expected Capacity Performance Payments being made a separate component of the de-list bid?

A: The assumptions supporting a resource's estimate of its expected Capacity Performance Payment will enable the IMM to evaluate whether the resource's bid is competitive.

Q: How are a resource's expected Capacity Performance Payments determined?

A: A resource's Capacity Performance Payment for a Capacity Commitment Period is the difference between the amount of energy and reserves it was obligated to provide during Capacity Scarcity Conditions, based on its share-of-system financial performance obligation, and the amount of energy and reserves it actually supplies times the Performance Payment Rate. This is described in detail in Section IV of Dr. White's testimony.[13] The details of the calculation are in revised Section III.13.7.2 of the Tariff.

Q: What is the significance of a resource's expected Capacity Performance Payments?

A: From the IMM's perspective, the significance of a resource's expected Capacity Performance Payments is their importance in determining a competitive bid for the resource. For most resources, a competitive bid will simply be the opportunity cost of taking on a Capacity Supply Obligation. Each resource will have its own estimate of that opportunity cost. This component of the de-list bid will enable the IMM to review the assumptions used by the resource in calculating its opportunity cost. For a minority of resources, however, a bid based simply on the opportunity cost of taking on a Capacity Supply Obligation will not be enough to cover their net going forward costs. The competitive bid for those resources must include an adder to their estimate of opportunity costs large enough to assure that they cover all of their going forward costs during the commitment period.

[13] White Testimony at Section IV.C.

The assumptions used in the calculation of the resource's expected Capacity Performance Payments enable the IMM to determine the resource's opportunity cost of taking on a Capacity Supply Obligation. Under Pay For Performance, a resource that has not taken on a Capacity Supply Obligation will also be paid the Capacity Performance Payment Rate multiplied by the amount of energy and reserves that it provides during a Capacity Scarcity Condition. The testimony of Drs. White and Cramton explain the economic importance of this aspect of the Pay For Performance design.[14]

Resources that do take on a Capacity Supply Obligation are selling forward their pro-rata share of the system's energy and reserve requirements during Capacity Scarcity Conditions. In other words, in exchange for the Capacity Base Payment, they agree to provide their share of the system's requirements during Capacity Scarcity Conditions in the commitment period. For a resource to take on this obligation, it will want to receive at least the amount of money it could have received by not taking on a Capacity Supply Obligation – that is, its opportunity cost.

The difference between a resource's Capacity Performance Payment with a Capacity Supply Obligation and without a Capacity Supply Obligation is the Capacity Performance Payment Rate times the expected number of hours of Capacity Scarcity Conditions times the expected Capacity Balancing Ratio. This is the resource's opportunity cost of acquiring a Capacity Supply Obligation, and

[14] White Testimony at 67-69; Cramton Testimony at 23-24.

therefore is the *minimum* payment that a resource will require to take on a Capacity Supply Obligation. The resource owner's expectations of the number of hours of Capacity Scarcity Conditions and the Capacity Balancing Ratio enable the IMM to evaluate the resource's opportunity cost of taking on a Capacity Supply Obligation.

A resource's expected revenues under Pay For Performance must be considered in evaluating its de-list bid to determine if these revenues are sufficient to cover the resources going-forward costs net of energy revenues. For a resource to take on a Capacity Supply Obligation, it must expect that it will earn enough money through its participation in the FCM to cover its net going forward costs. The going forward cost calculation described in Section IV.B.1 above shows whether or not a resource will earn enough revenue from the energy and ancillary services markets to cover its going forward costs. If a resource earns enough revenue from the energy and ancillary services markets to cover its going forward costs, then its competitive bid in the capacity market is simply its opportunity cost, as described above.

If a resource does not earn enough revenue from the energy and ancillary services markets to cover its going forward costs, then additional calculations must be done to determine whether its competitive bid in the capacity market is simply its opportunity costs or if the bid has to be increased to assure recovery of its net going-forward costs. The first such calculation is to determine whether the

resource would earn enough revenue from Capacity Performance Payments (absent a Capacity Supply Obligation) to cover its net going-forward costs. If it does, the resource would not *need* to assume a Capacity Supply Obligation to receive Capacity Base Payments to cover its net going-forward costs and consequently the only cost it incurs in taking on a Capacity Supply Obligation is its opportunity cost. If the first calculation shows that the expected revenue from Capacity Performance Payments (absent a Capacity Supply Obligation) is not enough, then a second calculation has to be done to determine how much additional revenue is needed. This calculation is done by subtracting the Capacity Performance Payments (absent a Capacity Supply Obligation) from the net going-forward costs. This difference has to be added to the resource's opportunity cost to assure that it will be able to cover both its share of the system financial obligation and its net going-forward cost if it receives a Capacity Supply Obligation.

Q: How will the IMM evaluate the Lead Market Participant's expectations regarding the applicable Capacity Balancing Ratio, the number of hours of Capacity Scarcity Conditions, and the resource's performance during Capacity Scarcity Conditions?

A: For the Capacity Balancing Ratio and the number of hours of Capacity Scarcity Conditions, the IMM will rely on two sources. The first source is the ISO's estimates of these two variables depending on the expected nature of Capacity Scarcity Conditions (whether they are expected in the summer or winter) and the

total amount of capacity available in the system. The number of hours with Capacity Scarcity Conditions is inversely related to the amount of excess supply in the system. The second source for reasonable estimates of these variables is the range that is established by other Static De-List Bid and Permanent De-List Bid submissions. The IMM can use other Static and Permanent De-List Bid submissions because (unlike resource-specific performance) the Capacity Balancing Ratio and the number of hours with Capacity Scarcity Conditions affect all resources. We will treat these estimates in the same way as estimates of the risk premium. Participants with submittals that are noticeably outside of the range of reasonableness established by the universe of submissions will likely be asked for additional information. In addition, and similar to evaluation of risk premia, the IMM may ask for information from a participant about resources that belong to that participant that have not submitted de-list bids to determine if applying the assumptions used in the submitted bids, particularly on Capacity Balancing Ratio and the expected number of scarcity conditions, to other resources would warrant submission of Static or Permanent De-List Bids for those other resources. If this occurs, the IMM will likely discuss these results with the participant to understand why de-list bids were submitted for the selected resources and not others.

For resource performance during Capacity Scarcity Conditions, the IMM can rely on years of data on existing resources. If a participant believes that its performance may be significantly different than what has been observed in the

past, it can explain this in its Static De-List Bid and Permanent De-List Bid submission or in response to IMM inquiries.

Q: In the discussion about risk premium above, you mentioned that resources face uncertainties with respect to the future number of reserve deficiency hours. In your opinion, should these uncertainties affect the expected Capacity Performance Payments analysis?

A: Such uncertainties should not enter the expected Capacity Performance Payment calculations. Expected Capacity Performance Payments should only include the *expected* values of the number of reserve deficiency hours and the Capacity Balancing Ratio. The uncertainties around these variables will play an important role in the calculation of the risk premium.

4. Opportunity Costs

Q: What changes are being made to the opportunity costs component of the de-list bid?

A: Unlike risk premia and expected Capacity Performance Payments, opportunity costs are already a de-list bid component under the current FCM rules. To conform with the revisions described above, however, some minor changes are being made to the opportunity costs provisions. First, the provision is being reworded to clarify that opportunity costs should only include costs not reflected in the net going-forward costs, expected Capacity Performance Payments, or risk

premium components of the bid. This is necessary to ensure that costs are appropriately categorized and that there is no double-counting. Second, references to quantifiable risk in the current opportunity cost provisions are being deleted. This is because any risk elements should instead be included in the new risk premium de-list bid component. Third, the revisions remove redundant procedural language from the opportunity costs provisions.

C. Increasing the Dynamic De-List Bid Threshold

Q: What is the Dynamic De-List Bid Threshold?

A: In the current FCM, there are two types of de-list bids that enable a resource to leave the capacity market for a single Capacity Commitment Period. Resources that wish to leave the market at prices equal to or above $1.00/kW-month, must submit Static De-List Bids in advance of the Forward Capacity Auction for review by the IMM. If resources wish to leave the market at prices below $1.00/kW-month, they may submit a Dynamic De-List Bids during the Forward Capacity Auction without review by the IMM.

Throughout the currently effective FCM rules, this $1.00/kW-month threshold between the two types of de-list bids is spelled out as "$1.00/kW-month." Whenever the threshold for submission of Dynamic De-List Bids is changed, each of these many instances must be updated in the Tariff. For simplification, the revised rules submitted here replace each of those instances with a new defined

term, the "Dynamic De-List Bid Threshold." A new Section III.13.1.2.3.1.A is being added to the Tariff to specify the numeric value of the Dynamic De-List Bid Threshold. If that value is changed in the future, it will no longer be necessary to update numerous sections of the Tariff; a single change to the new section will suffice.

Q: What principle should be used in setting the level of the Dynamic De-List Bid Threshold?

A: The Dynamic De-List Bid threshold should be set at the level of a competitive offer into the FCM. If a resource bids competitively, there is no need for the IMM to review its offer. However, if a resource bids above competitive levels, it may be attempting to exercise market power and its de-list bid should be reviewed. The current level of $1.00/kW-month is an estimate of the cost of taking on a Capacity Supply Obligation in the current market based on prices from annual reconfiguration auctions. Since it is an estimate of the cost of taking on an obligation, it represents a competitive offer.

Q: Will the Dynamic De-List Bid Threshold change under Pay For Performance?

A: Yes. Beginning with the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018), the Dynamic De-List Bid Threshold shall be $3.94/kW-month.

Q: Why is the Dynamic De-List Bid Threshold being raised?

A: The Dynamic De-List Bid Threshold is being raised because the Pay For Performance design changes the definition of the capacity product and therefore changes the level of a competitive offer in the capacity market for all resources. Ideally, the IMM would set the Dynamic De-List Bid Threshold at the competitive bid of the marginal unit. By doing this, the IMM would only review non-competitive bids that could have material impact on the market outcomes. However, since it is obviously not possible to know the marginal unit prior to the auction, the IMM used values representative of fossil steam units to set the Dynamic De-List Bid Threshold because these are the type of existing resources most likely to seek to leave the auction and therefore could be the marginal unit if there is more existing capacity than needed to meet the Installed Capacity Requirement.

Q: How did you calculate the Dynamic De-List Bid Threshold based on the representative characteristics of fossil steam units?

A: We used the same approach described above in the section on expected Capacity Performance Payments. We describe it more formally here using equations to derive the optimal bid or offer into the FCM under Pay For Performance.

The optimal bid for a profit-maximizing proxy unit (i) under Pay For Performance is described by the following formula:

$$b_i = PPR \times Br \times H + \max\{0,\ GFC_i - PPR \times A_i \times H\}$$

Where:

- *PPR* is the Capacity Performance Payment Rate specified in the Tariff.
- *Br* is the expected Capacity Balancing Ratio.
- *H* is the expected number of hours with Capacity Scarcity Conditions during the commitment period.
- *GFC* is the resource's net going-forward cost.
- *A* is the expected average performance of the resource during Capacity Scarcity Conditions during the commitment period.

In the formula above, the Capacity Performance Payment Rate, Capacity Balancing Ratio, and the expected number of hours with Capacity Scarcity Conditions during the commitment period are system characteristics and are not resource dependent. Except for the Capacity Performance Payment Rate, which is set by the Tariff, the IMM used historical values and expectations of future system conditions to establish the values for these variables to be used in setting the Dynamic De-List Bid Threshold.

The resource's net going-forward cost and the expected average performance of the resource during hours with Capacity Scarcity Condition during the commitment period clearly depend on the characteristics of the resource. The IMM used estimates of those characteristics for existing fossil steam resources in setting the Dynamic De-List Bid Threshold.

Q: Please explain the components of this formula and why it represents the competitive bid for such a resource?

A: The first portion of the equation ($PPR \times Br \times H$) represents the opportunity costs of assuming a Capacity Supply Obligation in the Forward Capacity Auction. These values are not resource-specific. The Capacity Payment Performance Rate (PPR) is a design parameter, and the Capacity Balancing Ratio (Br) and the number of hours with Capacity Scarcity Condition (H) are based on expected system conditions. $(PPR \times Br \times H)$ is also termed the common value component of a resource's capacity market offer because it is common to all resources. The common value component is the lowest competitive bid and hence the Dynamic De-List Bid Threshold should be no lower than that.

The second portion of the equation ($\max\{0,\ GFC_i - PPR \times A_i \times H\}$) is a resource-specific value that represents the portion of the resource's going forward costs that is not covered by its expected Capacity Performance Payments (absent a Capacity Supply Obligation). The term ($PPR \times A \times H$), that is, the Capacity Performance Payment Rate multiplied by the resource's average performance multiplied by the number of hours with Capacity Scarcity Conditions, determines the value of the resource's expected Capacity Performance Payments (absent a Capacity Supply Obligation). For resources submitting de-list bids, average performance is the reserve-shortage-duration weighted average of delivered energy and reserve divided by the unit's Capacity Supply Obligation.

If the expected Capacity Performance Payments are higher than the resource's net going-forward costs, then all of the resource's expected net going-forward cost is covered by its expected Capacity Performance Payments which all resources, irrespective of their Capacity Supply Obligation, receive. In this case, the resource would not need any Capacity Base Payments and would be active in the energy market even without having any FCM obligation, and the second portion of the equation will be zero.

If the Capacity Performance Payments (absent a Capacity Supply Obligation) are lower than the resource's going forward costs (GFC), the resource is unable to cover all of its net going-forward cost with its expected Capacity Performance Payments. In this case, the second portion of the equation will yield a positive value and this amount is added to the first portion of the equation. This means that that the resource will not clear in the capacity market unless the price is high enough to cover the sum of its opportunity cost of assuming a Capacity Supply Obligation *(PPR × Br × H)* and the portion of its net going-forward costs that is not covered by Capacity Performance Payments, if any ($\max\{0,\ GFC_i - PPR \times A_i \times H\}$). Together, these values represent the competitive bid for a profit-maximizing unit under Pay For Performance.

Q: What value is the IMM using for the Capacity Payment Performance Rate in applying the formula to calculate the Dynamic De-List Bid Threshold?

A: For the Capacity Performance Payment Rate (PPR), we use the rate specified in the Tariff under Pay For Performance. New Section III.13.7.2.5 states that for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2,000/MWh.

Q: What value is the IMM using for the Capacity Balancing Ratio in the formula?

A: For the Capacity Balancing Ratio (*Br*), which is generally described as the sum of load and reserve requirement divided by the total quantity of Capacity Supply Obligations, the IMM used the historical value of 0.75, for the most recent complete years for which the ISO has collected data (2010-2012).

Q: **What value is the IMM using for the average number of hours with Capacity Scarcity Conditions in the formula?**

A: For the average number of Capacity Scarcity Condition hours (*H*), the IMM used 20.4 hours per year. The number of reserve deficiency hours depends on the amount of total MW available in the system. In modeling the amount of MW available on the system, the amount of surplus capacity increases as the Capacity Performance Payment Rate increases. At a *permanent* Capacity Performance Payment Rate of $2,000/MWh, the report entitled "Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives" by Analysis Group Inc. dated September 2013 and provided in Attachment I-1g of this filing ("Impact Assessment") predicts that the system will have excess

capacity of 298 MW. This is the value that is used by the IMM to develop its estimates of the number of reserve deficiency hours.

Using the planning models that are regularly used to develop the Installed Capacity Requirement and are approved by the Commission, the ISO calculated the distribution of the reserve deficiency hours based on a system with 298 MW of surplus. In calculating the Dynamic De-List Bid Threshold the IMM used the 75th percentile of the distribution of reserve deficiency hours from that calculation which is equal to 20.4 hours per year.

Q: What value is the IMM using for the net going-forward cost in the formula?

A: The net going-forward cost used in setting the Dynamic De-List Bid Threshold was calculated using the de-list submissions made by fossil steam units for the eighth Forward Capacity Auction reviewed by the IMM in summer 2013. This is an excellent source for this data since nearly all of the region's fossil steam units submitted de-list bids. Unadjusted for inflation, the weighted average net going-forward costs of these units was $2.41/kW-month. Using the expected inflation figures published by the Federal Reserve Bank of Cleveland in December 2013, after adjusting for inflation, the weighted average net going-forward cost of these units is $2.56/kW-month. To reduce the likelihood of reviewing competitive offers, the IMM used $2.75 as the net-going forward cost establishing the Dynamic De-List Bid Threshold.

Q: What value is the IMM using for the average performance during reserve deficiency hours in the formula?

A: The value of average performance is based on the Impact Assessment. The Analysis Group analyzed resources in New England and their estimate of the weighted average performance of economic and non-economic oil units under Pay For Performance when the Capacity Performance Payment Rate is $2,000/MWh is 0.48. The IMM decided to use 0.4 for the average performance in the formula because the IMM finds this value consistent with the characteristics of the existing fossil steam fleet in New England. Choosing 0.4 rather than 0.48 will have the effect of slightly increasing the Dynamic De-List Bid Threshold and avoids unnecessary review of competitive de-list bids by the IMM.

Q: Will the Dynamic De-List Bid Threshold change over time?

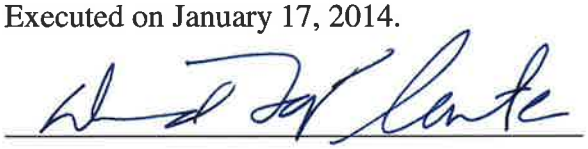
A: As stated in the revised rules, the Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the IMM will review the results of the recalculation with stakeholders and the new Dynamic De-List Bid Threshold shall be filed with the Commission under Section 205 of the Federal Power Act prior to the Existing Capacity Qualification Deadline for the associated Forward Capacity Auction.

Q: Does this conclude your testimony?

A: Yes.

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

Executed on January 17, 2014.



David LaPlante

Vice President, Market Monitoring

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

Executed on January 17, 2014.

Seyed Parviz Gheblealivand

Economist

Attachment I-1f

Testimony of Marc Montalvo on behalf of the ISO

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-_____-000**
New England Power Pool	**)**	

TESTIMONY OF MARC D. MONTALVO
ON BEHALF OF ISO NEW ENGLAND INC.

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

A: My name is Marc D. Montalvo. I am Director of Enterprise Risk Management at ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, MA 01040.

Q: Please describe your professional experience and qualifications.

A: I am Director of Enterprise Risk Management at the ISO. Previously, I served as Director of Assessment and Investigation for Internal Market Monitoring as well as Director of Market Development. I have energy industry experience that includes risk management, finance, market surveillance, and power market design. I have testified before the Federal Energy Regulatory Commission ("FERC" or "Commission") in support of the ISO's market design proposals and have testified before state regulatory agencies on issues including resource economics, portfolio design, and asset valuation. Prior to joining the ISO in 2004, I served as Manager of Wholesale Market Analytics at La Capra Associates, an energy industry consultancy based in Boston, MA. Before joining La Capra Associates, I was an Analyst in the generation operations and marketing group at

New England Power Company (NEES). I hold a M.S. in Finance from Clark University and a B.S. in Mathematics from Allegheny College.

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

A: The purpose of my testimony is to explain revisions to the ISO's Financial Assurance Policy ("FAP") made necessary by the implementation of the Pay For Performance design in the Forward Capacity Market ("FCM").[1]

Q: Why does the FAP need to be revised to accommodate Pay For Performance?

A: Market obligations are collateralized through the posting of financial assurance ("FA") under the FAP. The goal of the FAP is to ensure that there is sufficient cash available to clear the market each day and to cover a participant's settled obligations in the case of default. FA requirements are established to cover extreme loss scenarios, generally at the 99 percent not to exceed level.

To date, FA related to participation in the FCM has been limited to new resources that are not yet commercial. For a resource that is operating commercially, taking on a Capacity Supply Obligation in the FCM currently does not result in any additional financial obligations. Capacity payments during a Capacity

[1] Capitalized terms used but not otherwise defined in this testimony have the meanings ascribed thereto in the ISO New England Transmission, Markets and Services Tariff (the "Tariff"), the Second Restated NEPOOL Agreement, the Participants Agreement, or the Pay For Performance rules.

Commitment Period under the current FCM design cannot be negative, and hence, for commercial resources, there has been no potential financial obligation to collateralize. As described in detail in the ISO's transmittal letter and in the testimony of ISO witness Matthew White, however, under Pay For Performance, a resource's net capacity payments may be negative.[2] In this way, Pay For Performance introduces the possibility that commercial resources with Capacity Supply Obligations will have net payment obligations (*i.e.*, owe money) to the market. Market participants must post collateral against such exposures under the FAP.

Q: Please summarize the general approach to the proposed changes to the FAP.

A: To collateralize this additional potential obligation, a Market Participant with a Capacity Supply Obligation will be required to add *Forward Capacity Market Delivery Financial Assurance* ("FCM Delivery FA") to its total FA requirements calculation. FCM Delivery FA is designed to address three types of risk: (1) clearing risk, (2) credit risk, and (3) liquidation risk. Clearing risk is the risk that a Market Participant does not timely discharge settled payment obligations incurred in an already completed delivery month, which could result in a cash imbalance that impairs the ability of the ISO to clear all market positions. Credit risk is the risk that a Market Participant will default on payment obligations arising from negative capacity payments associated with Capacity Supply

[2] Testimony of Matthew White on behalf of the ISO, submitted with this filing as Attachment I-1c at 77.

Obligations in the current delivery month. Liquidation risk in this context has two components: the risk that losses may continue to accrue against a Capacity Supply Obligation position post default up to the annual stop-loss in any Capacity Commitment Period before a Market Participant is able to close the position, and the risk that the defaulted position, when closed, is sold at a loss. In addition to addressing these three types of risk, the FCM Delivery FA amount is adjusted to account for the phase-in of the Capacity Performance Payment Rate.

Q: Specifically, how will the FCM Delivery FA amount be calculated?

A: The monthly FCM Delivery FA requirement will be calculated using the following formula: FCM Delivery FA =

$$MCC + DFAMW \times PE \times \max[(ABR - CWAP), 0.1)] \times SF \times DF$$

I will explain each element of this formula in detail below.

I. CLEARING RISK

Q: How does the FCM Delivery FA formula address clearing risk?

A: The first of the three risks that I mentioned is clearing risk – the risk that a Market Participant does not timely discharge settled payment obligations incurred in an already completed delivery month. The first component of the FCM Delivery FA formula, MCC or "monthly capacity charge," addresses clearing risk. The monthly capacity charge is an amount equal to all negative capacity payments incurred in previous months, but not yet paid. This value will be estimated on the

first business day following a completed delivery month, and will be replaced with the actual settled value when settlement is complete. A similar approach is applied to all market charges under the FAP – the required FA reflects charges settled but not invoiced and charges invoiced but not paid. By requiring the posting of the monthly capacity charge, if the Market Participant fails to pay its invoice on time, the ISO can still meet its obligations to all other cleared positions by drawing against the Market Participant's posted collateral. Requiring the collateral to be posted on the first business day following the completion of the delivery month maximizes the potential offset against any incurred negative capacity payments in that month. Failure to post the required FA results in suspension from the markets, limiting the extent to which the Market Participant can accumulate additional market obligations.

II. CREDIT RISK

Q: How does the FCM Delivery FA formula address credit risk?

A: The second of the three risks that I mentioned is credit risk – the risk that a Market Participant will default on payment obligations arising from negative capacity payments associated with Capacity Supply Obligations in the current delivery month. This risk is addressed in the portion of the FCM Delivery FA formula that states: DFAMW x PE x max[(ABR – CWAP), 0.1)]. At a high level, the "DFAMW" term represents the MW amount on which a Market Participant must submit FCM Delivery FA; "PE" is the dollar per MW value that will apply

in calculating the Market Participant's FCM Delivery FA; and "max[(ABR – CWAP), 0.1]" is a ratio reflecting the performance of the Market Participant's capacity resources.

Q: Please explain the credit risk term "DFAMW" in more detail.

A: DFAMW, or "delivery financial assurance MW," is, simply, the total MW amount of a Market Participant's resources subject to a Capacity Supply Obligation in the current month. This MW amount serves as the basis for the credit risk portion of the FCM Delivery FA calculation. The DFAMW is equal to the sum of the Capacity Supply Obligations of all resources in the Market Participant's portfolio for the current month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss amount. In no case will DFAMW be less than zero.

Q: Why is the Capacity Supply Obligation of any resource that has reached the annual stop-loss amount excluded from the DFAMW calculation?

A: The annual stop-loss limits the amount of money a resource with a Capacity Supply Obligation can lose during a Capacity Commitment Period to three times its monthly stop-loss amount. A resource that has reached the annual stop-loss amount cannot incur any further negative capacity payments in the current month, so no additional amount of FA associated with that resource is needed to protect against default. For this reason, it is excluded from the calculation. However, should the resource receive performance payments in any subsequent month, the

resource's Capacity Supply Obligation will again be included in the FCM Delivery FA calculation.

Q: Why can DFAMW not be less than zero?

A: The purpose of FCM Delivery FA is to require collateral for potential payment obligations (negative capacity payments) under Pay For Performance. If there are no potential payment obligations, FCM Delivery FA should be zero. In no case, however, would it be appropriate for the FCM Delivery FA amount to be negative, possibly offsetting other, independent FA requirements. To prevent this, the DFAMW may not be negative.

Q: Please explain the credit risk term "PE" in more detail.

A: PE, or "potential exposure," is the dollar per MW value that will apply in calculating the Market Participant's FCM Delivery FA. Conceptually, this value is the maximum monthly payment a Market Participant would be required to make. As such, for a given delivery month, this value forms the upper bound on credit default exposure.

PE is calculated monthly for the Market Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss amount. The difference between

the Forward Capacity Starting Price and the capacity price is used because, as a general matter, this is equivalent to how the stop-loss amounts are calculated under Pay For Performance, and so represent the amount per MW that the Market Participant might be required to pay if its resources fail to perform.

For the purpose of calculating PE, the Forward Capacity Auction Starting Price shall be the one used in the Forward Capacity Auction corresponding to the instant Capacity Commitment Period, and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month. The reference to capacity prices in the Capacity Base Payment calculation is for simplicity, as capacity prices vary depending on whether the Capacity Supply Obligation was assumed in a Forward Capacity Auction, a reconfiguration auction, or a bilateral transaction. The Capacity Base Payment provisions in Section III.13.7.1 of the Pay For Performance rules detail which prices apply. The use of a capacity weighted average price ensures that the price per MW value properly corresponds to the capacity that is part of the DFAMW. Also, the PE calculation excludes the Capacity Supply Obligation of any resource that has reached the annual stop-loss amount, similarly ensuring that the price per MW value properly corresponds to the capacity that is part of the DFAMW.

Finally, the PE calculation recognizes that resources that cleared before the ninth Forward Capacity Auction and elected to have the clearing price apply for more

than one Capacity Commitment Period are subject to a special monthly stop-loss provision. For such resources, the Forward Capacity Auction Starting Price in the PE calculation shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) until the multi-year election period expires. This ensures that the PE properly reflects the monthly stop-loss values to which the resources in a portfolio that includes such resources are exposed.

Q: Please explain the credit risk term "max[(ABR – CWAP), 0.1]" in more detail.

A: "max[(ABR – CWAP), 0.1]" is a ratio reflecting the performance of the Market Participant's capacity resources. Under Pay For Performance, a resource is not held to the standard of providing the full amount of its Capacity Supply Obligation in all cases. Rather, the amount of capacity that a resource provides during a Capacity Scarcity Condition is measured against the ratio of the total amount of load plus the reserve requirement, divided by the total amount of Capacity Supply Obligations. This ratio is called the Capacity Balancing Ratio. As an example, if the total load plus reserve requirement is only 60 percent of the total amount of Capacity Supply Obligations (for a Capacity Balancing Ratio of 0.6), a resource with a 100 MW Capacity Supply Obligation would be over-performing if its actual capacity provided during a Capacity Scarcity Condition is greater than 60 MW, and under-performing if its actual capacity provided is less than 60 MW.

Because capacity payments are linked to the Capacity Balancing Ratio, FCM Delivery FA must be as well. Requiring a Market Participant to provide FA based on the full amount of its Capacity Supply Obligations would over-state the amount needed to protect against default because negative capacity payments will only be tied to the full Capacity Supply Obligation amount when the Capacity Balancing Ratio is 1.0 – that is, when the system is so stressed that the amount of load plus reserves is equal to the total amount of Capacity Supply Obligations. The term "max[(ABR – CWAP), 0.1]" is the minimum percentage of the calculated potential exposure (PE) that must be posted as FA given assumptions regarding the average system-wide Capacity Balancing Ratio and on the performance of the Market Participant's capacity resources.

Q: Please explain the term "ABR" as used in this credit risk term.

A: ABR, or "average balancing ratio," is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.

For example, assume that in summer 1, there are 2.5 hours of Capacity Scarcity Conditions during which the average system-wide Capacity Balancing Ratio was 0.90; in summer 2, there are 3.0 hours of Capacity Scarcity Conditions during

which the average system-wide Capacity Balancing Ratio was 0.95; and in summer 3, there are 2.0 hours of Capacity Scarcity Conditions during which the average system-wide Capacity Balancing Ratio was 0.93. The average balancing ratio calculated over the three historical summer periods would be:

$$(2.5 \times 0.90) + (3.0 \times 0.95) + (2.0 \times 0.93) / (2.5 + 3.0 + 2.0) = 6.96 / 7.5 = 0.93.$$

Q: Why are you using a different ABR for different groups of months?

A: This design component simply reflects the observation that the average system-wide Capacity Balancing Ratio is likely to be highest in the summer (June through September), lower (but still relatively high) in the winter (December through February), and lowest in the remaining months of the year.

Q: Because there will be no Capacity Scarcity Conditions until the ninth Capacity Commitment Period, how will ABR be determined before there is sufficient data?

A: Until data exists to calculate ABR, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60. As actual data becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary ABR values after the end of each group of months each year until all three years reflect actual data.

In other words, if there is only one year of actual data, that actual data will receive a weight of 1/3 in the calculation, and the remaining two years will be based on the temporary value. If there are two years of actual data, that actual data will receive a weight of 2/3 in the calculation, and the remaining one year will be based on the temporary value. For example, assume one year of actual performance data in which the average system-wide Capacity Balancing Ratio for June through September equals 0.92. The ABR for the June through September period would be: [(0.92) x 1/3] + [0.90 x 1/3] + [0.90 x 1/3] = 0.91.

Q: How did you determine these temporary ABR values?

A: The temporary ABR values are estimates determined by applying the criteria for Capacity Scarcity Conditions under Pay For Performance to actual operating data from 2010 through 2013, and then averaging by season the system-wide Capacity Balancing Ratios calculated according to the method described in the Pay For Performance rules.

Q: Please explain the term "CWAP" as used in the credit risk term "max[(ABR – CWAP), 0.1]."

A: CWAP, or "capacity weighted average performance," is the capacity weighted average performance of the Market Participant's portfolio. As I stated above, the term "max[(ABR – CWAP), 0.1]" is the minimum percentage of the calculated potential exposure (PE) that must be posted as FA given assumptions regarding the average system-wide Capacity Balancing Ratio and on the performance of the

Market Participant's capacity resources. Generally, the better a Market Participant's resources have performed, the higher its CWAP value will be, and the lower the value (ABR – CWAP) becomes. The worse a Market Participant's resources have performed, the lower its CWAP value will be, and the higher the value (ABR – CWAP) becomes. The higher the value (ABR – CWAP), the more FA the Market Participant must post for its portfolio.

Conceptually, CWAP is simply the amount of capacity provided divided by the amount of capacity obligated. Specifically, for each resource in the Market Participant's portfolio, excluding any resource that has reached the annual stop-loss amount, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Market Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

For example, assume a portfolio with three resources, each with an average performance value of 0.85, with the following Capacity Supply Obligations: 110 MW, 100 MW, and 90 MW. None of the resources has reached the annual stop-loss amount. In this simple case, the Market Participant's CWAP would be: [(110 x 0) + (100 x 0.85) + (90 x 0.85)] / 300 = 0.54. The 110 MW resource is the largest in the portfolio, and so in this example is multiplied by zero to exclude its performance.

Q: Why does the CWAP calculation exclude the largest resource remaining in the Market Participant's portfolio after resources that have reached the annual stop-loss have been excluded?

A: A portfolio with multiple resources provides some diversification benefits, with negative performance payments to one resource offset by positive payments to another. As a general matter, the portfolio is exposed to the greatest loss when the largest resource fails to perform. The failure of the largest resource also serves as a reasonable proxy for below-average performance by other resources in the portfolio. Assuming that all resources in a portfolio fail to perform, or perform substantially below average, would overestimate the degree to which any portfolio of resources actually faces negative performance payments. Given the composition of resource portfolios in New England, assuming that the largest resource in a multiple resource portfolio does not perform but that the balance of the portfolio performs as expected during shortage conditions provides a reasonable protection against Market Participant default under extreme loss scenarios.

Q: How will each resource's average performance be calculated for purposes of the CWAP determination?

A: The average performance of a resource is the cumulative amount of Actual Capacity Provided (as defined in the Pay For Performance rules) during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the

relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.

For example, assume a resource with a 100 MW Capacity Supply Obligation. In summer 1, there are 2 hours of Capacity Scarcity Conditions during which the resource delivered a cumulative 200 MWh of energy and reserves; in summer 2, there are 3 hours of Capacity Scarcity Conditions during which the resource delivered a cumulative 250 MWh of energy and reserves; and in summer 3, there are 2 hours of Capacity Scarcity Conditions during which the resource delivered a cumulative 150 MWh of energy and reserves. The average performance of this resource calculated over the three historical summer periods would be:

$(200 + 250 + 150) / (100 \times (2 + 3 + 2)) = 600 / 700 = 0.86$.

Q: Because there will be no Capacity Scarcity Conditions until the ninth Capacity Commitment Period, how will average performance be determined before there is sufficient data?

A: Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines, and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall

equal 0.65; and the temporary average performance for all other resources shall equal 1.00. As actual data for each resource becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary average performance values after the end of each group of months each year until all three years reflect actual data. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

In other words, if there is only one year of actual data, that actual data will receive a weight of 1/3 in the calculation, and the remaining two years will be based on the temporary value. If there are two years of actual data, that actual data will receive a weight of 2/3 in the calculation, and the remaining one year will be based on the temporary value. For example, again assume a resource with a 100 MW Capacity Supply Obligation, but only one year of actual performance data. There are 2.5 hours of Capacity Scarcity Conditions in that year, during which the resource delivered a cumulative 200 MWh of energy and reserves. The resource is a coal-fired steam plant, so as described above receives a temporary average performance value of 0.85. The average performance of this resource would be: [(200 / (100 x 2.5)) x 1/3] + [0.85 x 1/3] + [0.85 x 1/3] = 0.83.

Q: How did you determine these temporary average performance values?

A: The temporary average performance values are based on data contained in the report entitled "Assessment of the Impact of ISO-NE's Proposed Forward

Capacity Market Performance Incentives" by Analysis Group Inc. dated September 2013 and provided in Attachment I-1g of this filing. Specifically, see Table 6: "Resource Mix and Average Performance With and Without FCM PI, Equilibrium: No Gas Scenario" on page 38 of that report. The values from the report have been and rounded to the nearest five percent value and capped at 100 percent. For example, 86 percent is rounded to 0.85, and 105 percent is capped to 1.0.

Q: Please explain the role of the maximization function in the credit risk term "max[(ABR – CWAP), 0.1]."

A: As I explained above, generally, the better a Market Participant's resources perform, the higher its CWAP value will be, and the lower the value (ABR – CWAP) becomes. The worse a Market Participant's resources perform, the lower its CWAP value will be, and the higher the value (ABR – CWAP) becomes. For a resource with a CWAP value that approaches or exceeds ABR, the value (ABR – CWAP) will become very low, or possibly even negative. If this value reached zero, the credit risk portion of the FCM Delivery FA would also become zero. Although this would occur because the Market Participant's resources were performing well, even those portfolios with a CWAP value higher than the ABR are not completely without risk. The ABR and the CWAP are based on historical data, and if future performance is worse, holding some FA associated with credit risk is a reasonable and prudent protection.

For this reason, the maximization function included in the term "max[(ABR – CWAP), 0.1]" ensures that the value of that term will not be below 0.10, and hence, at least ten percent of the potential exposure amount will be included in the FCM Delivery FA amount.

III. LIQUIDATION RISK

Q: How does the FCM Delivery FA formula address liquidation risk?

A: The third of the three risks that I mentioned is liquidation risk – the risk that losses may continue to accrue against a Capacity Supply Obligation position post default up to the annual stop-loss in any Capacity Commitment Period before a Market Participant is able to close the position, and the risk that the defaulted position, when closed, is sold at a loss. Recall that the monthly FCM Delivery FA requirement will be calculated using the following formula: FCM Delivery FA =

$$MCC + DFAMW \times PE \times \max[(ABR - CWAP), 0.1)] \times SF \times DF.$$

Liquidation risk is addressed in the "SF," or "scaling factor," term included in the formula. The scaling factor is a month-specific multiplier, as follows:

- June: 2.000;
- December and July: 1.732;
- January and August: 1.414;
- all other months: 1.000.

Q: Please explain the liquidation risk "scaling factor" in more detail.

A: The risk that losses may continue to accrue against a Capacity Supply Obligation position post default (up to the annual stop-loss) before a Market Participant is able to close the position is not uniform across all months of the Capacity Commitment Period. The likelihood of a severe scarcity event is different each month of the year. Review of historical data (2010-2013) shows that the risk of scarcity conditions varies by season. The risk of scarcity is highest in the summer months (June – September), followed by the winter months (December – February) and lowest in the shoulder months (the other months).

Furthermore, given that in the summer and winter there are consecutive high-risk months in a row, should a resource default early in the summer season, for example, there is the risk that it will accrue additional losses in subsequent months due to the higher potential for additional Capacity Scarcity Conditions. In large measure this risk exists because a defaulted Capacity Supply Obligation position is not terminated from the market. Rather, the Market Participant must close the position through a bilateral contract or continue to be exposed to charges up to the annual stop-loss.

While the maximum possible exposure is the annual stop-loss, the probability that a resource will hit the monthly stop-loss three months in a row (the annual stop-loss equals three times the monthly stop-loss) is low. Thus, requiring Market Participants to post FA up to the annual stop-loss would unnecessarily over-

collateralize the market. Nonetheless, additional FA is required to address the risk that a defaulted position will accrue additional losses in subsequent months due to the higher potential for additional Capacity Scarcity Conditions in the summer and winter seasons when Capacity Scarcity Conditions are likely to be more frequent. For this purpose, we have assumed that the potential exposure in any remaining months of a season is normally distributed and that the exposure to incremental losses declines with the square-root of the number of months remaining in the season. Thus, during high risk months (summer and winter), the scaling factor (SF) is calculated as the square root of the number of summer or winter months remaining in the seasonal period. For example, the SF is two (square root of four) in June, and becomes one (square root of one) in September. During all the shoulder months, the scaling factor is one.

To see why the square root of the number of months remaining in the season is used as the scaling factor in the formula, consider the following. First, the potential exposure (PE), which captures the potential losses under extreme conditions in one month (*e.g.*, the first percentile value for a given distribution of risky cash flows), is measured by a multiple of the standard deviation of the underlying random variable. If we model the risky cash flows to a one MW Capacity Supply Obligation in each month of the same season with an identical independent random variable with a finite standard deviation, then the total risky cash flows for the season will be the sum of the risky cash flows assigned to each of these random variables. According to a basic property of variance (square of

standard deviation) of a random variable, the variance of the sum of independent variables equals the sum of the variance of the random variables. If we apply this property to the problem at hand, the variance of the risky cash flows for a season will equal the variance of the risky cash flows for the month times the number of months remaining in the season. By taking the square root of both sides of the equation above, we find that the standard deviation (square root of variance) of the risky cash flows for a one MW Capacity Supply Obligation for the season equals the standard deviation of the risky cash flows for the one MW Capacity Supply Obligation in the month times the square root of the months remaining in the season. Hence, the square root of the months remaining in the season is the scaling factor applied to the potential exposure component of the FCM Delivery FA calculation.

The practical effect of this scaling factor adjustment is that the Market Participant may be required to post FCM Delivery FA that exceeds the monthly stop-loss in months that come at the beginning of seasons where there is a higher risk of Capacity Scarcity Conditions. To reflect the annual cap on overall losses against a Capacity Supply Obligation, once a resource hits its annual stop-loss it is excluded from the FCM Delivery FA calculation.

IV. ADJUSTMENT TO FCM DELIVERY FA TO ACCOUNT FOR THE PHASING-IN OF THE CAPACITY PERFORMANCE PAYMENT RATE

Q: You stated above that in addition to addressing the three types of risk, the FCM Delivery FA amount is adjusted to account for the phase-in of the Capacity Performance Payment Rate. Please explain.

A: The only term in the FCM Delivery FA formula that I have yet to explain is the term "DF," or "discount factor." The discount factor is a multiplier to the credit risk portion of the FCM Delivery FA amount. For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the discount factor equals 0.75, and thereafter, equals 1.00.

Under the Pay For Performance design, the Capacity Performance Payment Rate is being phased in. For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5455/MWh.

The discount factor was added to the FCM Delivery FA calculation to reflect the reduced exposure to losses during the years in which the Capacity Performance Payment Rate is being phased in. The discount factor is based on the likelihood of a single resource portfolio reaching its monthly stop-loss under different Capacity Performance Payment Rates. For a single resource portfolio, a lower

Capacity Performance Payment Rate requires more hours of Capacity Scarcity Conditions to reach the monthly stop-loss amount.

Analysis performed by the ISO suggests an average number of Capacity Scarcity Condition hours on the order of six (expected value of 20 per year) to nine (95th percentile value of 30 per year) per summer month. At a Capacity Performance Payment Rate of $5,455/MWh and assuming an annual average system-wide Capacity Balancing Ratio of 0.75, it would take three to four hours of Capacity Scarcity Conditions to reach the $15,000/MW-month monthly stop-loss amount; less than the expected number of hours of Capacity Scarcity Conditions. At a Capacity Performance Payment Rate of $3,500/MWh and assuming an annual average system-wide Capacity Balancing Ratio of 0.75, it would take five to six hours of Capacity Scarcity Conditions to reach the $15,000/MW-month monthly stop-loss amount; similarly less than the expected number of hours of Capacity Scarcity Conditions. However, at a Capacity Performance Payment Rate of $2,000/MWh, and assuming an annual average system-wide Capacity Balancing Ratio of 0.75, it would take ten hours of Capacity Scarcity Conditions to reach the $15,000/MW-month monthly stop-loss amount. This value is greater than the 95th percentile value.

Based on these calculations, there is no material difference in exposure associated with a Capacity Performance Payment Rate of $3,500/MWh versus $5,455/MWh, so the discount factor is set to one (*i.e.*, the credit risk portion of the FCM Delivery FA calculation is unchanged for those instances of the Capacity

Performance Payment Rate). However, with a Capacity Performance Payment Rate of $2,000/MWh, it does take many more hours of Capacity Scarcity Conditions to reach the monthly stop-loss amount.

Based on the data above, for a Capacity Performance Payment Rate of $2,000/MWh the PE is 60 to 90 percent of the value at a Capacity Performance Payment Rate of $5,455/MWh. However, given the uncertainly in the data and the imprecision of the calculation, we have opted to split the difference and set the PE when the Capacity Performance Payment Rate is $2,000/MWh at 75 percent of its full value. Thus, for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, DF equals 0.75; and thereafter, DF equals 1.00.

V. OTHER CONFORMING REVISIONS

Q: Are there any other changes being made to the FAP as part of the Pay For Performance changes?

A: All of the changes to the FAP that I discussed above are contained in Section VII.A of the FAP, which details the new FCM Delivery FA. Several conforming revisions to the balance of Section VII are also required to accommodate that change. Because Section VII previously only discussed FA related to non-commercial capacity, it was referred to generically. Because the new revisions

add FA for commercial capacity resources, the previously-existing references are being revised to clarify they apply specifically to "non-commercial" capacity.

Furthermore, the revisions include some minor conforming changes to the treatment of composite resources. Part 2 of Section VII.E of the FAP is being deleted because under the revised rules, the FCM Delivery FA will automatically be set to zero when a Capacity Supply Obligation goes to zero and all outstanding payment obligations are discharged. A new part 6 of Section VII.E is being added to address the case when one component of a composite transaction incurs net charges. This provision clarifies that the payment obligation remains with the Market Participant responsible for that component of the composite transaction.

Finally, Section VII.F.3 is being deleted because it no longer applies. Under the current FCM rules, under certain conditions, expected future FCM revenues could offset FA requirements. However, under the revised Pay For Performance rules, all potential FCM payments are used in the FCM Delivery FA calculation to reduce negative performance payment exposure.

Q: Does this conclude your testimony?

A: Yes.

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

Executed on January 17, 2014.

Marc Montalvo

Director – Enterprise Risk Management

Attachment I-1g

Affidavit of Todd Schatzki on behalf of the ISO and Impact Assessment by Analysis Group, Inc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-___-000**
New England Power Pool	**)**	

AFFIDAVIT OF TODD SCHATZKI
ON BEHALF OF ISO NEW ENGLAND INC.

My name is Todd Schatzki, and I am a Vice President at Analysis Group Inc. ("Analysis Group"). I am submitting this affidavit in support of the proposal by ISO New England ("ISO-NE") to modify the Forward Capacity Market ("FCM") to include a Pay For Performance (also known as Performance Incentives) mechanism that would increase the current incentives for resource performance and investment by providing additional revenues to resources that supply power (or reduce demand) during periods of the greatest system need.

In my position with Analysis Group, I apply microeconomics, econometrics, and data analysis to complex business and regulatory problems, particularly in the areas of energy and environmental economics and regulation. Prior to joining Analysis Group, I held positions at LECG, LLC and National Economic Research Associates, Inc., where I performed similar types of economic analysis. I earned a Ph.D. in Public Policy from Harvard University, an M.C.P. from the Massachusetts Institute of Technology in Environmental Policy and Planning, and a B.A. from Wesleyan University in Physics. A complete list of my qualifications, publications, reports, and prior experience is set forth in Attachment A to my affidavit.

In March 2013, ISO-NE retained Analysis Group to assess the impact of ISO-NE's proposed FCM Pay For Performance market rule changes. The Analysis Group's impact assessment is set forth in a report entitled "Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives" (the "Impact Assessment"). A copy of that report is provided as Attachment B to my affidavit.

I hereby certify that the Impact Assessment was prepared under my direction and supervision and that the facts set forth therein are true to the best of my knowledge, information, and belief.

Todd Schatzki

Subscribed and sworn to before me
this 14th day of January 2014

Notary Public

My commission expires: 11/3/2017

DENISE VAN VOOREN
Notary Public
Massachusetts
Commission Expires Nov 3, 2017

Attachment A

Resume of Dr. Todd Schatzki

TODD SCHATZKI, Ph.D.
VICE PRESIDENT
ANALYSIS GROUP INC.

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Dr. Schatzki is an expert in energy and environmental economics and policy, and specializes in the application of microeconomics, econometrics, and data analysis to complex business and policy problems. He has worked with clients on corporate strategy, public policy design, and problems arising in regulation and litigation.

Dr. Schatzki has worked extensively on the design of electricity markets, analysis of wholesale electricity markets, economic analysis of energy and environmental regulations, asset valuation, resource planning and procurement, and utility ratemaking. His research has been supported by organizations such as the Electric Power Research Institute, Edison Electric Institute, Federal Energy Regulatory Commission, and National Association of Regulatory Utility Commissioners. His work has appeared in journals such as the *Journal of Environmental Economics and Management*, *the Electricity Journal*, *Public Utilities Fortnightly*, and *AEI-Brooking Joint Center for Regulatory Studies.* He has provided litigation support in many cases, including several high profile cases involving alleged wholesale electricity price manipulation and the implications of such manipulation for derivative contracts.

Prior to joining Analysis Group, he had research and consulting affiliations with the Harvard Institute for International Development and the International Institute for Applied Systems Analysis (Vienna, Austria), and was an economist at LECG, LLC and National Economic Research Associates.

EDUCATION

1998 Ph.D., Public Policy, Harvard University, Cambridge, MA

Specialized Fields: Microeconomics, econometrics, industrial organization, natural resource and environmental economics

- Doctoral Fellow, Harvard University, Cambridge, MA (1993-1995)
- Crump Fellowship, Harvard University, Cambridge, MA (1995-1996)
- Pre-doctoral Fellow, Harvard Environmental Economics Program

1993 M.C.P., Environmental Policy and Planning (Urban Studies and Planning,), M.I.T., Cambridge, MA

1986 B.A., Physics, Wesleyan University, Middletown, CT

PROFESSIONAL EXPERIENCE

2005-present	Analysis Group, Inc
2001-2005	LECG, LLC, *Managing Economist*
1998-2001	National Economic Research Associates, Inc., *Senior Consultant*
1997-1998	Harvard Institute for International Development, *Consultant*
1996-1997	Department of Economics, Harvard University, *Teaching Fellow and Research Assistant*
1994	International Institute for Applied Systems Analysis (IIASA)
1992	Toxics Reduction Institute, University of Massachusetts
1987-1991	Tellus Institute, *Research Associate*

SELECTED CASE WORK

Energy

- **ISO New England.** Assessment of the economic and reliability impacts of proposed capacity market rules introducing new performance incentives
- **Entergy.** Evaluation of economic damages associated with an alleged contract breach
- **ITC Midwest.** Analysis of the LMP and production cost impacts of new transmission infrastructure (using PROMOD)
- **Ameren.** Analysis of the impact of new transmission infrastructure on energy market competition in Illinois (using PROMOD)
- **Dayton Power and Light.** Evaluation of the aggregate benefits created by a proposed rate plan
- **Corporation with distribution companies across multiple jurisdictions.** Regulatory assessment considering current ratemaking models, regulatory environment and alternative ratemaking structures
- **ISO New England.** Assessment of the costs, feasibility and effectiveness of technical options to securing fuel supply for gas-fired generators
- **ISO New England.** Assessment of reliability risks and potential market and regulatory solutions to electric-gas interdependencies
- **Pacific Gas and Electric.** Assessment of ratemaking issues, including cost of capital adjustments, associated with a gas pipeline safety plan
- **ISO New England.** Statistical analysis of the performance of resources responding to system contingencies
- **Direct Energy.** Assistance developing regulatory options for promoting retail competition in Pennsylvania, including development of customer service auctions
- **ISO New England.** Assistance developing design enhancements for the region's Forward Reserve Markets
- **Confidential Client.** Analysis of energy and capacity market implications of a potential asset agreement (using GE's Multi-Area Production Simulation Software)

- **Confidential Client.** Analysis of fleet turnover decisions and outcomes (using GE's Multi-Area Production Simulation Software)
- **Confidential Regulated Utility.** Development of a white paper on transmission planning and policy needed to support legislative and regulatory goals for renewable development
- **Commonwealth Edison.** Analysis of appropriate ratemaking tools (cost of equity adjustment) in light of energy efficiency program requirements
- **New England Power Generators Association.** Analysis of impacts of proposed electric power company merger
- **Confidential Technology Company.** Development of a quantitative model of energy savings associated with end-use technological modifications..
- **Confidential Regulated Utility.** Development of a white paper assessing the potential for alternative ratemaking tools to mitigate multiple utility capital, load and service challenges
- **EDF Group.** Analysis of financial and credit implications of the sale of a portion of power generation assets
- **New England States Committee on Electricity.** Technical support and analysis related to design of regulations and wholesale electricity markets to achieve resource adequacy
- **National Grid Utilities.** Assistance developing ratemaking plans including revenue decoupling and associated revenue adjustments
- **NARUC and FERC.** Analysis of "best practices" in state policies for competitive procurement of retail electricity supply
- **New York ISO.** Analysis of single-clearing-price versus pay-as-bid market designs
- **Confidential System Operator.** Analysis of metrics for characterizing the economic value provided by regional transmission organizations
- **TransCanada.** Assessment of regulatory and finance issues involved in fuel adjustment clauses within long-term standard offer service contracts
- **New York ISO.** Analysis of market implications of fuel diversity issues
- **Confidential.** Analysis of alleged exercise and extension of market power in a wholesale electricity market, including statistical analysis of spot and real-time electricity markets and statistical modeling of outages using hazard model methods to examine potential physical withholding
- **Confidential.** Financial and strategic analysis of gas supply contracting alternatives
- **Confidential.** Analysis of value of generating assets using real options analysis
- **Confidential.** Statistical analysis of prices in the spot and forward markets using time-series methods for an energy trading firm in a federal proceeding related to the reasonableness of the terms of certain forward market contracts
- **Confidential.** Financial and strategic analysis of renewable generation technologies

Environment

- **Chevron.** Development of a white paper on post-2020 climate policy for California.
- **Greater Boston Real Estate Board.** Development of a white paper on mandatory building energy labeling/benchmarking policies

- **Chevron.** Analysis of the economic and environmental consequences of a local climate policy plan implemented in the context of a state-wide cap-and-trade system
- **Exelon.** Analysis of the economic and market consequences of EPA's Clean Air Transport Rule
- **Chevron.** Assessment of lessons learned from Federal requirements for regulatory review for the potential development of state requirements
- **Western States Petroleum Association and Chevron.** Regulatory support and analysis related to climate policy in California, including submission of various comments and reports to the Air Resources Board
- **Honeywell.** Analysis of proposed limits on HFC consumption under domestic climate policy
- **Electric Power Research Institute.** Analysis of three 2006 studies on the economic impact of meeting the California carbon emissions reduction targets (in the California Global Warming Solutions Act of 2006)
- **Confidential.** Assessment of various policy issues in the design of national climate change policies, including market-based policies, approaches to cost containment, offset projects, and non-CO_2 GHGs
- **Confidential.** Quantitative analysis of the impacts for technology, consumers and asset owners of a market-based domestic climate policy
- **Toyota.** Analysis of the economic value of emissions for a major auto manufacturer associated with alleged non-compliance with emissions control requirements

Finance and Commercial Damages

- Analysis of financial and credit implications of the sale of a portion of power generation assets
- Analysis of bond pricing, transactions and holdings related to default of sovereign bonds
- Analysis of transfers between financial institutions within credit card networks
- Analysis of the impact of product taxes on firm market shares related to determination of payments under a settlement agreement
- Analysis of damages related to breached contract and appropriation of trade secrets in the development of a pharmaceutical product
- Analysis of damages from breach of commodity swap contract (petroleum)
- Analysis of allegations regarding mutual fund day trading, including analysis of trading patterns and calculation of dilution

Antitrust

- Estimation of damages associated with an alleged monopolization and foreclosure resulting from a distribution agreement (retail consumer products)
- In a price-fixing case across multiple markets in the pharmaceutical industry, estimated overcharges and cartel periods based on a time-series analysis of price data
- Analysis of multiple antitrust claims (including foreclosure, monopolization, and vertical restraints) related to an alleged collusive distribution arrangement (retail consumer product)
- Analysis of alleged tying of aftermarket products and the provision of service, including evaluation of the alleged tie, competitive effects, and damages (office systems)
- Analysis of liability, timing, geographic scope, and damages issues for a petrochemical company facing potential price-fixing charges by DOJ and private parties

- Analysis of tying, monopolization, and patent abuse claims involving a patent licensing scheme for process and instrument patents (scientific equipment)
- Analysis of foreclosure, attempted monopolization of innovation markets, and damages claims arising from the termination of an investment/licensing agreement (medical devices)
- Estimation of damages related to alleged invalid patents and tying of products to patent rights associated with a process patent (scientific equipment)

ARTICLES AND PAPERS

"The Interdependence of Electricity and Natural Gas: Current Factors and Future Prospects," (with Paul Hibbard), *The Electricity Journal*, May 2012.

"California's Cap-and-Trade Decisions," Forbes.com, August 19, 2010.

"Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," (with Susan F. Tierney), *The Electricity Journal*, March 2009.

"Pay-as-Bid vs. Uniform Pricing: Discriminatory Auctions Promote Strategic Bidding and Market Manipulation" (with Susan F. Tierney and Rana Mukerji), *Public Utilities Fortnightly*, March 2008.

"Free Greenhouse Gas Cuts: Too Good to Be True?" (with Judson Jaffe and Robert Stavins) VoxEU.org, January 3, 2008.

"Too Good to Be True? An Examination of Three Economic Assessments of California Climate Change Policy" (with Robert N. Stavins and Judson Jaffe), AEI-Brookings Joint Center for Regulatory Studies, Related Publication 07-01. Jan 2007.

"Options, Uncertainty and Sunk Costs: An Empirical Analysis of Land Use," Journal of Environmental Economics and Management, Vol. 46, p. 86-105, 2003.

"The database on the economics and management of endangered species (DEMES)," (with David Cash, Andrew Metrick, and Martin Weitzman) in *Protecting Endangered Species in the United States: Biological Needs, Political Realities, Economic Choices*. Cambridge University Press, 2001

"The Issue of Climate," *Fundamentals of the Global Power Industry, Petroleum Economist, 2000.*

Review of "Sustainable Cities: Urbanization and the Environment in International Perspective," *Environmental Impact Assessment Review*, (Vol. 12, No, 4), 1993.

"Bottle Bills and Municipal Recycling," *Resource Recycling*, June 1991.

WORKING PAPERS

"Can Cost Containment Raise Costs? Allowance Reserves in Practice," March 2012.

Schatzki, Todd, Paul Hibbard, Pavel Darling and Bentley Clinton, Generation Fleet Turnover in New England: Modeling Energy Market Impacts, June, 2011.

"A Hazard Rate Analysis of Mirant's Generating Plant Outages in California," with William Hogan and Scott Harvey. Presented at the IDEI Conference on Competition and Coordination in the Electricity Sector, Toulouse, France, January 16-17, 2004.

"Estimating Structural Change in Industries with Application to Cartels," June 2003.

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Attachment B

FCM Pay For Performance Impact Assessment

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Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives

Todd Schatzki

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September 2013

Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives

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I. EXECUTIVE SUMMARY

Through its Strategic Planning Initiative (SPI), the New England Independent System Operator (ISO-NE) has identified multiple reliability concerns tied in part to the performance of generating resources in the region, including those with Capacity Supply Obligations (CSOs) made through ISO-NE's Forward Capacity Market (FCM). Concerns over performance include the potential failure of units to procure fuel, including natural gas-dependent resources during periods of limited gas supplies (particularly during the winter gas season),[1] and the failure of resources to closely follow dispatch requests when needed to address contingencies.[2] While these performance concerns exist today, the SPI recognized that they could become more important in the future, as aging units retire and the region integrates increased levels of renewable resources.

ISO-NE has taken a number of steps to address performance and reliability concerns in the near term, including, for example, an energy procurement (from non-gas resources) for Winter 2013/2014, and multiple changes to energy markets to mitigate coordination problems between gas and electric markets.[3] In addition, as a long-term solution to performance and reliability concerns, ISO-NE has proposed to modify the current FCM to include a Performance Incentives (PI) mechanism that would increase the current incentives for operational performance by providing additional revenues to resources that supply power (or reduce demand) during periods of the greatest system need. Under the FCM PI mechanism, these incentives are created through payments *between resources*, rather than between resources and load (customers) based on performance during reserve shortages. With each reserve shortage, higher performing resources would receive positive incremental payments, while resources that perform poorly would receive negative incremental payments. Thus, the aggregate payments by load (customers) will not exceed the fixed FCA prices regardless of the level of reserve shortages in the commitment period.

This report provides an Impact Assessment of the proposed FCM PI market rule changes, and its analyses are performed consistently with ISO-NE's framework for evaluating "major" initiatives, under which ISO-NE "will provide quantitative and qualitative *information* on the need for and the impacts, including costs, of the initiative"[4] (emphasis added). Thus, the Impact Assessment is designed to provide stakeholders with information about the possible impacts of the FCM PI proposal, including the potential benefits (including reliability improvements), costs, impacts on consumer payments, and other changes relevant to policy goals. However, it is not designed to provide a systematic evaluation of costs and benefits of the proposed rule, nor is it a forecast of FCM market outcomes.

[1] For example, *see* ISO-NE, "Winter Operations Summary: January-February 2013", February 27, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

[2] Analysis Group, *Analysis of Reserve Resources: Activation Response Following Contingency Events*, May 29, 2012. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/analysis_group_reserve_resource_analyses_5_29_2012.pdf.

[3] *See*, ISO-NE, "Interdependencies of Market and Operational Changes to Address Resource Performance and Gas Dependency," 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/interdependency_of_iso_proposals_to_key_spi_risks.pdf.

[4] ISO-NE and the Brattle Group, "Framework for Evaluating Major Initiatives," January 2011. Available at: http://www.iso-ne.com/pubs/spcl_rpts/2011/major_iso_initiatives_impact_analysis_final_report_1_28_11.pdf.

Market and system resource outcomes are evaluated through a quantitative model of bidding in the Forward Capacity Auction (FCA) for the 2018/2019 Commitment Period (FCA 9). The model allows comparison of outcomes with and without FCM PI, and comparisons between alternative proposals to address reliability concerns. Outcomes are evaluated under different assumptions about overall system conditions, including scenarios reflecting current ("Historical") conditions and postulated future conditions ("Equilibrium" scenarios). In addition, scenarios reflecting different levels of system reliability associated with limited gas fuel supplies are evaluated.

Table E1 summarizes these scenario results. Conclusions regarding impacts for reliability, costs and customers payments are as follows.

Table E1: Market and System Outcomes under Historical and Equilibrium Scenarios

		FCM PI, Historical Scenario			FCM PI, Near-Term Equilibrium Scenario		
	Current Rules (No FCM PI)	No Gas Shortages	Gas Shortages	High Gas Shortages	No Gas Shortages	Gas Shortages	High Gas Shortages
FCA Clearing Price ($/kW-month)	$1.31	$1.93	$2.55	$2.91	$3.76	$3.76	$4.49
Total FCM Payments ($bil)	$0.54	$0.80	$1.06	$1.20	$1.56	$1.56	$1.86
Avg FCM Payments ($/MWh)	$4.07	$5.99	$7.92	$9.01	$11.68	$11.66	$13.92
% Change Relative to 2012 Level	-57%	-36%	-15%	-4%	25%	25%	49%
New Entry Offers ($/kW-month)	$8.87	$8.67	$8.08	$7.49	$8.62	$8.09	$7.50
Surplus Capacity Above ICR (MW)	0	0	0	0	1,036	1,390	1,472
Expected Reserve Shortage Hours	21	-	-	-	9.00	10.00	12.75
Summer Peak RS Hours	21	-	-	-	9.00	7.00	6.75
Winter Gas-Related RS Hours	-	-	-	-	0.00	3.00	6.00
Incremental Dual Fuel Capacity (MW)	0	226	5,848	7,368	39	6,130	7,988

Note: For the Historical Scenario, Expected Reserve Shortage Hours are not reported as they do not reflect a consistent market-system equilibrium.

These results of this quantitative analysis indicate that FCM PI would likely result in improvements to reliability through several mechanisms.

First, the quantity of resources continuing to participate in the ISO-NE markets would increase under FCM PI compared to current market rules as a result of the additional revenues provided by performance incentives. In the near-term, estimated surplus capacity (above the Installed Capacity Requirement (ICR)) ranges from 1,036 MW to 1,472 MW with FCM PI in place. By comparison, the analysis finds there is no surplus economic capacity under current market rules.

Second, the analysis indicates that FCM PI would induce actions aimed at mitigating performance risks associated with gas supply curtailments, particularly during the winter gas season. The analysis finds that increased dual fuel capability provides the most cost-effective option to mitigate these risks. To the extent that other options (e.g., contracts with existing LNG resources, new pipeline capacity dedicated for electricity generation) become less costly to market participants than dual-fuel upgrades, our analysis would understate investment in reliability solutions. Across the range of winter gas market conditions evaluated, up to 7,988 MW of additional dual fuel capability is developed. Our sensitivity analysis found that the actual level of new dual fuel capability induced is sensitive to upgrade costs (and other assumptions regarding revenue streams), which suggests uncertainty in the

eventual equilibrium between actions to mitigate gas curtailment risks and the level of such risks. FCM PI would also mitigate any further mothballing of dual-fuel capability that would likely occur absent market incentives, although the analysis does not quantify this risk to reliability (absent FCM PI).

Third, FCM PI would likely shift the resources that remain economically viable in the ISO-NE markets toward a more flexible mix. This likely change in performance can be seen in several analysis results. First, across scenarios, FCM PI decreases the quantity of "economic" (i.e., resources that can operate profitably in the ISO-NE markets) oil-fired resources, while increasing the quantity of economic demand response, imports, gas-fired and coal-fired resources. Second, because of FCM PI incentives, higher performing resources are more likely to continue to participate in the ISO-NE markets. Consequently, average resource performance (as measured by output during reserve shortages) of economic resources increases. The option to adopt dual fuel capability allows gas-fired resources with gas dependency risks to continue to operate profitably in the ISO-NE markets.

Analysis of the economic impacts of FCM PI considers both the costs of meeting customer loads, and the payments made by loads for wholesale market services.

FCM PI would result in a variety of cost impacts, with ambiguous near-term and long-term aggregate impacts. Impacts would include: potential changes to production costs due to a fleet of more efficient resources; new investments and higher annual costs to improve resource performance (including dual fuel capability investments of up to $462 million in the "high gas" scenarios); and potential delays in the timing of when new generation resources are required to meet the ICR.

The analysis indicates that FCM PI would likely raise FCA prices under most market conditions until the system requires additional generation resources, when FCM PI would likely lower FCA prices. The analysis finds that FCM prices in FCA 9 would be $1.31 per kW-month under current market rules, but would range from $1.93 per kW-month to $4.49 per kW-month across the various scenarios evaluated with FCM PI in place. However, FCM PI would likely lower offers from new entry due to the incremental revenues provided under FCM, particularly as these resources are likely to (and under FCM PI have incentives to) be high performing resources. Consequently, in the long-run, FCM PI could lower FCA prices as the market nears an equilibrium in which new generation resources are required. Increases in FCM payments under the Equilibrium scenarios (relative to 2012 levels) would reflect a 5% to 10% increase in 2012 wholesale energy payments.

The analysis indicates that total FCM payments would increase under FCM PI, although the net impact of increases in FCM expenditures, estimated at $0.26 billion to $1.32 billion across scenarios, would likely be lower due to reductions in energy market payments because of surplus capacity. Changes in energy market payments arising from surplus capacity are not quantitatively evaluated. Surplus capacity will also diminish the level of reserve shortages, which in turn reduces Reserve Constraint Penalty Factor (RCPF) payments. Based on current RCPF prices and the difference in the number of reserve shortages, the reduction in RCPF payments could range from about $63 to $265 million.

II. INTRODUCTION AND STUDY PURPOSE

Through its Strategic Planning Initiative (SPI), the New England Independent System Operator (ISO-NE) has identified multiple reliability concerns that appear to be tied in part to the performance of generating resources in the region, including those with Capacity Supply Obligations (CSOs) made through ISO-NE's Forward Capacity Market (FCM). Concerns over performance include the potential failure of units to procure fuel, particularly natural gas-dependent resources during periods of tight gas supplies (particularly during winter gas season),[5] and the failure of resources to closely follow dispatch requests when needed to address contingencies.[6] While these performance concerns exist today, the SPI recognized that they could become more important in the future, as aging units retire and the region integrates increased levels of renewable resources. The SPI also identified other reliability concerns, such as the need for more flexible resources to ensure reliable integration of variable resources. While perhaps not as urgent for New England at present, these reliability concerns could emerge in the longer term, as evidenced by developments in other regions, notably California.[7]

ISO-NE has taken a number of steps to address performance and reliability concerns in the near term, including, for example, an energy procurement (from non-gas resources) for Winter 2013/2014, and multiple changes to energy markets to mitigate coordination problems between gas and electric markets (e.g., the timing of day ahead energy market offers and clearing, the timing of supplemental commitments, and energy market reoffers during the real-time market). In addition, as a long-term solution to performance and reliability concerns, ISO-NE has proposed to modify the current FCM to include a Performance Incentives (PI) mechanism that would increase the current incentives for operational performance by increasing revenues to resources that supply power (or reduce demand) during periods of the greatest system need. This proposal is described in further detail in Section III of this report.

This report provides an Impact Assessment of the proposed FCM Performance Incentives market rule changes. The assessment has been developed in a manner consistent with the "Framework for Evaluating Major Initiatives" developed by ISO-NE, which provides guidelines for developing quantitative and qualitative *information* for evaluating "major" market design and planning initiatives.[8] While designed to provide stakeholders with information about possible *impacts* of the proposed rule changes (relative to current rules), including the potential benefit, costs, impact on consumer payments, and other changes relevant to policy goals, the Impact Assessment is not designed to provide a systematic evaluation of costs and benefits of the proposed rule, nor is it a forecast of FCM market outcomes. Impact analyses are developed for major market rule initiatives to improve the quality of stakeholder

[5] For example, *see* ISO-NE, "Winter Operations Summary: January-February 2013", February 27, 2013. Available at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

[6] Analysis Group, *Analysis of Reserve Resources: Activation Response Following Contingency Events*, May 29, 2012. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/analysis_group_reserve_resource_analyses_5_29_2012.pdf.

[7] See, e.g., *Long Term Resource Adequacy Summit*, presentation by Mark Rothleder, California ISO, February 26, 2013. Available at: http://www.caiso.com/Documents/Presentation-Mark_Rothleder_CaliforniaISO.pdf.

[8] ISO-NE and the Brattle Group, "Framework for Evaluating Major Initiatives," January 2011. Available at: http://www.iso-ne.com/pubs/spcl_rpts/2011/major_iso_initiatives_impact_analysis_final_report_1_28_11.pdf.

deliberations, thus leading to better and more informed decisions based on the underlying merits of the proposals. Our Impact Assessment accomplishes this by providing both quantitative and qualitative assessment of the likely impacts of the FCM PI proposal, including changes to resource supply, mix and capabilities that have implications for system reliability; changes to production costs; and changes to market outcomes arising from FCM and energy market price effects.

The next section provides background on the FCM PI design. Following this, Section IV describes the analytic method for our Impact Assessment, and Section V outlines the data and assumptions applied in the analysis. Sections VI and VII present the result of our analysis, including the evaluation of both the FCM PI design and an alternative design proposed by NRG. Finally, Section VIII presents conclusions based on the analysis.

III. BACKGROUND ON FCM PERFORMANCE INCENTIVES PROPOSAL

ISO-NE is proposing FCM PI as a means to address concerns about the performance of resources that have taken capacity supply obligations under the FCM. Based on its assessment of resource performance under a variety of conditions, ISO-NE has concluded that the current approach to ensuring resource adequacy may not provide sufficient incentives for resources to perform when needed the most – that is, during reserve shortages. FCM PI is therefore designed to provide incentives for resource performance by rewarding resources that contribute to maintaining reliability by supplying output during periods of greatest system need. ISO-NE describes the approach as follows:

> The ISO proposes to modify the FCM design to make each resource's FCM revenue contingent, in part, upon its actual performance during periods when aggregate performance does not enable the ISO to satisfy system reserve requirements. The new performance incentive design will result in transfers from under-performing to over-performing resources, providing strong incentives for each resource to perform as needed and for resources that can meet the system's needs by exceeding their obligation to benefit by doing so. These incentives will place performance risk on all FCM resources, and this risk will need to be priced in each resource's bid in future capacity auctions.[9]

The FCM PI proposal operates under the simple principle that increasing payments for supply during periods of high reliability risk (as reflected by reserve shortages) provides the clearest incentive for resources to operate reliably during these periods. By using a market-based approach tied to an indicator that captures a wide range of reliability risks, FCM PI is designed to address any current or future risks to system reliability that may arise. Moreover, FCM PI addresses these risks through price signals that allow resources to mitigate these risks through the most cost-effective (i.e., least costly) actions. More information on the purpose and design of FCM PI may be found in Committee meeting materials and in ISO-NE's FCM Performance Incentives paper.

The FCM PI proposal includes several elements relevant to our Impact Analysis. First, under FCM PI, capacity supply obligations will still be established through the Forward Capacity Auction

[9] ISO-NE, "FCM Performance Incentives," October 2012. Available at http://www.iso-ne.com/committees /comm_wkgrps/strategic_planning_discussion/materials/fcm_performance_white_paper.pdf.

(FCA) performed three years prior to the commitment period, and resources clearing in the FCA will still receive a price (P_{FCM}) for each unit of capacity that clears the FCA. Thus, the fixed revenue stream resources receive under current FCM rules will remain in place with FCM PI.

Second, FCM PI provides performance incentive payments to *all* resources that supply output during reserve shortages. These additional payments are set based on the quantity of output supplied (*MW*) and the Performance Payment Rate (*PPR*), set in terms of dollars per MWh (e.g., $5,455 per MWh). Thus, resources that supply output when the system is in greatest need are rewarded for their performance.

Third, for all resources with a CSO, FCM PI adjusts incentive payments to reflect the system average performance needed at the time of the reserve shortage. The benchmark for this average performance is the "balancing ratio" (*BR*), which is measured as the ratio of the system load when the reserve shortage occurs divided by the Installed Capacity Requirement (*ICR*). Thus, incentive payments are adjusted to reflect the size of each resource's capacity commitment (i.e., its CSO), the balancing ratio, and the *PPR*. In effect, FCM PI acts like a financial option. In exchange for taking on the CSO and receiving fixed FCM base payments, resources agree to pay an amount equal to *PPR*BR* (for each MW of a CSO) every time there is a reserve shortage. Across all resources in the region, this option hedges both resources and load from the financial risk associated with uncertainty about the future level of reserve shortages. Thus, the payments by load (and the FCM revenues to suppliers) remain fixed at the price set during the FCA regardless of the level of actual reserve shortages during the commitment period.

The revenue stream to an individual resource under FCM PI is:

$$R = P_{FCM} * CSO + \sum PPR * \left(MW - CSO * BR \right)$$

where the change to revenue streams from PI and the downward balancing ratio adjustments occur over all reserve shortages during the commitment period.

With the balancing ratio adjustments, the net effect of FCM PI for a particular resource depends on how well it performs compared to system needs, as reflected in the balancing ratio. Resources with "above average" actual performance (i.e., $MW > CSO * BR$) are rewarded for their performance by receiving positive revenue adjustments, while those with "below average" actual performance (i.e., $MW < CSO * BR$) are penalized for their performance through negative revenue adjustments. These adjustments to FCM revenues for resource performance will result in changes to FCA offers depending on a resource owner's expectations about the performance of their resource and other factors that could affect PI payments (e.g., the level of reserve shortages). The implications of FCM PI for resource offers are described further in Section IV.A, below.

FCM PI also introduces new uncertainties for resources. Whereas current FCM revenues depend only on the fixed FCM price *P*, FCM PI revenues will ultimately depend on factors not known to resources when their FCA offers are submitted. Thus, FCM PI introduces uncertainty over FCM revenue streams that will have implications for financial risk, which is addressed in Section V.F, below.

IV. FRAMEWORK FOR ASSESSING THE IMPACT OF PERFORMANCE INCENTIVES

The impact of FCM PI is assessed through a comparison of FCM market outcomes with and without FCM PI. Market outcomes reflect an equilibrium between the offers to take on CSOs made by market participants, and the quantity of CSOs required (equal to the ICR). ICR is determined by ISO-NE prior to the relevant FCA. In our analysis, we assumed the ICR was set at 34,500 MW, based on an ICR forecast for the 2018/19 capacity year developed in the Regional System Plan (RSP).[10] Given uncertainty over this quantity, we also consider values three percent higher and lower than this forecast.

A. Resource Offers With and Without FCM PI

Under the current FCM, offers to take on a CSO by existing and new resources reflect estimates of the incremental revenues required for the resource to "break-even" financially. This "break-even" amount reflects a resource's Going Forward Cost (*GFC*), which under current market rules must equal its expected avoidable costs from delisting (retiring) the resource (*FC*) (including the annualized cost of avoided investment, I) less its expected net revenues in ISO-NE energy and ancillary services markets. More specifically, under current rules, resource offers (in dollars per kW-month) equal:[11]

$$Offer(FCM) = \frac{GFC + RF}{Capacity * 12} = \frac{FC + I - Q*\left(P - VC - HR*P_{Fuel}\right) + RF}{Capacity * 12}$$

The GFC reflects net energy and ancillary services market revenues, where Q is the quantity of output sold, P is the average energy market price, VC is the non-fuel variable costs, HR is the unit's heat rate, and P_{Fuel} is the fuel price. The last term, RF, is the risk factor. A risk factor is added to offers to account for financial risks taken on by market participants when they agree to CSO contractual terms. Current market rules allow market participants to account for a defined set of risks related to unanticipated plant outages and potentially other factors. Given that *GFC* reflects costs during a future capacity commitment period, all values reflect forecasted or expected values. Appendix A provides details on how each of these values is estimated.

FCM PI introduces several changes to resource offers. First, for resources that require FCM base payments (i.e., based on the fixed price, P_{FCM}) to remain in the ISO-NE energy market, resource offers will reflect the unit's *GFC* plus expected revenues from FCM PI – that is:[12]

$$Offer(FCM\ PI) = GFC - PPR * H * \left(A - BR\right) + RF$$

[10] ISO New England, *2012 Regional System Plan*, November 2, 2012, page 45. Available at http://www.iso-ne.com /trans/rsp/2012/rsp_final_110212.docx.

[11] This formula reflects current market rules for net risk-adjusted going forward costs, as described in Market Rule 1, Section III.13.1.2.3.2.1.2. Throughout, the calculation of going forward costs is developed in a manner consistent with these market rules.

[12] Resources will require FCM revenues to remain in the market if going forward costs, net of PI revenues and the risk factor, are positive – that is: $GFC - PPR * H * A + RF > 0$. Our analysis does not account for certain factors that could affect actual offers, including capital investment needed to continue production and option value given potential future positive changes in revenue streams.

where *H* is the *expected* level of reserve shortages (measured in hours), *A* is the unit's *expected average* performance over the course of the year, and *BR* is the *expected average* balancing ratio over the course of the commitment period.[13] Average performance *A* is measured as a unit's average output during reserve shortages (in MW) divided by its CSO. For example, a resource with a 100 MW CSO that produced average output of 65 MW during reserve shortages would have average performance *A* equal to 65%. Consequently, compared to the current market rules, FCM PI will result in upward and downward adjustments to offers depending on how each resource's *expected* average performance compares to the *expected* balancing ratio during reserve shortages.

Second, when submitting offers, resources can consider the option to forego a CSO. Without a CSO, market participants continue to receive positive PI payments for output from their resources. With a CSO, resources earn both the fixed FCM price and the positive incentive payment, but must consider the downward adjustments to revenues based on the balancing ratio (i.e., $PPR * CSO * BR$). Given this choice, in order to take on the CSO, market participants must receive a minimum payment that offsets the *expected* downward balancing ratio adjustments, which they could otherwise avoid by foregoing the CSO. Consequently, with PI, resources' offers will equal or exceed a minimum offer equal to their expectation of these downward adjustments – that is:

$$Minimum\,Offer\left(FCM\ PI\right) = PPR * H * BR + RF$$

This minimum offer differs from current market rules, under which some resources will be willing to accept a minimum offer as low as $0 per kW-month.

Third, resources taking on a CSO may face less or greater financial risk due to the financial hedge provided by the CSO compared to uncertain (but positive) net PI payments. Consequently, the risk factor *RF*, reflecting financial risk due to the uncertain revenue streams from accepting a CSO, included in resource offers may differ under FCM PI compared to current market rules. Note that, in theory, this adjustment could be upwards or downwards depending on the resource's expected performance and the aggregate risk profile of the entity that owns the asset.

To determine the clearing prices in the FCA, offer curves are constructed, reflecting the bids from each resource ordered from lowest to highest priced offers. Offer curves are developed for the 2018/2019 FCA with and without FCM PI. Offers are developed assuming resources offer their entire capacity as a single block, rather than as multiple blocks as allowed under the proposed rules. Section V describes how each of the individual terms in the offer formulas described above is calculated.

B. Scenarios Evaluated

A significant uncertainty affecting the analysis relates to the likely resource and system conditions in the 2018/2019 Commitment Period. These conditions affect key factors that must be

[13] For further discussion of the calculation of expected FCM payments *see* Gillespie, Andrew et al., ISO-NE, "FCM Performance Incentives," NEPOOL Markets Committee, April 9-10, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps /mrkts_comm/mrkts/mtrls/2013/apr9102013/a17a_iso_presentation_04_10_13.ppt.

considered in developing resource offers, including the likely level of reserve shortages hours, and the likely resource performance and balancing ratio during those shortages.

Current market conditions may not be a reliable predictor of future market conditions for several reasons. First, the price floor that supports the FCM price has resulted in a supply of resources in the ISO-NE region well in excess of the ICR. Starting in FCA 8 (for the 2017/2018 Commitment Period), the price floor will be removed, which could lead some resources to temporarily or permanently exit the market; this, in turn, would affect system conditions. Second, ISO-NE has identified that gas fuel supply limitations (particularly during winter months) pose a meaningful risk to system reliability.[14] While ISO-NE has taken many steps to improve the market's ability to mitigate these risks (e.g., intra-day reoffers, hourly offers, adjustment to the timing of the day ahead market, increases in the Reserve Constraint Penalty Factor (RCPF) for 30-minute system reserves, procurement of requirements for 30-minute "replacement" reserves)[15], this reliability risk could increase with time, particularly if resources retire due to lower FCM revenues or other economic factors.[16]

Given these uncertainties, the impacts of the FCM PI proposal are evaluated under multiple sets of assumptions regarding system conditions in order to identify the range of potential outcomes and the robustness of conclusions. Table 1 lists the scenarios and sensitivity cases we evaluated. At one end of the spectrum are "Historical" scenarios reflecting system conditions that have prevailed in recent years. However, given the potential for a net reduction in the region's resources (particularly with the removal of FCA price floors), we also develop a near-term Equilibrium scenario which reflects a postulated balance between forecast system conditions and expected market conditions in 2018/2019. For reasons we describe below, this scenario is a reasonable upper bound on prices. This near-term equilibrium may differ from a long-run equilibrium, where the system requires the entry of new generation resources to maintain resource adequacy. While we do not explicitly postulate long-run equilibrium conditions for 2018/2019, some of our results are informative to understanding outcomes under such conditions.

Along with uncertainty about system conditions, there is also uncertainty about the expected level of reserve shortages that arise specifically from limitations to gas supplies. While ISO-NE has taken steps to mitigate reliability risks related to coordination of gas and electric markets, these market enhancements are not expected to eliminate all reliability problems, particularly those arising when there are insufficient resources with fuel supply to meet load. To assess possible system conditions associated with winter gas reliability risks, additional scenarios are evaluated assuming there are 3 or 6 hours of reserve shortages associated with limited gas supply during winter months. Table 1 identifies the six scenarios we analyze, reflecting the different potential system conditions described above.

[14] For example, *see* ISO-NE, "Winter Operations Summary: January-February 2013", February 27, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

[15] *See*, ISO-NE, "Interdependencies of Market and Operational Changes to Address Resource Performance and Gas Dependency," 2013. http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/interdependency_of_iso_proposals_to_key_spi_risks.pdf.

[16] For example, Entergy has announced the retirement of the Vermont Yankee nuclear plan. Available at http://www.safecleanreliable.com/entergy-to-close-decommission-vermont-yankee-2.

In addition to these scenarios, we also consider the sensitivity of results to multiple underlying assumptions related to resource availability and costs, including elimination of offer risk factors; costs for compliance with environmental regulations (Clean Water Act (CWA) Section §316(b) cooling water intake requirements); the cost of dual fuel upgrades; and limitations on the ability of gas-dependent resources to develop dual fuel capability. These sensitivities and the underlying model assumptions are also included in Table 1.

Table 1: Alternative Scenarios and Sensitivities Considered

		Winter Gas Dependency Risks		
		No Gas Shortages	**Gas Shortages**	**High Gas Shortages**
Overall Resource Adequacy	**Current ("Historical") System Conditions**	Historical: No Gas	Historical: Gas	Historical: High Gas
	Near-term Equilibrium System Conditions for 2018/2019	Equilibrium: No Gas	Equilibrium: Gas	Equilibrium: High Gas

Sensitivity	**Model Assumptions**
Risk Factor	• Use Equilibrium: No Gas Scenario • No Risk Factor
Environmental Costs	• Use Equilibrium: No Gas Scenario • Incremental costs for compliance with CWA Section §316(b) Cooling Water Intake Requirements (Section V.E provides details on costs)
Dual Fuel Costs	• Use Equilibrium: Gas Scenario, and Equilibrium: High Gas Scenario • Increase dual fuel upgrade costs by 25% • Results reported/discussed in Section VI.A.2 (all other sensitivities reported/discussed in Section VI.D)
Dual Fuel Restrictions	• Use Equilibrium: High Gas Scenario • Limits dual fuel adoption to those already with decommissioned dual fuel capability

V. DATA AND ASSUMPTIONS

A. Going Forward Costs

Section IV.A provides the basic framework for calculating each unit's going forward cost (GFC). Each unit's GFC for the 2018/2019 Commitment Period is based on a combination of data on current operation costs, past utilization rates, and forecasts of future fuel prices. Future electricity prices are

estimated based on the past relationships between natural gas prices and the average prices earned by resources when operating. Estimates rely on a variety of data sources, including: SNL for unit-level fixed costs, non-fuel variable costs, and heat rates; EIA and NYMEX for fuel price forecasts; and ISO-NE for historical output and prices. Appendix A provides details on the data and approaches used.

B. Estimating Unit Performance and Balancing Ratio During Reserve Shortages

Unit performance and the balancing ratio are estimated to reflect the system conditions during reserve shortages under the scenarios evaluated for the 2018/2019 Commitment Period. Three system conditions are considered:

1. Historical Conditions, corresponding to average conditions in recent years, with the current level of surplus resources;
2. Peak (Summer) Conditions, corresponding to reserve shortages arising as a consequence of an inadequate level of resources to meet load; and
3. Winter Peak Conditions, corresponding to reserve shortages arising due to limitations on natural gas supplies during the peak winter gas season.

Average performance is measured for each unit based on output supplied during reserve shortages over the period 2010 to 2012. Estimates of likely performance during Historical, Peak (Summer) and Winter conditions are based on actual performance during reserve shortages that reflect these types of system conditions. Thus, for example, estimates of unit performance and the balancing ratio during reserve shortages due to resource adequacy risks (i.e., Peak Summer Conditions) are based on reserve shortages during the 2010 to 2012 period that also occurred due to insufficient aggregate resources.[17] Balancing ratios are estimated in a consistent fashion.

Figure 1 shows the average performance by resource type for each of the three market conditions described above, along with the balancing ratio during the corresponding time periods. Tables 1 to 3 in Appendix A provide additional statistics on average performance *A* across the same set of units. These additional tables show some skewing of performance within resource categories with larger resources tending to demonstrate higher performance.

[17] Other reserve shortages during the 2010 to 2012 time period occur due to other factors, including having insufficient resources committed to respond to unanticipated changes to load or supply.

Figure 1: Average Unit Performance by Resource Category

[1] Unit performance for each class is calculated as total class output divided by total class summer SCC. The summer SCC used is from the most recent year with available data.
[2] Summer SCC, generation type, and primary fuel type from CELT Reports. Operating data from ISO-NE.

Resource performance varies widely across resource categories. Nuclear power has the highest non-renewable performance because, as baseload resources, they operate under all market conditions. Gas turbines also have high performance because these resources are capable of starting quickly under circumstances when the market needs additional resources to meet load plus reserve requirements. Combined cycle and coal resources have somewhat lower performance because when reserve shortages occur these resources may not be committed or able to ramp up to their full operating capacity, if there is limited foreshadowing of the need for additional resources to meet load plus reserve requirements. Non-CT oil-fired resources have the lowest performance because many of these facilities are operated only when prices are sufficiently high to merit operation, or when there is sufficient foresight that the system will need additional resources to maintain reserve levels. Renewable resource performance varies with the particular characteristics of each type of resource. Wind resources have average performance that exceeds their eligible capacity, because FCM eligible capacity represents only of faction of the nameplate capacity of these resources. Hydro performance is high, potentially reflecting either high utilization or control of the timing of output. Pumped storage performance is below that of other hydro, suggesting either that reservoirs have been drained or have not been filled prior to reserve shortages.

Comparison of resource performance to the balancing ratio provides an indication of how each resource category fares under PI. Resources with performance above the balancing ratio would receive positive revenue adjustments, while those with performance below the balancing ratio would receive negative revenue adjustments. While the average performance levels reported in Figure 1 are indicative of the resource category performance, there is substantial variation in the performance within each category and the performance of individual units may differ from these category averages.

C. Reserve Shortage Hours

The level of reserve shortages is measured by the expected number of hours of reserve shortages over the 2018/2019 Commitment Period. The level of reserve shortages for each scenario evaluated is reported in Table 2. For the Historical Scenarios, the level of reserve shortages is based on market conditions from 2010 to 2012, when there was an average of 3.2 hours of reserve shortages annually.[18] Consequently, we assume 3.2 reserve shortage hours in the Historical Scenarios, to reflect current market conditions.

Near-term equilibrium conditions reflect a balance between system and market conditions for FCA 9, which procures commitments for the 2018/2019 Commitment Period. This near-term equilibrium will reflect resources that remain in the market due to FCM revenues, as well as resources that stay in the ISO-NE energy and ancillary services market without a CSO.

Under the current FCM market rules, resources that do not clear in the FCM do not have an obligation to remain in the market. However, assuming that delist offers reflect going forward costs (and

[18] This average reflects a combination of shortages due to insufficient resources (i.e., high loads relative to resources) and shortages due to unanticipated system conditions (particularly when there are insufficient resources committed).

that the FCA clearing price is greater than zero), failure to clear the market suggests there is a meaningful likelihood that a resource will exit the market.[19]

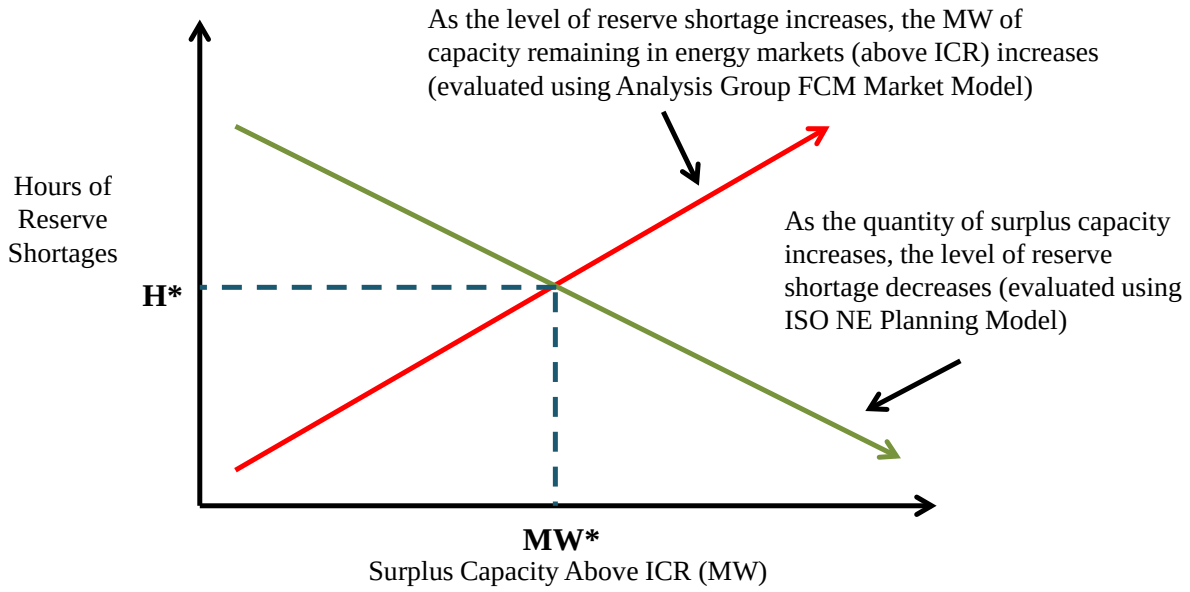
Table 2: Reserve Shortage Hours by Scenario

	Reserve Shortage Hours			
Scenario	**Historical**	**Peak (Summer)**	**Winter Gas**	**Total**
Historical: No Gas	3.2	0	0	3.2
Historical: Gas	3.2	0	3	6.2
Historical: High Gas	3.2	0	6	9.2
Equilibrium: No Gas	0	9	0	9
Equilibrium: Gas	0	7	3	10
Equilibrium: High Gas	0	6.75	6	12.75
No Risk Factor	0	9	0	9
Environmental Costs	0	9	0	9
Higher Dual Fuel Costs	0	7/6.75	3/6	10/12.75
Dual Fuel Restrictions	0	6.75	6	12.75

By contrast, under FCM PI, resources may find it financially profitable to remain in the ISO-NE energy market without a CSO. This can occur when the market clears at a price that is below the resource's minimum offer (based on its expectations of the level of future reserve shortages) but the resource does not need the FCM revenues to remain economically profitable (i.e., its going forward costs including PI revenues are less than zero). As the duration and frequency of reserve shortages increases, the additional PI revenue increases the number of "economic" resources that can profitably operate without a CSO. This is illustrated conceptually in Figure 2, which shows with the red line the relationship between the levels of surplus capacity for varying levels of reserve shortages. However, from a system perspective, as the quantity of resources increases, system reliability improves, which reduces the expected duration and frequency of reserve shortages. This is illustrated by the green line on Figure 2. The *equilibrium* level of reserve shortages and surplus capacity reflects equilibrium between these two opposing dynamics. Our analysis of the near-term Equilibrium for FCA 9 assumes the internally consistent level of surplus capacity and reserve shortages hours that arises under this equilibrium.

[19] In practice, resources may not exit due to a variety of factors, including the option of remaining and continuing to operate without an obligation in the hopes of higher future net revenues.

Figure 2: Graphical Depiction of Equilibrium Between Excess Resources and Reserve Shortages



The market model curve is estimated using the FCM PI model described in this report.[20] The system model is a probabilistic simulation model used by ISO-NE to establish ICR for the region given anticipated load and system conditions for the 2018/2019 Commitment Period.[21] The reserve shortages analyzed in this ISO-NE system model are driven by conditions in which there are insufficient resources available to meet load plus reserve requirements. Because reliability risks arising due to insufficient resource adequacy are most significant during summer peak load periods, the reserve shortages identified in the ISO-NE system model occur largely during the summer months.

Our analysis does not explicitly analyze the evolution of the FCM market toward a long-term equilibrium. This equilibrium can be characterized by the retirement of some existing resources and the entry of new resources as the FCM prices reach the cost of new entry. The timing of the retirement of existing resources will depend on many factors, including the degradation of performance (e.g., heat rate) over time, increasing maintenance costs and incremental capital expenditures to plant systems. Because of uncertainty over these factors, we have not attempted to analyze the evolution of market outcomes towards such an equilibrium. However, below we provide certain quantitative and qualitative information to inform understanding of how PI will affect the timing of and prices at the long-run equilibrium.

[20] Our analysis assumes that resources that either do not accept a CSO or that have insufficient expected revenues to operate profitably in the ISO-NE energy markets will (temporarily or permanently) exit these markets. To the extent that resources do not exit due to a positive option value to continue operations given potential profitable operation in future commitment periods or other factors, then our results would tend to understate the supply of excess resources relative to what would actually happen, which in turn would overstate the expected level of reserve shortages.

[21] ISO-NE Market Development, "Operating Reserve Deficiency Information – At Criteria And Extended Results," July 5, 2013. Available at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jul10112013/a12a_iso_memo_07_05_13.pdf.

Analysis of reserve shortages arising from limitations on gas supply during winter months is performed by evaluating market outcomes with two different levels of winter reserve shortages: 3 and 6 hours of winter gas shortages.[22] As with reserve shortages arising due to insufficient resources to meet load and reserve requirements, shortages arising due to over-reliance on limited gas supply will reflect a balance between the number of reserve shortages and the quantity of gas-dependent resources. On the one hand, as the level of reserve shortage hours increases, this creates incentives for resources to take steps to limit their dependence. On the other hand, as resources take steps to limit their gas dependence (in response to these incentives), the number of reserve shortage due to gas dependence would decline. Absent specific data on the likelihood of reserve shortage driven by gas dependence, however, we try to capture this potential impact by modeling up to six hours of gas-driven shortages (in addition to modeling no gas-driven shortages).[23]

Gas shortage scenarios are evaluated under both Historical and near-term Equilibrium conditions. In the near-term Equilibrium scenarios, a separate equilibrium is calculated for each scenario based on the FCM market response with different mixes of summer peak and winter gas reserve shortages. As shown in Table 2, the resulting level of reserve shortages reflects a mix of peak (summer) and winter gas reserve shortages. Equilibrium with winter gas reserve shortages are calculated assuming that equilibrium with the ISO-NE system model reflects only summer peak reserve shortages. This approach is consistent with the fact that a disproportionate number of reserve shortages identified in the ISO-NE system model occur during summer months.

D. Technical Options for Improving Performance

FCM PI is designed to create incentives for asset owners to take steps to improve the performance of existing resources, and/or choose higher performing technologies when investing in new resources. Resource owners can take many steps to improve resource performance, including operational practices to reduce forced outages and improve plant responsiveness to operator requests, investments to improve fast start capability and ramping rates, and actions to firm-up fuel supplies.

Under FCM PI, resources will find it economically beneficial to undertake actions to improve performance when the expected incremental revenues, including PI and other incremental revenues, exceed the costs of the actions taken, including annual expenditures and up-front capital investment. The expected level of incremental PI revenues will depend on multiple factors, including the expected level of reserve shortages and the improvement in the resources' expected performance (output) during these periods.

[22] Even as resources take action to address gas dependence, reserve shortages could remain. For example, the time for many dual fuel resources to switch to alternate fuels varies, such that some resources may require an hour or more to switch. During this period, the system will face resource limits that could result in reserve shortages.

[23] To date, while there have been many instances of reliability challenges tied to gas supply limitations during winter and non-winter months, there is not clear information on the relationship between market conditions related to gas supply and reserve shortages. Due to this fact and the many uncertainties about forecasting future market conditions, we have not attempted to quantitatively model the likelihood of reserve shortages arising from gas dependence.

Our analysis considers potential steps that resources with gas fuel curtailment risks – "gas-dependent resources" – may take to address limited natural gas availability, which would most likely or most often occur during the winter months. We do not consider other actions resources might take to generally improve their operational performance, given the lack of information about such opportunities for individual resources in the region.

The analysis of potential resource responses to FCM PI during winter gas shortages involves two steps. First, we compare the relative cost and effectiveness of alternative means of securing fuel supplies to identify the most cost-effective option. Second, we integrate this option into the FCM supply model such that resources develop dual fuel capability when there are sufficient incremental PI revenues to justify this investment.

Identification of the most cost-effective option for securing winter fuel supplies considered four alternatives:

1. Dual fuel capability
2. Firm or option service from existing Liquefied Natural Gas (LNG) facilities
3. LNG storage
4. Firm transportation services from a new gas pipeline

Table 3 summarizes the results of our assessment of the costs and effectiveness of these alternative options, with further details on our assessment provided in Appendix C. Our analysis of costs reflects the direct expenditures and investments required to implement the technical options for securing fuel supply, but does not consider all changes in revenues or costs that may occur with each option. For example, the costs of firm pipeline service from a new pipeline includes the incremental rates charged for such service, but does not account for the potential reduction in gas transportation costs during periods of tight gas supply (i.e., when the basis differential exceeds the tariff rate). In effect, our analysis considers the least-cost means to address the performance risks that are the focus of this report. While we identify and qualitatively describe differences in the effectiveness of these alternative services at securing fuel supply, this effectiveness does not enter into our identification of the most cost-effective option.

As shown in Table 3, the cost of alternative technologies varies widely. These estimates are based on multiple sources identified in Appendix C, including publicly available data and data provided by ISO-NE, but are not based on detailed engineering studies. Development of dual fuel capability appears to be the least cost option evaluated. Annualized costs range from $6,500 per MW for facilities with moth-balled or decommissioned dual fuel capability to $15,000 per MW for facilities that have never had dual fuel capability.[24] In principle, existing LNG facilities could provide service at a comparable cost to dual fuel capability. The rates for firm or option service provided by these facilities will depend on demand charges that facility owners have some discretion in setting. Costs for new LNG storage are roughly $30,000 per MW, significantly higher than incremental dual fuel costs. Costs for firm transportation service, reflecting the rates charged for such service, are also higher than dual fuel costs.

[24] Annualized costs reported in Table 3 reflect particular assumptions about discounting, depreciation terms and other factors that may differ from those used in the FCM PI analysis, but are comparable across the alternatives for addressing gas-dependency evaluated.

Table 3: Comparison of Options for Firming Gas-Dependent Resource Fuel Supply

Technology Option		Cost	Other Factors
Dual Fuel	Current Dual Fuel Capable	• $5,700 per MW	• Time to recommission or install is relatively brief • Long refill times may limit effectiveness over long curtailments • Operations limits and risks when switching to alternate fuels • Requires environmental permitting
	Under- or Unutilized Dual Fuel Capability	• $6,500 per MW (annualized, reflecting capital cost and annual expenditures)	
	No Dual Fuel Capability	• $15,000 per MW (annualized, reflecting capital cost and annual expenditures)	
Service from Existing LNG Facilities (Canaport, DOMAC)		• Not estimated – cost would reflect (1) foregone opportunity to sell LNG in higher-value markets; (2) carrying cost; (3) operating cost; and (4) transportation charge. • Rate would be subject to negotiation	• Could be subject to deliverability constraints without firm service (esp. for Canaport, requiring transport over Maritimes pipeline)
New LNG Storage		• $29,700 per MW (annualized, reflecting capital cost and annual expenditures)	• Long refill times may limit effectiveness over ong curtailments
New Pipeline Capacity		• $9,700 to $32,700 per MW for upfront costs • Rates for firm service would exceed these annualized costs	• Requires purchase of firm service • Time lag between commitments for firm service and new service availability • Reduces transport costs during periods of elevated prices (when basis differential exceeds tariff rate)

Our analysis allows gas-dependent resources to invest in dual fuel capability if the expected incremental FCM PI revenue streams are sufficient to cover the incremental costs, including any up-front investments and annual expenditures. Incremental FCM PI revenue streams reflect two factors. First, with dual fuel capability, a gas-dependent resource has a higher likelihood of supplying output during a gas supply related reserve shortage. The analysis assumes a 50% reduction in the average performance *A* of gas-dependent resources during winter gas shortages; this assumption is designed to strike a balance within the range of curtailment levels that resources may experience during gas reserve shortages. Investment in dual fuel capability eliminates this reduction, allowing the resource to operate at a normal performance level. For example, a gas-dependent resource with a performance *A* of 70% would operate at a 35% performance during winter gas reserve shortages unless it invests in dual fuel capability. While considering incremental FCM PI revenue streams, the analysis does not account for other changes in net revenues that might arise from dual fuel investment, including changes in energy market revenues. The second factor affecting the incremental revenues from a dual fuel investment is the level of winter gas reserve shortages. For example, if the resource in the example above expects 3 hours of winter gas

reserve shortages, then it would expect to earn an incremental 1.05 MWh during reserve shortages, or $5,728 at a *PPR* of $5,455 per MWh from investing in dual fuel capability.[25]

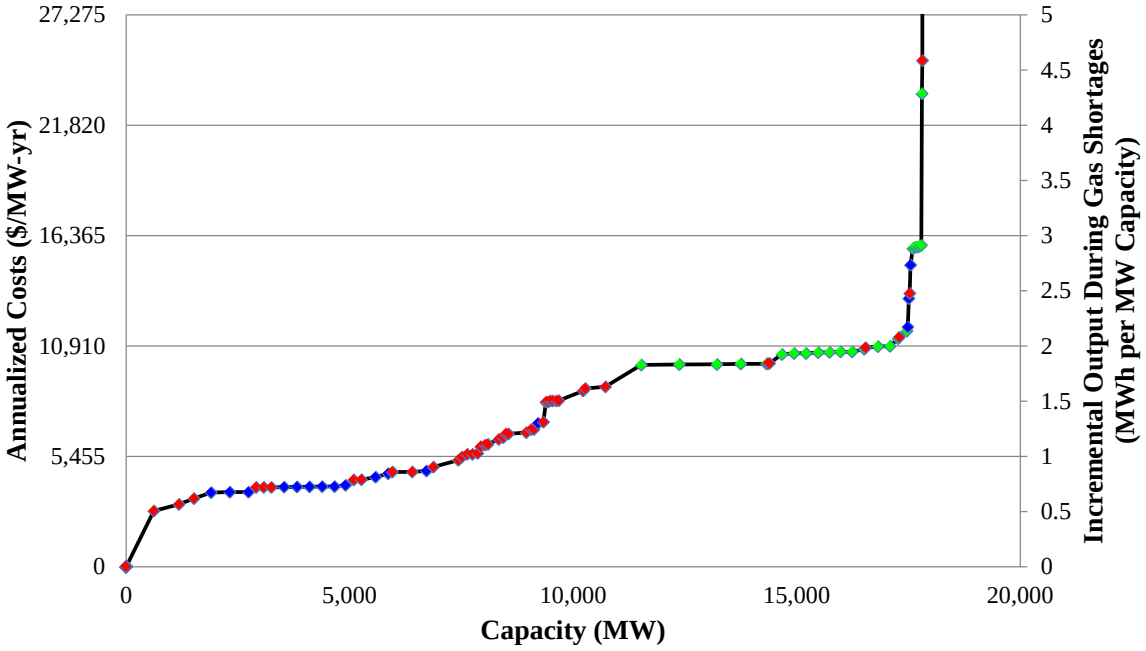
Figure 3 shows the dual fuel supply curve for existing gas-fired resources.[26] This curve includes resources currently without dual fuel capability, as well as resources currently with dual fuel capability that need to incur costs to cover on-going maintenance of dual fuel capability and fuel supplies. The decision to invest in dual fuel capability reflects lower costs for units with mothballed capability, and no limitations arising from environmental permits or other factors. Costs are reported in terms of annual expenditures per MW of capacity, as well as the number of incremental MWh of output during reserve shortages (at a *PPR* of $5,455 per MWh) that is sufficient to cover these annual expenditures. The figure shows that FCM PI can create incentives for investment in dual fuel capability when the resource expects to there to be winter gas shortages in the commitment period. For example, at 2 incremental hour of output during a gas related reserve shortage, roughly 11,000 MW of additional dual fuel capability is supported, including over 7,000 MW of incremental dual fuel capability from resources currently without this capability. Appendix C provides more details on the estimation of costs associated with investment in dual fuel capability.

The analysis assumes that all existing dual fuel resources retain this capability with and without FCM PI. As shown in Figure 3, maintaining dual fuel capability imposes costs on asset owners from on-going maintenance and holding of fuel supplies. Absent market incentives, these resources could opt to mothball this capability, as many resources have already done in recent years. By assuming that resources preserve dual fuel capability absent FCM PI, the analysis may understate FCM PI reliability benefits by failing to capture these potential losses of dual fuel capability.

[25] That is, $PPR * H * (A_{with\ dual\ fuel} - A_{without\ dual\ fuel}) = \$5{,}455 / MWh * 3\ hrs * 35\% = \$5{,}728 / MW$.

[26] Note that differences between annualized costs in Table 3 and Figure 3 reflect differences in certain assumptions, including discount rates and depreciation periods assumed in each analysis.

Figure 3: Supply Curve for Dual Fuel Resources, including Development and Annual Expenditures



Note: Each symbol corresponds to an individual facility, with existing dual fuel resources in RED, facilities with decommissioned dual fuel capability in BLUE and facilities with no dual fuel capability in GREEN.

E. Potential Environmental Compliance Costs

Compliance with emerging U.S. Environmental Protection Agency (EPA) rules could require that certain facilities undertake additional investments and in future years face additional expenditures in order to obtain permits for continued operation. While EPA has promulgated multiple regulations affecting air emissions, water discharges and waste management from power generation facilities, the regulation most likely to impact facilities in ISO-NE market is Section §316(b) of the Clean Water Act, which requires power plant cooling water structures to meet certain technological requirements in order to minimize adverse environmental impact, largely to aquatic life.[27] Because compliance requirements with these regulations are uncertain, we assume no incremental compliance requirements as the baseline assumption, but consider a sensitivity analysis with additional compliance requirements. In the compliance sensitivity analysis, units must take incremental action to comply with Section §316(b), but some units are left unmodified because their water sources suggest that the units have already made modifications or are unlikely to require retrofits. The identification of resources subject to Section §316(b) requirements reflects both fuel/technology type, and resource age under the assumption that many newer steam units are already compliant with Section §316(b). This case assumes that 50% of the overall capacity

[27] For more information on §316(b), *see* Environmental Protection Agency, "Cooling Water Intake Structures – CWA §316(b)," http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm.

potentially at risk actually faces additional Section §316(b) requirements, including all coal units, the two oldest nuclear plants, and the oldest oil units.

Compliance requirements have two implications for facility performance. First, compliance imposes additional going forward costs, including upfront investment and annual operating expenditures.[28] Second, the facility's rated capacity is diminished and heat rate is increased.[29] These penalties stem from the efficiency decrease and power required to drive water pumps in the new cooling towers. The adjustment to GFC when compliance requirements are assumed reflects both these direct and indirect cost impacts. Further detail on our approach is provided in Appendix A.

F. Risk Premiums

Market participants may include a risk factor in resource offers under both current rules and proposed rules for FCM PI. Under current rules, the risk factor can reflect certain pre-determined elements. To simplify the analysis, we assume the risk factors incorporated in resource offers without FCM PI equals zero. The remainder of this section addresses risk factors under FCM PI.

FCM PI introduces additional uncertainty about FCM market revenues that can have consequences for the financial risk faced by market participants. Under the current FCM, resources face uncertainty about their future costs and energy market net revenues when developing their offers. However, the revenue stream from the current FCM model is fixed after the FCA clears, assuming resources comply with their capacity obligation. However, with the introduction of FCM PI, future FCM revenue streams depend on system conditions beyond the resource's control (e.g., the frequency and duration of reserve shortages, and the balancing ratio during these shortages) and factors over which it has only partial control (i.e., the resource's performance during future reserve shortages). As a result of these uncertainties, future FCM revenues streams for individual resources will be uncertain, which is not the case under the current FCM model. Moreover, for poorly-performing resources, these downward adjustments could be large enough to erode most of the fixed portion of revenues under FCM PI (based on the fixed FCA price), or even result in negative total FCM payments.

Assessing the financial risk posed by FCM involves many challenges. First, the entities that own resources in the ISO-NE markets vary widely. Some are relatively small, owning several or even only one asset. However, many are large and have a wide variety of physical and contractual assets, along

[28] The going forward cost is based on estimates from: North American Electric Reliability Corporation, "Potential Impacts of Future Environmental Regulations: Extracted from the 2011 Long-Term Reliability Assessment," November 2011. Available at http://www.nerc.com/files/epa%20section.pdf.

[29] Steam turbines are given a heat rate penalty of 1.3% and a capacity penalty of 3.4%. "Electricity Reliability Impacts of a Mandatory Cooling Tower Rule for Existing Steam Generation Units," U.S. Department of Energy Office of Electricity Delivery and Energy Reliability, October 2008, p. 22. Available at: http://www.netl.doe.gov /energy-analyses/pubs/Cooling_Tower_Report.pdf. Nuclear plants are given a heat rate penalty of 1.5% and a capacity penalty of 1% of based on a variety of sources. Wheeler, Brian, "Retrofit Options to Comply with 316(b)," Power Engineering, October 2010. Available at: http://www.power-eng.com/articles/print/volume-114/issue-10/features/retrofit-options-to-comply-with-316-b.html; "Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule," U.S. Environmental Protection Energy, pp. 175, 207-210. Available at: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/phase2/upload/2009_03_26_316b_phase2 _devdoc_ph2toc.pdf. No adjustments to operating performance *A* have been made for these impacts.

with other business operations. Some entities own portfolios of generation (and contractual) assets with different performance characteristics, different markets and different geographical locations. The revenue streams received through these assets varies widely depending on the type of asset (gas/oil/nuclear, dispatchable/intermittent, old/new, fast-start/non-fast-start), the particular market (e.g., in New England there is the energy, operating reserves, ancillary services, and RECs along with the FCM) and geographies (including other RTOs and assets supported by long-term contracts). Moreover, some entities have revenue streams outside of wholesale power markets, including transmission, distribution, retail, market-making or even non-electric business entities.[30]

Second, the design of FCM PI partially mitigates financial risks for entities with multiple resources in the ISO-NE market, and creates opportunities for bilateral transactions to mitigate risks. For entities that own multiple ISO-NE resources, differences in the actual performance of those resources will tend to mitigate the risk of any individual resources due to portfolio effects. These portfolio effects are considered in the quantitative analysis of the risk factor. In addition, as discussed earlier, under FCM PI, total revenues to all resources in the region are fixed.[31] Consequently, as a whole, the region's resource fleet is fully hedged against the FCM PI financial risks faced by individual resources.[32] This fact suggests that there are opportunities for bilateral transactions among entities in the region that could mitigate the risks faced by individual entities.

Third, financial products could be developed to help mitigate financial risks. For example, an option could be developed that pays the owner based on the level of reserve shortages during a given period. If market participants with a CSO purchased such a product, then with every reserve shortage they would receive a payment from the option that could offset (to some degree) the downward revenue adjustment based on the balancing ratio.[33]

The likelihood that markets for these FCM PI options or bilateral transactions between market participants would emerge is highly uncertain at this stage. Thus, assessment of risk cannot presume that they will develop. However, to the extent that the analysis indicates that there are high risk premiums associated with FCM PI offers, this suggests that the financial rewards to developing these markets or transactions would be higher, which would increase the likelihood that these mitigating transactions would emerge. Should they emerge, these alternatives would result in additional financial costs, which would be reflected in resource offers through the risk factor. The quantitative analysis of the risk factor under FCM PI does not consider these costs, which would tend to increase resource offers and thereby raise FCA prices under FCM PI.

[30] A recent study indicated that Calpine and NRG were the only two publicly traded merchant generation companies. Brattle Group and Sargent & Lundy, "ISO-NE Offer Review Trigger Prices 2013 Update, Draft Results," presented to NEPOOL Markets Committee, August 7, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/aug7892013/a04_brattle_group_presentation_08_07_13.ppt.

[31] As previously noted, there is a small deficit in aggregate payments to generators that reflects the shortage of reserves in relation to the total customer demand (reflecting both load and the reserve requirement).

[32] With each reserve shortage event, resources in aggregate face a deficit equal to the size of the reserve shortage (in MW) times the PPR.

[33] The option could also be specified so that the payoff varied with the balancing ratio in the same manner as the downward revenue adjustments vary with the balancing ratio.

Fourth, risks to operational performance can be mitigated through actions to increase the likelihood that the resource supplies output during reserve shortages. This could include actions to reduce forced outages and failures to respond to system operator dispatch requests, actions to reduce the likelihood of fuel supply disruptions (particularly for gas-dependent resources) and actions to increase the likelihood that the energy-limited resources (such as pumped storage) have energy available to supply. Of course, creating incentives for these sorts of actions is a fundamental purpose of FCM PI. Taking such actions can also mitigate some – but not all – FCM PI financial risk, since performance is determined in part by factors that are beyond the resource's control (e.g., factors that affect energy market offers, such as heat rates and non-fuel operating costs).

Fifth, ISO has proposed "stop loss" provisions as part of the FCM PI design. The stop loss mechanism limits a capacity supplier's exposure to financial losses by capping monthly losses. Stop loss provisions are not designed to eliminate the risk of losses, but to insure against extreme losses. By limiting insurance to more extreme circumstances, the stop loss mechanism maintains performance incentives until monthly losses become particularly large. Under the current proposal, the stop loss mechanism limits losses to individual resources at the difference between the FCA starting price ($15 per kW-month) and the FCA clearing price. For example, if the FCA clearing price was $4 per kW-month, then monthly losses for each resources would be capped at the resource's CSO times $11 per kW-month (i.e., $15 minus $4 per kW-month).

Finally, energy and ancillary service market prices tend to increase during reserve shortages that occur during peak (summer) conditions, which are likely to prevail during future reserve shortages under equilibrium conditions. Figure 4 reports the percentage difference between energy market prices on days with peak period reserve shortages against energy prices on comparable days (i.e., either days in the same month or the same week). Day-ahead prices increase by 26% (within week comparison) or 64% (within month comparison) during on-peak periods, and 7% or 21% during off-peak periods. On-peak real-time price increases are larger than on-peak day-ahead prices (151% for the within week comparisons and 100% for the within month comparisons), although market participant revenues are typically most dependent on day-ahead prices.

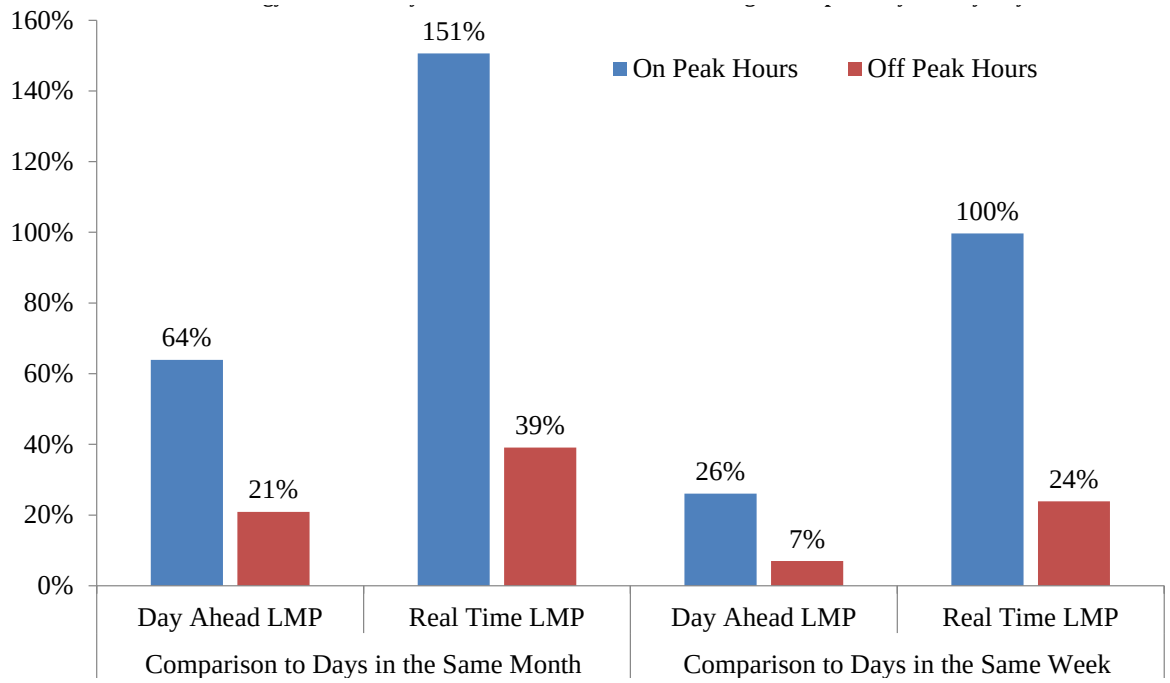
Given the uncertainty introduced by FCM PI in the FCM market, a risk factor is included in resource offers to reflect the resulting financial risk. In practice, the approach taken by individual market participants to estimate a risk factor to include in their offers will reflect many company-specific factors, including information that is often not publicly available. Given these information limitations and the complexities of performing company-level risk assessments for all entities in the ISO-NE market, certain simplifying assumptions are made.

In choosing an analytical approach for estimating the risk factor, it is important to keep in mind that economics and finance provide guidance on alternative ways of measuring financial risk, but do not conclude that there is a single optimal way to measure and manage financial risk. The analysis builds off the Value at Risk approach,[34] which is a standard approach used in the financial sector for valuing the

[34] Eydeland, Alexander, and Krzystof Wolyniec, *Energy and Power Risk Management, New Developments in Modeling, Pricing, and Hedging*, Wiley Finance: Hoboken, New Jersey. Berry, Romain, "Value at Risk: An Overview of Analytical VAR," J.P. Morgan Investment Analytics and Consulting.

financial risk associated with a portfolio of assets.[35] Under this approach, analytical models are used to measure the distribution of potential financial returns of a portfolio of assets. The Value at Risk (VaR) is then the maximum potential loss of the portfolio at a pre-specified confidence level. For example, a firm may estimate that the VaR for a given portfolio of assets is a loss of $2 million at the 5% level over the next month. This means that there is a 5% chance that this portfolio will lead to losses of $2 million or more. Given this information, the firm may adjust its portfolio to bring the risk within (potentially pre-determined) tolerance levels.

Figure 4: Average LMP Increase on Days with Peak Period Reserve Shortages



Note: Figures reflect only reserve shortage events that occurred during peak hours in June, July, or August 2010 - 2012.

Risk factors are calculated using the VaR approach in the following manner. For each resource, the risk factor equals the increase in a resource's offer needed to ensure, with a 95% probability, that it earns positive expected net revenues across all ISO-NE markets. The analysis only considers uncertainty in the level of reserve shortages, but not resource performance. Uncertainty over the level of reserve shortages creates meaningful financial risk, particularly for resources with poor performance. For poorly performing resources, each additional reserve shortage can result in financial losses because the unit's

[35] Other approaches to addressing financial risk include asymmetric (and potentially non-linear) valuation of losses and gains and requiring risk-adjusted returns (potentially reflecting the variance of potential losses). These models are grounded in certain fundamentals of financial analysis (including portfolio theory) but recognize certain costs to losses that may not be recognized in these models, including credit constraints (which may impose limits on the ability of a firm with poor credit from pursuing profitable business opportunities) and managerial risk aversion (which may be a fact of life given principal agent problems).

output is likely below the balancing ratio benchmark. Consequently, if the level of reserve shortages exceeds expectations, losses could grow large, even potentially leading to negative net FCM revenues.[36] By contrast, risks associated with resource performance are bounded by several factors. First, as shown in Figure 1, resource performance and the balancing ratio tend to be positively correlated. Thus, an element of performance uncertainty is addressed by the FCM PI design, which lowers the benchmark against which each resource's performance is compared during shortages when aggregate output is lower. Second, assuming actual reserve shortages equal expected levels, the minimum offer (essentially) provides sufficient revenue to avoid losses (negative net revenues).[37] Analysis that simultaneously considers uncertainty in both reserve shortage levels and operational performance was beyond the scope of our analysis.[38]

Based on uncertainty in reserve shortage levels, the risk factor is calculated as:

$$RF = \min\left\{0, GFC - P_{FCM} - PPR * H_{95\%} * \left(A - BR\right)\right\}$$

Here, $H_{95\%}$ is the reserve shortage level at the 95% confidence interval. This value is based on the probability distribution of future reserve shortages under different levels of excess resources from analysis performed with the ISO-NE system model. In effect, as shown in Figure 5, the risk factor shifts the distribution of total returns such that there is a 95% likelihood that the resource has positive net returns.

These VaR estimates reflect one approach to estimating resource risk factors, but may not consider all factors relevant to determining the risk factor for individual resources. For many resources, these risk factors will reflect conservative estimates of risk. For poor performing resources, the approach can result in tradeoffs between risk and expected returns suggesting that market participants are very risk averse.[39] On the other hand, for some market participants, the VaR approach may understate risk factors by assuming that they would be indifferent to the choice between a market position with and without a CSO that provides equal expected returns. It is quite likely that some market participants faced with these

[36] Even when actual performance equals the resource's expected performance, actual FCM revenues will be negative whenever the number of reserve shortage hours is greater than the ratio of the annual fixed FCM revenues (i.e., P_{FCM}) divided by the loss per hour of reserve shortage – that is: $H > \frac{P_{FCM}}{PPR * \left(BR - A\right)}$.

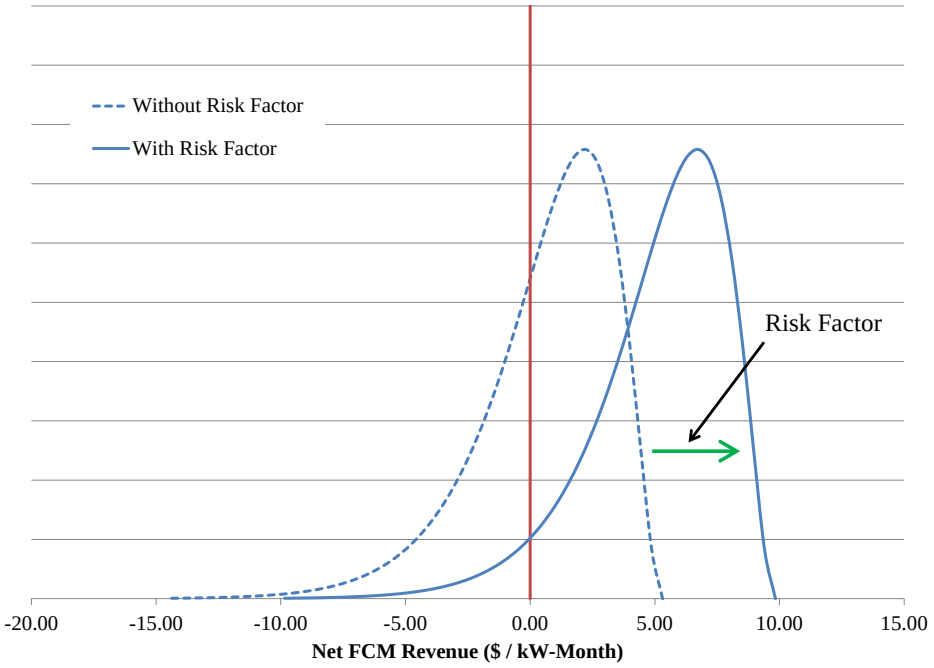
[37] With no uncertainty over *H*, the minimum offer is *PPR*H*BR*. So long as actual *BR* is no less than the expected *BR*, then the minimum offer exceeds the revenue adjustments for all levels of output. That is, $PPR * H * E\left[BR\right] + PPR * H * \left(A - BR\right) \geq 0$ for all levels of performance *A* as long as the actual average balancing ratio (*BR*) is less than the expected average balancing ratio (*E* [*BR*]).

[38] Such analysis would require Monte Carlo analysis that accounted for both reserve shortage and performance uncertainty, along with the relationship (correlation) between these factors, which would vary across individual resources.

[39] For example, consider a poorly performing resource (A = 0.1) with going forward cost of $1 per kW-month under the following market conditions: BR = 0.75, E[hours] = 12, $\text{Hours}_{95\%}$ = 25.2. This resource would have a risk factor equal to $3.57 per kW-month. A risk factor at this level suggests that the resource would prefer to forego a CSO and receive expected FCM revenues of $0.50 per kW-month from providing capacity without an obligation (reflecting performance incentive payments) rather than accept the CSO with expected returns of $4.57 per kW-month. This sort of tradeoff suggests a high degree of risk aversion on the margin.

two choices would require some risk premium to accept the financial option (contingent on the balancing ratio adjustments) that comes with a CSO under FCM PI. This type of preference is consistent with behavioral economics, managerial incentives, and certain corporate finance limits.[40] In practice the value of the FCM PI option will depend on each market participant's individual risk profile. Thus, our approach likely understates the quantity of resources that would opt to submit positive risk factors.

Figure 5: Illustrative Depiction of the Shift in Net Revenues with the Risk Factor



Risk factors also account for portfolio effects among resources owned by the same corporate entity. By considering these portfolio effects, the risk factor estimates account for hedging of risk across individual resources. For example, an entity with one high performing resource (typically receiving positive FCM revenues with every incremental reserve shortage) and one poor performing resource (typically receiving negative FCM revenues with every incremental reserve shortage) would face very different financial risks than an entity with only one poorly performing resource. To account for these portfolio effects, each resource's risk factor reflects the portfolio of resources that would clear if it were the marginal resource. Thus, for each resource, the risk factor reflects the marginal risk it adds to the portfolio of resources that would clear at or below its offer price.

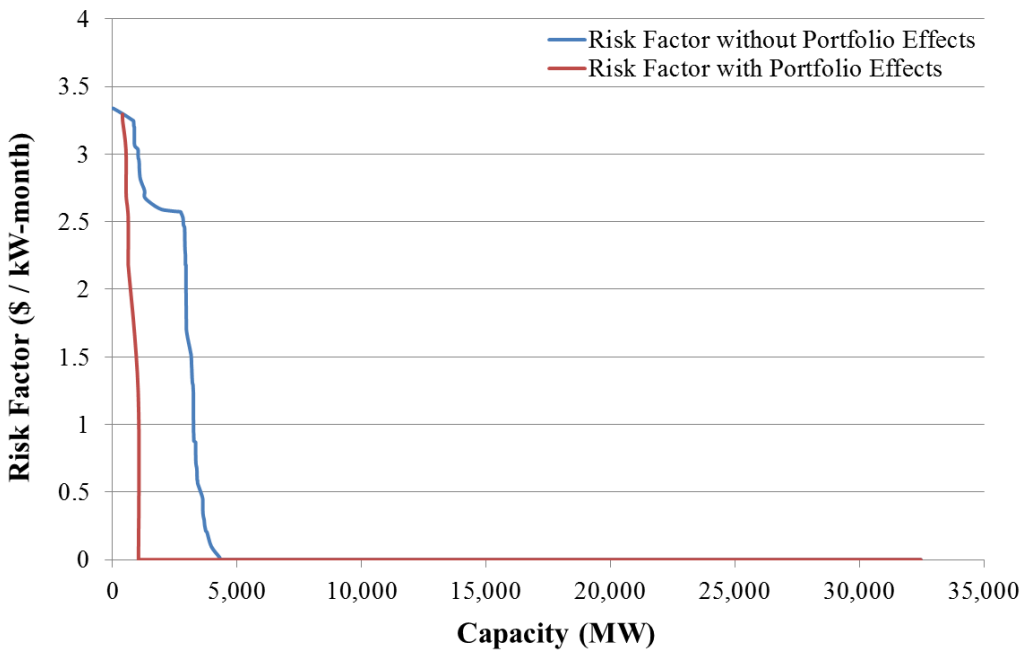
Because this approach accounts for only a limited set of factors, it may understate risks for some resources and overstate them for others. On the one hand, the analysis does not account for factors that would mitigate risks, including stop loss provisions and opportunities to hedge financial risks. On the

[40] For example, greater uncertainty can increase the risk that a firm faces circumstances in which it is credit constrained and potentially must forgo potentially profitable investments.

other hand, the analysis does not account for factors that would increase risk, including performance uncertainty and behavioral preference for more certain returns.

The resulting risk factors vary across scenarios. Figure 6 shows the risk factors for the Equilibrium: No Gas scenario. Without portfolio effects, about 4,300 MW of resources have positive risk factors, with the largest risk factor at nearly $3.50 per kW-month. Resources with positive risk factors include units with relatively low performance (below 40%) and some higher performing resources that rely on FCM revenues to remain economically viable (i.e., resources with positive GFC including FCM PI revenues). Financial risks are greater for resources with higher going forward costs because they have less financial cushion from other ISO-NE markets to ensure positive profitability. Accounting for portfolio effects reduces the quantity of resources with risk factors to about 1,000 MW, with a minimal change in the largest risk factor. After accounting for portfolio effects, resources with positive risk factors include those resources held by entities with few resources and some poorly performing units with high going forward costs held by entities with larger portfolios.

Figure 6: Risk Factors in Near-Term Equilibrium Scenario



VI. IMPACT OF PERFORMANCE INCENTIVES ON ISO-NE MARKET

A. Impact on Reliability

In principle, FCM PI has the potential to improve reliability through several mechanisms, including increases in the supply of resources in the ISO-NE energy markets, increased adoption of dual fuel capability, changes in the mix of resources toward higher performing resources, and improvements in the operational performance through changes in operating practices or other performance investments (e.g., ramping capability). The analysis quantifies many but not all of these impacts.

1. Increase in Resource Supply

The introduction of FCM PI can affect the quantity of resources that continue to participate in the ISO-NE energy market. As described in Section IV.A, if the expected level of reserve shortages is sufficiently high, then some resources that do not take on an FCM CSO may remain in ISO-NE's energy market in anticipation of additional FCM PI payments received for output supplied during reserve shortages. Under these circumstances, the quantity of resources in the ISO-NE energy markets can exceed ICR, which, in turn, results in improved reliability, including reductions in the level of reserve shortages.

Table 4 reports estimates of the difference between the total quantity of "economic capacity" and ICR, referred to as "surplus capacity." Surplus capacity includes all capacity with a CSO and any surplus capacity resources without a CSO that receive sufficient revenues to remain economically viable in the ISO-NE energy markets. Determination of which resources are economically viable (i.e., receive positive net revenues including all ISO-NE markets) reflects only the costs identified in Section V, but may not capture all relevant values affecting resource retirement decisions.[41] Under current market rules, the analysis finds that there is no surplus economic capacity – that is, at the clearing FCA price, only those resources receiving a CSO will find it economically profitable to remain in the market.

Table 4: Market and System Outcomes under Historical and Equilibrium Scenarios

		FCM PI, Historical Scenario			FCM PI, Near-Term Equilibrium Scenario		
	Current Rules (No FCM PI)	No Gas Shortages	Gas Shortages	High Gas Shortages	No Gas Shortages	Gas Shortages	High Gas Shortages
FCA Clearing Price ($/kW-month)	$1.31	$1.93	$2.55	$2.91	$3.76	$3.76	$4.49
Total FCM Payments ($bil)	$0.54	$0.80	$1.06	$1.20	$1.56	$1.56	$1.86
Avg FCM Payments ($/MWh)	$4.07	$5.99	$7.92	$9.01	$11.68	$11.66	$13.92
% Change Relative to 2012 Level	-57%	-36%	-15%	-4%	25%	25%	49%
New Entry Offers ($/kW-month)	$8.87	$8.67	$8.08	$7.49	$8.62	$8.09	$7.50
Surplus Capacity Above ICR (MW)	0	0	0	0	1,036	1,390	1,472
Expected Reserve Shortage Hours	21	-	-	-	9.00	10.00	12.75
Summer Peak RS Hours	21	-	-	-	9.00	7.00	6.75
Winter Gas-Related RS Hours	-	-	-	-	0.00	3.00	6.00
Incremental Dual Fuel Capacity (MW)	0	226	5,848	7,368	39	6,130	7,988

Note: For the Historical Scenario, Expected Reserve Shortage Hours are not reported as they do not reflect a consistent market-system equilibrium.

Under Historical system conditions, there is no surplus capacity as a consequence of FCM PI. Given the level of reserve shortages assumed in these Historical scenarios, incremental FCM PI revenues are insufficient to keep resources in excess of the ICR in the energy markets.

[41] Values not considered in our analysis include significant investments needed to maintain on-going operations and the option value to delay retirements given that revenue streams in future years could be sufficient to allow plant operation to be economically profitable.

In the near-term Equilibrium scenarios, surplus capacity ranges from 1,036 MW with no gas shortages to 1,472 MW with gas shortages (Equilibrium: High Gas). In these cases, more than 1 GW of resources in excess of the ICR would find it financially profitable to remain in operation in the energy markets, even without a CSO.

Table 4 also reports the expected number of reserve shortage hours given the level of surplus capacity in each scenario based on results from the ISO-NE system model. For the Equilibrium scenarios, there are 9.0 reserve shortages hours with no gas shortages, 10.0 total hours with gas shortages (3 hours) and 12.75 total hours with high has shortages (6 hours). These values equal the level of reserve shortages estimated when determining the market-system equilibrium based on the level of *summer peak* reserve shortages (as described in Section V.C). As higher levels of winter gas reserve shortages are assumed, the equilibrium level of total reserve shortages increases, which provides additional revenues for a larger quantity of surplus capacity. This higher level of surplus resources, then results in a lower level of *summer peak* reserve shortages. Thus, the level of summer peak reserve shortages declines as additional winter gas reserve shortages are assumed.

For the Historical scenarios, the values are not reported as they do not reflect a consistent market-system equilibrium.[42] Outcomes without FCM PI reflect the fact that under the current FCM model, the "economic" supply of resources equals ICR – that is, excess supply equals zero.[43] Thus, the expected level of reserve shortages is higher – 21 hours – because there is no surplus capacity. This outcome also corresponds to the long-term equilibrium in which new resources are needed to help meet future growth in ICR.

These results indicate that FCM PI would likely result in higher levels of reliability by increasing the quantity of resources participating in the ISO-NE markets. The improvements in reliability from this surplus capacity are reflected in the differences in the level of reserve shortages between the current FCM model (21 hours) and the Equilibrium scenario outcomes (9.0 to 12.75 hours). These reliability benefits would be experienced throughout the year, although they would be the most significant during summer peak load periods. Reliability risks associated with winter gas limitations would also benefit, to the extent that the surplus reflects resources that are not "gas dependent." Later sections address these factors in greater detail.

Our analysis considers resource outcomes for the 2018/2019 Commitment Period, but does not quantitatively assess outcomes in subsequent commitment periods. Thus, the length of time that surplus capacity remains under FCM PI is not estimated, although FCM PI could extend the period with surplus capacity under many plausible market outcomes. Thus, the reliability benefit of FCM PI found for the 2018/2019 Commitment Period could be further extended.

Eventually, as operating and investment costs for existing resources increase (or operating performance decreases), resources that are currently economically viable under FCM PI will retire. As

[42] That is, the market model assumes one level of reserve shortages but the resulting level of surplus capacity produces a different level of reserve shortages in the system model.

[43] In reality, some resources may continue to operate in the market due to variety of factors, including the option value to continuing operation in future years in anticipation of increases in future capacity or energy market prices. This suggests that, when accounting for these factors and option values, the quantity of resources with negative GFC costs (i.e., resources that require positive FCM revenues to remain financially viable) could exceed the ICR.

this occurs, the current surplus of capacity will diminish, leaving the region in need of new generation resources. However, while the long-run equilibrium under the current FCM rules tends toward a system in which the quantity of resources equals the ICR, under FCM PI, the incremental revenues (which can economically support existing resources and reduce offers from new entry, as discussed below) could result in a long-run with resources in excess of the ICR. At this point in time, FCM PI should be expected to provide the same or greater level of reliability, based on the 1-in-10 days loss of load expectation criterion used in setting the ICR.

2. Actions to Improve Performance, including Adoption of Dual Fuel

The opportunity to earn additional revenues during reserve shortages creates an incentive for resources to take actions to improve performance. Improved performance can be achieved through new investments (e.g., adding dual fuel capability, improving generation performance and lowering startup costs) and operational changes (e.g., improved maintenance to limit forced outages, increased pumping by pumped storage units, and improved systems to respond to system operator dispatch requests). To the extent that such actions are undertaken, they could result in improved reliability (including reductions in the level of reserve shortages), lower energy market costs and lower FCM prices.

The quantitative analysis assesses the extent to which resources that could face limited access to fuel supplies – gas-dependent resources – take steps to make their plants capable of burning an alternative fuel. With dual fuel capability these resources, which otherwise might lose revenues due to curtailed fuel supply, can continue operations during reserve shortages.

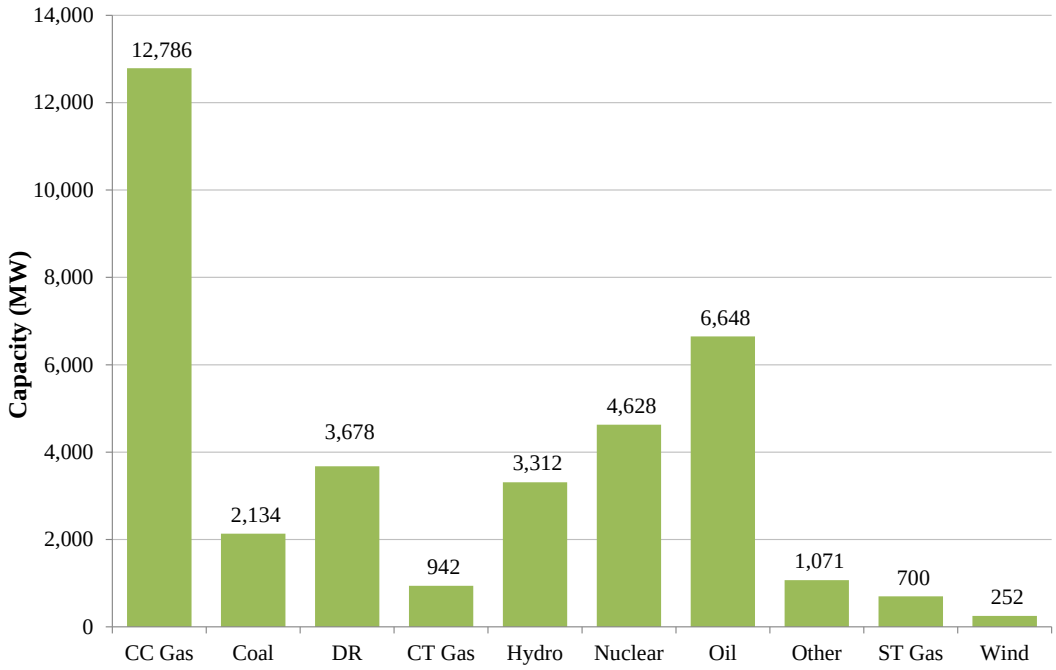
Figure 7 illustrates the mix of resources in the current ISO-NE fleet. Roughly 30% of the region's generation resources, or 10.1 GW out of 36.1 GW, are currently dependent solely on natural gas, with no option to operate on an alternative fuel. Today, roughly 6,600 MW of capacity has dual fuel capability, although this total has fallen from higher levels in recent years because the divergence of gas and oil prices has made oil combustion uneconomic.[44] As current market conditions do not support maintaining dual fuel capability (including maintenance of alternative fuel capabilities and storage of costly fuel supplies) for energy production, and there are currently no mechanisms for supporting dual fuel capability for reliability purposes, the supply of dual fuel capability has diminished over time.

The analysis indicates that the introduction of FCM PI would increase the supply of resources that are not subject to gas-dependency. Figure 8 illustrates these changes by highlighting both the quantity of dual fuel capability and the quantity of non-gas resources (which do not face gas curtailment risks) with and without FCM PI, under the Equilibrium scenarios. FCM PI would increase investment in dual fuel capability under conditions when market participants expect reserve shortages driven by limited gas fuel supplies. Without PI, there is 5,607 MW of dual fuel capability in the region. Under Equilibrium scenarios, dual fuel capability increases by 6,130 MW to 11,737 MW if 3 hours of winter gas shortages are assumed, and by 7,988 MW to 13,595 MW if 6 hours of winter gas shortages are assumed. Results are similar under the Historical scenarios, as shown in Figure 9. There is also a small increase in dual fuel capability (226 MW under Historical conditions and 39 MW under Equilibrium conditions) when no

[44] This total includes some resources that, in a past, tended to operate primary on non-gas fuels (primarily oil) that have switched largely to gas-fired operations in recent years.

winter gas shortages are expected because of shifts in the mix of "economic" resources with and without FCM PI.

Figure 7: Current ISO-NE Resource Mix (FCA 7)



Note: The figure lists only resources within the ISO-NE footprint, thus excluding imports that clear in FCA7.

These comparisons reflect the assumption that all existing dual fuel resources retain this capability under current market rules. Thus, our analysis does not account for the risk that owners of facilities with dual fuel capability opt to mothball this capability, as many resources have already done in recent years. By assuming that resources preserve dual fuel capability absent FCM PI, the analysis may understate FCM PI reliability benefits by failing to capture these potential losses of dual fuel capability. The analysis also assumes that the addition of dual fuel capability is the least-cost approach to mitigating gas curtailment risks, as discussed in Section V.D. To the extent that there other options that can provide this mitigation at lower cost, then the analysis would also tend to understate the reliability benefits of FCM PI.

In addition to these increases in dual fuel capability, FCM PI results in small increases in the quantity of non-gas resources that help maintain reliability in periods of limited gas supply. Without FCM PI, there are 19,304 MW of non-gas resources in the Equilibrium scenarios. With the introduction of FCM PI in the Equilibrium scenarios, the quantity of non-gas resources increases to 19,803 MW, without assuming any winter gas reserve shortages. When winter gas reserve shortages are assumed, the quantity of non-gas resources increases by another 452 MW with 3 winter gas reserve shortage hours and 534 MW with 6 hours.

Figure 8: Gas Dependency Resource Changes, Equilibrium Scenarios

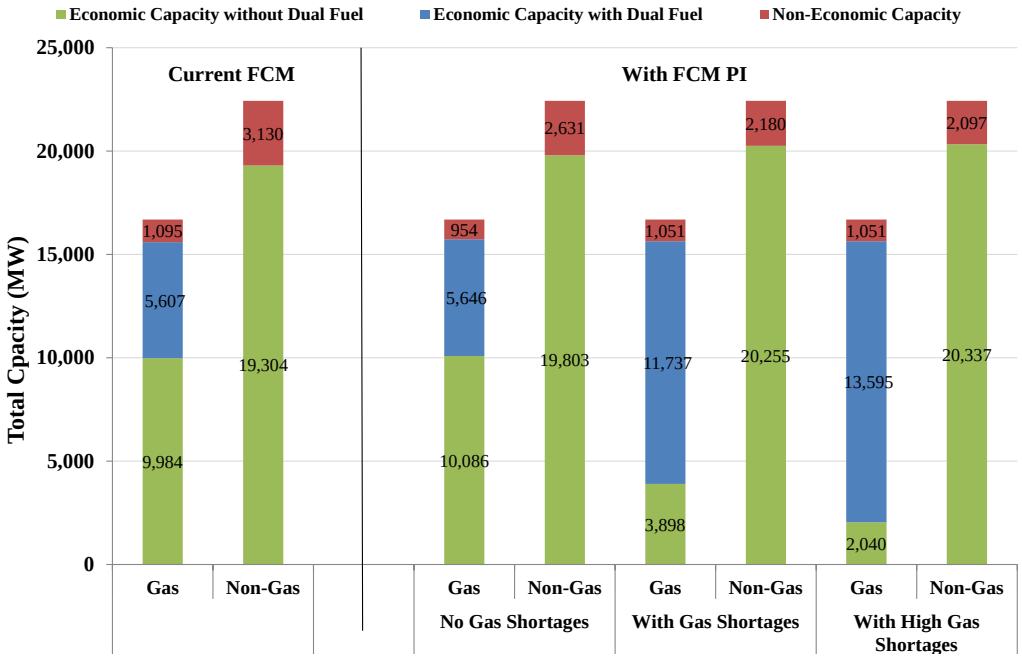
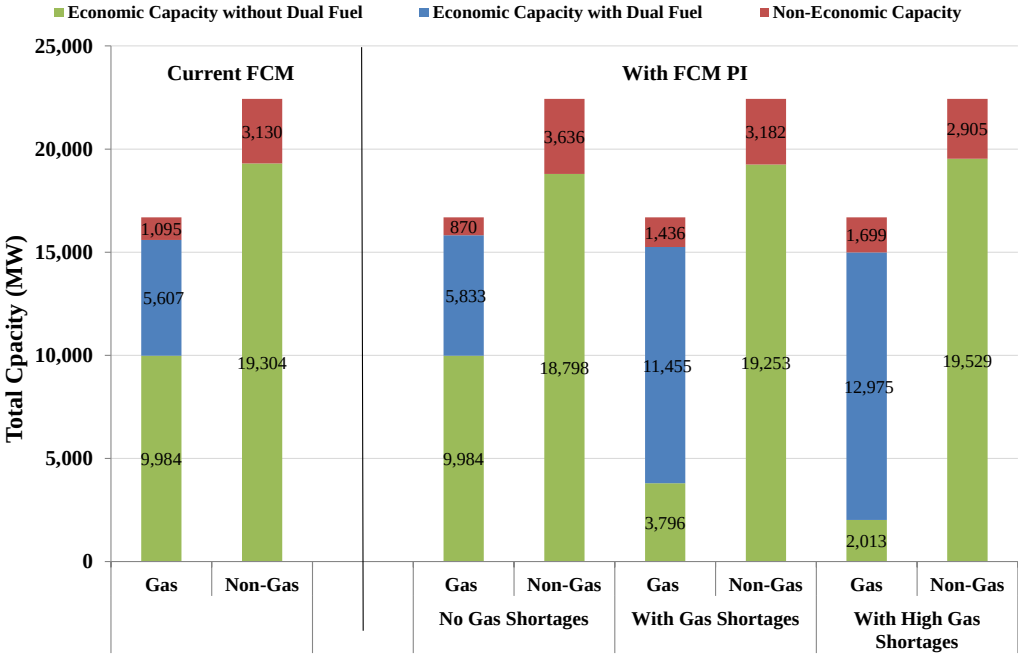


Figure 9: Gas Dependency Resource Changes, Historical Scenarios



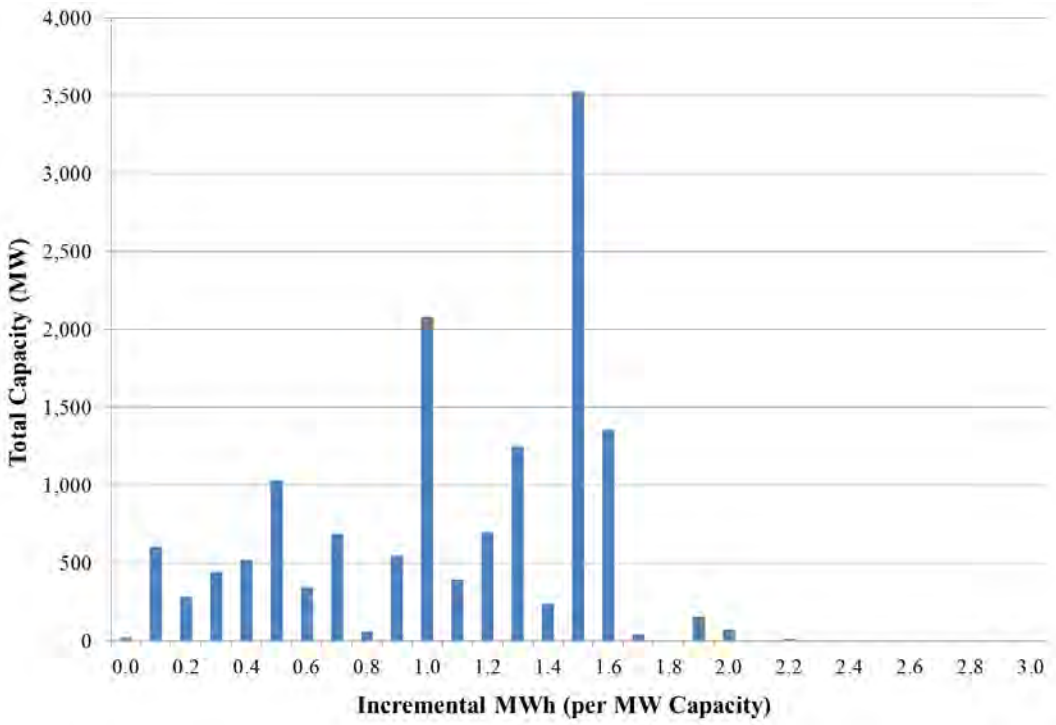
Notes for Figures 8 and 9:

[1] Dual Fuel Gas Capacity includes some units listed in the 2013 CELT Report with a primary fuel type of RFO or DFO that currently have dual fuel capability.

[2] Oil units based on primary fuel use from 2013 CELT Report, but may include units that have used gas as a primary fuel in recent years.

For each gas-dependent resource, the financial gains from adopting dual fuel capability reflect the incremental MWh of output that can be supplied during winter reserve shortages from having addressed the unit's gas curtailment risks. Figure 10 illustrates the distribution of operational benefit of maintaining dual fuel capability for all gas-fired resources, as reflected by the incremental MWh supplied during winter gas reserve shortages, for the Equilibrium: Gas scenario (i.e., 3 hours of reserve shortages). For example, consider a 100 MW resource with "Incremental MWh per MW of Capacity" equal to 1.6 MWh over the three hours of additional winter reserve shortages. This unit would receive an additional 160 MWh of output by investing in dual fuel capacity; over one year, assuming a PPR of $5,455, this resource would receive an additional $872,800 in revenues. The figure shows that even though there are 3 additional hours of reserve shortages, our approach results in relatively modest assumptions about the additional MWh of output that market participants would gain from investing in dual fuel.

Figure 10: Distribution of Incremental MWh (per MW of Capacity) during Winter Reserve Shortages, Gas Shortage Scenario (3 Hours)



These results are particularly sensitive to assumptions about cost. As shown in Figure 3, portions of the dual fuel supply curve are relatively flat, which could lead to large variation in the quantity of dual fuel upgrades depending on the magnitude of performance incentives. To determine whether this affects estimated outcomes, a sensitivity analysis is performed in which dual fuel costs (including both upfront capital and annual expenditures) are increased by 25%. The results of this scenario are reported in Table 5. When costs are increased by 25%, the quantity of dual fuel upgrades increases under FCM PI by 2,985 MW with 3 hours of gas shortages, and by 7,484 with 6 hours of gas shortages. Thus, dual fuel upgrades from FCM PI decrease by over 50% when costs are increased by 25% with 3 hours of winter reserve shortages. By contrast, dual fuel upgrades decrease by only 6% at the higher level of winter reserve shortages (6 hours). These results suggest that there is substantial uncertainty about the level of dual fuel

upgrades at moderate levels of gas dependency risks, but less uncertainty when these risks become sufficiently high.

Table 5: Market Outcomes for Dual Fuel Cost Sensitivity Analysis

		Baseline Costs		Baseline Costs + 25%	
	Current Rules (No FCM PI)	FCM PI Gas Shortages	FCM PI High Gas Shortages	FCM PI Gas Shortages	FCM PI High Gas Shortages
FCA Clearing Price ($/kW-month)	$1.31	$3.76	$4.49	$3.76	$4.49
Total Dual Fuel Capacity (MW)	5,607	11,737	13,595	8,592	13,091
Change in Capacity from No FCM PI	-	6,130	7,988	2,985	7,484

The results indicate that FCM PI can increase reliability by improving the quality of resources participating in ISO-NE markets. The analysis shows that resources that would otherwise face no incentive to develop dual fuel capability would choose to develop this capability under FCM PI when market participants anticipate meaningful system reliability risks associated with gas-supply curtailment. However, the analysis does not identify a final equilibrium between the quantity of dual fuel upgrades and the level of reliability (as reflected in reserve shortages) given gas dependency risks. As with the equilibrium between the level of total system resources and summer peak reliability, this eventual equilibrium will depend on the dynamic between these two factors. As the quantity of dual fuel upgrades increases, reliability risks associated with gas-dependency will improve; however, as winter gas reliability improves (and reduces the level of reserve shortages), revenues to support dual fuel upgrades will decrease. Thus, the analysis does not resolve uncertainty about the final level dual fuel upgrades and winter gas reliability under FCM PI.

The quantity of incremental dual fuel capability developed rises as high as 7,988 MW under the "worst case" expectations evaluated (i.e., 6 hours of winter gas reserve shortages under Equilibrium conditions). Because all but roughly 2 GW of gas-fired resources would upgrade to dual fuel under this scenario, the underlying reliability risks driving these winter gas reserve shortages would likely be fully mitigated. This suggests that an "equilibrium" level of gas reserve shortages and additional new dual fuel capability could be below the levels assumed in this "worst case" scenario. This conclusion is further supported by the fact that FCM PI would provide additional incentives for resources relying on on-site fuel supplies (particularly oil-fired resources and existing dual fuel resources) to maintain higher levels of on-site stored fuel, which could mitigate reliability risks associated with prolonged and sequential episodes of gas supply limitations.

While the results of this "worst case" scenario suggest that FCM PI would provide sufficient incentives to mitigate gas dependency risks, the analysis does not identify a precise equilibrium level of dual fuel upgrades and winter gas reliability. Moreover, the sensitivity of the quantity of dual fuel upgrades to assumptions about underlying upgrade costs highlights the substantial uncertainty about the eventual equilibrium levels of incremental actions taken to mitigate winter gas curtailment risks

(including dual fuel) and winter gas reliability (as reflected in reserve shortage hours) when winter gas dependency risks are at levels more moderate than the "worst case" scenario.[45]

3. Change in Mix of Economic Resources in ISO-NE Markets

The introduction of FCM PI is intended to create incentives for higher performing resources to compete more effectively against lower performing units. With these incentives, resource entry (new build) and exit (retirement) decisions should result in a mix of higher performing resources in the long run as these retirement and new build decisions are made. The analysis of outcomes in FCA 9 and impacts on the cost of new entry can provide insights on the extent to which these incentives have meaningful effects on these decisions.

The introduction of FCM PI has several effects on the mix of available resources. These effects are illustrated in Table 6, which reports the mix of "economic" resources with and without FCM PI under the Equilibrium: No Gas Scenario, as well as Figure 11, which shows "non-economic" capacity by resource type for the Equilibrium: No Gas and Historical: No Gas scenarios. As discussed above in Section VI.A.1, the total quantity of economic resources is expected to be greater under FCM PI than under current FCM rules. Despite this aggregate increase, the quantity of oil-fired resources decreases with FCM PI. Figure 11 shows that the quantity of "non-economic" oil-fired capacity increases from 1,047 MW to 2,282 MW in the Equilibrium: No Gas scenario, suggesting an increased likelihood of retirement of oil-fired resources under FCM PI. By contrast, the quantity of all other resource types increases under FCM PI compared to current rules. Demand response and imports (combined) increase by 1,407 MW in the Equilibrium: No Gas scenario, while there is combined increase of 476 MW between gas-fired resources (CC Gas, CT and ST Gas) and coal-fired resources. These changes to the resource mix are generally supportive of reliability, as they result in a larger supply of more flexible resources, including fast start and demand response, and a reduced supply of slower fossil units, such as oil units.

As seen in Table 6, performance varies across resource categories, and the average performance masks variation among the units within individual categories. Variation in performance reflects operational factors (e.g., forced outages) and economic factors (e.g., heat rates, start-up costs and other factors that affect resource energy market offers). For existing resources, market participants have some control over these factors and limited control over others.

Table 6 also illustrates that under FCM PI, resource performance (as measured by average performance *A*) tends to increase for certain generator categories compared to current rules. These shifts in performance reflect two offsetting factors. The first arises from the fact that more economic resources remain in the market with FCM PI than without. Because marginal resources will tend to have poorer performance than resources that remain in the market, under any scenario, the *average* performance will tend to decrease as the quantity of surplus resources increases simply because the last resources added tend to have lower performance. This effect would tend to result in *lower* average performance under FCM PI, because it supports a larger pool of resources.

[45] This sensitivity mirrors the uncertainty underlying other assumptions, including the level of gas curtailment risk that resources would face during winter gas-related reserve shortage, which was set at a 50% reduction in output without dual fuel capability to balance the range of curtailments that resources could face.

Table 6: Resource Mix and Average Performance With and Without FCM PI, Equilibrium: No Gas Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,717	100%	791	100%
Renewables	4,698	112%	7	4%
Nuclear	4,628	105%	0	NA
CC Gas	12,712	91%	74	22%
Coal	1,703	86%	431	90%
CT or ST Gas	1,642	89%	0	NA
Oil	4,366	66%	2,282	14%
Other	1,070	91%	0	15%
Total	35,536		3,585	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	112%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,470	92%	315	70%
Coal	1,591	85%	543	93%
CT or ST Gas	1,520	89%	122	91%
Oil	5,601	54%	1,047	39%
Other	1,071	91%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

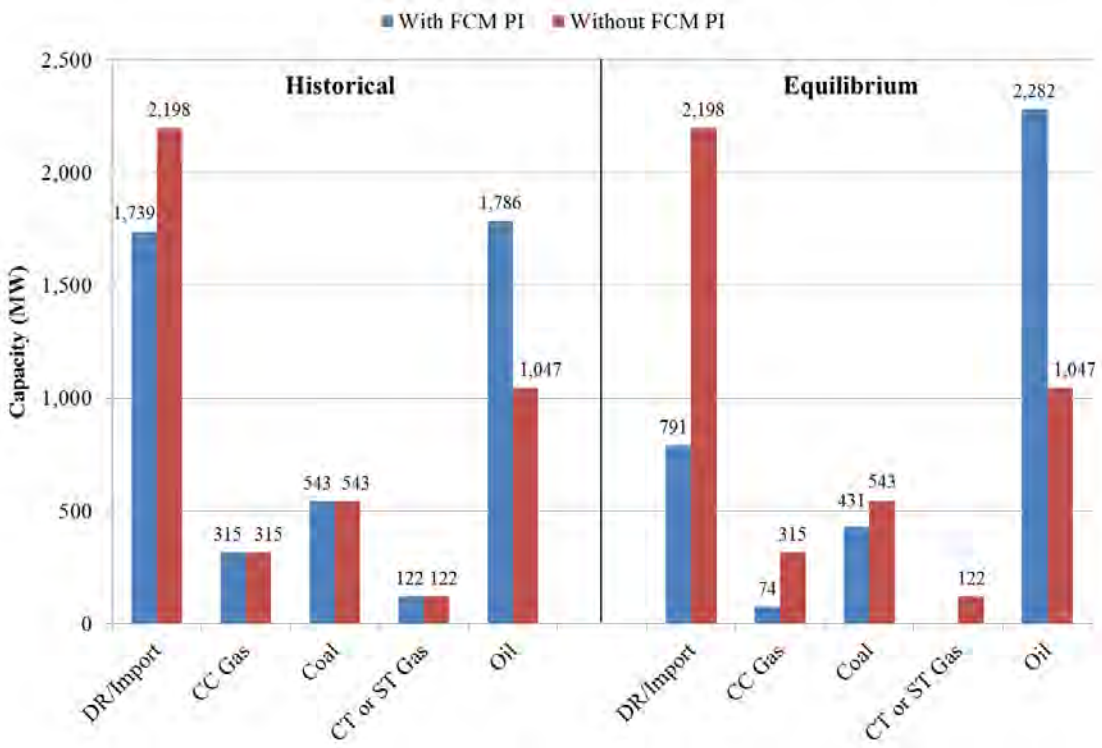
	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,407	0.0%	-1,407	0.0%
Renewables	-7	0.2%	7	NA
Nuclear	0	0.0%	0	NA
CC Gas	241	-0.1%	-241	-48%
Coal	113	1.3%	-113	-3%
CT or ST Gas	122	0.1%	-122	NA
Oil	-1,235	12%	1,235	-25%
Other	0	0.0%	0	NA

Notes:
[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.
[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).
[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine
ST: Steam Turbine.

However, FCM PI also results in shifts among resources that are economic, with higher performing resources clearing due to PI, and lower performing resources becoming non-economic. This effect would tend to result in higher average performance with FCM PI.

As shown in Table 6, the effect of FCM PI on average performance tends to outweigh the effect of the higher quantity of resources, suggesting that these incentives would likely have a positive effect on improving the average performance of resources in the region. For all resource categories but CC Gas, average performance increases with FCM PI. The improvement in performance is most notable with oil-fired resources, which have performance of 66% with FCM PI and 54% without FCM PI.

Figure 11: Non-Economic Capacity by Technology/Fuel Type with and without PI, Historical and Equilibrium (No Gas) Scenarios



Changes to the resource mix introduced by FCM PI under the Historical: No Gas scenario have similar effects to those for the Equilibrium: No Gas scenario, as shown in Figure 11. Under the Historical scenario, there is no surplus economic capacity because the level of FCM PI revenues is reduced with the lower level of expected reserve shortages.[46] Non-economic capacity is higher in the Historical scenario for all resource types except oil-fired capacity. Under historical conditions, there are fewer non-economic

[46] The small quantity of capacity in excess of the ICR in the Historical scenarios and the scenario with no FCM PI arises because only a fraction of the marginal resource is required to meet the ICR. Because our model assumes that a portion of a unit cannot retire, the remaining fraction of the marginal resource is assumed to remain in the market.

oil-fired resources because the performance incentive payments are lower, which in turn reduces the competitive disadvantage that the oil-fired resources with lower performance experience under FCM PI.

Detailed tables for other scenarios are provided in Appendix B, which illustrates the change in resource mix when there are winter gas reserve shortages. As the level of winter reserve shortages increases, the changes in the resource mix introduced by FCM PI tend to be similar across scenarios, although the quantity of non-economic oil-fired resources increases with high gas-related reserve shortages. Although a higher level of winter gas reserve shortages could create financial risks for gas-dependent resources, the ability to develop dual fuel capability provides these resources with an option to mitigate this financial risk to maintain economic operations. Thus, the quantity of economic gas-fired capacity remains unchanged as the level of winter gas reserve shortages increases.

Our analysis does not account for actions resources can take to improve operating performance aside from the opportunity for gas-dependent resources to invest in dual fuel capability. These potential actions range from investments to improve operating efficiency (e.g., heat rates) and ramp rates to improved management and maintenance to reduce forced outages.

The results indicate that FCM PI can improve reliability through shifts in the mix of resources toward more flexible types and toward higher performing resources within individual resource categories. While the analysis captures these changes in performance, it does not provide any information on the technical or operational factors that lead to varying average performance across units in the ISO-NE fleet, or the factors that tend to affect the ability of resources to operate profitably in the ISO-NE markets.

B. Impact on Costs

FCM PI has several potential impacts on costs. In principle, FCM PI can lower production costs if shifts in the mix of resources results in a fleet of resources with higher operating efficiencies (e.g., lower heat rates). Statistical analysis indicates that there is typically a correlation between higher performing resources and more efficient resources, which suggests that FCM PI could contribute to increasing the operating efficiencies of resources in the region's fleet.[47]

FCM PI will also result in additional expenditures, as resources take additional steps to improve performance. As gas-dependent resources invest in dual fuel capability, they will incur both upfront capital costs and annual operating costs. In the Equilibrium: Gas scenario (3 hours winter reserve shortages), upfront capital investment is about $310 million and incremental annual expenditures are $31 million for 6,130 MW of new dual fuel capability. In the Equilibrium: High Gas scenario (6 hours of winter reserve shortages), upfront capital investment is about $462 million and incremental annual expenditures are $46 million for 7,988 MW of new dual fuel capability. These costs reflect the upward sloping supply curve in Figure 3, which results in higher costs for the additional dual fuel capability added when the level of winter gas reserve shortages increases from 3 to 6 hours.

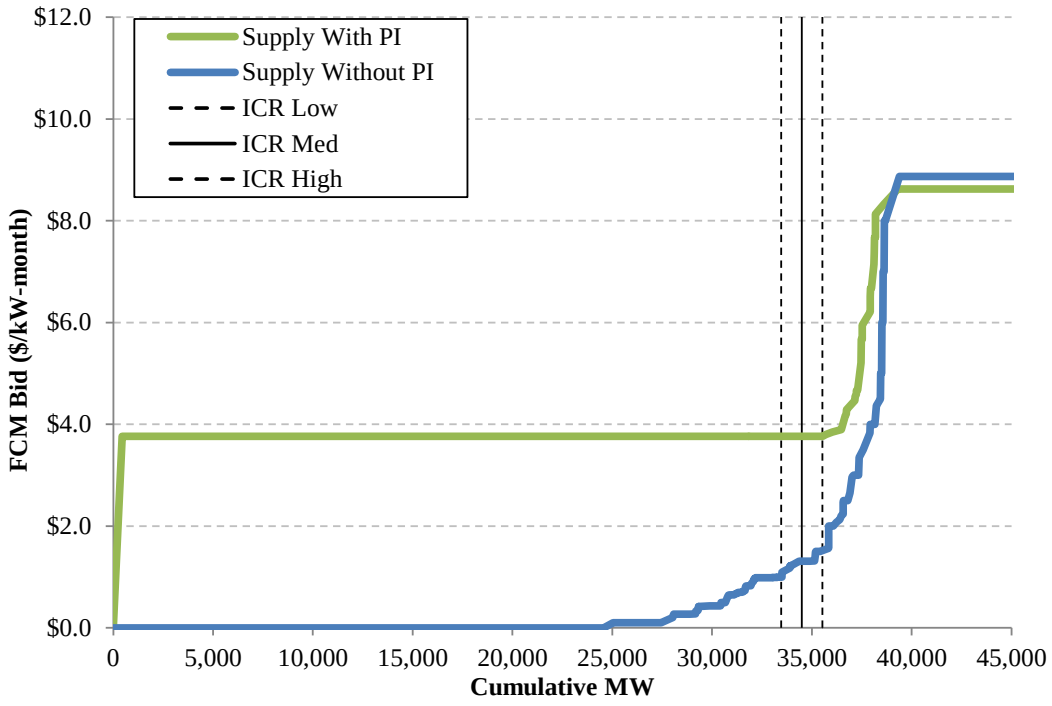
[47] Analysis of the correlation between average performance and heat rate for five resource categories across each of the three types of reserve shortages (historical, peak summer, winter gas) found a negative correlation for 11 of 15 tests, with oil-fired resources showing a positive correlation over all three types of reserve shortages.

Although not an element of our quantitative analysis, FCM PI could delay the date when new generation resources are needed to meet the ICR. Such delays could arise because the additional PI revenues can delay the retirement date for some resources, thus extending the operating lifetime of the region's current resource surplus further into the future.[48] By delaying the date at which new generation resources are required, FCM PI can lower resource costs. Because our analysis quantitatively evaluates outcomes only for 2018/2019, we do not estimate the likelihood that FCM PI delays new investment needed to meet the ICR, the length of such days or the associated cost savings.

C. Impact on Prices and Payments

The introduction of FCM PI will have both direct and indirect effects on many ISO-NE markets, including energy, ancillary services and capacity markets. Figure 12 illustrates the supply of offers from FCM resources with and without FCM PI in the Equilibrium: No Gas scenario. The introduction of FCM PI results in several shifts to the offer curve, including: an upward shift to minimum offers (reflecting the downward FCM PI revenue adjustments for the balancing ratio, $PPR * CSO * BR$), an upward shift in offers from many "marginally economic" units which tend to have relatively poor performance; and a downward shift to the cost of new entry, reflecting performance A greater than the balancing ratio for new resources. At the anticipated ICR of 34,500 MW for 2018/2019, the market clearing prices are $3.76 per kW-month with FCM PI and $1.31 per kW-month without FCM PI.

Figure 12: FCM Offer Curve with and without PI, Near-Term Equilibrium, No Gas Conditions



[48] FCM PI incentives could also induce new resources to enter the market at prices below the cost of new entry under conditions when there is surplus capacity above the ICR.

Table 4 reports the clearing prices for the other scenarios evaluated. Across the six scenarios, the clearing price without FCM PI remains unchanged ($1.31 per kW-month) because variations in the level of reserve shortages have no impact on FCA offers without FCM PI. However, with FCM PI, offers change to reflect anticipated FCM PI revenues. Under Historical scenarios, prices are lower due to the lower level of reserve shortages. This difference is best seen by comparing the scenarios with no gas shortages, with FCA prices at $1.93 per kW-month under historical conditions, and $3.76 per kW-month under near-term equilibrium conditions. Under historical conditions, FCA prices rise with the addition of winter gas reserve shortages hours to $2.55 per kW-month (6.2 total reserve shortage hours) and $2.91 per kW-month (with 9.2 total reserve shortage hours). Under equilibrium conditions, FCA prices vary across scenarios from $3.76 per kW-month to $4.49 per kW-month for the two approaches to modeling the high gas scenario equilibrium.

While FCM PI increases FCA offers for most existing resources, offers from new resources could decrease with the introduction of FCM PI if anticipated performance exceeds the balancing ratio. Whether this occurs, in practice, will depend on project developers' expectations about the performance of proposed projects, given various technological, operational and geographic factors. Moreover, FCM PI is designed to encourage development of those new resources with high performance.

To gauge the potential effect of FCM PI on the FCA offers from new entry, a benchmark group of gas-fired combined cycle and combustion turbine generation facilities recently developed in the ISO-NE region was chosen to represent new resource performance. The average performance of each group of resources was used to estimate the impact of FCM PI on the FCA offers from new entry for each technology. As shown in Table 7, which reports the offers from new combined cycle and combustion turbine technologies, FCM PI would likely reduce FCA offers from new resources below the cost of new entry (CONE) under current market rules, reflecting average performance by the benchmark group that exceeds the average balancing ratio in most cases.[49]

Table 7: Offers from New Entry with and without FCM PI

		FCM PI, Historical Scenario			FCM PI, Near-Term Equilibrium Scenario		
	Current Rules (No FCM PI)	No Gas Shortages	Gas Shortages	High Gas Shortages	No Gas Shortages	Gas Shortages	High Gas Shortages
Combined Cycle	$8.87	$8.67	$8.08	$7.49	$8.62	$8.09	$7.50
Combustion Turbine	$13.42	$13.34	$13.02	$12.70	$13.55	$13.20	$12.88

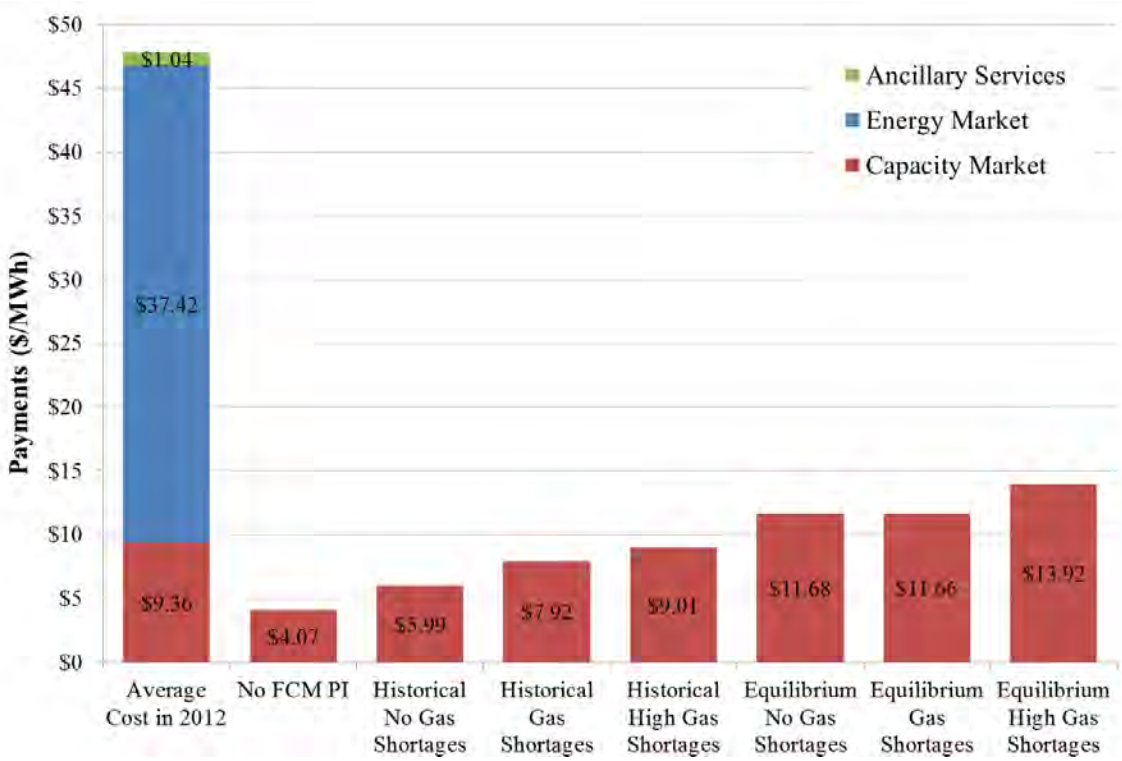
As shown by the scenarios with no gas shortages, when future reserve shortages are driven largely by summer peak conditions, the adjustments tend to be relatively small. However, when future reserve shortages are driven by winter gas supply limitations, the adjustments tend to be relatively large, reflecting the fact that performance of these flexible resources tends to be high during tight winter gas periods. For example, for a new combined cycle unit in the near-term equilibrium, these adjustments are $1.37 per kW-month in the Equilibrium: High Gas scenario. Because the level of adjustments in these Equilibrium scenarios reflects a level of reserve shortages with over 1 GW of surplus capacity, downward

[49] This conclusion does not reflect any adjustments due to financial risk.

adjustments in subsequent years (or the long-term equilibrium) could be greater as the quantity of surplus capacity decreases, and the expected level of reserve shortages increases.

Payments by load follow changes in FCM prices. Consequently, the introduction of FCM PI increases aggregate payments and payments per MWh compared to current rules. Figure 13 shows payments per MWh with and without FCM PI, and also compares these to current payment levels (as reflected in average 2012 payments). Compared to 2012 FCM payments, which reflect the administratively set price floors,[50] payments with FCM PI are lower than current levels under the Historical scenarios (by 4% to 36%, as shown in Table 4), but are higher than current levels under the Equilibrium scenarios (by 25% to 49%). When measured relative to all wholesale electricity market payments, these changes represent an even smaller fraction. For example, under the Equilibrium: No Gas Scenario, FCM payments are $11.68 per MWh with FCM PI compared to $9.36 per MWh in 2012. While this reflects a 25% increase in FCM payments, this increase is only 5% of total 2012 wholesale energy payments (of $47.82 per MWh).

Figure 13: Customer Payments Under Various Market Rules and Scenarios



Changes in energy market payments will arise due to changes in the quantity and mix of resources participating in the ISO-NE markets. These impacts are not quantitatively analyzed, although several observations can be made. First, when FCM PI results in surplus capacity above the ICR, this capacity would likely lower energy market prices, all else equal. The magnitude of this effect will depend

[50] This reflects the prorating of capacity supply obligations.

on energy market offers from those resources that remain in ISO-NE markets that would otherwise have exited the market, absent FCM PI. Surplus capacity will also diminish the level of reserve shortages, which in turn reduces RCPF payments. A simplified calculation indicates that the reduction in RCPF payments could range from $63 to $265 million.[51]

Second, to the extent that FCM PI encourages participation of higher performing units, including units with more competitive heat rates, then this greater performance would flow through to customers in lower energy market prices.

The results indicate that FCM PI would likely raise FCA prices under most circumstances when prices clear below the cost of new entry. However, FCM PI would likely lower offers from new entry due to the incremental revenues provided under FCM, particularly as these resources are likely to (and under FCM PI have incentives to) be high performing resources. Increases in FCM payments under the equilibrium scenarios (relative to 2012 levels) would reflect a 5% to 10% increase in 2012 wholesale energy payments.[52]

D. Sensitivity to Model Assumptions

The analysis of FCM PI relies on many modeling assumptions. To test the robustness of model results, in this section, we consider the sensitivity of results to three modeling assumptions:

1. Risk factors
2. Environmental costs
3. Restrictions on incremental dual fuel capability for new resources

Tables 8 to 10 report the results of these sensitivities. Each scenario is evaluated under near-term Equilibrium conditions. In general, conclusions about the impact of FCM PI do not change materially as a consequence of changes to the assumptions tested.

[51] This calculation assumes: reserve shortages levels reported in Table 4; load of 20,000 MW during winter gas reserve shortages and 26,000 MW during summer peak reserve shortages; and RCPF values of either $250 per MWh (for 30-minute local reserves) or $850 per MWh (for 10-minute system reserves). The reduction in payments ranges from $62.6 to $78.0 million at the $250 per MWh RCPF, and $212.9 to $265.2 million at the $850 MWh RCPF across the range of reserve shortage hours used in the Equilibrium scenarios.

[52] This reflects an increase in FCM payments of $2.30 per MWh (Equilibrium: Gas) and $4.56 per MWh (Equilibrium: High Gas) relative to a total payment of $47.82 per MWh.

Table 8: Market Outcomes for Risk Factor Sensitivity Analysis

	With Risk Factors		Without Risk Factors
	Current Rules (No FCM PI)	FCM PI	FCM PI
FCA Clearing Price ($/kW-month)	$1.31	$3.76	$3.76
Total FCM Payments ($bil)	$0.54	$1.56	$1.56
Avg Payments FCM ($/MWh)	$4.07	$11.68	$11.68
% Change Relative to 2012 Level	-57%	25%	25%

As seen in Table 8, elimination of the risk factor results in no change in outcomes for the Equilibrium: No Gas Scenario. This result arises because eliminating the risk factor does not change either the marginal unit that clears the FCM (which could occur if the risk factors affected the order of resource offers in the offer curve), or the offer of the marginal unit offer. Thus, although many resources incorporate a risk factor into their offers (as shown in Figure 6), risk factors do not affect the clearing price. .

Table 9: Market Outcomes for Environmental Cost Sensitivity Analysis

	Without Environmental Costs		With Environmental Costs	
	Current Rules (No FCM PI)	FCM PI	Current Rules (No FCM PI)	FCM PI
FCA Clearing Price ($/kW-month)	$1.31	$3.76	$2.00	$4.17
Total FCM Payments ($bil)	$0.54	$1.56	$0.83	$1.73
Avg Payments FCM ($/MWh)	$4.07	$11.68	$6.20	$12.95
% Change Relative to 2012 Level	-57%	25%	-34%	38%

The introduction of costs to comply with environmental regulations (Section §316(b) regulation of cooling water intake structures) increases the FCA clearing prices with and without PI. As shown in Table 9, under current market rules, FCA prices increase from by $0.69 per kW-month (from $1.31 per kW-month to $2.00 per kW-month) due to the higher FCA offers submitted by resources that need to comply with these regulations. Under FCM PI, FCA prices increase by $0.41 per kW-month (from $3.76 per kW-month to $4.17 per kW-month). Thus, FCM PI has a relatively similar impact on FCA clearing prices with and without the additional environmental costs.

Table 10: Market Outcomes for Dual Fuel Restrictions Sensitivity Analysis

	Equilibrium, High Gas		
	Current Rules (No FCM PI)	FCM PI	FCM PI Restricted DF
FCA Clearing Price ($/kW-month)	$1.31	$4.49	$4.49
Total FCM Payments ($bil)	$0.54	$1.86	$1.86
Avg Payments FCM ($/MWh)	$4.07	$13.92	$13.92
% Change Relative to 2012 Level	-57%	49%	49%

The last sensitivity evaluates how limits on the ability of gas-dependent resources to develop dual fuel capability affect market outcomes. Such limits could occur due to a variety of factors, such as restrictions on environmental permits needed to burn alternative (non-gas) fuels. To evaluate these impacts, dual fuel adoption is limited to those facilities with dual fuel capability that is currently decommissioned. Table 10 shows that, under Equilibrium: High Gas conditions, FCA prices with PI remain unchanged at $4.49 per kW-month with the dual fuel restrictions. Thus, the restrictions do not affect FCA prices. However, with these restrictions, the quantity of dual fuel resources falls from 13,595 MW to 8,906 MW, a reduction of 4,689 MW. Thus, while restrictions on dual fuel capability may not affect the FCA price, they could affect the reliability benefits achieved by FCM PI.

VII. EVALUATION OF OTHER OPTIONS

Our analysis considers an alternative proposal, offered by NRG, to ISO-NE's proposed FCM PI.[53] ISO-NE identified this alternative for evaluation, in part, because it was developed in sufficient detail early enough in the stakeholder process that it could be analyzed in the context of the initiative proposed by ISO-NE. This proposal includes multiple elements, which we describe below.[54] Following these descriptions, we provide quantitative and qualitative assessment of this alternative in comparison to FCM PI.

A. NRG Alternative

NRG has proposed an alternative to FCM PI that includes several elements.[55]

[53] Although other stakeholders offered alternative proposals, ISO-NE viewed these proposals as insufficiently developed to warrant detailed quantitative analysis.

[54] NRG, "FCM Performance Incentives – An Alternative Proposal," November 16, 2012; Fuller, Pete, NRG, "Market Reform Proposal," NEPOOL Markets Committee, August 7, 2013. Available at http://www.iso-ne.com /committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/nov162012/a02_nrg_alternative_proposal_11_16_12_ .pdf and http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/aug7892013 /a10d_nrg_presentation_08_07_13.ppt.

[55] NRG also proposed certain changes to market rules regarding the type of costs that can be included in FCA offers for existing resources. We did not evaluate these changes because they were considered outside the scope of analysis appropriate for the Impact Assessment.

First, current RCPF's would be increased by $5,455 per MWh above current levels. Thus, energy market prices could rise as high as $6,305 per MWh during reserve shortages.[56]

Second, the Peak Energy Rent (PER) Adjustment would be eliminated. Current FCM rules include a PER Adjustment that reduces FCM payments whenever prices exceed a predetermined price threshold. By eliminating the PER Adjustment, the change in RCPFs results in changes in energy market revenues that are not also offset by subsequent PER Adjustments (which are fixed for each MW of capacity). However, these additional energy revenues streams would affect each unit's going forward cost, which in turn would result in reductions in FCM offers. Consequently, under the NRG Alternative, these PER Adjustments would be eliminated.[57]

Third, an "EFOR-based" mechanism would be implemented as part of the FCM. This new mechanism would adjust actual FCM payments received by individual resources such that (1) aggregate FCM revenues would remain unchanged (i.e., revenue-neutral once the FCA has cleared), and (2) each unit's payments would adjust upward or downward depending on its how its *availability* compares to a resource- or unit-specific benchmark.

The "EFOR-based" mechanism includes several components.[58] First, performance would be based on availability metrics reflecting performance during high demand periods, which could reflect a predetermined number of peak load hours (e.g., the top 100 highest load hours) or reserve shortages. These alternatives would have different implications for when performance is measured. Reserve shortages can occur during periods of peak load, but they can also occur during other periods, including winter periods or even shoulder seasons (when maintenance may reduce the supply of available resources). Consequently, reserve shortage hours are typically less predictable than peak load hours, which are typically concentrated during summer periods. An EFOR-based mechanism can also differentially weight hourly availability based on each hour's "importance" for reliability.[59] In other respects, the availability measurement would follow the same type of procedures used in calculating the Effective Forced Outage Rate (EFOR).[60] Second, the FCA (and subsequent reconfiguration auctions) would establish the aggregate payments from load to resources.

Third, FCM payments to each unit would be adjusted based on each unit's availability relative to a pre-determined benchmark. In principle, the benchmark could be based on unit-specific or class-

[56] Note that the NRG Alternative did not specify the value of RCPF assumed, but rather tied the value to the proposed PPR under FCM PI. The current RCPF for ten minute non-spinning reserve (TMNSR) is $850 per MWh, which would rise to $6,305 per MWh with the proposed increase. Other RCPFs would also rise: the system thirty minute operating reserve (TMOR) RCPF would rise to $5,955 per MWh and the local TMOR would be $5,655 per MWh.

[57] If PER Adjustments remain in place with the proposed increase in RCPF values, the financial outcome would be similar to FCM PI. Both the PER Adjustments and PI balancing ratio adjustments operate similar to a financial option, in which resources must pay load whenever certain conditions occur. While the specifics of these options differ somewhat, they are similar enough that an NRG Alternative with PER Adjustments would have many similarities to FCM PI.

[58] *See* Fuller, Pete, NRG, "Market Reform Proposal," NEPOOL Markets Committee, August 7, 2013, slides 5-10.

[59] For example, "UCAP" rules used in ISO-NE's earlier capacity markets adjusted capacity based on an EFOR-based mechanism that weighted availability differentially across hours of the year.

[60] North American Electric Reliability Corporation (NERC), "GADS Data Reporting Instructions," Appendix F – Performance Indexes and Equations, January 2012.

specific historical availability. The assessment presented below assumes a unit-specific benchmark. The change in FCM payment to each resource would be based on the following formula:

$$\Delta FCM\ Payment = MW\ Deviation * FCM\ Price * Marginal\ Multiplier$$

The *FCM Price* would equal the clearing price from the appropriate auction, and the *Marginal Multiplier* is a fixed multiplier that shifts revenue adjustments upwards or downwards. Each unit's *MW Deviation* would reflect differences between its actual and baseline share of available system capacity, which would reflect its availability (relative to its unit-specific benchmark) as well as the availability of all other units in the system (relative to their respective benchmark availability). NRG materials provide further details.[61]

This analysis considers two aspects of the NRG Alternative:

1. $5,455 RCPF Increase + Elimination of PER
2. EFOR-based mechanism

These two elements of the NRG Alternative are evaluated separately to simplify the assessment. The analysis of the NRG Alternative is performed within the same model used to evaluate FCM PI. First, net energy market revenues are adjusted for the elevated prices during reserve shortages and the level of reserve shortages. When comparing the NRG Alternative to FCM PI, we assume the same level of reserve shortage hours; this assumption arises from the conclusion (discussed further below) that the two models provide comparable levels of reliability (assuming that the PPR and RCPF increases are set at the same level). Thus, we assume that there are no resources with energy market offers above the current RCPF values that could mitigate the reserve shortage. Next, FCM revenues are adjusted downward to reflect reduced FCA offers given the reduction in GFC from the additional energy market revenues.

B. Analysis of the NRG Alternative: $5,455 RCPF Increase + Elimination of PER Adjustment

Under both FCM PI and the NRG Alternative, actions to improve resource performance are induced through incremental revenues to resources that supply during reserve shortages. Thus, because both FCM PI and a $5,455 increase in the RCPF will have similar market outcomes and marginal incentives, the anticipated reliability benefits between these proposals should be quite similar. Thus, for the most part, the reliability impacts identified in Section VI.A would be expected under the NRG Alternative, as well as FCM PI.

Table 11 and Figure 14 provide a comparison of FCM clearing prices, energy market payments and total payments by load between FCM PI and the NRG Alternative for the Equilibrium: No Gas scenario. Under the NRG Alternative, FCA offers are reduced to reflect the increase in energy market revenues, which reduces each unit's going forward cost. As a result of these lower offers, the FCM clearing price will be lower than clearing prices under current rules or FCM PI. In fact, in the Equilibrium: No Gas scenario, under the NRG Alternative, the FCA clears at a price of zero. This means that there are sufficient economic resources that do not need FCM revenues to maintain profitable

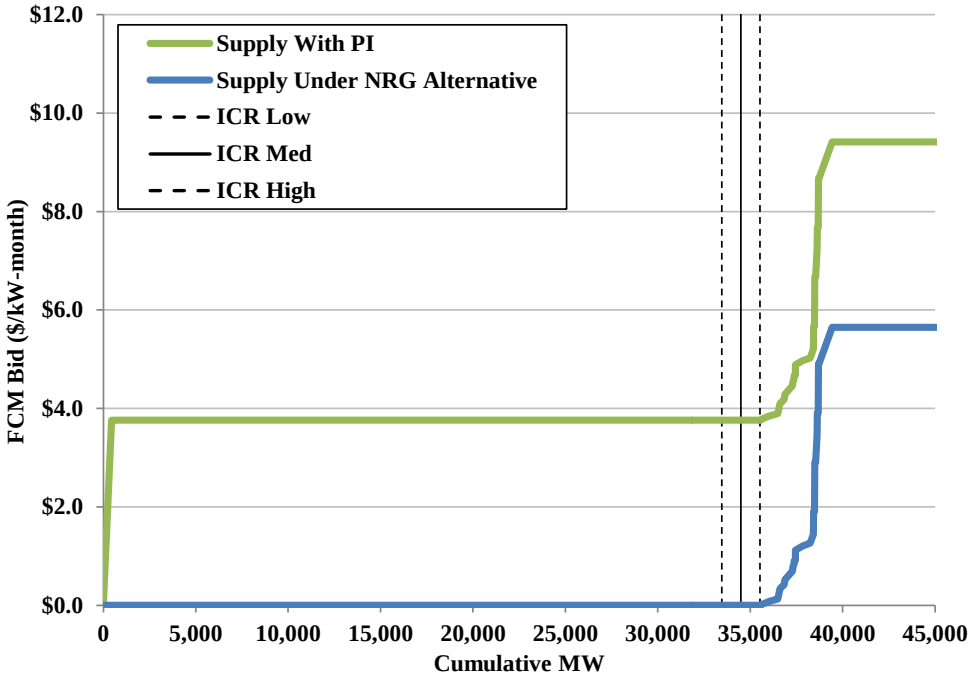
[61] *See* Fuller, Pete, NRG, "Market Reform Proposal," NEPOOL Markets Committee, August 7, 2013, slides 7-8.

operation (i.e., resources with negative going forward costs) to meet the ICR. In practice, if this occurs, market outcomes could reflect bidding behavior in which market participants submit FCA offers that exceed the resource GFC, resulting in a clearing price that is greater than zero.[62] We do not model bidder behavior under these circumstances. To the extent that the FCA cleared with positive prices under this scenario, payments under the NRG Alternative would exceed those under FCM PI by the FCM payments corresponding to this positive FCA price.

Table 11: Market Outcomes with FCM PI and NRG Alternative, Equilibrium: No Gas Scenario

	With FCM PI	With NRG Alternative	Difference
FCA Clearing Price	$3.76	$0.00	($3.76)
FCM Payments ($ billion)	$1.56	$0.00	($1.56)
Additional RCPF Payments ($ billion)	$0.00	$1.56	$1.56
Total Payments to Suppliers ($ billion)	**$1.56**	**$1.56**	**$0.00**

Figure 14: FCM Offer Curve, FCM PI versus NRG Alternative

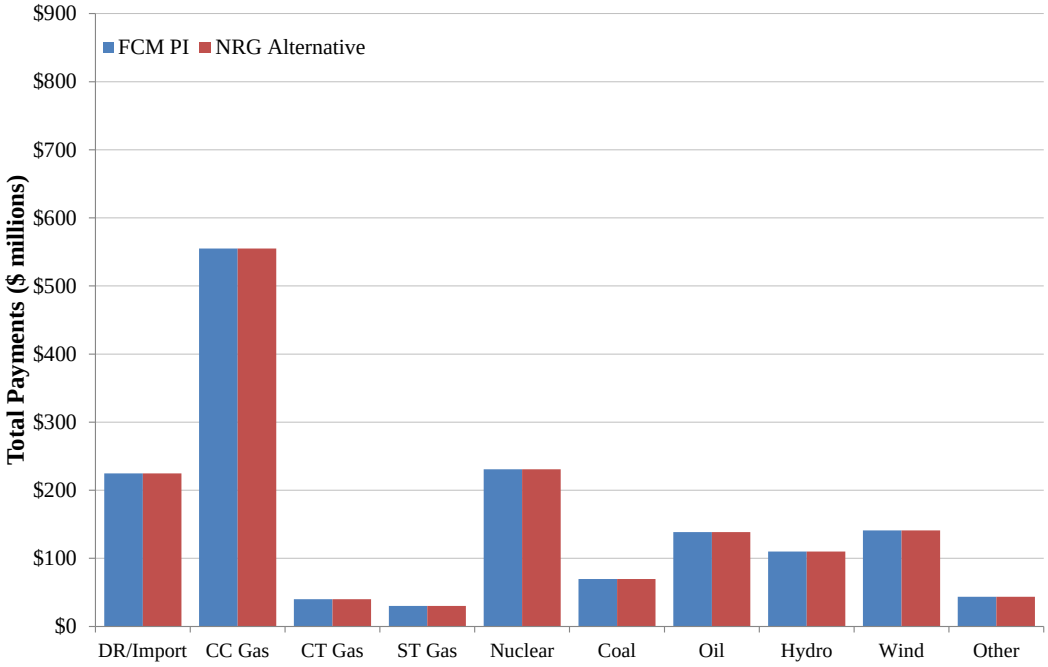


[62] Offers could reflect strategic bidding behavior in an effort to achieve a positive FCA price, or opportunity costs of taking on a CSO (e.g., administrative costs or compliance risk).

Table 11 shows the total FCM payments and the changes in energy market payments, as reflected in increased RCPF values, under FCM PI and NRG Alternative. Under the Equilibrium: No Gas scenario, expected payments are the same under the two alternatives. The NRG Alternative results in additional energy (RCPF) market payments of $1.56 billion, but FCM payments equal zero. By contrast, FCM PI results in FCM payments of $1.56 billion but no change in energy market payments. Thus, both alternatives have the same impact on payments in the FCM and energy markets.

While expected payments are the same under FCM PI and the NRG Alternative, actual payments can differ depending on the actual level of reserve shortages. Consider the three possible outcomes in Figures 15, 16 and 17, which show the payments made under each approach to different resource types for different levels of actual reserve shortages. Figure 15 shows that payments under the two alternatives are the same when the actual and expected levels of reserve shortages are the same. However, Figures 16 and 17 show that when the actual and expected levels of reserve shortages differ, payments under the two models will diverge.[63] These figures illustrate two important differences between the programs.

Figure 15: Total Payments Under FCM PI and NRG Alternative by Fuel Type, Actual Reserve Shortages Equals Expected Reserve Shortages



First, there is less variation in payments under FCM PI than the NRG Alternative. For each resource category, the change in payments when actual reserves shortage levels differ from expectations is greater under the NRG Alternative than FCM PI. Thus, in aggregate, the NRG Alternative results in greater volatility in payments by load and to suppliers. This greater volatility translates into a higher level of aggregate financial risk for both customers (load) and resources, although, as discussed below, the implications for individual resources vary depending on resource-specific characteristics.

[63] These scenarios assume 9, 5, and 15 reserve shortage hours for Figures 15, 16 and 17, respectively.

Figure 16: Total Payments Under FCM PI and NRG Alternative by Fuel Type, Actual Reserve Shortages Less Than Expected Reserve Shortages

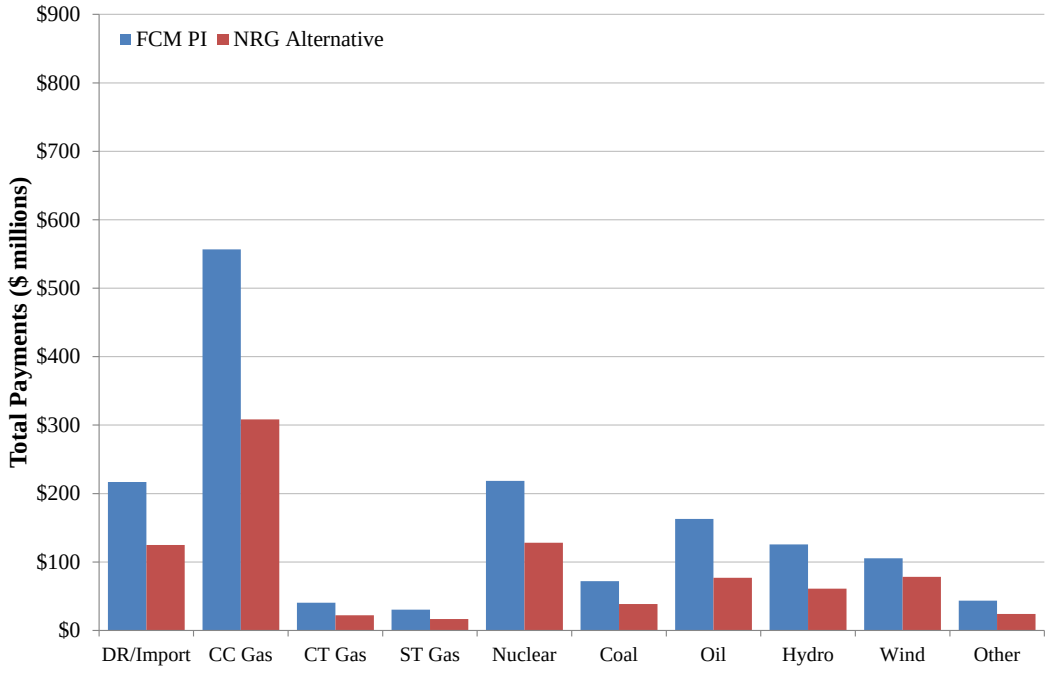
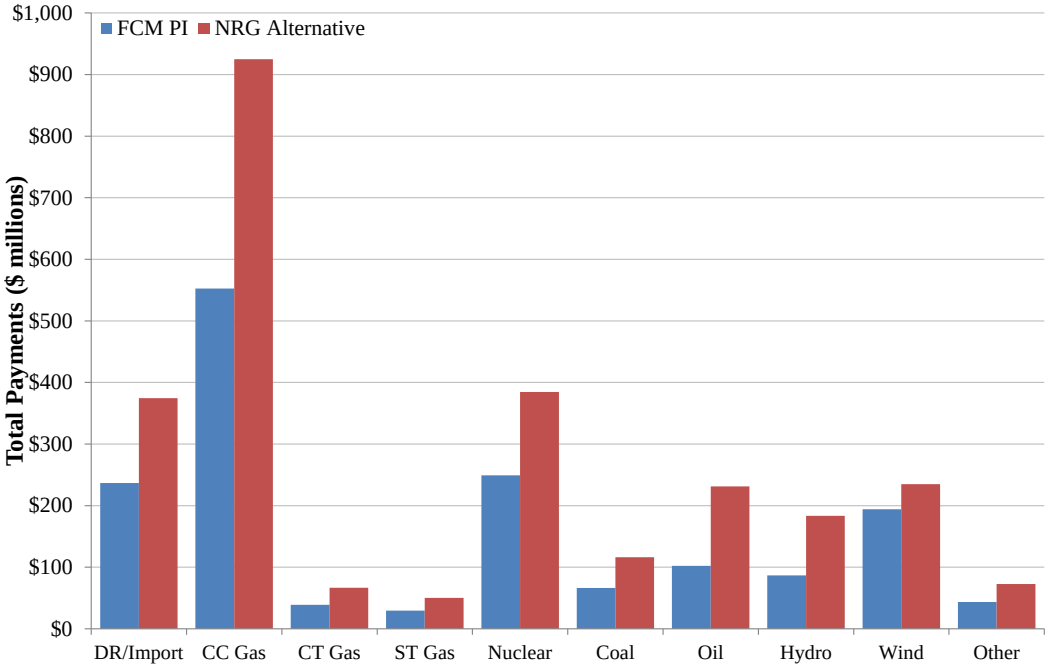


Figure 17: Total Payments Under FCM PI and NRG Alternative by Fuel Type, Actual Reserve Shortages Greater Than Expected Reserve Shortages



Second, under the NRG Alternative, all resources receive higher payments as the level of reserve shortages increases. By contrast, payments under FCM PI can increase or decrease with a higher level of reserve shortages depending on whether the resource is a high or low performer. For example, payments to nuclear resources, with performance levels typically above the balancing ratio, increase from $218 million to $249 million as reserve shortage levels increase (from Low to High). By contrast payments to oil resources decline from $163 to $102 as reserve shortage levels increase (from Low to High).

Figures 15 to 17 unmask some important differences in payment volatility between the two alternatives that are relevant for individual resources. Figure 18 shows the payments made under FCM PI and the NRG Alternative to illustrative units under varying levels of reserve shortages. The figures (calculated for Historical conditions) show that for individual resources, the implications of uncertainty in reserve shortages vary significantly depending on the resource's performance. For high performing units (90-100%), payments vary little under FCM PI, whereas they vary by nearly a factor of three under the NRG Alternative. For average performing units (60-70% performance), variation is still less under FCM PI than the NRG Alternative, although the degree of variation is of the same order of magnitude. However, for low performing resources (10-20%), variation is greater under FCM PI, and the resource faces the risk of negative net FCM payments. Thus, while FCM PI results in less financial risk for high performing resources, financial risk is greater for low performing resources relative to the NRG Alternative.

C. Analysis of the NRG Alternative: EFOR-based mechanism

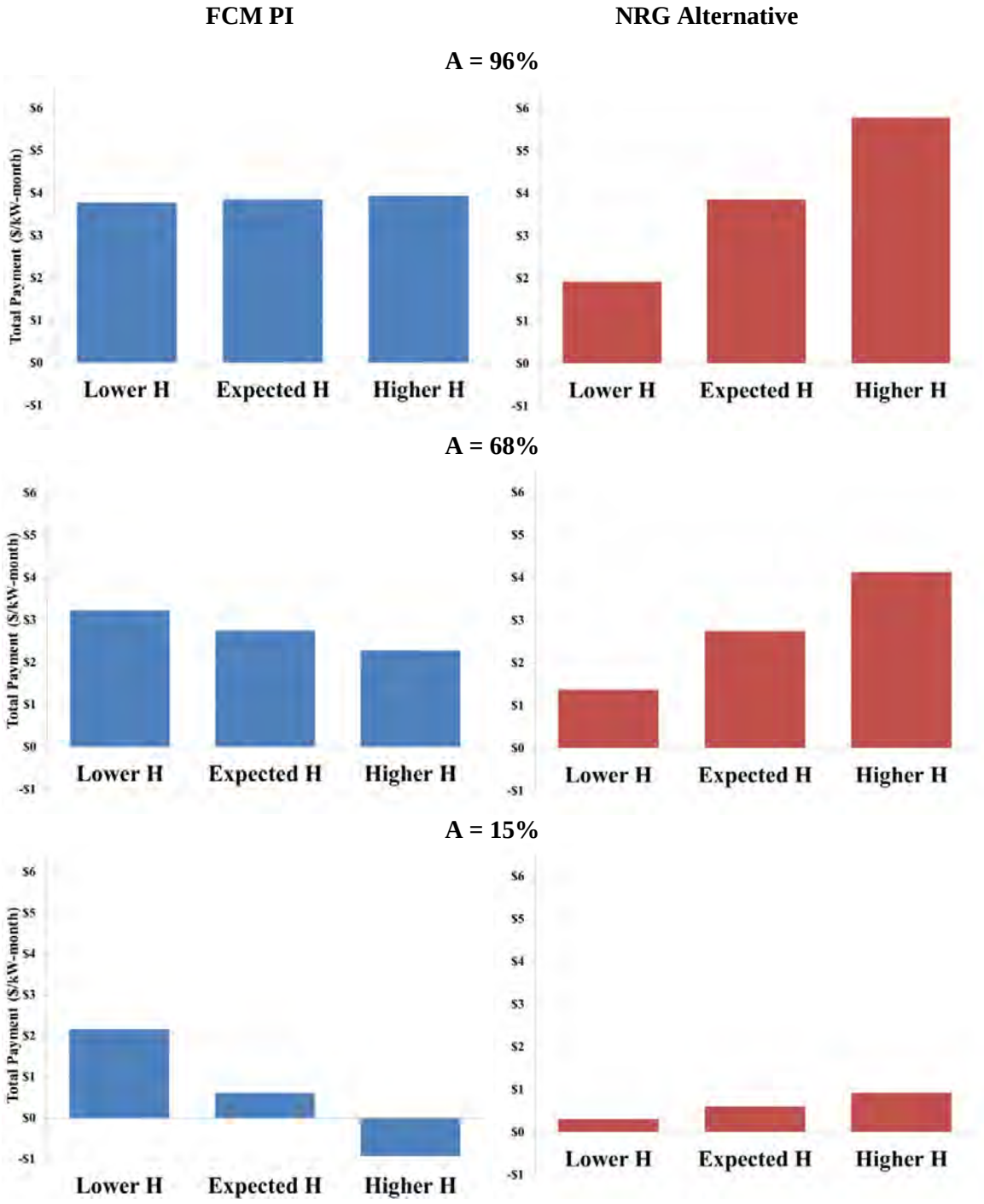
The introduction of the EFOR-based mechanism (in addition to the $5,455 RCPF increase and the elimination of the PER Adjustments) could have implications for both reliability and market outcomes. From a reliability standpoint, the introduction of EFOR-based incentives for availability in addition to the increase in RCPFs of $5,455 per MWh would further enhance the incentives to improve performance. The incremental incentives would be limited to actions that improved *availability*, but would not affect other sorts of operational performance. Our analysis does not consider any quantitative benefits that would arise from these additional incentives.

In terms of potential market outcomes, impacts would depend strongly on assumptions about expected future performance. The EFOR-based mechanism could affect resource offers depending on the expectations of each market participant regarding future resource availability compared to the benchmark against which each resource's availability is measured.

Under the NRG Alternative, benchmarks would be set at the individual resource level based on historical availability. Under this rule, the most reasonable assumption about a market participant's expectation about future availability is that it will reflect past historical availability. However, if resource benchmarks are also based on historical availability, then market participants' expectations about future availability would equal the benchmark availability. Consequently, market participants would not expect to win or lose as a consequence of the rule, and would not adjust their FCM offers, leaving FCA prices unchanged.

If benchmarks were set based on broader resource categories, then resources would find it optimal to adjust their offers upward or downward depending on whether their past availability was higher or lower than their category average. We have not quantitatively evaluated such a proposal.

Figure 18: Payments to Illustrative Individual Units Under FCM PI and the NRG Alternative



VIII. CONCLUSIONS

The assessment of ISO-NE's FCM PI proposal has identified a range of changes to reliability, costs and payments by load. The assessment identifies many types of potential impacts and analyzes these through quantitative estimates and qualitative assessments.

These results indicate that FCM PI would likely result in improvements to reliability through several mechanisms, including: increases in the quantity of resources participating in the ISO-NE markets; investments to improve resource performance, including investments to develop dual fuel capability at gas-dependent resources; and changes to the mix of resources that remain in the ISO-NE fleet and are used to satisfy the region's Installed Capacity Requirement. Reliability benefits would likely be greatest in summer peak load periods (from surplus capacity) and in winter months, particularly during periods of high gas demand (from surplus capacity and dual fuel investments).

FCM PI would result in a variety of cost impacts, including changes to production costs, new investments to improve performance, and potential delays in the timing of when new generation resources are required to meet the ICR. Our analysis does not quantitatively estimate the net impact of these various effects.

The results indicate that FCM PI would likely raise FCA prices under most circumstances when prices clear below the cost of new entry (under current market rules). However, FCM PI would likely lower offers from new entry due to the incremental revenues provided under FCM PI, particularly as these resources are likely to (and under FCM PI have incentives to) be high performing resources. Consequently, in the long-run, FCM PI could lower FCA prices as the market nears an equilibrium in which new generation resources are required. Increases in FCM payments under the equilibrium scenarios would reflect a 5% to 10% increase in 2012 wholesale energy payments.

The key element of the NRG Alternative – the $5,455 increase in RCPF values – would provide comparable reliability benefits and expected costs, but have different implications for the financial risk born by suppliers and load given the variation in aggregate payments under the NRG Alternative compared to FCM PI. FCM PI would reduce variation in total FCM payments, which would be not exceed the prices established in the FCA. Under the NRG Alternative, FCM payments would vary depending on system conditions (the level of reserve shortages, and loads during these shortages) during the commitment period.

APPENDIX A: METHODOLOGICAL APPROACH AND DATA ASSUMPTIONS

A. Going-Forward Costs

Going-forward costs are calculated using the following formula:

$$Offer(FCM) = \frac{GFC + RF}{Capacity * 12} = \frac{FC + I - Q*\left(P - VC - HR*P_{Fuel}\right) + RF}{Capacity * 12}$$

Fixed costs (*FC*) and investments (*I*) are offset by the remainder of the equation, reflecting net energy and ancillary services market revenues, where *Q* is the quantity of output sold, *P* is the average energy market price, *VC* is the non-fuel variable costs, *HR* is the unit's heat rate, and P_{Fuel} is the fuel price. *RF* is the risk factor. *Capacity* reflects the resources Summer Qualified Capacity, the quantity (in MW) of each resource's nameplate capacity that is eligible to bid into the FCA (for the summer months). The individual elements of the above formula are calculated using the following data and assumptions.

Fixed Costs

Fixed O&M costs for each unit are reported in SNL Financial for 2011. These values are adjusted to reflect a $/kW-year cost and applied to each unit's Summer Qualified Capacity as reported in FCA 7. Values for units that do not have reported data in SNL are imputed based on category averages for similar units based on unit size, vintage, and fuel type. For imputed fixed costs, an additional random noise factor of 0-1% is added, to avoid a situation where multiple units have the same GFC. Costs for certain resources were adjusted in light of resource- or region-specific information about costs from a variety of sources.

Investment Costs

Investment costs are broken into two components: costs to install and operate dual-fuel fired capability and costs to install and operate equipment for environmental compliance. Other investments needed for resources to continue operations are not considered. Appendix C provides detail on the methodology, data, and assumptions used for dual-fuel investment decisions.

The need for environmental compliance equipment installation is based on Analysis Group's review of prior ISO-NE analyses of which generators may face CWA Section §316(b) regulations. The analysis assumes that 50% of the overall capacity potentially at risk actually faces additional Section §316(b) requirements, including all coal units, the two oldest nuclear plants, and the oldest oil units. In total, 19 generators are assumed to face additional environmental investments to continue operation.

Fossil fuel units facing compliance costs are assessed a 1.3% penalty to heat rate and a 3.4% penalty to MW capacity. For nuclear generators, there is a 1.5% penalty to heat rate and 1.0% penalty to MW capacity. Depreciation of investment costs is based on the useful life remaining of the asset, using

ISO-NE Market Rule guidance and the Offer Review Trigger Price (ORTP) study performed by Shaw Consultants International, Inc.[64] In addition, a depreciation tax shield is assumed on investment costs, of:

$$Corporate\ Tax\ Rate * \left(\frac{Upfront\ Costs}{5\ years}\right).$$

A discount rate of 5.67% is used for calculating investment costs, representing the Weighted Average Cost of Capital (WACC) methodology provided in Shaw Consultants' ORTP study, updated to reflect current market rates.

Variable Costs

Variable O&M costs for each unit are reported in SNL Financial for 2011. These values are adjusted to reflect a $/MWh cost and applied to each unit's average of 2010-2012 actual net generation as reported by ISO-NE. Values for units that do not have reported data in SNL are imputed based on category averages for similar units based on unit size, vintage, and fuel type.

Fuel expenditures are calculated using unit heat rates and fuel costs. Unit heat rates are based on SNL Financial data for 2011. Values for units that do not have reported data in SNL are imputed based on category averages for similar units based on unit size, vintage, and fuel type.

Natural gas prices are based on NYMEX Henry Hub natural gas futures for 2018-2019, and are then adjusted to account for a basis differential reflecting the difference in prices between Henry Hub and New England hub prices over the last three years. Oil and coal price forecasts are delivered fuel prices to electricity generators in the New England region from EIA's 2013 Annual Energy Outlook. Nuclear fuel prices reflect the reported unit prices from SNL for 2011, with no anticipated change.

Revenues

LMPs are estimated based on a regression of unit-level average annual LMPs on year-end natural gas prices. This specification is consistent with the assumption that gas-fired resources are the marginal units during most hours in recent years. A separate regression is run for each technology/fuel type, with unit-level fixed effects. The results of these regressions are used to forecast expected average prices for each unit for the 2018/2019 commitment year. Average LMP estimates are calculated using the technology/fuel-specific parameters for gas prices, forecast gas prices, and each unit's individual fixed effect. Through this approach, both fuel-level and unit-level heterogeneity are captured in the LMP model. ISO-NE LMP data from 2007-2012 are used in the regression model.

Ancillary service payments are collected from ISO-NE data for NCPC payments, regulation payments, and real-time reserve payments. The 2018-2019 ancillary payments per MWh for each unit are assumed to be the average of actual payments per MWh over 2010-2012.

[64] While new ORTP values developed by Brattle Group and Sargent & Lundy are used, the financial assumptions used in assessing capital investments based on the prior Shaw ORTP study.

Non-Reported Revenues

All cogeneration plants, and plants running on biomass, hydro, solar, fuel cells, or wind are assumed to have a GFC equal to zero. This is based on the expectation that these plants will have significant non-energy-market revenues or credits that are not captured in the data sources used.

Other Inputs

The inflation index used was the Federal Reserve Board's prediction of long-run PCE inflation, 2.0%.[65] Details on the risk factor methodology and calculation can be found in the main text of the report in Section V.F.

Going-Forward Costs for New Entry

New unit going-forward cost estimates are taken from the study of Offer Review Trigger Prices (ORTP) performed by the Brattle Group and Sargent & Lundy.[66] The model only considers new entry for combined cycle and combustion turbine resources, although the study evaluates other resource types.

B. Operational Performance

Data used to estimate operational performance *A* and balancing ratio *BR* is as follows:

1. Average Historical Conditions: Estimates reflect performance during all system reserve shortages that occurred during the period 2010 to 2012.[67]
2. Peak (Summer) Conditions: Estimates reflect performance during all system reserve shortages that occurred during the months of June, July and August during the period 2010 to 2012.
3. Winter Peak Conditions: Estimates reflect performance during all hours when the balancing ratio exceeded 0.6 during winter months in the years 2010 to 2012.[68]

[65] Federal Reserve Board, "Economic Projections of Federal Reserve Board Members and Federal Reserve Board Presidents, March 2013," March 20, 2013. Available at: http://www.federalreserve.gov/monetarypolicy/files /fomcprojtabl20130320.pdf.

[66] Brattle Group, "ISO-NE Offer Review Trigger Prices 2013 Study, Final Results," presented to the NEPOOL Markets Committee, September 10, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps /mrkts_comm/mrkts/mtrls/2013/sep10112013/a02_the_brattle_group_presentation_09_10_13.ppt.

[67] System reserve shortages considered include shortages under the current RCPFs of $500 per MWh for TMOR. These include actual reserve shortages from June to December 2012, when $500 TMR RCPFs were in effect, and reserve shortages identified in simulations performed by ISO-NE for the period January 2010 through May 2012. These data are reported in ISO-NE, "Reserve Constraint Penalty Factor Activation Data, October 2006 - December 2012," March 5, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls /2013/mar11122013/a14_iso_rcpf_activation_data_03_05_13.xlsx.

[68] Across units, performance during system reserve shortages in winter months was highly variable. Consequently, performance during high load periods, as reflected by the balancing ratio, was used in lieu of performance during reserve shortages.

Performance is measured as the ratio of total output and operating reserves (*MW*) supplied over all of the reserve shortages (*RS*) (during the relevant time period) divided by the product of the total qualified capacity (*SCC*) and the duration of the reserve shortages (*H*) – that is:

$$A = \frac{\sum_{RS} MW}{SCC * H}$$

Performance is measured over the resource's entire eligible capacity.

The balancing ratio equals load plus reserves divided by ICR. The average balancing ratio equals the sum of the loads during all reserve shortages divided by the product of the ICR times the number of reserve shortages hours – that is:

$$BR = \frac{\sum_{RS} L}{ICR * H}$$

C. Demand Response, Imports, and Renewables

Demand response (DR) is assumed to bid into the FCM PI model in the same amounts as FCA 7. Two categories of DR exist in the model:

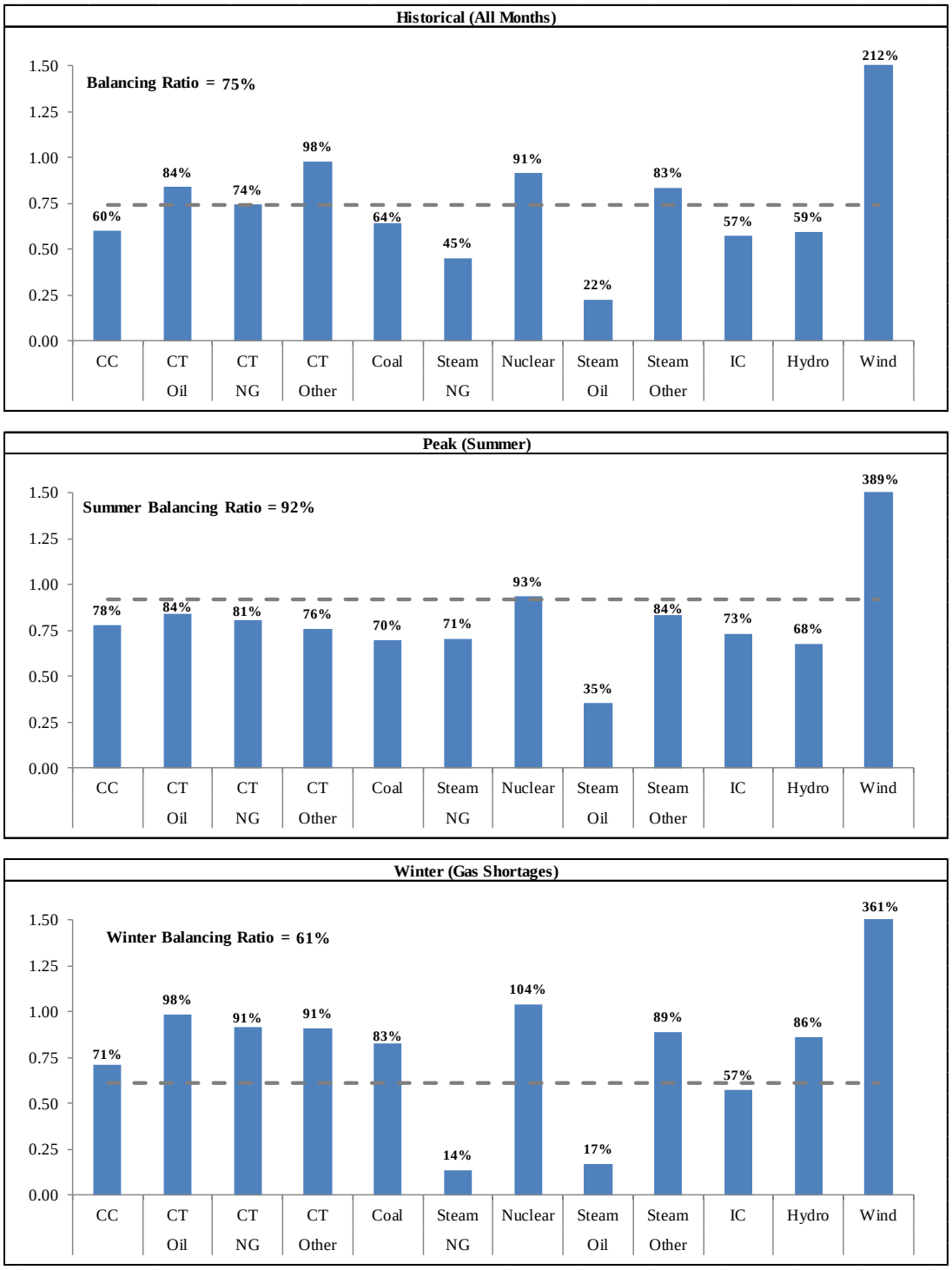
1. Passive DR: 1,850 MW of supply is assumed to be fixed given existing utility-operated energy efficiency programs. These resources are "price takers" in the model – that is, they will accept any price.
2. Active DR: Lacking detailed information on the supply of DR at various prices, the aggregate supply of DR is assumed to grow linearly between several known price/quantity pairs from FCA 7 (i.e., the quantity supplied at each price in the descending clock auction). Starting at bids of $14.00, 856 MW of DR delists linearly in 50 cent increments down to $0.50. The remaining 917 MW of DR is assumed fixed (i.e., resources are price takers down to a very low price).

Imports are treated similarly to active DR in the FCM PI model. The 1,830 MW of imports with capacity supply obligations in FCA 7 are assumed to linearly delist in 450 MW and $1.00 increments starting at $4.00, with the last 30 MW bidding in at $0.10.

Sufficient renewables are added to the fleet to meet state RPS standards in 2018-2019. Based on the most recent ISO New England Regional System Plan[69], 1,142 MW of onshore wind is added beyond what has already cleared in FCA 7 to achieve these requirements. This capacity total reflects the quantity of renewables eligible for the FCM, using a 31% capacity factor.

[69] ISO New England, "Regional System Plan", November 2, 2012.

Figure A1: Average Unit Performance by Resource Category



[1] "Unit Performance" is calculated for each unit and event as a unit's average output during the event divided by its summer seasonal claimed capability (summer SCC). The summer SCC used is from the most recent year with available data. Mean unit performance is weighted by summer SCC.
[2] Summer SCC, generation type, and primary fuel type from CELT Reports. Operating data from ISO-NE.

Table A1
Unit and Class Performance During System Reserve Shortage Events
Summary Statistics by Generation/Primary Fuel Type
All Months January 2010 - December 2012

	Unit Performance				
Generation/Primary Fuel Type	**Mean**	**Standard Deviation**	**Minimum**	**Maximum**	**Aggregate Class Performance**
Combined Cycle	0.60	1.20	0.00	12.40	0.67
Gas Turbine/Oil	0.84	0.46	0.00	1.92	0.93
Gas Turbine/Natural Gas	0.74	0.45	0.00	1.30	0.84
Gas Turbine/Other	0.98	0.37	0.00	1.55	0.94
Steam/Coal	0.64	0.43	0.00	1.07	0.89
Steam/Natural Gas	0.45	0.37	0.00	1.06	0.60
Steam/Nuclear	0.91	0.26	0.00	1.18	1.02
Steam/Oil	0.22	0.40	0.00	1.25	0.28
Steam/Other	0.83	0.40	0.00	2.73	0.99
Internal Combustion Engine	0.57	0.52	0.00	2.58	0.64
Hydro	0.59	2.19	0.00	30.65	0.78
Wind Turbine	2.12	2.60	0.00	10.02	3.28

Notes:
[1] "Unit Performance" is calculated for each unit and event as a unit's average output during the event divided by its summer seasonal claimed capability (summer SCC). The summer SCC used is from the most recent year with available data. Mean unit performance is weighted by summer SCC.
[2] "Aggregate Class Performance" is calculated as total class output divided by total class summer SCC.
[3] Summer SCC, generation type, and primary fuel type from CELT Reports. For each unit, data comes from the most recent year with available data.
[4] The system RCPF value equaled $100 until June 1, 2012, at which point it was increased to $500. ISO-NE used a simulation to determine when reserve events would have occurred with a system RCPF value of $500 for the period from January 2010 - May 2012. The data from this simulation was used together with data on actual reserve events for the period from June 2012 - December 2012 to calculate unit performance and aggregate class performance for the period from January 2010 - December 2012.

Table A2
Unit and Class Performance During System Reserve Shortage Events
Summary Statistics by Generation/Primary Fuel Type
Summer Months January 2010 - December 2012

	Unit Performance				
Generation/Primary Fuel Type	**Mean**	**Standard Deviation**	**Minimum**	**Maximum**	**Aggregate Class Performance**
Combined Cycle	0.78	1.05	0.00	10.61	0.86
Gas Turbine/Oil	0.84	0.38	0.00	1.92	0.93
Gas Turbine/Natural Gas	0.81	0.34	0.00	1.16	0.92
Gas Turbine/Other	0.76	0.33	0.00	1.22	0.72
Steam/Coal	0.70	0.35	0.00	1.07	0.99
Steam/Natural Gas	0.71	0.25	0.00	1.06	0.91
Steam/Nuclear	0.93	0.14	0.66	1.18	1.04
Steam/Oil	0.35	0.44	0.00	1.25	0.43
Steam/Other	0.84	0.36	0.00	2.36	1.03
Internal Combustion Engine	0.73	0.42	0.00	1.65	0.77
Hydro	0.68	1.48	0.00	16.77	0.90
Wind Turbine	3.89	2.30	0.00	10.02	4.60

Notes:
[1] "Unit Performance" is calculated for each unit and event as a unit's average output during the event divided by its summer seasonal claimed capability (summer SCC). The summer SCC used is from the most recent year with available data. Mean unit performance is weighted by summer SCC.
[2] "Aggregate Class Performance" is calculated as total class output divided by total class summer SCC.
[3] Summer SCC, generation type, and primary fuel type from CELT Reports. For each unit, data comes from the most recent year with available data.
[4] The system RCPF value equaled $100 until June 1, 2012, at which point it was increased to $500. ISO-NE used a simulation to determine when reserve events would have occurred with a system RCPF value of $500 for the period from January 2010 - May 2012. The data from this simulation was used together with data on actual reserve events for the period from June 2012 - December 2012 to calculate unit performance and aggregate class performance for the period from January 2010 - December 2012. Data are limited to reserve events during June, July, and August.

Table A3
Unit and Class Performance During System Reserve Shortage Events
Summary Statistics by Generation/Primary Fuel Type
Winter Months January 2010 - December 2012

	Unit Performance				
Generation/Primary Fuel Type	**Mean**	**Standard Deviation**	**Minimum**	**Maximum**	**Aggregate Class Performance**
Combined Cycle	0.71	1.51	0.00	11.90	0.72
Gas Turbine/Oil	0.98	0.45	0.00	1.71	1.00
Gas Turbine/Natural Gas	0.91	0.51	0.00	1.37	0.89
Gas Turbine/Other	0.91	0.51	0.00	1.45	0.90
Steam/Coal	0.83	0.29	0.00	1.07	0.97
Steam/Natural Gas	0.14	0.37	0.00	1.08	0.16
Steam/Nuclear	1.04	0.10	0.45	1.18	1.04
Steam/Oil	0.17	0.37	0.00	1.11	0.20
Steam/Other	0.89	0.41	0.00	2.50	0.98
Internal Combustion Engine	0.57	0.51	-0.14	2.19	0.57
Hydro	0.86	1.96	0.00	14.45	0.88
Wind Turbine	3.42	3.32	0.00	10.83	3.73

Notes:
[1] "Unit Performance" is calculated for each unit and event as a unit's average output during the event divided by its summer seasonal claimed capability (summer SCC). The summer SCC used is from the most recent year with available data. Mean unit performance is weighted by summer SCC.
[2] "Aggregate Class Performance" is calculated as total class output divided by total class summer SCC.
[3] Summer SCC, generation type, and primary fuel type from CELT Reports. For each unit, data comes from the most recent year with available data.
[4] The system RCPF value equaled $100 until June 1, 2012, at which point it was increased to $500. ISO-NE used a simulation to determine when reserve events would have occurred with a system RCPF value of $500 for the period from January 2010 - May 2012. The data from this simulation was used together with data on actual reserve events for the period from June 2012 - December 2012 to calculate unit performance and aggregate class performance for the period from January 2010 - December 2012. Data are limited to periods events during December, January, and February when the balancing ratio exceeded 0.6.

APPENDIX B: DETAILED SCENARIO RESULTS

Table B1: Resource Mix and Average Performance With and Without FCM PI, Historical: No Gas Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,769	100%	1,739	100%
Renewables	4,705	83%	0	NA
Nuclear	4,628	102%	0	NA
CC Gas	12,470	72%	315	48%
Coal	1,591	73%	543	85%
CT or ST Gas	1,520	72%	122	65%
Oil	4,862	44%	1,786	11%
Other	1,071	87%	0	NA
Total	34,615		4,506	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	83%	0	NA
Nuclear	4,628	102%	0	NA
CC Gas	12,470	72%	315	48%
Coal	1,591	73%	543	85%
CT or ST Gas	1,520	72%	122	65%
Oil	5,601	39%	1,047	27%
Other	1,071	87%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	459	0.0%	-459	0.0%
Renewables	0	0.0%	0	NA
Nuclear	0	0.0%	0	NA
CC Gas	0	0.0%	0	0.0%
Coal	0	0.0%	0	0.0%
CT or ST Gas	0	0.0%	0	0.0%
Oil	-739	5%	739	-16%
Other	0	0.0%	0	NA

Notes:

[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.

[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).

[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

Table B2: Resource Mix and Average Performance With and Without FCM PI, Historical: Gas Shortage Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,258	100%	1,250	100%
Renewables	4,705	91%	0	NA
Nuclear	4,628	104%	0	NA
CC Gas	12,470	72%	315	47%
Coal	1,703	75%	431	86%
CT or ST Gas	1,499	61%	143	48%
Oil	4,171	40%	2,478	13%
Other	1,070	88%	0	15%
Total	34,504		4,617	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	91%	0	NA
Nuclear	4,628	104%	0	NA
CC Gas	12,470	72%	315	47%
Coal	1,591	74%	543	89%
CT or ST Gas	1,520	60%	122	52%
Oil	5,601	34%	1,047	21%
Other	1,071	88%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	948	0.0%	-948	0.0%
Renewables	0	0.0%	0	NA
Nuclear	0	0.0%	0	NA
CC Gas	0	0.0%	0	0.0%
Coal	113	2%	-113	-3%
CT or ST Gas	-21	0.5%	21	-4%
Oil	-1,430	6%	1,430	-8%
Other	0	0.0%	0	NA

Notes:

[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.

[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).

[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

Table B3: Resource Mix and Average Performance With and Without FCM PI, Historical: High Gas Shortage Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,717	100%	791	100%
Renewables	4,705	93%	0	NA
Nuclear	4,628	104%	0	NA
CC Gas	12,442	74%	343	50%
Coal	2,039	78%	95	82%
CT or ST Gas	1,499	61%	143	43%
Oil	3,416	41%	3,232	15%
Other	1,070	88%	0	15%
Total	34,516		4,605	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	93%	0	NA
Nuclear	4,628	104%	0	NA
CC Gas	12,470	74%	315	52%
Coal	1,591	74%	543	90%
CT or ST Gas	1,520	61%	122	48%
Oil	5,601	32%	1,047	19%
Other	1,071	88%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,407	0.0%	-1,407	0.0%
Renewables	0	0.0%	0	NA
Nuclear	0	0.0%	0	NA
CC Gas	-28	0.1%	28	-3%
Coal	448	4%	-448	-8%
CT or ST Gas	-21	0.6%	21	-5%
Oil	-2,185	9%	2,185	-4%
Other	0	0.0%	0	NA

Notes:

[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.

[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).

[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

Table B4: Resource Mix and Average Performance With and Without FCM PI, Equilibrium: No Gas Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,717	100%	791	100%
Renewables	4,698	112%	7	4%
Nuclear	4,628	105%	0	NA
CC Gas	12,712	91%	74	22%
Coal	1,703	86%	431	90%
CT or ST Gas	1,642	89%	0	NA
Oil	4,366	66%	2,282	14%
Other	1,070	91%	0	15%
Total	35,536		3,585	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	112%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,470	92%	315	70%
Coal	1,591	85%	543	93%
CT or ST Gas	1,520	89%	122	91%
Oil	5,601	54%	1,047	39%
Other	1,071	91%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,407	0.0%	-1,407	0.0%
Renewables	-7	0.2%	7	NA
Nuclear	0	0.0%	0	NA
CC Gas	241	-0.1%	-241	-48%
Coal	113	1.3%	-113	-3%
CT or ST Gas	122	0.1%	-122	NA
Oil	-1,235	12%	1,235	-25%
Other	0	0.0%	0	NA

Notes:

[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.

[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).

[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

Table B5: Resource Mix and Average Performance With and Without FCM PI, Equilibrium: Gas Shortage Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,917	100%	591	100%
Renewables	4,698	108%	7	27%
Nuclear	4,628	105%	0	NA
CC Gas	12,712	85%	74	36%
Coal	2,039	84%	95	87%
CT or ST Gas	1,642	77%	0	NA
Oil	4,185	58%	2,463	13%
Other	1,070	90%	0	15%
Total	35,890		3,231	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	108%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,470	85%	315	63%
Coal	1,591	81%	543	93%
CT or ST Gas	1,520	77%	122	75%
Oil	5,601	46%	1,047	32%
Other	1,071	90%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,607	0.0%	-1,607	0.0%
Renewables	-7	0.1%	7	NA
Nuclear	0	0.0%	0	NA
CC Gas	241	-0.3%	-241	-27%
Coal	448	3%	-448	-6%
CT or ST Gas	122	-0.1%	-122	NA
Oil	-1,416	12%	1,416	-18%
Other	0	0.0%	0	NA

Notes:

[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.

[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).

[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

Table B6: Resource Mix and Average Performance With and Without FCM PI, Equilibrium: High Gas Shortage Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,976	100%	532	100%
Renewables	4,705	106%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,712	84%	74	44%
Coal	2,039	83%	95	88%
CT or ST Gas	1,642	73%	0	NA
Oil	4,201	51%	2,447	13%
Other	1,070	90%	0	15%
Total	35,972		3,149	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	106%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,470	84%	315	63%
Coal	1,591	80%	543	93%
CT or ST Gas	1,520	73%	122	66%
Oil	5,601	42%	1,047	27%
Other	1,071	89%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,666	0.0%	-1,666	0.0%
Renewables	0	0.0%	0	NA
Nuclear	0	0.0%	0	NA
CC Gas	241	-0.3%	-241	-18%
Coal	448	3%	-448	-5%
CT or ST Gas	122	-0.5%	-122	NA
Oil	-1,400	9%	1,400	-14%
Other	0	0.0%	0	NA

Notes:

[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.

[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).

[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

APPENDIX C: ASSESSMENT OF ALTERNATIVE TECHNICAL OPTIONS FOR SECURING FUEL SUPPLY

This appendix provides qualitative and quantitative background information on categories of potential costs associated with new infrastructure alternatives to address risks of natural gas fuel curtailment, or "gas dependence" risks. This information is used to identify the least-cost approach to addressing gas-dependency risks. This assessment considers the direct cost of these options, but does not consider indirect economic impacts, such as net revenues gained from increased output in the energy market, or changes in fuel costs.

The assessment relies on various studies, reports, and analyses conducted by third parties and available in the public domain, related to natural gas and dual fuel infrastructure options that could emerge from market rule changes, along with estimates developed by Analysis Group based on information and data provided by ISO-NE or contained in these studies and reports. The list of studies reviewed is presented at the end of this memo.

There are a number of potential technical options that resources can take to address gas dependence risks. Our assessment considers the following options:[70]

- Increases in dual-fuel capability or operations
  - From existing units with dual fuel capability that is currently mothballed or underutilized
  - From newly developed dual fuel capability at existing gas plants
- Storage/transportation arrangements tied to existing LNG facilities
- New in-region LNG storage
- New natural gas interstate pipeline capacity

The identification of the least-cost approach to mitigate gas dependence reflects the cost-effectiveness of each option to resource owners. This assessment also considers (1) feasibility and the timeline for development, and (2) operational characteristics to ensure that the resource owners would have sufficient time to implement the technical option for the commitment period, that there are not regulatory, technical or practical barriers to deploying the option, and that the option addresses gas dependence risks with reasonable certainty. In the sections that follow, information and data are presented for each of these factors, and for each of the options identified. Specifically, we review:

1. *Costs* – life-cycle costs, including upfront costs and annual operating costs.[71] Options are compared based on their annualized cost (dollars per kW-month), reflecting assumptions about the discounting of each option's upfront costs. The cost estimates reflect implementation of the option at generic resources based on data provided by ISO-NE and publicly available information

[70] It should be noted that there may be additional or alternative outcomes of market rule changes focused on natural gas dependence that are not identified or evaluated in this memo.

[71] In addition to these infrastructure development and operational costs, the integration of such new infrastructure would likely have an impact (positive or negative) on *system costs* over time. Such impacts could arise, for example, from changes in system unit commitment and dispatch in some or all hours of the year given the integration of new resources, and/or changes in system transmission costs. These system cost impacts are not reviewed in this analysis.

on recent development projects. Unless noted below, the estimates do not reflect resource-specific factors that would lead actual costs to vary from these estimates. Figure C1 describes how categories of costs are identified and normalized to allow for comparison.

2. *Development timeline/feasibility* – the time required between conceptualization and commercialization for the options reviewed varies widely. The analysis presents qualitative assessments of development feasibility and barriers to implementation that would affect when specific alternatives would be available to influence reliability and market outcomes.

3. *Operational characteristics* – not all options reviewed provide equal assurance of fuel delivery or generation availability, and so they present different implications for resource availability that may or may not affect market valuation. For example, options differ in their (1) ability to ensure fuel delivery for prolonged or frequent curtailments, (2) ability to support reserve-quality resources, and (3) ability to withstand interstate natural gas pipeline contingencies. The analysis presents qualitative assessments of operational constraints that would affect how specific alternatives would influence reliability and market outcomes.

Figure C1: Analytic Approach to Estimating Costs of Options to Address Gas Dependence

Capacity (MW)	200
Upfront Cost	
Project cost ($)	1,000,000
Total Upfront Costs ($)	1,000,000
Annual Costs	
O&M ($)	1,500,000
Carrying Cost ($)	1,000,000
Total Annual Costs ($)	2,500,000
PV	
Lifetime	20
Discount Rate	9%
Present Value ($)	23,821,364
Present Value per MW ($)	119,107
Cost per kW-month ($)	1.09

Each facility is sized to serve a quantity of gas-fired capacity

Upfront costs reflect siting, permit, engineering, facilities, technology and testing

Annual Costs include O&M, carrying costs of fuel storage, technology and air permit testing

Present value of lifetime costs of technical option reflect assumed lifetime and discount rate

Cost of technical options are normalized in terms of costs per kW-month

7In the sections that follow, we summarize results for each of the infrastructure options identified above. Table C1 summarizes the assessment of options to mitigate gas dependency and is equivalent to Table 3.

Table C1: Comparison of Options for Firming Gas-Dependent Resource Fuel Supply

Technology Option		Cost	Other Factors
Dual Fuel	Current Dual Fuel Capable	• $5,700 per MW	• Time to recommission or install is relatively brief • Long refill times may limit effectiveness over long curtailments • Operations limits and risks when switching to alternate fuels • Requires environmental permitting
	Under- or Unutilized Dual Fuel Capability	• $6,500 per MW (annualized, reflecting capital cost and annual expenditures)	
	No Dual Fuel Capability	• $15,000 per MW (annualized, reflecting capital cost and annual expenditures)	
Service from Existing LNG Facilities (Canaport, DOMAC)		• Not estimated – cost would reflect (1) foregone opportunity to sell LNG in higher-value markets; (2) carrying cost; (3) operating cost; and (4) transportation charge. • Rate would be subject to negotiation	• Could be subject to deliverability constraints without firm service (esp. for Canaport, requiring transport over Maritimes pipeline)
New LNG Storage		• $29,700 per MW (annualized, reflecting capital cost and annual expenditures)	• Long refill times may limit effectiveness over long curtailments
New Pipeline Capacity		• $9,700 to $32,700 per MW for upfront costs • Rates for firm service would exceed these annualized costs	• Requires purchase of firm service • Time lag between commitments for firm service and new service availability • Reduces transport costs during periods of elevated prices (when basis differential exceeds tariff rate)

Dual-Fuel Capability

All natural gas-fired units are capable – in theory – of dual fuel (DF) operation. However, they can differ significantly in the amount of work that would be required to establish operational DF capability and in the costs that would be incurred to establish and use DF capability. Existing facilities fall into three basic categories:

1. *Facilities that currently have DF capability* – such units require *on-going* costs to (a) actively maintain alternate fuel burners, including burner and air permit testing, and (b) maintain sufficient fuel supply for an adequate period of operation (from the perspective of reliability needs under natural gas curtailment or contingency circumstances). These annual on-going costs are estimated at roughly $1.5 million for a 260 MW facility, or $5,700 per MW. Absent market incentives to maintain this capability and a means to recover these on-going costs, DF capability has been, or likely will be, decommissioned.

2. *Facilities with decommissioned DF capability* – such units require the same on-going costs as category 1 units, once operational. However, these units would also incur up-front costs including modest technical upgrades, as needed, to bring alternate fuel burners back to operational status, as well as testing to obtain or reinstitute air permits, and to ensure burner operability. The extent of these technical upgrades likely varies across units in the ISO-NE fleet given the type of equipment and turbines, and time period since mothballing. The annualized cost of recommissioning and maintaining DF capability is roughly $2 million for a 260 MW facility, or about $6,500 per MW.
3. *Facilities with no DF capability* – such units require the same on-going costs as category 1 units, once operational. However, these units would also incur up-front costs involving major technical upgrades to add alternate fuel burners and fuel storage capability, including testing of new burners and acquiring necessary permits. The annualized cost of developing and maintaining DF capability is are estimated at roughly $4 million for a 260 megawatt (MW) unit, or about $15,000 per MW.

Table C2 presents a summary of the cost estimates and assumptions used to develop these estimates, including up-front costs, annual costs, and present value cost per kW-month. Cost estimates reflect multiple data sources, including publicly available data and data provided by ISO-NE. Results range from approximately $5,700 per MW-year for units with DF capability, to $15,000 per MW-year for units with no DF capability, including levelized capital costs of installing new infrastructure.

Table C2. Cost and Technical Assumptions Regarding Dual Fuel Capability

	Dual Fuel		
	Dual Fuel Capable	**Under- or Unutilized Dual Fuel Capability**	**No Dual Fuel Capability**
Capacity (MW)	260	260	260
Upfront Costs			
Unit Cost ($/MW)		3,600	81,000
Total Development Cost ($)		936,000	21,060,000
Testing ($)		979,050	979,050
Total Upfront Cost ($)	0	1,915,050	22,039,050
Annual Costs			
O&M ($)	200,000	200,000	200,000
Annual Testing ($)	979,050	979,050	979,050
Fuel Carrying Cost ($)	307,862	307,862	307,862
Days Fuel Supply	3	3	3
Fuel Cost ($/MMBtu)	22.8	22.8	22.8
Total Annual Costs ($)	1,486,912	1,486,912	1,486,912
Lifetime (Years)	20	20	20
Discount Rate	9%	9%	9%
Present Value ($)	13,573,340	15,488,390	35,612,390
Present Value per MW ($)	52,205	59,571	136,971
Annualized Cost per MW ($)	5,719	6,526	15,005

There are a number factors related to timing, deployment, and operational characteristics that are important to consider with respect to DF capability, and differences between DF options, including the following:

- The actions needed to re-commission DF capability at units with mothballed or unused capability can likely be performed relatively quickly – burner upgrades are typically fairly limited in scope; there are relatively few barriers to securing sufficient fuel supply (other than cleaning unused storage tanks and securing cost recovery for fuel carrying costs); and minimum testing time is needed to maintain burner operability and permit status. There is more than sufficient time for resources to implement these technical changes in time for a commitment period three years ahead.
- Actions to install DF capability at units that do not have it are more involved and would require additional time – including development, permitting, and construction activities. However, there is more than sufficient time for resources to implement these technical changes prior to a commitment period three years ahead.
- In some cases there are or would be variations in output and risk of outage when actively switching from gas- to oil-firing. Some units – in particular those burning heavy fuel oil as a secondary fuel, need to power down before switching, and thus would provide less flexibility than units that can switch on the fly. In addition, there is an increased risk of outage with switching, particularly when alternate fuels are used infrequently.
- It is anticipated that regulatory limits on oil firing to address air quality concerns would generally allow for sufficient operability of DF units to cover electric system reliability needs. While some units may only be allowed to operate on oil when gas is unavailable, for most units, environmental permits typically set operational limits based on the annual number of hours operated (based on continuous operation at full output).
- Storage capacity (relative to burn at continuous full output) and storage refilling methods and rates can be an important element of maintaining resource availability, particularly during winter cold-snap conditions. DF units can have very different capacities and refill rates.
- Generally speaking, facilities served by oil pipelines or rail would be able to maintain burn if needed, and/or refill relatively quickly. But most facilities are served by truck refills, which can require days or weeks to refill to storage representing three days of continuous output.[72] For example, assuming tanker truck capacity of 9,000 gallons (generally on the high end) and representative heat rates, it would take 20 trucks per day to support continuous output of 130 MW.

[72] Three days of continuous output was chosen only to construct a representative calculation. Market performance obligations and/or reliability needs could require less than three days of continuous output.

New and Existing LNG Storage Capability

There are two options tied to liquefied natural gas that have been identified as opportunities to firm up natural gas fuel supply to natural gas-fired generating facilities in New England: (1) the construction of new land-based LNG storage facilities with liquefaction capability dedicated to providing backup gas fuel supply to power plants,[73] and (2) new services associated with spare capacity – to the extent it exists – at the two major LNG terminals serving the region (Distrigas of Massachusetts Corp, or DOMAC, located in Boston, and Canaport, located in Canada).

New LNG Storage Capacity

Estimated costs of new LNG storage capacity reflect the costs of three recently-sited facilities of roughly equal storage capacity. These facilities offered a combination of size, performance (vaporization and liquefaction), and cost that would be technically appropriate for providing backup fuel supply for gas-fired generators.

Table C3: Cost and Technical Assumptions Regarding New LNG Storage

Capacity	
LNG Volume (cubic meters)	60,000
NG Energy Capacity (MMBtu)	1,262,400
Flow capabilities	
Maximum vaporization rate (MMBtu / day)	91,300
Max MW per Day (given vaporization rate)	543
Maximum liquefaction rate (MMBtu / day)	6,333
Max MW Refill per Day (given liquefaction rate)	38
Variable Operating Costs	
Liquefaction cost ($ / MMBtu)	1.6
Storage and vaporization cost ($ / MMBtu)	0.4
Backup Fuel Supply Capability	
MW-Days of Backup Fuel Supply Stored	7,514
Max MW per Day (full output, given liquefaction rate)	543
Days to Refill (Liquefy) Sufficient Supply for Max MW per Day	14
Assumed Heat rate (Btu / kwh)	7,000

[73] With respect to new LNG storage, we focus on on-land facilities with liquefaction capability similar in size to many peak-shaving LNG storage facilities in existence today. We do not review facilities without liquefaction, as refill rates for storage without liquefaction are estimated to be too slow to provide a reliable back-up fuel supply. We also do not review new large-scale LNG terminals given the demonstrated and likely barriers to the siting of such facilities within New England.

The cost of a new LNG storage facility includes up-front development costs, annual operating costs, and the carrying cost of the stored fuel. Our estimates are based on the three facilities reviewed, sized to a generic facility with (a) a vaporization rate sufficient to provide backup fuel supply for approximately 540 MW of capacity; (b) 60,000 cubic meters (cm) of storage, equivalent to roughly 14 days of operation at the assumed vaporization rate; (c) a liquefaction rate that would be sufficient to refill enough supply to operate the facility (540 MW) for one day, in 14 days. Technical assumptions based on these three facilities are reported in Table C3.

Based on the recently-completed facilities, up-front costs range from $1,850 to $2,450 per cm of storage, amounting to approximately $128 million for the generic facility, including siting, permitting, engineering, and capital costs. Variable costs include fuel carrying costs and operating costs related to liquefaction, storage and regasification. This translates to a cost on the order of approximately $30,000 per MW-year, as shown in Table C4.

Table C4: Estimated Cost of New LNG Storage

Capacity (MW)	543
Upfront Cost	
Project cost ($)	127,666,667
Cost per cubic meter	2,128
Annual Costs	
O&M ($)	1,500,000
Carrying Cost ($)	633,920
Initial Fuel Cost (including liquefaction) ($)	7,043,561
Total Annual Costs ($)	2,133,920
PV	
Lifetime	20
Discount Rate	9%
Present Value ($)	147,146,257
Present Value per MW ($)	270,988
Annualized Cost per MW ($)	29,686

There are a number of factors related to timing, deployment, and operational characteristics that are important to consider with respect to LNG storage capability, including the following:

- Siting and development of a LNG storage facility could require multiple years, even under relatively easy siting conditions. Storage facilities of this size are modest-sized industrial facilities, so in some cases and/or locations opposition to siting at the local level could further lengthen the development timeline.
- The mix of liquefaction and vaporization rates introduces certain constraints on the market value of such facilities, and also on their reliability benefit. At the assumed (and achievable) vaporization rate, it would take between 7 and 20 days to fully discharge the tank. However, the liquefaction rate limits the ability to refill the tank after discharge. Specifically, it could take more than 190 days to fully refill the tank after discharge. Consequently, such a facility could

provide backup fuel for an extended curtailment (or multiple shorter curtailments), but that backup capability could be significantly limited for subsequent curtailments after full discharge.

Existing LNG Facilities

With respect to the existing DOMAC and Canaport facilities, it has been suggested that backup fuel supply to electric generators could be provided through arrangements to essentially store fuel and inject it into the pipelines upon request by electric generators from these two facilities.[74] Reliance on such services would require excess storage and regasification capacity at the terminal in question, and delivery service on Algonquin or Tennessee to the gas-fired generator's connection point on the pipelines. In addition, for Canaport service there would need to be delivery service on the Maritimes and Northeast pipeline. The stored gas, and the capacity to inject and deliver it, would need to be available as and when needed by the gas generator.

In this case, there are essentially no up-front costs. All services would be on existing facilities to the extent capacity exists. An estimate of annual costs can be derived by estimating (1) the opportunity cost of storing LNG instead of selling it in higher-value markets (i.e., Europe); (2) the carrying cost reflecting interest on the value of stored fuel; (3) the operating cost required to cool and store LNG at the facilities (including any lost fuel due to "boil off") and (4) if firm service is required to meet reliability requirements, a transportation charge for moving gas from storage to delivery point.

We have not attempted to estimate the type and cost of pipeline transportation charges, given the uncertainty around the type of service and rate that would be charged within the constraints of existing pipeline capacity. We have also not attempted to estimate the cost associated with service from existing LNG facilities due to uncertainty about the avoidable variable costs of storing incremental quantities of LNG supplies for use by gas-fired generators, and uncertainty about the rates the LNG facilities would charge for storage and release service for gas-fired generators. These rates would be subject to negotiations between generators and existing LNG facilities, which would reflect many factors, including the next-best options available to generators to storage and release service from an existing LNG facilities (such as foregoing service or developing dual fuel capability). Public information provided by existing LNG facilities on illustrative costs of such service suggests that this service would be more expensive than incremental development of dual fuel capability.[75] To the extent that resources can obtain service at terms that are less costly than dual fuel capability, the estimates of the quantity of incremental resources that address fuel dependency risks as a result of FCM PI would tend to be understated.

[74] In theory, these same services could be supplied by the offshore Neptune and Northeast Gateway terminals, through tankers "parked" at the intake pipes, or from existing local gas distribution company (LDC) peak shaving storage capacity. However, we did not review this separately given the potentially prohibitive costs of using tankers (on top of the other costs that would be faced by Canaport or DOMAC), and given the dedication of LDC storage facilities to serve natural gas LDC customers on peak.

[75] For example, see the illustrative terms and conditions for Call Option Service from the Canaport Facility provided by Repsol. Vince Morrisette, Repsol, "Gas Supply Peaking Option from Canaport LNG," ISO-NE Markets Committee, May 13, 2013.

New Interstate Pipeline Capacity

Relatively little firm service is available on the primary pipelines serving New England, so additional firm natural gas supply will likely require the construction of additional pipeline capacity. Increased natural gas pipeline capacity could support the transport of additional fuel supplies to the region, and so would reduce the risk of curtailment to gas-fired generators, relative to current market conditions. Additional pipeline capacity to provide firm gas supply can be achieved through various changes to the interstate pipeline system to relieve pipeline congestion or add incremental capacity, ranging from new compressor stations along existing pipe, to looping, to the construction of new pipelines from key gas sources (e.g., the Marcellus Shale region). The cost of various changes are difficult to identify absent engineering studies, and depend on the extent to which lower-cost technical changes to expand the capacity of the existing pipeline assets have already been exhausted.

The range of potential upfront costs to increase pipeline capacity from Marcellus and other lower-cost natural gas reserve regions is wide, and depends on the location of constraints being relieved, and/or the overall size and route of the project. Figure C2 provides estimates of the underlying capital costs of recently developed pipelines in the New England region in terms of the dollars per MW of firm service to gas-fired electricity generators. In addition to up-front costs, annual costs are incurred for operations and maintenance on the pipeline system. This estimate, based on an assumed increase in pipeline capacity of nearly 400,000 dekatherms per day, is approximately $1.17/kW-mth of equivalent electrical generating capacity.

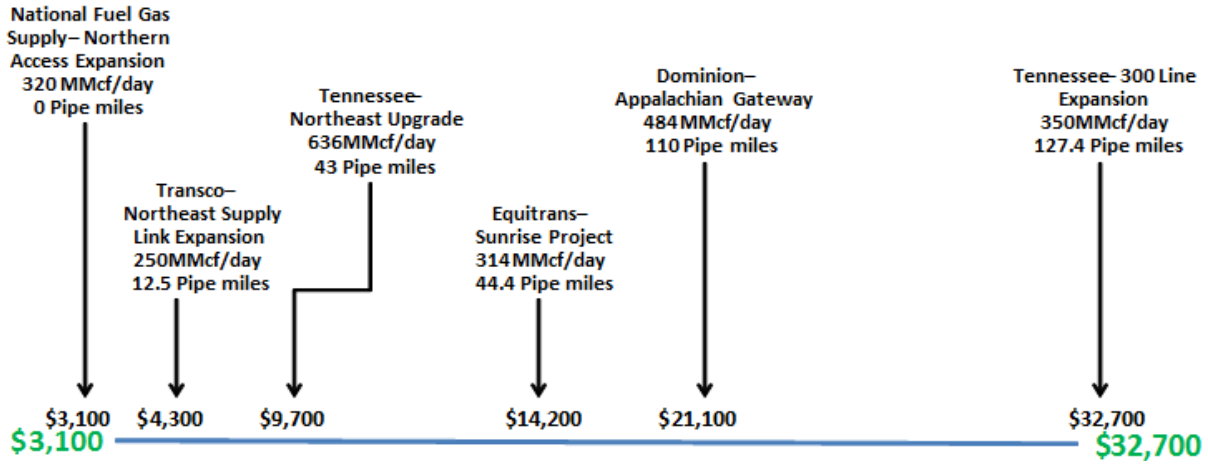
Ignoring the expansion projects, the annualized cost of upfront capital investments ranges from $9,700 per MW to $32,700 per MW (reflecting generation at a heat rate of 7,000 BTU per kw). These costs are comparable to those estimated by Black and Veach in a recent study for the New England States Committee on Electricity (NESCOE).[76] Total costs would account for additional factors such as annual operating expenditures.

Costs in Figure C2 do not reflect the rates that would be charged to generators for firm service. These rates would be higher than the costs reflected in these tables due to a variety of factors such as annual expenditures included in rates, differences in discount rates, and delays between when costs are incurred and when cost recovery begins from pipeline construction. Cost estimates also do not reflect potential reduction in gas transportation costs during periods of tight gas supply, particularly when the basis differential exceeds the tariff rate, or the ability of new pipeline to lower power system costs during such periods when supply from such regions would otherwise be constrained.

Assuming actual project costs would be toward the upper end of costs represented in Figure C2, and considering differences between estimates of annualized upfront costs and actual rates charged for firm service, we conclude that firm service on new pipelines is likely to be a more costly option for market participants to address gas dependency risks. To the extent that resources can obtain firm service at rates that are less costly than dual fuel capability, the estimates of the quantity of incremental resources that address fuel dependency risks as a result of FCM PI would tend to be understated.

[76] Black & Veatch, "New England Natural Gas Infrastructure and Electric Generation: Constraints and Solution", prepared for the New England States Committee on Electricity, April 16, 2013.

Figure C2: Capital Costs of Recent Northeast Pipeline Projects



There are a number factors related to timing, deployment, and operational characteristics that are important to consider with respect to the reliability and economic value of increasing pipeline capacity, including the following:

- The timeline for new pipeline capacity siting, permitting, and construction is on the order of several years. Consequently, this is not an option that can provide meaningful power system reliability benefits for at least several years.
- Under current FERC rules and past practices for funding new pipeline capacity, new projects typically will not go forward without up-front financial commitments from customers to take firm delivery service for all – or most – of the new capacity. Entering into such long-term financial commitments for natural gas transportation is challenging for electric generators under current market conditions.
- Current pipeline capacity firm commitments are held almost entirely by natural gas local distribution companies (LDCs) for the benefit of natural gas ratepayers, and with the guarantee that such capacity will be used to meet the need of LDC end-use customers for heating and process needs as necessary, particularly at the time of winter peak conditions. This means that while substantial amounts of such capacity may be released to secondary markets for use by electric generators throughout the year, it cannot be counted on during winter peak or cold-snap conditions.

List of Sources Reviewed for Appendix C

Sources of information relied on for the Dual Fuel section include the following:

- ESS Group, "Dual-Fuel Generating Capacity and Environmental Constraints Analysis," Interim Report, prepared for ISO-NE, April 1, 2005.
- Conversations with ISO-NE staff.
- Settlement between NYISO and TransCanada, Ravenswood for recovery of on-going costs of maintaining dual fuel capability, April 2011.
- PJM Cost of New Entry (CONE), incremental cost for dual fuel capability on new generation units, 2011.
- Handy-Whitman Index of Public Utility Construction Costs.
- Analysis Group estimates based on these reports, and on data provided by ISO-NE.

Sources of information relied on for the New Interstate Pipeline section include the following:

- INGAA publication #17742 (sourced from North American Midstream Infrastructure Through 2035 – A Secure Energy Future, ICF International for INGAA, June 28, 2011).
- "2012 Worldwide Pipeline Construction Report," Pipeline & Gas Journal, January 2012.
- "Pipeline Costs in Shale Gas Regions," Ziff Energy Group, June 29, 2011; "Natural Gas Under Siege," Ziff Energy Group, April 2012.
- "Gas and Electric Infrastructure Interdependency Analysis," Prepared for MISO by EnVision Energy Solutions, February 2012.
- "Jobs & Economic Benefits of Midstream Infrastructure Development, US Economic Impacts Through 2035," Black & Veatch for INGAA, February 15, 2012.
- Black & Veach, "New England Natural Gas Infrastructure and Electric Generation: Constraints and Solution", prepared for the New England States Committee on Electricity, April 16, 2013.

Sources of information relied on for the LNG Storage section include the following:

- "CB&I Awarded Contract for Temple LNG Expansion Project," Pipeline & Gas Journal, December 2009.
- UGI LNG company website: http://www.ugilng.com/
- "LNG Facility Brings Positive Economic Change to Former Manufacturing Center," Pipeline & Gas Journal, November 2009.
- "LNG Peakshaving Facility, Connecticut, USA," CB&I company website, http://www.cbi.com/markets/project-profiles/lng-peakshaving-facility-connecticut-usa/
- "Mt. Hayes Liquefied Natural Gas Storage Facility, Terasen Gas (Vancouver Island) Inc.," Stakeholder Workshop for the CPCN Application, June 27, 2007.

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- Repsol, "A Potential LNG Solution for Maintaining Pipeline Deliverability During Peak Demand Periods," ISO NE / NGA Meeting, April 12, 2012.
- Vince Morrisette, Repsol, "Gas Supply Peaking Option from Canaport LNG," ISO-NE Markets Committee, May 13, 2013.
- EIA, "World LNG Shipping Capacity Expanding," Report #DOE/EIA-0637, 2003.
- Massachusetts gas utility resource plans and forecasts.
- Analysis Group estimates.