NEPGA Exhibit 1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and New England Power Pool	)	Docket No. ER10-787-___
New England Power Generators Association, Inc.	)	
	)	
v.	)	Docket No. EL10-50-___
	)	
ISO New England Inc.	)	
PSEG Energy Resources & Trade LLC, *et al.*	)	
	)	
v.	)	Docket No. EL10-57-___
	)	
ISO New England Inc.	)	

TESTIMONY OF ROY J. SHANKER PH.D.
ON BEHALF OF NEW ENGLAND POWER GENERATORS ASSOCIATION

JULY 1, 2010

TABLE OF CONTENTS

INTRODUCTION

Q PLEASE STATE YOUR NAME, PROFESSION AND ADDRESS.

A My name is Roy J. Shanker. My address is P.O. Box 60450, Potomac, Maryland 20859.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A I have been asked by the New England Power Generators Association ("NEPGA")[1] to review and comment on a February 22, 2010 filing made by the Independent System Operator-New England ("ISO-NE") and New England Power Pool ("NEPOOL") addressing modifications to the ISO-NE Forward Capacity Market ("FCM"), *see ISO New England Inc.*, Docket No. ER10-787-000, Various Revisions to FCM Rules Related to FCM Redesign (Feb. 22, 2010) ("FCM Revision"), as well as the Commission's related April 23, 2010 Order on Forward Capacity Markets Revisions and Related Complaints setting these proposed revisions for hearing, *see ISO New England, Inc.*, 131 FERC ¶ 61,065 (2010) ("Hearing Order"). Specifically, I was asked to focus my review and analyses on the portions of the FCM Revision and the Hearing Order related to modifications of the Alternative Price Rule ("APR"), *see* FCM Revision at 13-19; Hearing Order at PP 40-68, 69-87, and to the establishment of capacity zones, *see* Hearing Order at PP 109-130, 131-135.

Q DID THE COMMISSION REQUEST COMMENTS ON THE MATTERS YOUR TESTIMONY WILL ADDRESS?

A Yes. The Commission set the following issues for hearing:

[1] NEPGA is a private, non-profit entity that advocates for the business interests of non-utility electric power generators in New England. NEPGA's member companies represent approximately 28,000 megawatts of electrical generating capacity throughout the New England region.

a. Issues Relating to Alternative Price Rule (APR)

(1) Triggering conditions, if any, for the APR;

(2) Treatment of Out-of-Market ("OOM") resources that create capacity surpluses for multiple years; and

(3) Appropriate price adjustment under APR;

b. Modeling of Capacity Zones

(1) Whether zones should always be modeled;

(2) Whether all de-list bids should be considered in the modeling of zones;

(3) Whether a pivotal supplier test is necessary; and

(4) Whether revisions to the current mitigation rules would be necessary in order to model all zones.

Hearing Order at P 18.

While I address several specific elements outlined in the Hearing Order, this testimony focuses on three major areas: (i) capacity market fundamentals and related Commission guidance for evaluation of market design elements; (ii) buyer market power in the FCM design, and the various APRs intended to remedy it (as well as recommended modifications); and (iii) the need to always model locational constraints.

Q DOES YOUR TESTIMONY ADDRESS ANY OTHER KEY DOCUMENTS OR ISSUES?

A Yes. I also have reviewed proposed changes to the FCM that the ISO-NE recently released to stakeholders. *See* Bob Ethier *et al.*, Draft Response to FERC Order of April 23, 2010 (June 15, 2010), http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2010/final_prop_fcm_rev6_15_10.pdf ("June 15 slide presentation"). It is my understanding that

ISO-NE will modify its February 22, 2010 FCM Revision to conform to the June 15 slide presentation, although the full details likely will not be known until ISO-NE makes its own filing on July 1. At the conclusion of each section of my testimony, I comment on ISO-NE's proposed revisions as I understand them at this time.

Q HOW DOES YOUR TESTIMONY DISTINGUISH BETWEEN THE HISTORIC APR AND THE VARIOUS PROPOSALS PRESENTED BY ISO-NE?

A In my testimony, I will make reference to the three different APR regimes: first, the Historic APR that was in effect for the first three Forward Capacity Auctions, FCA #1 through FCA #3;[2] second, the February APR proposed in ISO-NE's February 22, 2010 FCM Revision, which will be in effect for FCA #4; and third, the June APR proposed by ISO-NE staff in its June 15 slide presentation.

Q HOW ARE YOU QUALIFIED TO PRESENT TESTIMONY ON THE MATTERS YOU HAVE JUST DESCRIBED?

A I have extensive experience with capacity market design in all three eastern Regional Transmission Organizations ("RTOs")—ISO-NE, PJM Interconnection, L.L.C. ("PJM"), and the New York Independent System Operator, Inc. ("NYISO")—and have previously offered testimony in Commission proceedings (for example, in Docket ER03-563) addressing the original ISO-NE capacity market design. I have also been a long-term, active participant on several committees and working groups addressing these issues of the NYISO and PJM markets. In NYISO, I have worked on the capacity market concepts since prior to the start of the market. In PJM, I participated for seven years in the work

[2] The Historic APR was set forth in ISO-NE's Transmission, Markets, and Services Tariff (FERC Electric Tariff No. 3) at 2nd Revised Sheet No. 7314T (issued Apr. 15, 2009), Original Sheet No. 7314U (issued Feb. 15, 2007), 1st Revised Sheet No. 7314V (Issued Nov. 9, 2007), Original Sheet No. 7314W (issued Feb. 15, 2007), and Original Sheet No. 7314X (issued Feb. 22, 2010).

related and leading to the development of the current Reliability Pricing Model ("RPM") markets. I have submitted testimony and participated in technical sessions before the Commission numerous times on these and related issues. A summary of my experience is attached as Exhibit 1-A.

Q HOW IS THE REMAINDER OF THIS TESTIMONY STRUCTURED?

A The following discussion has four main sections: The first is a summary of my findings and conclusions; the second addresses the general need for capacity markets and four general principles that the Commission has established as essential elements of capacity market design; the third addresses my criticisms and recommendations regarding the ISO-NE's APR proposals, and the fourth addresses issues related to the modeling of locational constraints.

FINDINGS AND CONCLUSIONS

Q PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS REGARDING THE NEED FOR AND ESSENTIAL ELEMENTS OF CAPACITY MARKETS

A The need for capacity markets is well established both in technical testimony submitted to the Commission, and the Commission's own orders establishing such markets in all three of the eastern RTOs. *See, e.g.*, *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, *order denying reh'g and approving settlement*, 117 FERC ¶ 61,331 (2006), *order on reh'g and clarification*, 119 FERC ¶ 61,318 (2007); *Devon Power LLC*, 113 FERC ¶ 61,075 (2005), *order approving settlement*, 115 FERC ¶ 61,340 (2006); *New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201, *reh'g denied*, 105 FERC ¶ 61,108 (2003); *New York Indep. Sys. Operator, Inc.*, 89 FERC ¶ 61,109 (1999), *order on reh'g and clarification*, 90 FERC ¶ 61,085 (2000). Similarly, to my knowledge, there is no control area that operates without the equivalent of some mandated adequacy requirement, either directly or indirectly. Merchant generators in these markets face both fixed costs and variable costs that must be recovered to continue operations. When there are mandated surpluses of capacity to assure reliability coupled with price caps on energy in the rare events that scarcity actually occurs, suppliers cannot recover from the energy and ancillary services markets alone sufficient revenues over time to attract new supply and retain existing supply. In general the marginal unit of energy supply will only have the opportunity to recover its variable costs under such structures not its fixed costs or capital. Further, rules that allow for generation to be procured for reliability via reliability-must-run ("RMR") agreements and not set price exacerbate this problem. This is a short summary of the "missing money" problem I have referred to in previous testimony.

I have identified four general requirements for capacity markets to succeed—each based on bedrock economic theory. These core principles may be summarized as follows:

Principle 1—Capacity markets must permit sufficient revenue to average true net CONE over time in order to attract new entry and retain economic generation.

Principle 2—Capacity markets must reflect all locational and reliability constraints in order to accurately reflect the true value of generation assets.

Principle 3—Capacity markets must compensate similarly-situated generation assets consistent with the law of one price in order to prevent undue discrimination and inefficient price signals that stifle competition.

Principle 4—Capacity markets must mitigate both buyer and seller market power.

Without ever formalizing these requirements, the Commission, in a series of orders, has recognized that these principles are necessary attributes of capacity markets. These principles transcend any notion of regional differences in implementation, and must be incorporated in some fashion into any working capacity market design. In a sense, these become the screening criteria to consider capacity market design or sets of design changes such as those presented by ISO-NE.

Q PLEASE DESCRIBE THE FOUR GENERAL PRINCIPLES FOR CAPACITY MARKET DESIGN THAT YOU DRAW FROM THE COMMISSION'S PRECEDENT.

A *First*, over time, compensation must be sufficient to attract new entry and retain economic existing generation. *See ISO New England Inc.*, 125 FERC ¶ 61,102 at P 43 (2008) ("The purpose of the New England FCM is to attract and retain sufficient capacity to maintain ISO-NE's Installed Capacity Requirement."), *order on reh'g*, 130 FERC ¶ 61,089 (2010). This means that on average and over time, the recovery from the bulk power markets for energy and capacity must result in payments equal to the cost of new entry. *See Blumenthal v. ISO New England, Inc.*, 117 FERC ¶ 61,038 at PP 82-87 (2006), *order on reh'g,* 118 FERC ¶ 61,205 (2007) (determining that the long-term design of electric market must be based on competitive outcomes and that over the long-term just and reasonable rates are equal to marginal cost of generation); *Devon Power*, 115 FERC ¶ 61,340 at P 114 (explaining that offers at prices below a resource's long-term average costs, net of non-FCM market revenues, should be mitigated in order "to reset the clearing price to a level that would be expected in a competitive market"). Implicit in this principle is the fact that if prices will be lower than average some of the time, they *must* be higher than average during other periods. The Commission has also expressed a preference for designs that reduce price volatility, although this has not been a requirement. *See PJM Interconnection*, *L.L.C.*, 115 FERC ¶ 61,079 at P 104 (2006).

Second, capacity markets must include locational and reliability price signals to reflect the fact that capacity in certain congested areas potentially has greater value than capacity located elsewhere. *See*, *e.g*., *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318 at P 76 (2007) ("Capacity market prices must be locational in order to be fully effective. Because of transmission constraints . . . separate capacity prices are necessary in separate locations in order to reflect the differences in costs and capacity needs among the locations."); *Devon Power LLC*, 103 FERC ¶ 61,082 at P 37 (2003) (directing ISO-NE to develop "a mechanism that implements location or deliverability requirements in the ICAP or resource adequacy market" so that capacity within zones "may be appropriately compensated for reliability"). In general, to the extent any capacity has attributes that provide for a differential reliability benefit, those attributes should be recognized in the market design and compensated accordingly. A corollary of this principle is the desire to minimize, if not eliminate, the need for out-of-market contracts, such as RMR agreements.

Third, all competitive resources within a given location should be compensated at the same price. *See, e.g.*, *PJM Interconnection*, 117 FERC ¶ 61,331 at P 141 ("In a competitive market, prices do not differ for new and old plants or for efficient and inefficient plants; commodity markets clear at prices based on location and timing of delivery, not the vintage of the production plants used to produce the commodity. Such competitive market mechanisms provide important economic advantages to electricity customers in comparison with cost-of-service regulation. . . . This market result benefits customers, because over time it results in an industry with more efficient sellers and lower prices."); *Commonwealth Edison Co.*, 113 FERC ¶ 61,278 at P 43 (2005) (nondiscriminatory single-clearing price capacity auctions "ha[ve] the benefit of encouraging all sellers to place bids that reflect their actual marginal opportunity costs" and have been "found to produce just and reasonable rates for all the energy and ancillary service markets currently operated by the independent system operators and regional transmission organizations under our jurisdiction."), *order on reh'g*, 115 FERC ¶ 61,133 (2006); *Devon Power LLC*, 110 FERC ¶ 61,315 at P 45 (2005) (paying all "generators the same market-clearing price creates incentives to minimize costs, because a generator's cost reductions are retained by the generator and thus increase its profits" while paying "different amounts to different generators based on the level of compensation needed to keep the generator in operation would create a unit-specific cost-based system and undermine the advantages of a market for capacity."); *New York Indep. Sys. Operator, Inc.*, 110 FERC ¶ 61,244 at P 65 & n.76 ("Efficient pricing requires that suppliers receive the highest market value for their resources, independent of their bids [as] [t]his gives all sellers the proper incentive to offer their resources at the marginal cost of their highest valued use."), *order on reh'g*, 113 FERC ¶ 61,155 (2005); *New York Indep. Sys. Operator*, 103 FERC ¶ 61,201 at P 81 ("[A]ll capacity suppliers, regardless of the age of their resources, are entitled to the same treatment in the ICAP market. . . . The Commission does not see how [more expensive] generators could receive ICAP revenues that were fundamentally different from those paid to other generators. Moreover, those are the types of market signals the Commission would expect to encourage new generation additions."). The law of one price for similarly-situated competitive units providing the same reliability service is a basic economic building block, and price discrimination among competitive supply is inefficient and in the long run will increase costs. *Blumenthal v. ISO New England Inc.*, 117 FERC ¶ 61,038 at P 83.

Fourth, the exercise of market power by both sellers *and buyers* must be mitigated to ensure that prices are neither artificially inflated nor artificially suppressed. *See, e.g.*, *New York Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211 at P 32 (2008) ("We find NYISO's proposal is a just and reasonable methodology for mitigating supplier market power, while maintaining revenue adequacy for suppliers . . . ."); *id.* at P 100 ("We accept NYISO's proposal for net buyer mitigation, with modifications, in order to prevent uneconomic entry that would reduce prices in the NYC capacity market below just and reasonable levels."); *Edison Mission Energy v. FERC*, 394 F.3d 964, 968-70 (D.C. Cir. 2005) ("[T]he Commission's contradiction of its prior rulings acknowledging the potential ill effects of forcing down prices absent structural market distortions [and yet still imposing seller market power mitigation as] the epitome of agency capriciousness."); *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,043 at P 78 (noting appellate court's "concerns with mitigation plans that mitigate workably competitive markets, suppress prices and deter market entry"), *order on reh'g*, 112 FERC ¶ 61,086 (2005). The exercise of market power by either side of the market is destructive for competition and long-term consumer welfare. *See Devon Power*, 115 FERC ¶ 61,340 at P 114.

Q WHAT ARE YOUR RECOMMENDATIONS BASED ON THESE FOUR PRINCIPLES?

A As an initial matter, I recommend that the Commission formally recognize these four "capacity market requirements" as necessary attributes of capacity markets and the foundation for evaluating any new or existing market design elements. If a capacity market design proposal is inconsistent with any single element of these basic principles, it should be rejected or modified to conform with them. Any rule that, for example, fails to adequately mitigate buyer market power, or fails to recognize locational constraints, should be changed. This is the key to developing capacity market designs that are sustainable over the long-term.

Q WHAT CONCLUSIONS DID YOU REACH WITH RESPECT TO THE ALTERNATIVE PRICE RULE AS IT HAS EXISTED TO DATE?

A The APR that existed prior to the Hearing Order (the "Historic APR"), and its variants APR-1, APR-2, and APR-3 which have been placed in effect for FCA #4 (the "February APR") are the FCM rules that are intended to address the artificial price suppressive impacts associated with uneconomic entry as well as the inability of the FCM to recognize certain material locational reliability requirements. The Historic and February APRs attempts to identify narrowly prescribed situations where OOM capacity resources artificially suppress prices and offer limited remedies. As ISO-NE and NEPOOL implicitly recognize, the Historic APR fails to adequately remedy the problem. Unfortunately, the February APR, while a step in the right direction, also falls well short. Based on my review, I have identified at least three major flaws in the February APR proposals.

First, the APRs adopt too narrow a definition of OOM capacity resources. They continue to grandfather all of the existing OOM projects that have entered the capacity market in the first three FCAs. In addition, they inappropriately and arbitrarily terminate OOM status for future OOM projects after six years. I recommend that any offers of capacity that have been obtained via a discriminatory procurement process (*e.g.*, new entrant only) or other OOM pricing and offered into an FCA at below the cost expected of a purely merchant plant (that can only rely on normal, widely available market revenue streams and costs) by a purchaser of capacity (or entity working on behalf of such a purchaser),[3] specifically including governmental entities, should be subject to mitigation. This includes the procurement of what would otherwise be deemed uneconomic demand-side management. My recommendation would be that uneconomic entry via discriminatory actions by such entities should include mitigation to reflect 100% of the effective net cost of new entry of the underlying generation supporting the contract pricing (*i.e.*, the all-in cost of the contract over time less the expected market value of energy and ancillary services that are economically provided under the contract) in the APR adjustment. While the Commission has accepted lower mitigation values, the 100% figure is the most representative of the true economic cost of the resource and, absent any estimation uncertainty, is the value that should be used.

Second, the APRs' pricing method is incorrect. In particular, in the February APR, APR-1 and APR-2 identify the lowest price associated with displaced economic

[3] While from a theoretical perspective it would be sufficient to apply such mitigation only to net purchasers, as noted later, *see infra* note 20, the Commission has already made a determination that such mitigation should be extended to all parties, not just net purchasers, to prevent uneconomic entry from artificially suppressing prices. *See New York Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61,301 at P 29 (2008) ("NYISO will not be required to modify its proposed market power mitigation rules for uneconomic entry so that they only apply to net buyers. We find that all uneconomic entry has the effect of depressing prices below the competitive level and that this is the key element that mitigation of uneconomic entry should address."), *order on reh'g and clarification*, 131 FERC ¶ 61,170 (2010).

entry, not the appropriate "but for" clearing price that would have been observed absent the OOM capacity resources. When there is substantial OOM generation, this discrepancy can be expected to be substantial. The last incremental resource to de-list can cost significantly less than the marginal "but for" resource that would have set clearing prices if (a) there had been no underpriced OOM, or (b) OOM resources were priced at levels reflective of their true costs. I recommend that the APR pricing method be based on true "but for" clearing prices established on the basis of the mitigated prices identified above. This will ensure that the full price suppression impact of OOM capacity is eliminated. The rules should not be set up to permit "partial" price suppression. The Commission would never allow this on the supply side; nor should it be permitted on the buyer side if competitive markets are to be sustainable over the long-term.

Third, the February APR treats capacity that has been de-listed but retained for reliability, RMR generation, inappropriately. It fails to squarely address the underlying reliability need forcing the rejection of de-list bids, and may under-compensate other capacity resources, including those similarly situated to the RMR supply that are satisfying the same invisible constraint, but are similarly not paid the correct, higher, clearing price associated with that constraint. Further, under APR-3, there is an extraneous trigger/requirement related to the level of clearing prices (.6 times CONE) which serves no purpose and should be removed. I recommend that the FCA clearing process be reformed to reflect existing constraints to the fullest extent possible. This would greatly reduce, or may eliminate, the need for any RMR contracts to ensure reliability through Transmission Security Analysis ("TSA") or local resource adequacy requirements ("LRAR"). If constraints only become apparent during or after the FCA, for example, through the need to reject higher priced de-list bids that failed to clear in the auction, the FCA should be rerun incorporating an appropriate constraint. Ideally, all such constraints would be in place prior to the conduct of the FCA.

Q HOW DOES ISO-NE'S JUNE APR PROPOSAL CHANGE YOUR FINDINGS AND RECOMMENDATIONS?[4]

A In general it appears that the ISO-NE recommendations—assuming that its July 1 Filing adopts the proposals circulated in advance—will conform closely to the recommendations that I have made above. ISO-NE will consolidate the three rules into one, as I recommended, greatly simplifying it. Most importantly, ISO-NE will modify the pricing mitigation for the impact of OOM units on the capacity clearing prices received by existing in market generation. Specifically, ISO-NE will recommend what I see as a "first pass" or Tier 1 solution to set a clearing price for existing generation based on the use of a mitigated supply curve or set of offers reflecting pricing for OOM generation at appropriate reference prices indicative of the OOM generation's "true" economic cost of new entry. These mitigated offer levels will be used to calculate clearing prices for existing units, and the offers will be based on a review by the internal market monitor.

This aspect of ISO-NE's recommendation, assuming mitigated prices are used for all OOM resources (historic and new), in determining the auction price exactly conforms to my recommendation presented above and in earlier comments. It will assure that existing generation is compensated without distortion due to the presence of OOM. A

[4] These comments are based on June 15, 2010 slide presentation presented by ISO-NE to the stakeholders. I understand that the ISO-NE may slightly modify or change the details of their proposal as it will be presented in final testimony in this proceeding, but it is also my understanding that the slides represent the fundamental elements of their proposal. Obviously to the extent there are any material changes, I will modify my conclusions as appropriate.

Tier 2 set of prices will be established based on the original unmitigated offers, and, by allowing the OOM units to clear in future auctions, having already sunk their investment—albeit at the distorted prices that they themselves have caused—ISO-NE's proposal assures that OOM units can participate in the market, while preventing them from distorting prices for existing units.[5] This two-tier pricing will create a disincentive for uneconomic new entry. The NEPGA proposal calculates the Tier 1 price by mitigating all historic and new OOM offers to an appropriate reference price. It applies Tier 2 prices (reflecting the original OOM offers) to new OOM and new entry, and takes no position with respect to which of these prices is to be applied to historic OOM.

Q WHAT CONCLUSIONS AND RECOMMENDATIONS DID YOU REACH WITH RESPECT TO THE DEFINITION OF LOCATIONAL CONSTRAINTS WITHIN THE FCA?

A The proper treatment of locational or other reliability constraints can be seen as a corollary to APR-3. If a unit is needed for reliability, and that need cannot "be seen" by the auction process, then it is clear that the auction is not solving and pricing for the right reliability problems and associated configuration of the power grid. The only way to properly address this issue is to include all reliability and locational constraints that are known to impact adequacy requirements within the basic auction process. The correct approach is to do this all the time. If a constraint is included, and it is not binding on the auction solution, the solution and pricing will be the same as if the constraint was not included in the first place. However, should the constraint become binding, it will never

[5] Ideally, the uneconomic OOM would be rejected. Absent this action, the ISO-NE approach solves three major issues, first assuring that the existing generation is properly compensated, and second allowing OOM to clear reflecting what are principally discretionary actions of state political entities and third showing the price associated with the physical excess to new entrants. However, as in most "second best" solutions, this solution still allows price distortion with respect to some new entry.

be properly represented in the unit selection and pricing produced by the auction unless it was included from the start. The continual debate about whether or not and when to include relevant constraints is the proverbial red herring. If the constraints are material, they always should be included. The Commission's concern regarding adequate mitigation under this type of correct locational and reliability constraint representation is legitimate, and appropriate mitigation of potential market power should be in place whenever such modeling leads to unacceptable concentration of supply. However, the correct remedy for such concentration is mitigation, not the elimination of appropriate locational and reliability constraints.

Therefore, I recommend that any relevant locational/reliability constraints always be represented in the FCA process. The recently approved proposal for setting LSR requirements is a reasonable start, but it is relatively meaningless unless the resulting requirements are established and always solved for as part of the auction process. Otherwise there is no way to "see" when the relevant constraints actually become binding. An associated issue is that the necessary locational detail may create a complicated descending clock process. Thus, I would also recommend that, going forward, the ISO-NE consider whether the continued use of a descending clock auction mechanism is appropriate if the underlying locational and reliability constraints necessary to properly represent adequacy needs become too complex.

Q HOW DO THE CHANGES PROPOSED BY ISO-NE IN THE JUNE 15, 2010 SLIDE PRESENTATION IMPACT THE RECOMMENDATIONS THAT YOU HAVE MADE REGARDING LOCATIONAL DEFINITION AND CONSTRAINTS?

A The new ISO-NE position—again assuming that it does not significantly change in ISO-NE's July 1 filing—is virtually identical to my original recommendations and the position I summarize above. ISO-NE has proposed to reflect 8 zones within a descending clock auction all of the time, and to modify those zones over time based on the effect of actual bidirectional constraints. Further, recognizing the complexity of a descending clock auction to capture locational/reliability detail, it has also committed to investigate the use of a linear programming-based auction structure that would be more compatible with the necessary zonal and reliability complexity.

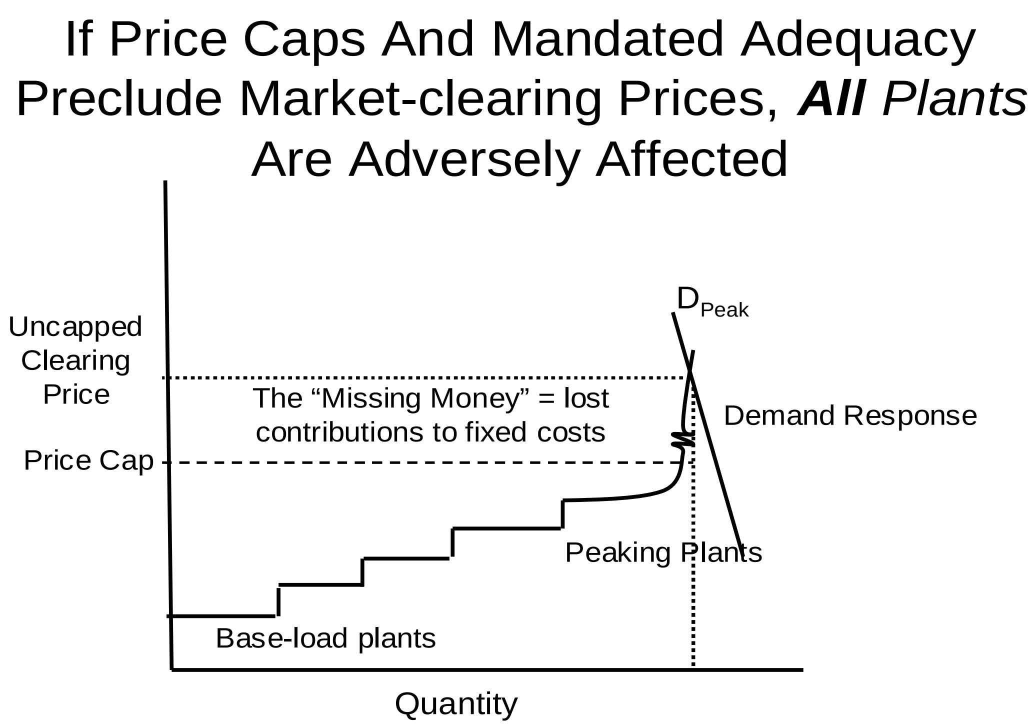
GENERAL BACKGROUND

Q COULD YOU PROVIDE SOME GENERAL BACKGROUND REGARDING THE NEED FOR CAPACITY MARKETS?

A The Commission has already fully accepted the logic supporting the implementation of locational capacity/adequacy markets in the major eastern markets, including ISO-NE. *See* cases cited *supra* at 4:17-23. The Commission has also accepted and supported implementing capacity markets with a forward procurement component designed to encourage new entry. However, it is worth summarizing the basic concepts of capacity markets in order to put in context the types of elements and criteria that should be included and considered in any modification to the FCM design.

Q WHY DO WE NEED CAPACITY MARKETS?

A Capacity markets, in whatever form, are all needed for one universal reason: In markets with capped energy prices and mandated adequacy requirements, returns from the energy and ancillary services markets alone, on average and over time, will not provide sufficient compensation to support the cost of new generation where or when it is needed, nor will these returns retain needed existing generation. Energy margins sufficient to support new entry and maintain investment in existing economic facilities cannot be reached due to binding price caps and enforced installed capacity requirements implemented through planning or other governmentally mandated processes that explicitly provide for intentional surplus resources to meet reliability targets for the market (for example, the Net Installed Capacity Requirement). The under-compensation of all generating units due to these two effects is illustrated in Figure 1 below.



Mandated adequacy/reserve requirements shift the supply curve to the right and have the SAME impact.

Q DO CAPACITY MARKETS SERVE ANY OTHER PURPOSES?

A Yes. Transmission limitations create an overlay of locational requirements that must be addressed. Not every generation resource can meet local reliability requirements, and some adjustment is needed to reflect local requirements either through price or directed requirements or both. The objective should be, as always, to send the appropriate price signal for the attraction and retention of capacity in the right quantity and location.

Q IS A CAPACITY MARKET NECESSARY TO MEET THESE OBJECTIVES?

A Under current circumstances in the northeast markets, yes. While a "pure energy only" market might theoretically work absent these mandated caps and surpluses, experience has shown that bid limits will be imposed—even after the fact—and energy prices will not be permitted to vary sufficiently to assure new entry when and where it is needed. Similarly there is no indication that it would be permitted to maintain a level of reliability that may be lower than NERC mandates, should that be required to yield the necessary energy revenues. This surplus will preclude necessary revenues and deter or eliminate private merchant development. Some additional form of compensation is needed to make up for what is generally referred to as the "Missing Money" problem. Capacity markets are a mechanism to provide these funds.

Q IF CAPACITY MARKETS ARE ESSENTIAL, THEN WHY DO THEY ONLY EXIST IN CERTAIN REGIONS?

A The Commission thus far has permitted some organized markets to go without the organized capacity markets seen in ISO-NE, NYISO and PJM. The record in each of the eastern RTOs reflects exactly the concerns and basic economic principles that I stated above. And while organized markets do not exist in all regions, I am not aware of any area of the country where there is not, in effect, an implicit reliability requirement based on either RTO or local planning requirements. Based on my understanding of the Energy Policy Act of 2005, it would be a violation of the explicit national reliability standards if such requirements were not in place in all control areas. *See* Energy Policy Act of 2005, Pub. L. No. 109-58, § 1211, 119 Stat. 594, 941 (adding FPA § 215, 16 U.S.C. § 824o). In other areas, such requirements may be met via other means, such as mandatory bilateral contracts or the assets of vertically integrated companies, however, the use of market mechanisms offers the potential for enhanced efficiency and transparency—factors that have been recognized and incorporated into the eastern RTO market designs.

Q HOW SHOULD A CAPACITY MARKET BE DESIGNED?

A The challenge is to design the capacity market to be as efficient as possible (that is, at the least total economic cost), while complementing other market design elements (such as energy and reserve markets and transmission system planning) and assuring general and locational reliability. Thus, a key objective for FCM redesign, specifically for the APR, should be to complement the overall efficiency of the ISO-NE FCM market design. Revenues from all markets in a region must, on average and over time, support the actual cost of new entry. Because the FCM market design includes a Peak Energy Rent credit that reduces payments to suppliers whenever energy costs are above a strike price,[6] a properly designed APR is even more critical in ensuring market efficiency as energy

[6] ISO-NE Tariff § III.13.7.2.7.1.1. It is my understanding that suppliers question the efficiency associated with the current design of the current Peak Energy Rent credit, including the reduction of capacity payments to resources that may perform in the Day-Ahead market but never receive the energy payment associated with the Peak Energy Rent. My testimony here does not address this concern, though I note that the current application of the Peak Energy Rent credit further complicates any projection of the total payments received by suppliers.

rents will be reduced (potentially significantly) by this deduction.[7] The FCM must make up for the energy margins/scarcity rents that are explicitly removed from compensation for capacity resources.

Inevitably there are elements in an administratively-established market that require estimation or adjustment. A design objective is to minimize the error in determining such factors and to allow for appropriate corrective actions. In particular this means that the design should satisfy the four general principles outlined below, including the need to address certain administrative requirements. This includes the recognition that a market cannot remain viable if it is subject to the abuse or exercise of market power, whether intentional or not. A comprehensive and balanced approach to this issue has to be a key concern in any FCM adjustment.

Q WHAT IS COMMISSION POLICY WITH RESPECT TO CAPACITY MARKETS?

A Proceedings related to capacity market designs in PJM, NYISO and ISO-NE have been before the Commission for at least ten years. While often only subsets of the market design issues have been addressed in each proceeding, collectively the Commission has created a set of very sound precedents that are consistent with the underlying economic theory on the need for capacity markets. As summarized above, I have categorized these findings as four general principles of capacity market design that the Commission has already firmly established. Viewing these principles together is a useful exercise given the broad scope of inquiry that the Commission has established in this proceeding. In accordance with basic principles of economics, I see them as forming the minimum

---

[7] Peak Energy Rents are deducted from the capacity payments of generators regardless of whether they are on-line producing energy or the energy price they are being paid. During a time that Peak Energy Rent event is occurring, it is possible and, in fact, likely that a given generator is being paid less than the cap implied by the Peak Energy Rent strike price and it is possible that the effective energy payment could be negative on a dollars-per-megawatt-hour basis, even with perfect generation performance in the PER hours..

design criteria or review standards for any capacity market design. While not offering a legal opinion, it would seem that consistency with these basic economic principles would at least establish the analytic underpinnings for any determination of "just and reasonable" with respect to proposed market design elements and changes to existing procedures.

GENERAL PRINCIPLES FOR CAPACITY MARKET DESIGN

Q WHAT IS THE FIRST GENERAL PRINCIPLE YOU IDENTIFIED?

A It is unambiguous that correct economic theory and the Commission's policy is to create mechanisms that attract new entry and retain economic existing generation, based on the expectation that on average, over time, market participants will have the opportunity to achieve payments equal to the long run average cost of new entry (net CONE or true net CONE).[8] The Commission has asserted this position in some form or another for ISO-NE, PJM and NYISO. *See, e.g.*, cases cited *supra* at 6:11-22 (quoting discussion in orders concerning ISO-NE).

The logic is simple and hard to refute in any meaningful fashion. No one will invest in a long-lived capital-intensive product in a market environment where not only is there general business risk, but the fundamental market design does not allow an opportunity or likelihood for the full recovery of return on, and of, invested capital. If structural elements in the design suppress prices or create biases or limitations on the

[8] The term true net CONE is used to refer to the net cost, after earned margins from the energy and ancillary services markets, to support new entry by the cheapest form of capacity, in this case a combustion turbine peaking unit. It is differentiated from the term CONE as used in the FCM/FCA market rules, where CONE is an output of an adjustment process that may result in values materially different than the true net CONE defined above.

ability to achieve such returns, the market design is fundamentally flawed and will not work.

Q HOW DOES A MECHANISM PRODUCE THE OPPORTUNITY TO OBTAIN AVERAGE REVENUES AT THE TRUE COST OF NEW ENTRY?

A If the market design allows prices to fluctuate over time based on various market conditions, the design elements that respond or adjust to such fluctuations must have the property of allowing for the achievement of this average true net CONE. Again the logic is simple; people will not invest in market where the design that pays the average some of the time, and less than average the rest of the time. So if the design allows for pricing that can be below average, presumably when supply is in excess, then it similarly *must* allow for and provide, at other times, a premium over the expected long run average value of true net CONE, presumably when the relative level of resources is lower, but not necessarily below, the mandated reliability requirements. The Commission has also expressed its understanding of this basic principle.[9]

[9] For example, in a recent order concerning PJM, the Commission explained:

> PJM also has not shown that prices using the VRR curve will not be sufficient to attract the entry of needed capacity. When the amount of capacity procured up to the date of the Incremental Auction is less than the Updated Reliability Requirement, the price offered to procure additional capacity on the VRR Curve would exceed the Net CONE, and thus, would send a strong economic signal to encourage additional supply. Of course, the amount of capacity procured in the RPM auctions for a given Delivery Year may occasionally fall somewhat short of the Reliability Requirement for a single year. RPM is based on the need to satisfy Reliability Requirements over a ten-year time horizon, but will not necessarily procure capacity equal to the Reliability Requirement in each year. In the years when PJM is short of the Reliability Requirement, the higher prices should encourage entry. In addition, the design of the VRR curve is biased (*i.e.*, designed to procure the Installed Reserve Margin (IRM) plus 1 percent of IRM, not simply IRM), so that over 10 years, on average PJM should procure on average more than the Reliability Requirement. In these circumstances, we see no reason for PJM to depart from the structure of RPM simply because the Reliability Requirement has changed since the Base Residual Auction.

PJM Interconnection, L.L.C., 131 FERC ¶ 61,168 at P 38 (2010) (footnote omitted).

Q HOW IMPORTANT IS THIS PRINCIPLE?

A The importance of this principle and the Commission's underlying policy goals cannot be understated, particularly when combined with regulatory mandates addressing minimum adequacy levels. The capacity pricing mechanism can be seen as a type of dampening system that is intended to result in the average price being set at the net true CONE. Market participants' responses to various incentives, such as price and expectations regarding future business conditions, drive supply up or down, and correspondingly drive prices the opposite direction.

The market rules have to allow for the average to be achieved. If, for example, some additional rules, such as NERC reliability standards, set minimum reliability criteria, then the use of a capacity market design must accommodate the NERC constraint while still allowing the average compensation target to be met. Implicit in this observation is that the entire variation in supply quantity may have to occur above the mandated reserve level. Again, the Commission has recognized these facts (at least in principle) in its decisions regarding the PJM market, where the proposed demand curve was "shifted" to the right in order to allow an equilibrium average quantity where prices equaled net true CONE in excess of the IRM. *See supra* note 9 (quoting *PJM Interconnection, L.L.C.*, 131 FERC ¶ 61,168 at P 38). This was done to accommodate the fact that it would be difficult to maintain reliability if, whenever higher, above-average prices occurred, as they must, the market might be physically short and potentially in violation of reliability rules. These conditions would invite out-of-market intervention to add supplies outside of the capacity market pricing mechanisms and, in turn, would interfere with the ability to achieve, on average, true net CONE.

Q WHAT OTHER CONSIDERATIONS ARISE WITH RESPECT TO THIS FIRST PRINCIPLE?

A Another corollary to this principal is control of volatility. While it is clear that the average must be at net true CONE, the magnitude and frequency of the variation around the average is another design factor that must be considered. And the Commission has expressed concerns about the volatility being too great. In moving to the use of demand curves in both PJM and NYISO, the Commission recognized that the use of a vertical demand curve was a material cause of so-called "boom/bust" business cycles and sought to minimize based on concerns that such volatility translated to risk to investors and costs to consumers. As the Commission explained:

> A downward-sloping demand curve would reduce capacity price volatility and increase the stability of the capacity revenue stream over time. This is because, as capacity supplies vary over time, capacity prices would change gradually with a sloped demand curve . . . . The lower price volatility under the sloped demand curve would render capacity investments less risky, thereby encouraging greater investment and at a lower financing cost.

PJM Interconnection, L.L.C., 115 FERC ¶ 61,079 at P 104 (2006).

Q WOULD YOU SUMMARIZE YOUR OBSERVATIONS WITH RESPECT TO THE FIRST PRINCIPLE?

A Yes. The Commission has established strong precedent for the concept that the design of capacity markets must allow for the opportunity to recover long-run costs on average and over time. Similarly, the Commission has recognized that the market must be allowed to either go long or short or otherwise vary in a fashion that allows higher payments during some periods to offset lower payments during others. The Commission's precedent also recognizes the value of the control of price volatility as a design parameter. These Commission policies are consistent with sound economic theory. Market designs that fail to meet these criteria will be economically flawed, will not attract and retain necessary supply, and will fail to comply with the general principles established by the Commission. Again, no one will invest in a market where they cannot expect to have the opportunity and reasonable probability to both recover their investment and earn a return on that investment.

Q WHAT IS THE SECOND GENERAL PRINCIPLE YOU IDENTIFIED?

A The Commission has made very clear that capacity markets must include locational signals consistent with the reliability requirements of the underlying market. *See* Hearing Order at P 134 & n.64 (citing *New England Power Pool and ISO New England, Inc.*, 100 FERC ¶ 61,287 at P 101 (2002) ("[W]e direct NEPOOL to develop a locational mechanism together with the other Northeast ISOs as it proceeds with the development of the Northeastern RTO."). Again, this is not a surprising conclusion. It is obvious that excess generation in northern Maine cannot meet local reliability needs in Connecticut. In all three eastern RTO capacity markets the Commission has concluded that locational requirements are necessary for the markets to be sustainable over the long term. *See, e.g.*, *supra* at 7:6-13 (quoting *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318 at P 76 and *Devon Power LLC*, 103 FERC ¶ 61,082 at P 37); *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 at PP 49-50 & nn.59, 60 (2006) (quoting *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112 at P 20 (2004) ("We believe that market design features such as locational requirements for installed capacity may prove an effective approach to create stable revenue streams.")); *id.* at P 51 & nn.61, 62 (noting the Commission "approved the use of a locational element in the capacity construct for" NYISO and ISO-NE) (citing *Central Hudson Gas & Elec. Corp.*, 88 FERC ¶ 61,138 (1999) and *Devon Power LLC*, 107 FERC ¶ 61,240 (2004)); *see also Midwest Indep. Sys. Operator, Inc.*, 131 FERC ¶ 61,228 at P 26 (2010) (discussing the need for a locational capacity construct in MISO). In particular, it has been noted that, absent constraints in the auction or procurement process that identify local needs and pay appropriate premiums when necessary to attract or maintain capacity to constrained areas, it will be necessary to enter into out-of-market, cost-based RMR contracts. The Commission has similarly expressed its conclusions that such contracts are antithetical to a market solution, and it is desirable to minimize or eliminate the need for such RMR devices. *See, e.g.*, *Devon Power, LLC*, 109 FERC ¶ 61,154 at PP 44, 67 (2004).

Q WHY ARE SUCH LOCATION REQUIREMENTS NECESSARY?

A The underpinnings of locational needs go beyond the intuitive statements above. Electrical networks can be seen as linear models. For adequacy, peak load requirements and generation can be represented where they occur on a transmission network, with appropriate flow limitations and operating contingencies linked to the same physical network. While different methods may be used, locational requirements can be observed if the problem described in this manner either doesn't have enough generation close to load or doesn't have sufficient transmission to allow remote generation to flow to meet load requirements (*i.e.*, the associated electric reliability planning problem to meet the required load doesn't "solve"). In these situations, it is clear that local generation is both needed and of greater value than remote generation, which may be constrained from reaching the load.

The models help quantify the limits that apply to the amount of capacity that can be reliably transferred, as well as the resulting zones with local sourcing requirements, and, if necessary, the presence of one or a small handful of generation units necessary to serve specific local reliability functions. When such information is directly incorporated into the auction solution "engine," the need for OOM or RMR units is eliminated, because the auction solves and prices in such a fashion that these requirements are met. The Commission has explicitly recognized that a need exists to reflect this different value, and further has recognized that there is a need to develop compensation and market designs that solve for the differentiated value, rather than using OOM mechanisms to pay for needed local requirements on a "one off" basis.[10]

The failure to allow for the representation of these locational requirements when they occur is a failure to comply with core economic objectives, the physical reality of the underlying adequacy requirements, and the general findings of Commission precedent.

Q WHAT IS THE THIRD GENERAL PRINCIPLE WHICH YOU IDENTIFIED?

A The Commission has recognized locational needs when some capacity is not fungible with all other capacity. *See, e.g.*, *ISO New England Inc.*, 130 FERC ¶ 61,235 at P 40 (2010) (rejecting the argument that ISO-NE's "tariff should be interpreted to mean, in essence, that suppliers may elect price proration rather than quantity proration, even when that election could result in reliability violations"). Similarly, the Commission has also recognized that when capacity is fungible—that is when it meets the same locational and

[10] The following example from a Commission order concerning PJM illustrates these points:

> We agree with PJM that a locational element should be included in the capacity construct as a means of attracting new resource investment in the locations where it is needed most. Not all capacity in PJM is deliverable to all locations in PJM, and it is unreasonable to allow an LSE in one location to satisfy its capacity requirement with resources whose energy is not deliverable to the LSE. The evidence provided by PJM shows that the lack of a locational element is a contributing factor to reliability problems within PJM.

PJM Interconnection, L.L.C., 115 FERC ¶ 61,079 at P 49.

reliability needs—it is appropriate that all capacity be paid the same price. *See, e.g.*, cases quoted *supra* at 7:19–9:4. The simple statement here is that one MW of capacity in the same location is worth exactly the same as any other MW in that location because all of these MWs are providing the same reliability service (adjusted for individual unit performance). The Commission again has been very explicit in supporting this finding, and, in turn, the need for there not to be any form of price discrimination between similarly-situated generation. *See, e.g.*, *New York Indep. Sys. Operato*r, 103 FERC ¶ 61,201 at P 81 ("[T]he Commission finds that all capacity suppliers, regardless of the age of their resources, are entitled to the same treatment in the ICAP market.").

Once again, this principle is supported by market and economic fundamentals—in this case what is usually referred to as the "law of one price." For similar-situated commodities, absent the presence of market power, there is no basis to compensate or pay for a product from one supplier a different price than the same product from another source.[11] Competition enforces this effectively: if one party tries to charge more, the buyer simply moves to the next supplier with the comparable product, and the process continues until all suppliers are driven to price at equilibrium (where the marginal production cost equals the marginal value of the commodity in the market place). Similarly, buyers will not be able to hold out for lower prices than justified by the value set by the intersection of demand and supply curves. There will be no alternative price

[11] As discussed further in the testimony of Professor McAdams, there may be situations where the most appropriate mitigation *after* the exercise of market power or to resolve uneconomic excess capacity, the use of several different prices. But this is in the context of correcting a distortion to what would have been an efficient single clearing price for comparable goods absent the external manipulation and/or subsidies. Having separate pricing as a means to correct defects in market behavior or bids that would otherwise distort market prices is not inconsistent with this general principle.

that would allow buyers as a group to be better off. Deviations from this pricing are well understood to be inefficient and non-welfare maximizing.

Q HAS THE COMMISSION RECOGNIZED THE LAW OF ONE PRICE?

A Yes. *See, e.g.*, *Blumenthal v. ISO New England Inc.*, 117 FERC ¶ 61,038 at P 83 ("[T]he purpose of single price auctions and competitive markets [is] to establish just and reasonable rates over the long term that reflect the marginal cost of competitive generation in this market."). When confronted with various proposals that would result in some capacity being paid more or less than others, particularly the notion of "old or existing" capacity being paid less than new generation, the Commission has properly found that this is a form of price discrimination and an attempt to exercise market power, which, in the long run, results in an inefficient and more expensive solution for consumers as a whole. *See New York Indep. Sys. Operato*r, 103 FERC ¶ 61,201 at P 81.

Again, the obvious conclusion here is that the inclusion of design principles that result directly or indirectly in price discrimination, and the associated exercise of market power, are inappropriate and violate the concept of just and reasonable rates. In turn, ensuring that such discrimination is not embedded in the market design (other than in the limited circumstances of need to address other market failures such as the exercise of market power as proposed by Professor McAdams) becomes another fundamental objective in establishing the appropriateness of any capacity market design.

Q ARE THERE ANY CIRCUMSTANCES WHEN IT IS APPROPRIATE TO PAY DIFFERENT PRICES?

A Yes. In situations where the market design has allowed deviation from what would be considered a fully competitive solution, it may be appropriate to modify the prices of some market participants prospectively to reflect both the mitigation of uneconomic entry, and to prevent further entry where there is no actual need. I discuss this further below.

Q WHAT IS THE FOURTH GENERAL PRINCIPLE THAT YOU IDENTIFIED?

A The final principle is the recognition that the exercise of market power, both by buyers and sellers, must be mitigated. No market design (for energy or capacity) can be sustained in the presence of the exercise of market power. Typical capacity markets are concentrated with respect to both market buyers and sellers, increasing the potential for the exercise of market power on either side of the market. While the overall capacity market can be seen as an administrative structure designed to result in the "right" level of compensation for new entrants over time, in ISO-NE and the other eastern RTOs, market-type mechanisms are used to implement this design objective. The ability of buyers or sellers to distort prices via the exercise of market power would undercut the effectiveness of any market-based design to reasonably attract and retain needed generation at competitive pricing levels. The Commission has recognized this principle in a number of orders, explicitly approving the adoption of rules designed specifically to mitigate market power in capacity markets by both buyers and sellers to ensure that prices are neither artificially increased nor artificially suppressed. *See, e.g.*, *New York Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211 at PP 35, 100 (2008).

As the final principle and screen, if a design element or modification results either in the ability to intentionally or unintentionally allow for the exercise of market power by either buyers or sellers, it should be rejected.

Q HOW SHOULD THESE FOUR PRINCIPLES AND THE RELATED CONCLUSIONS BE USED BY THE COMMISSION IN REVIEWING CAPACITY MARKET DESIGNS?

A One of the problems that has occurred in the development of capacity markets has been the fact that often issues have been isolated in different proceedings, and evaluated on a stand alone basis. Thus, even when identifying the need for any single one of these conditions in a specific proceeding, the net result can be a "bad" overall design if all of these basic elements are not considered simultaneously. For example, it makes little sense to have a lot of locational detail in an auction process for capacity if the remaining market rules do not allow for the long-run recovery of the true CONE over time, do not allow for the actual pricing of locational differences, and/or also allow for load to exercise market power to suppress prices. Similarly, having exactly the right locational and pricing rules would be meaningless if suppliers can physically or economically withhold and distort prices in the upward direction or submit bids below their true, unsubsidized costs and distort prices downward. All of these principles have to be met simultaneously as a necessary condition for any new market design element to be adopted.

Indeed, the purpose of presenting the above four principles in a single location is to encourage the Commission and others to begin to view them as fundamental capacity market requirements, regardless of the limits of scope within any one proceeding. Only in this fashion will we be able to break out of the cycle of fixing one thing, and then, faced with a market that is still not operating properly, returning a few months later to address another inconsistency created by ignoring some aspect of these four principles.

ALTERNATIVE PRICE RULE—THE NEED FOR BUYER MITIGATION

Q WHAT IS THE ALTERNATIVE PRICE RULE (APR), AND WHAT QUESTIONS DID THE COMMISSION RAISE WITH RESPECT TO THE ALTERNATIVE PRICE RULE?

A Under the market design that pre-dated the Hearing Order, there was a very limited APR (the "Historic APR") that applied to pricing when there are units deemed to be OOM (*e.g.*, provided with some external source of revenues that allows the supplier to submit bids at less than its cost, and, in turn, artificially results in depressed prices for the overall market). In the presence of both OOM and the need for new capacity, prices were reset to the lesser of (a) the administrative CONE or (b) $.01 less than the price of the last new entrant to exit the descending clock auction, notwithstanding the number of OOM megawatts that cleared in the FCA. Most of the ISO-NE FCM Revision filing was devoted to efforts to expand the scope and effectiveness of the APR rule by modifying the rule and adding two additional elements. Even then ISO-NE acknowledged that there were open issues in this area that still remained to be addressed. In the Hearing Order, the Commission requested comments on three elements related to the revised APRs: (1) triggering conditions, if any, for the APR; (2) treatment of OOM resources that create capacity surpluses for multiple years; and (3) appropriate price adjustment under APR. Hearing Order at P 18.

Q WHY IS THERE A NEED FOR BUYER SIDE MARKET POWER MITIGATION IN THE FIRST PLACE?

A It has become increasingly clear to me that certain market participants operate under the (sometimes-explicit) fundamental belief that price discrimination is a legitimate and desirable goal to be pursued in capacity market design. Such viewpoints persist notwithstanding Commission findings that, while artificially suppressed prices appear attractive to consumers in the short run, they cannot be sustained—and actually result in higher costs all else equal—in the long run. Yet, over and over again, despite repeated Commission rulings regarding the need for uniform pricing for efficiently set uniform products to ensure the long-term sustainability of competitive markets, and despite the associated fundamental economic theory supporting these conclusions, parties repeatedly have voiced a desire to implement mechanisms where old or existing capacity receives one lower price, and only new entrants are compensated at market rates. *See, e.g.*, *New York Indep. Sys. Operator*, 103 FERC ¶ 61,201 at P 81. Despite the fact that the fundamental sources of these parties' discontent typically is unhappiness with historic business or regulatory decisions (such as the failure to hedge when prices were lower or regrets regarding the prices and agreements related to divested generation), there is nonetheless a continuing sentiment that it is "unfair" for older, infra-marginal capacity resources to receive equal and non-discriminatory market clearing capacity payments. While the rationales vary, the common denominator in these parties' market design proposals are attempts to institute mechanisms that bypass market clearing processes and yield differentiated pricing for some or all of the existing capacity resources versus new capacity resources.

I am continually amazed by the methods and justifications employed to attempt to get this discriminatory result. The reality, however, is that many times parties do succeed in establishing rules or procedures that allow for this type of discrimination. To some extent that is true in the FCM design with respect to the current rules regarding OOM capacity resources. Despite any purported justification to procure uneconomic supply, the net result is that this type of OOM results in discriminatory pricing that artificially suppresses prices for all of those parties other than the beneficiary of OOM payments. Thus the existing rules clearly fail the four principles screen with respect to the need to mitigate market power, the ability to obtain the long-run necessary level of compensation, and also with respect to the basic principle of the law of one price.

To its credit, ISO-NE has attempted to grapple with a major potential source of this type of price discrimination: OOM capacity resources that are either uneconomic and reflect a long term excess, or those that are driven by reliability constraints hidden from the general reliability assurance process. The February APR properly focused on OOM and associated market power issues, but ultimately was inadequate to properly mitigate the exercise of market power by buyers and the resulting price discrimination.

Q WHAT EFFECT WILL OOM SUPPLY HAVE ON THE MARKET?

A I make several specific recommendations—detailed below—to properly address distorting OOM supply that is either a function of uneconomic entry or missing constraints in the resolution of the capacity market. However, before discussing these criticisms and recommendations, it is important to first fully understand the corrosive nature of the exercise of buyer market power.

I cannot emphasize enough that unless buyer market power is effectively mitigated, ISO-NE's capacity market will fail. To have any hope of effectiveness, such buyer market power—past and present—must be mitigated prospectively, including any actions taken by government entities that, in fact, often are in the best position to either directly exercise exactly this type of improper market power or make feasible uneconomic investment by others by allowing recovery of what would otherwise be uneconomic expenses.

Q CAN YOU EXPLAIN MORE GENERALLY HOW BUYER'S CAN EXERCISE MARKET POWER AND ARTIFICIALLY DEPRESS PRICES?

A Yes. It is a fundamental point that no market design will work in the face of the exercise of market power, either by buyers or sellers. Absent sufficient intrinsic competition, some mechanisms to screen and mitigate market power are necessary. The potential exercise of market power by buyers is of particular concern in this situation, given the abrupt clearing price structure of the declining clock auction mechanism and the absence of a demand curve, where small excesses of capacity can significantly depress pricing, and also given the concentrated purchasing power of several buyers with the ability to make discriminatory investments in uneconomic capacity resources, and then to subsequently recover these uneconomic investments through cost-of-service rate making or its equivalent.

The current rules provide incentives that support precisely this kind of behavior. We have already seen it occur,[12] and it is likely to continue in the future.

---

[12] Connecticut entered into a contracting process with new resources that included requirements for how to bid into the FCM. *See DPUC Review of Peaking Generation Projects*, Docket No. 08-01-01, 2008 Conn. PUC LEXIS 126, at *15 (June 25, 2008) (listing the "effect on the forward capacity market (FCM) price" as first factor in the OCC's evaluation of proposed peakers); *DPUC Review of Energy Independence Act Capacity Contracts*, Docket No. 07-04-24, 2007 Conn. PUC LEXIS 219, at *82-83 (Aug. 22, 2007) ("The Department agrees with the [Office of Consumer Counsel] and finds that Section 3.4(b) of the Master Agreement between Ameresco and UI explicitly requires it to participate in the FCA. This was *driven by the objective of obtaining a New England-wide price impact in the FCA*, which was desirable for the Department in its objective to *lower costs for Connecticut ratepayers*.") (emphasis added); *id*. at *99 ("There will be a multiplier effect for the benefit of ratepayers as a result of the hedge created by these [Contracts for Differences] – even if the contracted capacity is a small portion of the supply meeting Connecticut's requirements, these contracted resources are *expected to lower the market clearing price and therefore reduce costs to all load*.) (emphasis added); *DPUC Investigation of Measures to Reduce Federally Mandated Congestion Charges*, Docket No. 05-07-14PH02, Second Interim Decision, Attach. 4 at 4 (Nov. 16, 2006) ("The DPUC's objectives in its bidding requirements has always been that it does not want the Supplier, who already is covering his fixed costs through this Agreement, to set prices in the FCM . . . .").

Q CAN YOU PROVIDE A SIMPLE EXAMPLE?

A Yes. A hypothetical example shows the incentive for this type of behavior. Assume that the Net Installed Capacity Requirement ("Net ICR") was 35,000 MW. Also assume that there is a net need for new capacity of 1,000 MW. Assume further that the actual cost of new entry ("CONE") was $8/kW-month and that this was the price paid for 1,000 MW of OOM capacity procured via a governmental entity "new supply only" solicitation. Finally, assume that all of the OOM was actually directed to be offered into the FCA at the permitted level of 75% of CONE (that is, $6/kW-month) and set the clearing price in the auction. In this hypothetical, even though partially mitigated, the uneconomic OOM offer depresses the price of 34,000 MW by $2/kW-month, or $68 million/month. In this case, the cost to the party offering the artificially lowered price is actually nothing, as absent the uneconomic offer, they would still have paid $8/kW-month to the new entrant if they both offered and cleared at the same price.

The impact can be even greater if the OOM capacity is procured in such a manner as to allow it to be offered at zero price and the amount of OOM is larger. This could happen under current rules if a large block of capacity, say 3,000 MW were procured OOM, and then carried into the next FCA. In that case there is 3,000 MW OOM permitted to be bid at zero price and now, further assume that this results in a de-list bid setting the clearing price at the depressed level of $4/kW-month. Now prices paid on 32,000 MW are artificially depressed by $4/kW-month, or $128 million/month. This dwarfs the purchaser's cost, paying $4/kW-month above the depressed clearing price for the 2,000 MW of uneconomic resources, or $8 million/month. (Depending on the details of the actual clearing, there would also be an adverse impact of forcing the retirement of otherwise economic units over time displaced by the artificially low bids because these prices are not sustainable. No direct cost is attributed to this distortion in this example.)

Q WOULD THIS STRATEGY WORK EVEN IF THE BUYER ONLY REPRESENTED A PORTION OF THE MARKET?

A Yes. While the above example is for the market as a whole, the mechanics of this process still work even if the load purchasing the excess only serves a portion of the market. For example, consider what happens if the load-serving entity serves only half of the load in the market. In this case, depressing the price on only half of the market results in savings of "only" $64 million/month—still vastly profitable compared to the cost of $8 million/month for the uneconomic supply.

Q DOESN'T THE EXERCISE OF BUYER MARKET POWER REDUCE PRICES?

A Absolutely not. As the Commission has observed, while this exercise of market power seems an attractive proposition for load—at least in the short run—it is disastrous for the ongoing viability of competitive markets in the long run. *See New York Indep. Sys. Operator*, 122 FERC ¶ 61,211 at PP 100-106; *id.* at P 104 & nn.55 & 56 (citing orders approving buyer market power mitigation measures in PJM and ISO-NE). Suppliers are victimized by the price discrimination wherein only new entrants receive the competitive market price, indicative of the steady state cost of new entry, while all other existing units receive an artificially suppressed payment. This effectively creates an unjustified pricing structure where competitive existing suppliers are discriminated against vis a vis subsidized new entrants via the exercise of power market power. This occurs even though other market participants provide the same reliability product or service, but certain individual new entrants are paid a higher price and all other existing suppliers unjustifiably are paid a lower price. Ultimately no one will seek to enter the market other than by such OOM agreements, as a supplier without such protection would practically be asking to be victimized following the initial "lock-in" period through the future exercise of buyer market power. After all, eventually all favored "new suppliers" will become "existing suppliers" subject to victimization. To compensate for that risk, any entrant would have to be compensated by ever increasing price levels, encouraging ever greater use of buyer market power as the perceived cost of new entry rises. As the market structure is unwound, required contract by required contract, risk gets shifted back to consumers and one of the core benefits of competitive markets is lost.

Q DOES THIS TYPE OF BUYER MARKET POWER HAVE OTHER ADVERSE IMPACTS?

A Yes. There are additional adverse impacts associated with this type of distortion. These relate to the important function regarding retention of existing units that would otherwise be economic but for this price distortion. By artificially depressing prices, some resources, which would have been committed in a competitive auction, will fail to clear the market, and therefore retire unless they are needed for reliability. This effect will inefficiently accelerate the "turn-over" of the entire capital generation stock and, as discussed below, will lead back to the need for RMR contracts.

These types of adverse effects are not news to either economists or regulators. The Commission has explicitly rejected this type of discriminatory pricing in the ISO-NE, PJM and NYISO capacity markets. In accepting the NYISO demand curve design for capacity payments, the Commission explicitly rejected the argument that it would be appropriate to price in such a manner so as to discriminate between new entrants and existing capacity, stating:

> The Commission finds that all capacity suppliers, regardless of the age of their resources, are entitled to the same treatment in the ICAP market . . . . The Commission does not see how [new] generators could receive ICAP revenues that were fundamentally different from those paid to other generators.

New York Indep. Sys. Operator, 103 FERC ¶ 61,201 at P 81. Similarly, the Commission endorsed uniform market clearing prices for all participants, new entrant or existing. *See id.* at PP 77, 81.

Any attempt to bypass such decisions via the exercise of market power would eviscerate the capacity market over time and as a result also lead to the need for existing suppliers to rely on RMR contracts for the remaining capacity that otherwise would have been "in market" but for the price discrimination. This accentuates the very harm the Commission has spent the last three years attempting to rectify in all three capacity markets.[13] When the party purchasing the excess capacity controls the entire market, or is able to recoup via regulatory approval what are otherwise uneconomic excess payments for such capacity, market power—not market forces—improperly distort the market outcomes.

Even a party that is obligated to pay for only a fraction of the system's capacity requirements can still profit itself (and other loads) by purchasing uneconomic supplies.

---

[13] *See*, *e.g.*, *ISO New England Inc.*, 120 FERC ¶ 61,087 at P 2 (2007) (recounting history of FCM in New England, and highlighting "concerns regarding the number of generators seeking" RMR contracts "and the effect that widespread use of such contracts could have on the competitive market"); *Devon Power*, 103 FERC ¶ 61,082 at P 29 ("extensive use of RMR contracts undermines effective market performance"); *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275, *order on reh'g*, 128 FERC ¶ 61,157 (2009); *PJM Interconnection*, 115 FERC ¶ 61,079, *order denying reh'g and approving settlement*, 117 FERC ¶ 61,331, *order on reh'g and clarification*, 119 FERC ¶ 61,318; *Devon Power*, 113 FERC ¶ 61,075, *order approving settlement*, 115 FERC ¶ 61,340 at P 7; *New York Indep. Sys. Operator*, 103 FERC ¶ 61,201, *reh'g denied*, 105 FERC ¶ 61,108; *New York Indep. Sys. Operator, Inc.*, 111 FERC ¶ 61,117, *reh'g denied*, 112 FERC ¶ 61,283 (2005); *New York Indep. Sys. Operator*, 89 FERC ¶ 61,109, *order on reh'g and clarification*, 90 FERC ¶ 61,085.

When there are multiple, independent capacity purchasers, the party engaging in this anti-competitive behavior will wind up with an average price that can be significantly higher than its competitors who serve the remaining load in the system (or locational area). Under a competitive regime where retail load is contestable by multiple sellers, this type of behavior, even though profitable for the party exercising market power, could not persist over the long-term because, while the costs to the exerciser of market power decline, that party would still have higher average unit costs than its competitors' because it is the only party that pays the price for the distortion (*i.e.*, the market price for the uneconomic entry). Ultimately this factor would cause it to lose market share to its competitors and therefore eventually also lose the benefits of this market power exercise.

Thus, while there may be a short-term incentive for this behavior when there is competition for sales, it is not sustainable long-term without regulatory help to socialize the cost of the exercise of market power across all of its beneficiaries.

However, if a party with only partial market share, who purchases the excess capacity in a discriminatory manner, can be assured of recouping its investment, the incentive will exist to exercise market power continually, because that party is protected from the competitive downside. Market shares may adjust, but the guaranteed recovery will keep the party making the uneconomic investment from experiencing a loss, while also dropping prices for the market as a whole. Thus, the exercise of buyer market power is at its safest, most profitable, and most pernicious, when it is under the direction of state or other regulatory agencies that artificially lower the costs for their own constituents, while at the same time offering contracts or regulated recovery to assure the recoupment of expenses incurred for those procuring the uneconomic resources. This is why the concern must be focused not only on those directly making such uneconomic investments, but also on those for whom these parties may be acting as an agent.

Q HAVE OTHERS SUGGESTED THAT THERE IS NO NEED TO MITIGATE AGENTS WHO ARE THE BENEFICIARY OF SUCH SUBSIDIZED CONTRACTS OR SIDE PAYMENTS?

A Yes. Several parties offered this logic, and the specific comments of the Connecticut Department of Public Utility Control are discussed in more detail below. The presence of such comments (and actions) is exactly why we must reject the apparently straightforward notion that a party with a bilateral out-of-market agreement is bidding rationally at zero. We must recognize the fact that while this seller/agent may see no reason to offer at the true cost of the capacity, the party on the other side of the bilateral agreement, who is purchasing the uneconomic capacity, is the *real* party exercising market power, and it is this party's behavior that must be reviewed and form the basis upon which the clearing price should be mitigated.

Q WHAT IS THE LONG-RUN EFFECT OF THIS TYPE OF EXERCISE OF BUYER MARKET POWER?

A These corrosive elements ultimately undermine any incentives for private investment and effectively, over time, will lead to a default back to a central procurement, cost-of-service market—the very form of inefficient regime that led to the movement to competition in the first place. The only difference is that, here, the existing capacity that is not the beneficiary of the discriminatory prices will receive the artificially reduced prices rather than the same cost-of-service approach applied to all resources equally. There likely will never be sufficient private new entry because any participant other than those selected via the discriminatory process would expect always to receive prices that are well below the required average true CONE. In fact, participants that obtain a discriminatory contract will likely be required to add an additional margin into their offers to address the fact that, at the expiration of such an agreement, they too will be ready victims of price discrimination.

Similarly, over time, otherwise economic and needed existing capacity resources may be forced either to retire early or to seek an RMR contract—should the exercise of seller market power drive prices below the long-run going-forward costs of such existing capacity. This leads to the inefficient turnover of the capital stock mentioned above.

Eventually, all capacity will either be based on long-term discriminatory procurements or enter RMR contracts. This effectively defaults back to a world that looks like central rate-based planning, except for the de facto seizure of capacity from existing suppliers at arbitrary prices set by the entry or procurement of uneconomic capacity resources and the associated exercise of market power. Unless fully mitigated, this combination of events assures the demise of a market-based solution and the benefits that have been produced by this model.

Q WHAT ARE THE IMPLICATIONS OF A FAILURE TO ADDRESS OOM AND THE EXERCISE OF BUYER MARKET POWER IN TERMS OF THE FOUR BASIC PRINCIPLES?

A Clearly any design with this weakness fails to assure the opportunity for the long-term recovery of the true CONE due to the underpayment. Similarly, because this is effectively a form of price discrimination, the law of one price is being violated by the exercise of market power, so the third and fourth principles are likewise not met.

ALTERNATIVE PRICE RULE—ISO-NE PROPOSALS

Q CAN YOU DISCUSS ISO-NE'S FEBRUARY APR IN THE CONTEXT OF THE ABOVE COMMENTS?

A In the context of the above general policy discussion, it is possible to draw several conclusions and make associated recommendations regarding the specific adjustments to the February Alternative Price Rule that ISO-NE and NEPOOL originally proposed, as accepted in the Hearing Order solely for use in FCA #4. Conceptually, I address the three rules in the February APR in two pieces: (a) APR-1 and APR-2, which are focused on uneconomic entry, and (b) APR-3, which deals with RMR-type OOM related to rejected de-list bids that reflect missing or invisible operational or reliability constraints in the FCM/FCA design. As I said before, the good news is that ISO-NE, while always recognizing the need for reformulating its approach to these issues, has now taken some affirmative steps in this direction as reflected in the June APR proposal.

As a general observation, the overall structure, and attempt to formulate the three APR rules as separate and mutually exclusive, is needlessly complicated and also likely to create unintended gaps. By focusing on the detailed mechanics, rather than the big picture, ISO-NE and NEPOOL failed to hit the target, and the proposals could have been more simply formulated and more effectively applied. Below I discuss some of the more flagrant failings of the ISO-NE/NEPOOL proposals.

Q DID THE COMMISSION OFFER ANY GENERAL OPINION ON THE FEBRUARY APR AND ITS EFFECTIVENESS AT ADDRESSING PRICE DISTORTIONS ASSOCIATED WITH OOM SUPPLY?

A Yes, the Commission reaffirmed concerns that the three APRs in the February APR may be inadequate while reinforcing its support for two of the general principles set forth above—the first general principle regarding the need for adequate long term cost recovery and the fourth general principle regarding the need to mitigate the exercise of buyer market power and uneconomic entry. The Commission stated:

> APR is a market power mitigation rule intended to discourage buyers who have the incentive and ability to suppress market clearing capacity prices below a competitive level from doing so. We have previously accepted rules to address such uneconomic entry in the capacity markets of ISO-NE, as well as in NYISO and PJM. Our objective in accepting these provisions has been to ensure that the prices in capacity markets reflect the market cost of new entry when new entry is needed.
>
> We agree with the EMM and the commenters that ISO-NE's existing APR does not fully meet this objective. For example, the existing APR provides a price adjustment for OOM resources only when there is a need for new capacity as reflected by an ICR that exceeds all existing capacity. But new capacity may be needed in other situations, such as when some existing capacity retires from the market. Moreover, we also agree with commenters that OOM resources can affect prices even when no new capacity is needed, by displacing what would otherwise be the marginal, price-setting existing resource. And we agree with commenters that the price adjustment under the existing APR does not always fully correct for the effect of OOM resources on the capacity price. That is, the existing APR does not establish the price that would have arisen had all of the OOM resources offered at prices that reflect their full entry costs net of in-market revenues. Thus, when OOM resources are offered into the market, the existing APR does not ensure that capacity market prices reflect the market cost of new entry when new entry is needed.

Hearing Order at PP 69-70.

Q ARE APRS 1 AND 2 SUFFICIENT TO MEET THE MARKET DISTORTIONS ASSOCIATED WITH OUT OF MARKET SUBSIDIES?

A No. Both rules explicitly attempt to moderate (though not eliminate) the impact of OOM capacity but fail to offer a complete remedy that I would consider compliant with the four general principles. This uneconomic capacity surplus could be caused by either an excess of OOM in the current FCA or excess OOM carry-forward from previous FCAs. However, the triggering mechanisms and the ultimate mitigation proposed by ISO-NE are needlessly complicated and don't reach the desired objective of pricing capacity as if the distortion were not there in the first place, in compliance with the first and third general principles.

Q DID YOU COME TO A CONCLUSION REGARDING A CORRECT WAY TO ADDRESS THIS PROBLEM?

A Yes. The rules originally proposed by ISO-NE try to distinguish between different circumstances in which new capacity clears, creating mutually exclusive triggers based on new or previously existing OOM. But this misses the point. OOM is OOM, and the right solution that meets the four general principles is the same: mitigate the OOM capacity offers into the FCA to a justified bid or cost, consistent with either the underlying contract or construction costs. Under this purest form of price correction there is no distortion in the resulting auction prices as "true" bids are substituted for any OOM offer.

If there is a legitimate need for the OOM, the mitigation will not matter. Market prices would properly be higher in all events and the resource will clear at the mitigated price; if the OOM is not needed when appropriately priced, it won't clear. In other words, these units have effectively become "in merit." If not needed when appropriately priced, they won't clear. This is also the economically efficient result. This *ex ante* mitigation should persist for so long as there is excess uneconomic capacity that was introduced to the market, be it a year or a decade after the uneconomic introduction. This simple type of solution eliminates several weak elements of the proposed rules, particularly the arbitrary nature of the duration of mitigation.

Q ARE THERE MORE RESPONSIBILITIES FOR ISO-NE THAT GO ALONG WITH THE FORM OF MITIGATION FOR OOM RESOURCES YOU ARE SUGGESTING?

A Yes, but I don't believe that they are either onerous, or for that matter much different than already occurs in a market like PJM. It does require more detailed analyses of the potential anti-competitive pricing and behavior. This, however, should not be a bar to getting the solution right and does not appear to require substantially different administrative effort than the procedures now in place where the PJM market monitor conducts similar evaluations. There, the market monitor routinely sets mitigated price caps reflecting marginal costs of existing units and offer floors for use in mitigation of uneconomic entry based on either general generation classes or unit specific data. Given the long lead-time of the auctions this is not a particularly difficult task. Further, as I understand the user interfaces, it would be likely that ISO-NE could purchase or just be given the software used by Monitoring Analytics in PJM and duplicate the same type of screens and information relatively easily.

Consistent with the fourth general principle, and obviously complementing the first, the Commission has supported this approach, and I am not aware of any barriers to use of similar data here.[14] Another benefit here would also be the proper ordering of compensation for OOM units' entry to reflect relative economic benefits as they do become needed in the market, further reducing the distorting effects that OOM payments have on the capital stock mix.

Q WILL THIS TYPE OF APPROACH SOLVE THE TYPE OF UNDER-PRICING BIAS YOU IDENTIFIED ABOVE ASSOCIATED WITH THE INTRODUCTION OF LARGE AMOUNTS OF OOM AND THE APR PRICE RESET?

A Yes. This simple solution solves a material error in the current and February APR pricing rules. In the February APR, if one of the APRs is triggered, the mitigated price would be the lesser of CONE or one cent less than the last new entry bid to exit the FCA. This *ex post* adjustment can differ substantially from the correct clearing price which would have resulted had all supply properly bid into the FCA at its economic or mitigated price. The best way to visualize this is to imagine a bid "stack" of supply, ordered by price, summing to our hypothetical 35,000 MW of Net ICR. If 3,000 MW of OOM are offered at zero, the current and proposed pricing rule would reset the price effectively at the price of the 32,001st most expensive MW in the bid stack (sans the OOM). However, had there been fully competitive and economic supply pricing, the clearing price would have been set at the price of the 35,001st most expensive MW.

This "gap" in the mitigated price result would not be as significant if the level of OOM supply had only been a few MW. As discussed by Mr. Stoddard, this apparently was the condition assumed when the FCM settlement was negotiated. But when the problem has grown to potentially thousands of MW of OOM supply, it is a material error

[14] In fact it would seem to me that, other than the need for appropriate regional adjustments, the same data could be shared and updated cooperatively by the various market monitors.

not to correct this as prices may vary significantly as new entry ranges from forms of demand response, to retrofits/repowerings of existing generation, to complete new entry of generation.

Q CAN THIS PROBLEM BE REMEDIED?

A Yes. There is no need for concern regarding this flaw in the APRs if the prices are properly mitigated *ex ante*. The correction occurs automatically if, prior to the FCA, mitigated prices are substituted for the OOM offers in the auction process calculation of the mitigated clearing price, because the FCA then clears at the "right" price without distortion or need for further modification.

This also eliminates any distortion related to the current and proposed rule introduced by the use of CONE in the pricing result. Prices will be formed based on the competitive offer price for the OOM, without the need either to use the price incorrectly designated as marginal or a CONE value, which may not be related at all to the true offer prices of the OOM capacity resources. This enhances efficiency by properly ordering the OOM resources with respect to relative economics within the FCA process.

Q WOULD MITIGATION OF THIS TYPE INTERFERE WITH THE ABILITY OF THE STATES TO PROCURE OOM CAPACITY FOR REASONS THAT MIGHT NOT BE DEEMED "ECONOMIC" SOLELY WITHIN THE SCOPE OF THE BULK ELECTRIC POWER MARKETS?

A No. With respect to APR-1 and APR-2, it is important to recognize that none of this mitigation in any fashion limits the discretion and prerogative of States to procure OOM capacity resources for non-economic reasons. For example, if a state wishes to engage in an explicit discriminatory procurement to advance state specific goals (for example, building a specific type of capacity resource), it is free to do so. It has long been established that resource procurement lies within the State's province. However, it is equally well-established that the wholesale *pricing* of this capacity lies exclusively within this Commission's province. What this type of corrected APR for OOM limits, however, is the extent to which such actions enable the party seeking OOM resources can exercise market power and adversely impact the pricing of other capacity resources in the FERC jurisdictional electricity markets. This is a very important distinction to maintain, and for the Commission to preserve.

Q HOW DOES THE ABOVE RECOMMENDATION RELATE TO THE JUNE APR?

A My recommended approach here is very similar to what the ISO-NE plans to propose in its July 1 Filing. My understanding is that ISO-NE will propose establishing a mitigated supply curve based on economic benchmarks for OOM units, and establish a clearing price using those mitigated prices in the supply "stack." The resulting "right" prices would then apply to all existing units. These are the first pass or Tier 1 prices. As proposed, the mitigated or reference prices would only be substituted for new OOM. Except for the details of exactly how the mitigated/references prices are established for the OOM units, this portion of the proposal is almost exactly the same as my recommendation. My proposal would also include use of mitigated or reference prices for the existing OOM resources.

Further, after review of the earlier filings, it became clear that some mechanism was needed to both set proper prices, as is accomplished through the mechanism described above, and also to allow for the clearing and pricing of the OOM units themselves. Under my original proposal, I supported simply excluding the units, if they failed to clear, as is done in New York. In discussions with Mr. Stoddard and Professor McAdams, we identified a process very similar to the ISO-NE proposal which would allow both the right pricing for existing units and still allow OOM units to clear. Our conclusion was to simply let the auction proceed with the unmitigated pricing, and pay the OOM units the resulting lower prices (second pass or Tier 2 prices). This would effectively result in two-tier pricing. A "right" and mitigated price, reflecting the modification to a reference price for all OOM, for the existing units, and lower prices for those pursuing uneconomic entry and potentially exercising market power. The major distinction in the ISO-NE proposal is that while this pricing for existing units is exactly the same under the proposed June 15 APR as my original recommendation to simply fully mitigate all OOM to reference levels, there would be a difference in new entry pricing as the ISO-NE would clear new entry in their "second" pass pricing including the OOM units at their original offers.[15]

Q ISN'T THIS INCONSISTENT WITH PRINCIPLE THREE REGARDING THE LAW OF ONE PRICE?

A No. In this case the need for a second price is premised on the mitigation of an out of market or uneconomic bid. But for this behavior, there would be no need for two-tiered pricing. In a sense the two-tier pricing is a compromise to allow the continued development of the OOM without financially penalizing the existing units for the OOM behavior. This is contrasted with my original position which would have precluded the OOM generation from participating in the market at all if they could not clear at their

[15] At this time, pending the full characterization of the ISO-NE proposal, there is no recommendation as to whether the Tier 1 or Tier 2 price should be applied to the existing OOM. The recommendation is only that the historic OOM bids are set to the appropriate reference levels when establishing the supply curve and Tier 1 prices.

mitigated price. To achieve the right single price, OOM would have to be excluded from the market. Accepting that the policy decision has been made to allow continued OOM entry and participation as capacity, other considerations drive a second-best solution such as that put forward by ISO-NE. In this case, existing generation gets the right price, OOM is discouraged via the result of the reduced price they created, and new entry is shown a reduced price indicative of the real excess capacity that exists in the market due to the OOM.

Q ARE THERE OTHER WAYS IN WHICH THE STATES' OBJECTIVES COULD BE MET WITHOUT FURTHER DISTORTING PRICING WITHIN THE FCM/FCA?

A Yes. The FCM/FCA process could be easily modified to incorporate directly the procurement of resources such as renewables that are now seen as externalities. While it is still important that no "invisible" subsidies be applied and the resources bid at their true costs, it would be a relatively easy matter to incorporate constraints into an auction design to assure the procurement of a minimum amount of specific types of generation and/or RECs as part of the auction process. PJM introduced exactly these types of constraints into its original formulation presented to the Commission regarding the procurement or load following/ramping resources and quick start resources. *See generally PJM Interconnection, L.L.C.*, Docket Nos. ER05-1410-000 & EL05-148-000, Reliability Pricing Model Filing (Aug. 31, 2005).

Q WOULD YOU EXPLAIN YOUR PROPOSAL FOR APR-3 AND WHY IT IS DIFFERENT FROM APR-1 AND APR-2, AND FROM THE ISO-NE FEBRUARY PROPOSAL?

A The February APR's APR-3 addresses a different type of OOM capacity resource. It is applied to situations where resources are kept from de-listing (that is, their de-list bids are rejected in the midst of the FCA process) due to reliability or other security-related constraints identified during the auction process. While APR-1 and APR-2 apply to what is uneconomic excess, APR-3 addresses what amounts to unforeseen or "invisible" reliability constraints only identified during the FCA process. These rejected bids reflect a failure of the second principle, the need to appropriately reflect locational and reliability constraints.

While these units will receive OOM revenues, they are needed to resolve "real" reliability issues and, as such, do not reflect the same sort of notion of "uneconomic excess" as the situations addressed by APR-1, -2. However, here again my conclusion is that ISO-NE's and NEPOOL's February APR is at most second-best and, at least generically, there is a much better solution, which goes to the underlying need for the APR-3 OOM.

By failing to implement certain constraints in the FCA, the auction is effectively being run to solve for the quantity of capacity supply and associated prices for the wrong problem. An example at the highest level would be simply failing to recognize a locational sourcing requirement. In this case, an entire region of ISO-NE would be priced improperly, and while only some de-list bids might be rejected (the most expensive units still needed to address the "hidden" LSR requirement), all supply needed to resolve the invisible locational constraint would be underpriced.[16] Such an example of an omission makes the solution easy to see: properly insert the missing constraint and solve for pricing in the correctly specified auction.

And this is just the generic solution that I would recommend. In the Historic APR, and under APR-3, such rejected bids would only be identified in the midst of the auction process, when presumably the invisible (or consciously suppressed) constraint is recognized. At that point, rather than continuing to solve the wrong problem, my recommendation would be to modify the auction process to incorporate the invisible constraint and re-run the process, and when possible, include such constraints to the fullest extent known from the very beginning. Potentially rerunning the auction does not create a timing problem because the constraint can be identified finally at close to real time in the conduct of the FCA, allowing appropriate modifications to the overall process incorporating the constraints to be undertaken immediately. Certainly this is feasible given the auction is approximately 40 months prior to any specific delivery year.

Further, it is my understanding that to date, the OOM associated with these types of rejected de-list bids has not been for invisible constraints at all, but rather for the fundamental locational requirements fully known in advance to the ISO-NE. These known constraints were simply not included in the solution process due to faulty market design, which failed to properly and continually recognize locational requirements as per general principle two. By having an “artificial” trigger to a known constraint, the entire locational element was lost in these auctions, though that element was fully known and

[16] Similarly, by failing to recognize the constraint and both select and properly price the needed generation, additional supply on the “other side” of the constraint would inappropriately be selected and potentially over-compensated in situations where adjustments are made after auction clearing. If the rejected de-list quantity is included in overall supply at zero cost, than there is no price distortion on the low or non-binding side of the constraint.

easily anticipated. In these cases, the problem is solved by simply including the known constraint from the very beginning and making sure it is contained in the original auction structure. These situations demonstrate clearly why one must always include the constraint. Had it not bound, it would have been superfluous, but having failed to include it when it did bind and de-list bids were rejected, this guaranteed that the pricing was incorrect.

Q DOES ISO-NE'S ORIGINAL PROPOSAL DO ANYTHING TO ADDRESS THIS LIMITATION?

A Yes. To some extent, ISO-NE and NEPOOL have recognized this in their efforts to modify the locational requirements to reflect the more restrictive of their new LRAR procedures or TSA evaluations. However, as I understand the FCA process, rejected de-list bids could still be identified within the actual conduct of the auction (as opposed to having been incorporated prior to the auction), and the resulting price distortion would fail to properly resolve the invisible constraint, again requiring some OOM treatment for a unit whose de-list bid was rejected.[17]

Theoretically, all of the potential constraints that might have led to a rejected de-list bid might be identified in advance. However, I believe that this is an empirical issue, and the most appropriate general procedure would be to anticipate as many constraints as possible in the auction structure, and then to modify the structure and re-run the auction, if and when such additional constraints actually are identified during the conduct of the FCA.

[17] Despite TSA requirements reflected in the auction LSR, there remain voltage or stability impacts of de-listing that may not be satisfactorily modeled. For example, an exogenous reduction of the Boston import limit by a few hundred MW helped cause the de-list bid for Salem Harbor 3-4 to be rejected.

It should be understood that again this is not an unreasonably broad task. The ISO-NE has or should have good information on both the "to go" costs of various generation, as well as potential clearing prices. In turn, this information allows the reasonable *ex ante* identification of "at risk" generation that may be expected to offer de-list bids higher than the ultimate clearing prices. With the identification of such "at risk" generation, the task of identifying potential "hidden" constraints prior to the FCA is greatly simplified, and should be incorporated not only into the FCA process prior to the commencement of the auction, but also into any reasonable planning process for the overall RTO and associated future generation and transmission expansion.[18]

Q DOES THE ADDITION OF THESE TYPES OF LOCATIONAL AND RELIABILITY CONSTRAINTS MAKE THE USE OF A DESCENDING CLOCK AUCTION MORE DIFFICULT?

A Yes. My understanding is that moving beyond a radial locational structure is difficult with a descending clock auction. In the interim, there may be sufficient flexibility to address some of the broader locational issues. However, in the long run, in order to capture the full complexity of the adequacy requirements of the market, a more robust auction structure may be needed, such as the linear programming formulation used in PJM. Again this isn't a significant barrier. The auction software is readily available, and the constraints are fully known to the ISO-NE. The only real issue would be the level of aggregation of constraints necessary to capture adequacy rather than pure operational constraints in New England. Again, there is no reason to think that this couldn't be

---

[18] Similar concerns regarding *ex ante* evaluation of "at risk" generation to avoid any associated RMR-type requirements have been raised in PJM. The market monitor has expressed support for both the evaluation of the potential impacts of the retirement of such units, as well as incorporating the associated constraints into the capacity market construct (RPM). Monitoring Analytics LLC, State of the Market Report for PJM, Vol. 1 at 51 (Mar. 11, 2010), http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-som-pjm-volume1.pdf .

purchased and implemented given that a similar system is already up and running in another RTO.

However, it is important to understand that moving to an alternative auction structure does not change the expected efficiency or results of the auction itself. My understanding is that to the extent that you can capture relevant constraints, the expected clearing prices in a descending clock auction would be the same as those obtained from a linear programming formulation, assuming competitive or mitigated behavior. The difference lies in the complexity of the underlying system that can be captured in the auction system, not any bias within the auction results.

Q IS THERE ANY REASON TO LINK THE INCLUSION OF NECESSARY LOCATIONAL CONSTRAINTS OR RELIABILITY CONSTRAINTS TO THE CLEARING PRICE RANGE OF THE FCA?

A No. The ISO-NE February APR, which suggested that APR-3 be limited to conditions where prices were below 0.6 CONE, is irrational, and no logical justification is offered. Why should the existence of, and compensation for, an unknown or unincorporated constraint in the auction formulation have any relationship to the absolute level of the auction result? Wherever the auction clears, the fact that a legitimate de-list bid was rejected identifies the existence of the price distortion, and the need for corrective action. All one needs to know is that the right price for the generator(s) that resolve the missing constraint is higher than the unadjusted clearing price, nothing more. The price range of such rejected de-list bid or where the market clears absent the proper representation of the constraint is irrelevant. Regardless of whether a de-list bid is rejected for reliability at .6 CONE or 1.2 CONE, if it is a competitive resource needed to be included to solve locational or reliability constraints, it should be included in the auction constraints and allowed to clear and set price.[19]

Q HOW DOES YOUR RECOMMENDATION HERE RELATE TO THE JUNE APR PROPOSED BY THE ISO-NE?

A Once again, it seems that ISO-NE has essentially adopted my recommendation. As I understand it they are agreeing to model all of their locational constraints all of the time (although the details of how they will accomplish this are limited). Similarly it appears that they have recognized the limitations of a descending clock auction to capture the potential complexity of a true representation of adequacy requirements, and are investigating alternative formulations such as those I suggested above.

DEFINITION OF OOM

Q THE ABOVE DISCUSSION ASSUMES THAT OOM SUPPLY IS IDENTIFIED. HOW WOULD YOU DEFINE OOM SUPPLY?

A The current rules call for the review of any new supply offered at less than 75% of CONE (as defined in the ISO-NE tariff, not the "true" net CONE). Based on such a review the internal market monitor may classify the supply as in or out of market.

This process is obviously inadequate. First, the use of the current administrative CONE is an arbitrary standard. The starting point has to be the relationship to the offer to the true net CONE for the specific resource type offering the supply. While in the abstract one would expect in equilibrium this to be the true net CONE of the cheapest form of generation, a combustion turbine, there is no reason why such a determination

[19] There is a legitimate concern that any such resource, which may be unique in its ability to resolve a constraint, may exercise market power, but the appropriate solution is to mitigate the bid, not to solve the wrong problem and misprice all other capacity in the auction.

should not be case-specific. It is my understanding that the alternative of individual review of any new offer price is available as an option currently in PJM and NYISO for just these reasons with respect to setting minimum offer prices. However, under the FCM these prices, either generic or case-specific, are obscured because the administrative standard for review (.75 CONE) is based on the mechanical output of previous auction prices, and doesn't necessarily have any relationship to true CONE. Indeed, by offering in more and more OOM resources and depressing prices, the target for review, and thus the lower bound for avoiding OOM classification, can be depressed lower and lower, such that any meaningful mitigation can be avoided.

Given an understanding of the true cost of any specific new supply, the issue then becomes what other factors should be considered in establishing any floor price that should apply to such capacity to mitigate the ability of load to exercise buyer market power by offering below this level.

The general concept that seems most appropriate is to look at the conditions that apply to the receipt of external payments allowing the offer at less than the true net CONE, and the relationship of such conditions to the basic function of the adequacy market with respect to revenues, or to the first major principle regarding attracting and retaining economic generation. While some general concepts may apply, particularly with respect to discriminatory procurement and or the procurement of new only traditional resources when the market is "long," there are enough complications to suggest that case-specific evaluation may be the most appropriate approach.

In my opinion, the easiest example of OOM supply that must be mitigated to 100% of its economic cost of entry is supply that was acquired by an entity or agent of an entity that was net short in the market,[20] and for which a condition of the procurement was that only new construction be eligible. It would be more egregious if such an entity also had the benefit of a regulatory guarantee of expense. This is transparently a violation of basic principle four, the exercise of market power to depress prices, and a *de facto* violation of principle two, because of the resulting price discrimination. However, if the exact same party had a procurement for the exact same amount of MWs but didn't distinguish that the generation must be from a new supply, there would be no reason to mitigate, as the underlying procurement itself was non-discriminatory and sought what should only be the most economic resources, new or existing. This extreme example is easy, but more subtle actions may be just as bad, for example continuing to build even after short positions are covered to assure a perpetuation of the excess and potentially evade mitigation depending on specific market rules.

Another general observation of OOM payments that should be mitigated would be sources of supply that receive revenues that are not otherwise available to other market participants. The most obvious examples of this type of resource would be renewables that are eligible for production tax credits or renewable energy credits. This is not to say that such resources cannot obtain long term contracts from the states or benefit from these types of payments, but it does suggest that such payments should not be allowed to

[20] Theory would indicate that there is a need to be net short (directly or indirectly) to profit from such strategies. However the Commission has previously determined that despite the cumulative position of an individual party, uneconomic entry is to be discouraged, and mitigated. *See New York Indep. Sys. Operator*, 124 FERC ¶ 61,301 at P 29 ("NYISO will not be required to modify its proposed market power mitigation rules for uneconomic entry so that they only apply to net buyers. We find that all uneconomic entry has the effect of depressing prices below the competitive level and that this is the key element that mitigation of uneconomic entry should address."). This is a rational position, recognizing: (i) the difficulty of determining a true net position, (ii) the ease of circumventing any rule to determine what is "net short", and (iii) the general proposition that what is uneconomic is uneconomic despite intent.

undercut the recovery of costs by other jurisdictional market entities providing adequacy services.

Q DO YOU AGREE WITH THE ISO-NE POSITION PRESENTED IN THEIR JUNE 15 PRESENTATION OF EXCUSING EXISTING OOM FROM MITIGATION TO ESTABLISHED THE REVISED SUPPLY CURVE TO PRICE EXISTING GENERATION?

A No. ISO-NE suggested that their position was justified based on previous Commission decisions regarding similar mitigation in New York City. This is incorrect. The decision with respect New York City was materially different. For NYISO, the proposed mitigation would have resulted in the mitigated units potentially not clearing at all should their "true" price exceed the market-clearing price. It was in this context that the Commission ruled that it was inappropriate to apply such full exclusory mitigation on units that were built and operating, *i.e.*, had already "sunk" their costs, and thus their behavior could no longer be policed by the mitigation rules.

However, under the ISO-NE proposal, the result of mitigation is solely to establish a "right" price for existing units against a competitive standard, and another clearing price for the remaining OOM units that reflects their price distorting impact. As a result, it would be consistent to keep existing OOM categorized exactly as it is, treat it like other OOM, and not "grandfather" it for the purposes of establishing the Tier 1 price.[21]

It is important to understand that, absent this type of adjustment to include the existing OOM in establishing the Tier 1 prices, the remedial effect that needs to be

[21] As noted above, the proposal is to include mitigated or reference prices for OOM in establishing Tier 1 prices, but makes no decision at this time with respect to which tier price historic OOM receives.

produced by the revised APR will be diluted and may not come to fruition for many years. The ISO itself has acknowledged that the backlog or overhang of such units may take approximately 7 years to outgrow. Failing to immediately put the existing OOM at mitigated prices into the determination of the Tier 1 prices makes the improved structure almost meaningless.

Perpetuating this type of distortion for this extended a period seems to fly directly in the face of the first general principle I stated above and Commission precedent. *See Edison Mission Energy*, 394 F.3d at 968-70 (describing "the Commission's contradiction of its prior rulings acknowledging the potential ill effects of forcing down prices absent structural market distortions [and yet still imposing seller market power mitigation as] the epitome of agency capriciousness").

Q IN THE DIRECT COMMENTS FILED ON MARCH 15, 2010 IN THIS PROCEEDING, SEVERAL PARTIES INDICATED THAT THEY SAW NO PROBLEMS WITH WHAT YOU ARE CHARACTERIZING AS SUBSIDIZED OUT OF MARKET BIDS AT LOW PRICES, AND THAT SUCH BIDS WERE RATIONAL BEHAVIOR. DO YOU AGREE?

A No. These comments were offered by the Connecticut Department of Public Utility Control ("CDPUC") and others through their witness, Mr. James Wilson. *See ISO New England Inc.*, Docket No. ER10-787-000, Motion to Answer and Answer of the CDPUC, *et al.*, Exhibit DPUC-1, Direct Testimony of James F. Wilson ("Wilson Test.") (Mar. 30, 2010). These comments trying to justify ignoring the adverse and anti-competitive impact of such bids are comprised of a series of fundamental and crucial errors that infect Mr. Wilson's conclusions regarding the adverse effects of the exercise of market power by buyers via price discrimination and the introduction of subsidized Out-of-Market ("OOM") supply and other uneconomic new entry into the ISO-NE capacity markets. The reasoning is almost tautological. Mr. Wilson's testimony and the CDPUC comments seem to be arguing that reducing short-term costs to consumers is *per se* good; therefore anything that achieves this end, including the exercise of buyer market power, must be good. The critical fact that the exercise of buyer market power violates the Commission's policy and the four basic principles discussed above is simply ignored or dismissed without justification.

Q IN WHAT WAY DID THE CDPUC AND MR. WILSON ERR IN THERE ATTEMPTS TO JUSTIFY WHAT YOU CHARACTERIZE AS OOM SUPPLY, AND THE NEED FOR ASSOCIATED MITIGATION.

A Mr. Wilson's most material mistake was failing to distinguish the motives and rationales of some parties who might hold OOM contracts from the actions and incentives of those who initiated the contracts. Similarly he failed to distinguish between bilateral agreements in general, and those specifically entered into by net short buyers—requiring new resources only—during periods when the market is long on capacity and sufficient capacity to meet reliability targets is available at lower prices. It is crucial that the Commission recognize these factors in making any decision related to the proposed APR. Because Mr. Wilson ignored these fundamental elements of the debate, his comments were at best irrelevant to a full understanding of the issue and, at worst, substantively misleading.

Q CAN YOU PROVIDE AN EXAMPLE OF HOW THE CDPUC AND MR. WILSON'S DEFINITION FAIL TO INCLUDE OBVIOUS OOM SUPPLY?

A Yes. For example, the Wilson Testimony stated that:

> Capacity that is under contract or receives incentives is rationally offered into the FCA at prices that makes accepting a capacity supply obligation attractive, which is generally lower than its "long-run average cost." Offering such capacity at such prices is competitive conduct.

Wilson Test. at 6:18-21.

While the statement itself is not necessarily true,[22] Mr. Wilson misses the central point of my original affidavit in the proceeding. The concern is *why* the counter-party to the bilateral agreement is entering into an above market contract, not the subsequent behavior of the seller in the FCA after the contract is consummated. If the counter-party is net short, and there are excess and cheaper resources available in the market, the net effect of such agreements to add new generation and requiring it to bid below entry costs is to artificially suppress prices via uneconomic procurement of excess capacity and the provision of incentives not otherwise available to existing supply. This is an exercise of market power by the true buyer, the purchasing counterparty to the contract. This supply is obviously OOM.

Q DID MR. WILSON AND THE CDPUC CONSIDER THESE FACTORS IN ARGUING THAT SUCH SUPPLY WAS NOT OOM?

A No. In Mr. Wilson's discussion he ignored both the basic question of why the purchasing party is forgoing cheaper existing resources, and the fact that the counterparty subsequently offering the contracted supply into the FCAs is simply the instrumentality

[22] The correctness of this statement is solely a function of the terms of the bilateral agreement; for many plausible bilateral agreements it would not be. But perhaps the Wilson Testimony is so affixed to defending price-suppressing bilateral agreements that he fails to realize that other contracting agreements might yield different behavioral results.

of the party who is undertaking the exercise of market power. He also ignored that the procurement required specific bidding behavior by the winners to assure the price suppression effect. What Mr. Wilson has observed is akin to noting that the laws of physics apply to a bullet after it is fired, while ignoring who pulled the trigger, what they were aiming for, and their reasons for shooting.

It is hard to imagine that Mr. Wilson (or his sponsors) would file comments so obtuse if the positions of buyer and seller were reversed.

Q WHAT WOULD BE THE ANALOGOUS BEHAVIOR AND DEFINITIONS OF UNECONOMIC BEHAVIOR AND THE EXERCISE OF MARKET POWER BY SELLERS THAT WOULD BE ACCEPTABLE IF THE WILSON AND CDPUC POSITIONS WERE ADOPTED CONSISTENTLY BY THE COMMISSION?

A This can be seen by example. Consider the situation where a pivotal supplier identifies all other generation supply in the market that is barely infra-marginal (for example, those with net revenues from energy and capacity exceeding going-forward costs by $100 a year—*i.e.*, they earn a net of $100 per year by staying in the market and selling both capacity and energy). In turn, assume that such a pivotal supplier, who has an overall net long position in the market, offered all of these barely profitable suppliers $200 per year to retire their generation. Obviously it would be rational, and apparently from Mr. Wilson's view, pro-competitive, for these marginal suppliers to take the money and retire. I doubt that any other observers of the markets would share this conclusion without questioning the motives and actions of the party paying for others to retire.

Q DO YOU AGREE WITH THE POSITIONS SUGGESTED BY THE CDPUC AND MR. WILSON THAT WOULD CONTINUE TO ALLOW UNFETTERED OOM ENTRY?

A No. It was clear from Mr. Wilson's testimony that Mr. Wilson favors continued OOM entry. He states that "New England has surplus capacity at this time and is likely to continue to have surplus capacity for years to come; there is no reason to go further with the APR rule and the protestors' experts' proposals to do so should be rejected." Wilson Test. at 7:16-18. In other words, having successfully suppressed prices via use of discriminatory procurements, the beneficiaries should be rewarded by the cessation of any efforts to mitigate these actions prospectively. Again, merely imagining the reverse situation, where market power was successfully exercised by sellers, and the Commission's (not to mention Mr. Wilson's sponsors) likely reaction to such success obviates any need for further response.

Q IS THIS FAILING ADDRESSED BY YOUR RECOMMENDATIONS AND THE ISO-NE JUNE 15, 2010 SLIDE PRESENTATION?

A Yes. Under the two-tiered pricing proposal the benefit to buyers of these exercises of market power would be removed.

Q DO YOU AGREE THAT THE THIRD GENERAL PRINCIPLE RELATED TO THE LAW OF ONE PRICE IS MET BY HAVING AN UNMITIGATED FCA WITH A SINGLE PRICE?

A No. Mr. Wilson glibly suggests that there is no price discrimination because all FCA participants receive the same price *in the FCA*. *See* Wilson Test. at 29:1-5. This is largely true but beside the point. *Of course*, all similarly-situated capacity resources do indeed receive the artificially depressed and manipulated FCA price. The point is that the favored OOM resources *also* receive side-payments or similar pecuniary benefits from their buy-side sponsors or their proxies which gross up their total revenues to a level far higher—and hence *discriminatory*.[23] It is that very fact, undisputed by Mr. Wilson, that results in uneconomic entry and discriminatory procurements prior to the conduct of the FCA and hence the exercise of market power. This point is so fundamental that it is troubling that Mr. Wilson should not even attempt to address it, but rather suggest that there is no discrimination based on his consideration only of the FCA itself. This is no more informative than the fact that, after the exercise of supplier market power via economic or physical withholding, there would be a single clearing price. Can anyone possibly believe that makes the price just and reasonable?

Q ARE BILATERAL AGREEMENTS IN AND OF THEMSELVES INDICATIVE OF A PROPERLY WORKING MARKET?

A No. Mr. Wilson continued in the same vein, suggesting repeatedly that there is nothing wrong with the market, and that bilateral contracts are both constructive and reasonable. *See* Wilson Test. at 21-22. Once again, he ignored the predicate that the underlying contracts were established via a discriminatory process. This demonstrated the lack of thought given by some policy makers—or the defined purpose of such policy makers—to the exercise of buyer market power through price discrimination.[24]

---

[23] For example, many of these OOM resources have explicit contracts-for-differences, guaranteeing that they receive their contract price for capacity regardless of the FCA clearing prices. Just because the *auction* price for capacity is the same does not mean the *payments* to all resources is the same.

[24] As indicated in several of the cases cited above, *see, e.g.*, *New York Indep. Sys. Operator*, 122 FERC ¶ 61,211 at PP 100-106, the Commission is an honorable exception, even in the present complex environment.

Q CAN YOU OFFER ANY COMPARISONS THAT FURTHER DEMONSTRATE THIS DISCRIMINATION?

A Yes. It is useful to contrast the buyer market power behavior in question as if it occurred under the "old" regulated regime—which for all its faults, had a history of parsing the equities of what should be a reasonable competitive/market-like solution.

For example, if after a regulated utility had built all of its required capacity to meet system needs, regulators subsequently decided to "add" an renewable portfolio standard ("RPS") and the associated "excess new" capacity, this new consideration of an externality would not suddenly make existing supply not "used and useful," nor would it be expected that any existing resources would be removed from rate base or paid only a portion of its costs. Similarly, existing rate-based capacity would not be devalued if regulators decided to increase overall levels of installed capacity for any other reason to create "excess." Yet Mr. Wilson is continually recommending exactly the opposite result in response to the exercise of market power by buyers (whether intentional or not) with respect to the procurement of excess and uneconomic capacity. His view of the world would effectively devalue existing resources and/or remove them from rate recovery despite the underlying prudence of parties in purchasing such resources, and the externalities considered by third parties in securing excess resources.

Contrast this historic regulated structure with the uneconomic or discriminatory procurement occurring in today's markets. If not properly addressed, uneconomic or discriminatory procurement will distort the current market in the same way as in the example above under regulation. FCM is a market mechanism to compensate supply/capacity based on certain competitive assumptions. FCM does not mandate any specific price. Suppliers entered competitive markets accepting that risk. However, FCM does mandate the elimination of the exercise of market power to distort prices via uneconomic or discriminatory procurement. In building or acquiring power plants, suppliers assumed risks regarding changes in general economics and market technology and to some extent regulation. However, they cannot fairly be asked to shoulder the risk that buyers would be allowed to exercise market power.

Q WHAT CONCLUSIONS DO YOU DRAW FROM THE ABOVE?

A The underlying conclusion has to be that the Commission should take action, including imposition of an *effective* APR that is consistent with the underlying objective of the use of a market mechanism to attract and *retain* capacity where it is needed. This means that OOM supply, no matter its origin or purpose, cannot be allowed to distort recovery by other market participants. Again, this does not mean that states cannot pursue out of market procurement. What it does mean is that such discriminatory procurement cannot be allowed to distort prices in a Commission-approved capacity market such that appropriate levels of compensation are unavailable.

LOCATIONAL CONSTRAINTS

Q WHAT INQUIRIES DID THE COMMISSION POSE WITH RESPECT TO THE REPRESENTATION OF LOCATIONAL CONSTRAINTS AND CAPACITY ZONES?

A The Commission posed four questions with respect to the representation of capacity zones and reliability constraints:

(1) Whether zones should always be modeled;

(2) Whether all de-list bids should be considered in the modeling of zones;

(3) Whether a pivotal supplier test is necessary; and

(4) Whether revisions to the current mitigation rules would be necessary in order to model all zones. Hearing Order at P 18.

Q DID THE COMMISSION OFFER ANY GUIDANCE WITH RESPECT TO THIS ISSUE?

A Yes. The Commission confirmed once again the general principle regarding the need for clear locational signals in capacity markets as stated above in principle 2.

> The Commission believes that it is important to model zones wherever possible to set appropriate locational prices. We have cited the need for locational pricing in New England for many years, noting that its absence in the Installed Capacity (ICAP) market (the predecessor to the FCM) was a significant flaw since "location is an important aspect of ensuring optimal investment in resources." The FCM incorporates locational pricing, but through three FCAs, zonal price separation has yet to occur despite the rejection of de-list bids for reliability in the first and third FCAs. Moreover, as noted by the generator parties, even if the proposed Rule Changes on this issue were in place at the time of those two auctions, no zonal price separation would have occurred.

Hearing Order at P 134 (footnotes omitted). The Commission also concurred, though with some concerns, regarding the need for representing all constraints:

> While we believe that always modeling zones should be the ultimate goal, we agree with ISO-NE that such a change would require further analysis and is not required to be implemented prior to FCA # 4.

Id. at P 135.

Q IS THIS CONSISTENT WITH YOUR OWN VIEWS?

A Yes, although I think my position would be even stronger regarding the need to fully represent all locational and reliability constraints to the extent possible. I believe that my comments above with respect to ISO-NE's original proposed APR-3 answer the Commission's questions 1 and 2 directly. It should be obvious that you always model all locational zones and relevant reliability constraints. In turn, if the constraints are always modeled, then there is no issue with respect to the consideration of the de-list bids, it is addressed automatically by the mechanics of the auction process. If the constraint does not bind—*i.e.*, there is enough supply in a area at low enough prices such that the LSR requirement can be met regardless of de-list bids and thus the presence of the constraint in the auction formulation is irrelevant—then the final price is the same whether the constraint is included or not.

However, should the constraint bind, and there are insufficient local resources to meet the LSR or any specific reliability obligation, then, unless the constraint is included *ex ante*, the auction model is set up incorrectly and *all* prices will be incorrect. Those prices on the "high" side of the constraint or locational/reliability violation will be too low, and those on the low side of the constraint will be too high.[25] Thus, in this situation it does not matter what de-list bids were included or not in the consideration of whether to include the constraint. The damage is already done by not reflecting a "real" constraint, and mispricing all of the auction results.

It should be obvious that failing to always include relevant and known constraints is in direct violation of the second Commission principle discussed above, and that in turn doing so makes the *ex ante* evaluation of de-list bids (other than for market power concerns) irrelevant. Further, as implemented by ISO-NE, not only is the pricing wrong for all market participants under the APR, but because the constraint may only be seen by exception, based on whether or not specific forecast criteria are met with respect to

[25] Only in the situation where there is a sole resource that can resolve a reliability constraint (versus the most expensive of multiple resources available to address the constraint) will even a portion of the pricing be correct. In that case the single unit on the high side of the constraint will get the "right" capacity price via uplift (RMR), and it will be the same as what would have been the constrained clearing price. Supply on the low side is overpriced unless it is augmented by the rejected delist supply (and offered at a zero cost). If the auction were solved "simultaneously" via a mechanism such as a linear programming type formulation, than all "low" side supply would be over paid when there is a missing constraint. If the solution mechanism allows for the "low" side supply to be augmented by the rejected delist bid in a sequential fashion, than the prices would be correct for these resources.

expected quantities of supply and de-list bids, the general situation will be that the constraint is simply not considered at all *ex ante* unless conditions are relatively extreme with respect to short supplies. This makes the presence of the locational information least available when it is most needed, right at the point where retention of existing resources to meet the requirement is at the margin for a number of suppliers.

No matter how you look at it, eliminating known reliability information from the formulation of the auction is wrong.

Q HOW DO YOU RESPOND TO THE THIRD AND FOURTH COMMISSION QUESTIONS ADDRESSING MARKET POWER ASSOCIATED WITH CAPACITY ZONES?

A Again, I believe that the Commission itself has already provided guidance within the Hearing Order, at P 135 (noting both the need for full representation of locational constraints and the potential that such representation could give rise to the ability to exercise market power by suppliers), and within the general principles that the Commission has already established. As explained above, market power mitigation must be even handed. While much of the above discussion related to buyer market power, but in the context of the arguments relating to capacity zones, the concerns are legitimately focused on seller market power. The greater the level of detail in locational and reliability constraints represented in the auction process to accurately set capacity pricing, the higher the probability that the units eligible to resolve the locational needs will have either concentrated ownership, or be explicitly pivotal. In this situation appropriate mitigation is necessary. Where a supplier is explicitly pivotal with respect to a reliability constraint, mitigation based on properly-defined marginal “to go” or “opportunity” costs in general is appropriate. However, as I said initially, *all* four general principles must be met *simultaneously*. Thus, such mitigation is appropriate in a construct where all the other conditions, particularly the first regarding an opportunity to earn the true net CONE, are also met. This should be seen as a basic quid pro quo: So long as there are no biases in the overall market design that interfere with principle 1, including the exercise of buyer market power or the mischaracterization of locational needs, then there is no reason to not similarly mitigate all supply offers to rational and economically consistent levels when appropriate.

Similarly, simply the potential to exercise market power, should not in of itself give rise to a justification to improperly specify the auction model and distort all prices. The resolution lies in getting both concerns right. To ensure that prices are neither artificially increased nor depressed, the locational constraints must be included, and appropriate mitigation should be applied to prevent the exercise of market power.

Q HOW DOES YOUR OBSERVATION HERE WITH RESPECT TO THE COMMISSION'S INQUIRIES REGARDING ZONES AND LOCATIONAL REQUIREMENTS MATCH THE ISO-NE POSITIONS PUT FORWARD IN ITS JUNE 15, 2010 PRESENTATION?

A They are a totally consistent match as explained with respect to my comments regarding APR-3. As I understand it the ISO-NE position now is to the extent possible model all constraints all the time, for just the reasons I discussed above. Similarly they will investigate whether alternative auction designs may allow greater detailed representation of the relevant locational and reliability constraints.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes.

NEPGA Exhibit 1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and New England Power Pool	))	Docket No. ER10-787-000
New England Power Generators Association Inc. v. ISO New England Inc.	)))))	Docket No. EL10-50-000
PSEG Energy Resources & Trade LLC, PSEG Power Connecticut LLC, NRG Power Marketing LLC, Connecticut Jet Power LLC, Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, and Somerset Power LLC v. ISO New England Inc.	)))))))))	Docket No. EL10-57-000

I, Roy J. Shanker, being duly sworn, depose and state that the contents of the foregoing Testimony on behalf of the New England Power Generators Association is true, correct, accurate and complete to the best of my knowledge, information, and belief.

Roy Shanker

SUBSCRIBED AND SWORN to before me this 28 day of June 2010.

Chao Chieh Hsu

(Notary Public)

My commission expires: January 10 2012

CHAO CHIEH HSU
NOTARY PUBLIC
MONTGOMERY COUNTY
MARYLAND
MY COMMISSION EXPIRES JANUARY 10, 2012

QUALIFICATIONS
AND
EXPERIENCE OF

DR. ROY J. SHANKER

EDUCATION:

Swarthmore College, Swarthmore, PA
A.B., Physics, 1970

Carnegie-Mellon University, Pittsburgh, PA
Graduate School of Industrial Administration
MSIA Industrial Administration, 1972
Ph.D., Industrial Administration, 1975

Doctoral research in the development of new non-parametric multivariate techniques for data analysis, with applications in business, marketing and finance.

EXPERIENCE:

1981 - Present	Independent Consultant P.O. Box 60450 Potomac MD 20854 Providing management and economic consulting services in natural resource-related industries, primarily electric and natural gas utilities.
1979-81	Hagler, Bailly & Company 2301 M Street, N.W. Washington, D.C. Principal and a founding partner of the firm; director of electric utility practice area. The firm conducted economic, financial, and technical management consulting analyses in the natural resource area.
1976-79	Resource Planning Associates, Inc. 1901 L Street, N.W. Washington, D.C. Principal of the firm; management consultant on resource problems, director of the Washington, D.C. utility practice. Direct supervisor of approximately 20 people.

1973-76 Institute for Defense Analysis
Professional Staff
400 Army-Navy Drive
Arlington, VA

Member of 25 person doctoral level research staff conducting economic and operations research analyses of military and resource problems.

RELEVANT EXPERIENCE:

2009

Federal Energy Regulatory Commission Docket No. ER09-1682. Two affidavits on behalf of an un-named party regarding confidential treatment of market data coupled with specific market participant bidding, and associated issues.

American Arbitration Assoication, Case No. 75-198-Y-00042-09 JMLE, on behalf of Rathdrum Power LLC. Report on the operation of specific pricing provision of a tolling power purchase agreement.

Federal Energy Regulatory Commission. Docket No. IN06-3-003. Analyses on behalf of Energy Transfer Partners L.P. regarding trading activity in physical and financial natural gas markets.

Federal Energy Regulatory Commission. Docket No. ER08-1281-000. Analyses on behalf of Fortis Energy Trading related to the impacts of loop flow on trading activities and pricing.

American Arbitration Association. Report on behalf of PEPCO Energy Services regarding several trading transactions related to the purchase and sale of Installed Capacity under the PJM Reliability Pricing Model.

Federal Energy Regulatory Commission Docket No. EL-0-47. Analyses on behalf of HQ Energy services (U.S.) regarding pricing and sale of energy associated with capacity imports into ISO-NE.

Federal Energy Regulatory Commission Docket No. ER04-449 019, Affidavit on behalf of HQ Energy Services (U.S.) regarding the implementation of the consensus deliverability plan for the NYISO, and associated reliability impacts of imports.

Federal Energy Regulatory Commission Docket ER09-412-000, ER05-1410-010, EL05-148-010. Affidavit and Reply Affidavit on behalf of PSEG Companies addressing proposed changes to the PJM Reliability Pricing Model and rebuttal related to other parties' filings.

2008

Pennsylvania Public Service Commission. *En Banc* Public Hearing on "Current and Future Wholesale Electricity Markets", comments regarding the design of PJM wholesale market pricing and state restructuring.

Maine Public Utility Commission. Docket No. 2008-156. Testimony on behalf of a consortion of energy producers and suppliers addressing the potential withdrawal of Maine from ISO New England and associated market and supplier response.

Federal Energy Regulatory Commission. Docket No. EL08-67-000. Affidavit on behalf of Duke Energy Ohio and Reliant Energy regarding criticisms of the PJM reliability pricing model (RPM) transitional auctions.

Federal Energy Regulatory Commission. Docket AD08-4, on behalf of the PJM Power Providers. Statement and participation in technical session regarding the design and operation of capacity markets, the status of the PJM RPM market and comments regarding additional market design proposals.

Federal Energy Regulatory Commission. Docket ER06-456-006, Testimony on behalf of East Coast Power and Long Island Power Authority regarding appropriate cost allocation procedures for merchant transmission facilities within PJM.

2007

FERC Docket No. EL07-39-000. Testimony on behalf of Mirant Companies and Entergy Nuclear Power Marketing regarding the operation of the NYISO In-City Capacity market and the associated rules and proposed rule modifications.

FERC Dockets: RM07-19-000 and AD07-7-000, filing on behalf of the PJM Power Providers addressing conservation and scarcity pricing issues identified in the Commission's ANOPR on Competition.

FERC Docket No. EL07-67-000. Testimony and reply comments on behalf of Hydro Quebec U.S. regarding the operation of the NYISO TCC market and appropriate bidding and competitive practices in the TCC and Energy markets.

FERC Docket Nos. EL06-45-003. Testimony on behalf of El Paso Electric regarding the appropriate interpretation of a bilateral transmission and exchange agreement.

2006

United States Bankruptcy Court for the Southern District of New York. Case No. 01-16034 (AJG). Report on Behalf of EPMI regarding the properties and operation of a power purchase agreement.

FERC Docket No. EL05-148-000. Testimony regarding the proposed Reliability Pricing Model settlement submitted for the PJM RTO.

FERC Docket No. ER06-1474-000, FERC. Testimony on behalf othe PSEG Companies regarding the PJM proposed new policy for including "market efficiency" transmission upgrades in the regional transmission expansion plan.

FERC Docket No. EL05-148-000, FERC. Participation in Commission technical sessions regarding the PJM proposed Reliability Pricing Model.

FERC Docket No. EL05-148-000, FERC. Comments filed on behalf of six PJM market participants concerning the proposed rules for participation in the PJM Reliability Pricing Model Installed Capacity market, and related rules for opting out of the RPM market.

FERC Docket No. ER06-407-000. Testimony on behalf of GSG, regarding interconnection issues for new wind generation facilities within PJM.

2005

FERC Docket No. EL05-121-000, Testimony on behalf of several PJM Transmission Owners (Responsible Pricing Alliance) regarding alternative regional rate designs for transmission service and associated market design issues.

FERC Technical Conference of June 16, 2005. (Docket Nos. PL05-7-000, EL03-236-000, ER04-539-000). Invited participant. Statement regarding the operation of the PJM Capacity market and the proposed new Reliability Pricing Model Market design.

American Arbitration Association Nos. 16-198-00206-03 16-198-002070.On behalf of PG&E Energy Trading. Analyses related to the operation and interpretation of power purchase and sale/tolling agreements and electrical interconnection requirements.

Arbitration on behalf of Black Hills Power, Inc. Expert testimony related to a power purchase and sale and energy exchange agreement, as well as FERC criteria related to the applicable code and standards of conduct.

2004

Federal Energy Regulatory Commission. Docket No. Docket No. EL03-236-003 Testimony on behalf of Mirant companies relating to PJM proposal for compensation of frequently mitigated generation facilities.

Federal Energy Regulatory Commission. Docket No. ER03-563-030. Testimony on behalf of Calpine Energy Services regarding the development of a locational Installed Capacity market and associated generator service obligations for ISO-NE. Supplemental testimony filed 2005.

Federal Energy Regulatory Commission. Docket No. EL04-135-000. Testimony on behalf on the Unified Plan Supporters regarding implications of using a flow based rate design to allocate embedded costs.

Federal Energy Regulatory Commission. Docket No. ER04-1229-000. Testimony on behalf of EME Companies regarding the allocation and recovery of administrative charges in the NYISO markets.

Federal Energy Regulatory Commission. Dockets No. EL01-19-000, No. EL01-19-001, No. EL02-16-000, EL02-16-000. Testimony on behalf of PSE&G Energy Resources and Trade regarding pricing in the New York Independent System Operator energy markets.

Federal Energy Regulatory Commission. Invited panelist regarding performance based regulation (PBR) and wholesale market design. Comments related to the potential role of PBR in transmission expansion, and its interaction with market mechanisms for new transmission.

Federal Energy Regulatory Commission. Docket No. ER04-539-000 Testimony on behalf of EME Companies regarding proposed market mitigation in the energy and capacity markets of the Northern Illinois Control Area.

Federal Energy Regulatory Commission. Standardization of Generator Interconnection Agreements and Procedures Docket No. RM02-1-001, Order 2003-A, Affidavit on Behalf of PSEG Companies regarding the modifications on rehearing to interconnection crediting procedures.

Federal Energy Regulatory Commission. Dockets ER03-236-000,ER04-364-000,ER04-367-000,ER04-375-000. Testimony on behalf of the EME Companies regarding proposed market mitigation measures in the Northern Illinois Control Area of PJM.

Federal Energy Regulatory Commission. Dockets PL04-2-000, EL03-236-000. Invited panelist, testimony related to local market power and the appropriate levels of compensation for reliability must run resources.

2003

American Arbitration Association. 16 Y 198 00204 03. Report on behalf of Trigen-Cineregy Solutions regarding an energy services agreement related to a cogeneration facility.

Federal Energy Regulatory Commission. Docket No. EL03-236-000. Testimony on behalf of EME Companies regarding the PJM proposed tariff changes addressing mitigation of local market power and the implementation of a related auction process.

Federal Energy Regulatory Commission. Docket No. PA03-12-000. Testimony on behalf of Pepco Holdings Incorporated regarding transmission congestion and related issues in market design in general, and specifically addressing congestion on the Delmarva Peninsula.

Federal Energy Regulatory Commission. Docket Nos. ER03-262-007, Affidavit on behalf of EME Companies regarding the cost benefit analysis of the operation of an expanded PJM including Commonwealth Edison.

Supreme Court of the State of New York, Index No. 601505/01. Report on behalf of Trigen-Syracuse Energy Corporation regarding energy trading and sales agreements and the operation of the New York Independent System Operator.

Federal Energy Regulatory Commission. Docket No. ER03-262-000. Affidavit on behalf of the EME Companies regarding the issues associated with the integration of the Commonwealth Edison Company into PJM.

Federal Energy Regulatory Commission. Docket No. ER03-690-000. Affidavit on behalf of Hydro Quebec US regarding New York ISO market rules at external generator proxy buses when such buses are deemed non-competitive.

Federal Energy Regulatory Commission. Docket RT01-2-006,007. Affidavit on behalf of the PSEG Companies regarding the PJM Regional Transmission Expansion Planning Protocol, and proper incentives and structure for merchant transmission expansion.

Federal Energy Regulatory Commission. Docket No. ER03-406-000. Affidavit on behalf of seven PJM Stakeholders addressing the appropriateness of the proposed new Auction Revenue Rights/Financial Transmission Rights process to be implemented by the PJM ISO.

Federal Energy Regulatory Commission. Docket No. ER01-2998-002. Testimony on behalf of Pacific Gas and Electric Company related to the cause and allocation of transmission congestion charges.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. On behalf of six different companies including both independent generators, integrated utilities and distribution companies comments on the proposed resource adequacy requirements of the Standard Market Design.

United States Bankruptcy Court, Northern District of California, San Francisco Division, Case No. 01-30923 DM. On behalf of Pacific Gas and Electric Dr. Shanker presented testimony addressing issues related to transmission congestion, and the proposed FERC SMD and California MD02 market design proposals.

2002

Arbitration. Testimony on behalf of AES Ironwood regarding the operation of a tolling agreement and its interaction with PJM market rules.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. Dr. Shanker was asked by the three Northeast ISO's to present a summary of his resource adequacy proposal developed in the Joint Capacity Adequacy Group. This was part of the Standard Market Design NOPR process.

Federal Energy Regulatory Commission. Docket No. ER02-456-000. Testimony on behalf of Electric Gen LLC addressing comparability of a contract among affiliates with respect to non-price terms and conditions.

Circuit Court for Baltimore City. Case 24-C-01-000234. Testimony on behalf of Baltimore Refuse Energy Systems Company regarding the appropriate implementation and pricing of a power purchase agreement and related Installed Capacitycredits.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the characteristics of capacity adequacy markets and alternative market design systems for implementing capacity adequacy markets.

2001

Federal Energy Regulatory Commission. Docket ER02-456-000. Testimony on behalf of Electric Gen LLC regarding the terms and conditions of a power sales agreement between PG&E and Electric Generating Company LLC.

Delaware Public Service Commission. Docket 01-194. On behalf of Conectiv et al. Testimony relating to the proper calculation of Locational Marginal Prices in the PJM market design, and the function of Fixed Transmission Rights.

Federal Energy Regulatory Commission. Docket No. IN01-7-000 On behalf of Exelon Corporation . Testimony relating to the function of Fixed Transmission Rights, and associated business strategies in the PJM market system.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the basic elements of RTO market design and the required market elements.

Federal Energy Regulatory Commission. Docket No. RT01-99-000. On behalf of the One RTO Coalition. Affadavit on the computational feasibility of large scale regional transmission organizations and related issues in the PJM and NYISO market design.

Arbitration. On behalf of Hydro Quebec. Testimony related to the eligibility of power sales to qualify as Installed Capacitywithin the New York Independent system operator.

Virginia State Corporation Commission. Case No. PUE000584. On behalf of the Virginia Independent Power Producers. Testimony related to the proposed restructuring of Dominion Power and its impact on private power contracts.

United States District Court, Northern District of Ohio, Eastern Division, Case: 1:00CV1729. On behalf of Federal Energy Sales, Inc. Testimony related to damages in disputed electric energy trading transactions.

Federal Energy Regulatory Commission. Docket Number ER01-2076-000. Testimony on behalf of Aquila Energy Marketing Corp and Edison Mission Marketing and Trading, Inc. relating to the implementation of an Automated Mitigation Procedure by the New York ISO.

2000

New York Independent System Operator Board. Statement on behalf of Hydro Quebec, U.S. regarding the implications and impacts of the imposition of a price cap on an operating market system.

Federal Energy Regulatory Administration. Docket No. EL00-24-000. Testimony on behalf of Dayton Power and Light Company regarding the proper characterization and computation of regulation and imbalance charges.

American Arbitration Association File 71-198-00309-99. Report on behalf of Orange and Rockland Utilities, Inc. regarding the estimation of damages associated with the termination of a power marketing agreement.

Circuit Court, 15th Judicial Circuit, Palm Beach County, Florida. On behalf of Okeelanta and Osceola Power Limted Partnerships et. al. Analyses related to commercial operation provisions of a power purchase agreement.

1999

Federal Energy Regulatory Commission. Docket No. ER00-1-000. Testimony on behalf of TransEnergie U.S. related to market power associated with merchant transmission facilities. Also related analyses regarding market based tariff design for merchant transmission facilities.

Federal Energy Regulatory Commission. Docket RM99-2-000. Analyses on behalf of Edison Mission Energy relating to the Regional Transmission Organization Notice of Proposed Rulemaking.

Federal Energy Regulatory Commission. Docket No. ER99-3508-000. On behalf of PG&E Energy Trading, analyses associated with the proposed implementation and cutover plan for the New York Independent System Operator.

Federal Energy Regulatory Commission. Docket No. EL99-46-000. Comments on behalf of the Electric Power Supply Association relating to the Capacity Benefit Margin.

New York Public Service Commission, Case 97-F-1563. Testimony on behalf of Athens Generating Company describing the impacts on pricing and transmission of a new generation facility within the New York Power Pool under the new proposed ISO tariff.

JAMS Arbitration Case No. 1220019318 On behalf of Fellows Generation Company. Testimony related to the development of the independent power and qualifying facility industry and related industry practices with respect to transactions between cogeneration facilities and thermal hosts.

Court of Common Pleas, Philadelphia County, Pennsylvania. Analyses on behalf of Chase Manhattan Bank and Grays Ferry Cogeneration Partnership related to power purchase agreements and electric utility restructuring.

1998

Virginia State Corporation Commission. Case No. PUE 980463. Testimony on behalf of Appomattax Cogeneration related to the proper implementation of avoided cost methodology.

Virginia State Corporation Commission. Case No. PUE980462 Testimony on behalf of Virginia Independent Power Producers related to an applicaton for a certificate for new generation facilities.

Federal Energy Regulatory Commission. Analyses related to a number of dockets reflecting amendments to the PJM ISO tariff and Reliability Assurance Agreement.

U.S. District Court, Western Oklahoma. CIV96-1595-L. Testimony related to anti-competitive elements of utility rate design and promotional actions.

Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Analyses related to historic measurement of spot prices for as available energy.

Circuit Court, Fourth Judicial Circuit, Duval County, Florida. Analyses related to the proper implementation of a a power purchase agreement and associated calculations of capacity payments. (Testimony 1999)

1997

United States District Court for the Eastern District of Virginia, CA No. 3:97CV 231. Analyses of the business and market behavior of Virginia Power with respect to the implementation of wholesale electric power purchase agreements.

United States District Court, Southern District of Florida, Case No. 96-594-CIV, Analyses related to anti-competitive practices by an electric utility and related contract matters regarding the appropriate calculation of energy payments.

Virginia State Corporation Commission. Case No. PUE960296. Testimony related to the restructuring proposal of Virginia Power and associated stranded cost issues.

Federal Energy Regulatory Commission. Dockets No. ER97-1523-000 and OA97-470-000, Analyses related to the restructuring of the New York Power Pool and the implementation of locational marginal cost pricing.

Federal Energy Regulatory Commission Dockets No. OA97-261-000 and ER97-1082-000 Analyses and testimony related to the restructuring of the PJM Power Pool and the implementation of locational marginal cost pricing.

Missouri Public Service Commission. Case No. ET-97-113. Testimony related to the proper definition and rate design for standby, supplemental and maintenance service for Qualifying facilities.

American Arbitration Association. Case 79 Y 199 00070 95. Testimony and analyses related to the proper conditions necessary for the curtailment of Qualifying Facilities and the associated calculations of negative avoided costs.

Virginia State Corporation Commission. Case Number PUE960117 Testimony related to proper implementation of the differential revenue requirements methodology for the calculation of avoided costs.

New York Public Service Commission. Case 96-E-0897, Analyses related to the restructuring of Consolidated Edison Company of New York and New York Power Pool proposed Independent System Operator and related transmission tariffs.

1996

Florida Public Service Commission. Docket No. 950110-EI. Testimony related to the correct calculation of avoided costs using the Value of Deferral methodology and its implementation.

Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Testimony and Analyses related to the estimation of historic market rates for electricity in the Virginia Power service territory.

Circuit Court of the City of Richmond Case No. LA-2266-4. Analyses related to the incurrence of actual and estimated damages associated with the outages of an electric generation facility.

New Hampshire Public Utility Commission, Docket No. DR96-149. Analyses related to the requirements of light loading for the curtailment of Qualifying Facilities, and the compliance of a utility with such requirements.

State of New York Supreme Court, Index No. 94-1125. Testimony related to system planning criteria and their relationship to contract performance specifications for a purchased power facility.

United States District Court for the Western District of Pennsylvania, Civil Action No. 95-0658. Analyses related to anti-competitive actions of an electric utility with respect to a power purchase agreement.

United States District Court for the Northern District of Alabama, Southern Division. Civil Action Number CV-96-PT 0097-S. Affadavit on behalf of TVA and LG&E Power regarding displacement in wholesale power transactions.

1995

American Arbitration Association. Arbitration No. 14 198 012795 H/K. Report concerning the correct measurement of savings resulting from a commercial building cogeneration system and associated contract compensation issues.

Circuit Court City of Richmond. Law No. LX-2859-1. Analyses related to IPP contract structure and interpretation regarding plant compensation under different operating conditions.

Federal Energy Regulatory Commission. Case EL95-28-000. Affidavit concerning the provisions of the FERC regulations related to the Public Utility Regulatory Policies Act of 1978, and relationship of estimated avoided cost to traditional rate based recovery of utility investment.

New York Public Service Commission, Case 95-E-0172, Testimony on the correct design of standby, maintenance and supplemental service rates for qualifying facilities.

Florida Public Service Commission, Docket No. 941101-EQ. Testimony related to the proper analyses and procedures related to the curtailment of purchases from Qualifying Facilities under Florida and FERC regulations.

Federal Energy Regulatory Commission, Dockets ER95-267-000 and EL95-25-000. Testimony related to the proper evaluation of generation expansion alternatives.

1994

American Arbitration Association, Case Number 11 Y198 00352 94 Analyses related to contract provisions for milestones and commercial operation date and associated termination and damages related to the construction of a NUG facility.

United States District Court, Middle District Florida, Case No. 94-303 Civ-Orl-18. Analyses related to contract pricing interpretation other contract matters in a power purchase agreement between a qualifying facility and Florida Power Corporation.

Florida Public Service Commission Docket 94037-EQ. Analyses related to a contract dispute between Orlando Power Generation and Florida Power Corporation.

Florida Public Service Commission Docket 941101-EQ. Testimony and analyses of the proper procedures for the determination and measurement for the need to curtail purchases from qualifying facilities.

New York Public Service Commission Case 93-E-0272, Testimony regarding PURPA policy considerations and the status of services provided to the generation and consuming elements of a qualifying facility.

Circuit Court for the City of Richmond. Case Number LW 730-4. Analyses of the historic avoided costs of Virginia Power, related procedures and fixed fuel transportation rate design.

New York Public Service Commission, Case 93-E-0958 Analyses of Stand-by, Supplementary and Maintenance Rates of Niagara Mohawk Power Corporation for Qualifying Facilities .

New York Public Service Commission, Case 94-E-0098. Analyses of cost of service and rate design of Niagara Mohawk Power Corporation.

American Arbitration Association, Case 55-198-0198-93, Arbitrator in contract dispute regarding the commercial operation date of a qualifying small power generation facility.

1993

U.S. District Court, Southern District of New York Case 92 Civ 5755. Analyses of contract provisions and associated commercial terms and conditions of power purchase agreements between an independent power producer and Orange and Rockland Utilities.

State Corporation Commission, Virginia. Case No. PUE920041. Testimony related to the appropriate evaluation of historic avoided costs in Virginia and the inclusion of gross receipt taxes.

Federal Energy Regulatory Commission. Docket ER93-323-000. Evaluations and analyses related to the financial and regulatory status of a cogeneration facility.

Federal Energy Regulatory Commission. Docket EL93-45-000; Docket QF83-248-002. Analyses related to the qualifying status of cogeneration facility.

Circuit Court of the Eleventh Judicial Circuit, Dade County, Florida. Case No. 92-08605-CA-06. Analyses related to compliance with electric and thermal energy purchase agreements. Damage analyses and testimony.

Board of Regulatory Commissioners, State of New Jersey. Docket EM 91010067. Testimony regarding the revised GPU/Duquesne 500 MW power sales agreement and associated transmission line.

State of North Carolina Utilities Commission. Docket No. E-100 Sub 67. Testimony in the consideration of rate making standards pursuant to Section 712 of the Energy Policy Act of 1992.

State of New York Public Service Commission. Cases 88-E-081 and 92-E-0814. Testimony regarding appropriate procedures for the determination of the need for curtailment of qualifying facilities and associated proper production cost modeling and measurement.

Pennsylvania Public Utility Commission. Docket No. A-110300f051. Testimony regarding the prudence of the revised GPU/Duquesne 500 MW power sales agreement and associated transmission line.

1992

Pennsylvania Public Service Commission. Dockets No. P-870235,C-913318,P-910515,C-913764. Testimony regarding the calculation of avoided costs for GPU/Penelec.

Public Service Commission of Maryland. Case No. 8413,8346. Testimony on the appropriate avoided costs for Pepco, and appropriate procedures for contract negotiation.

1991

Board of Regulatory Commissioners, State of New Jersey. Docket EM-91010067. Testimony regarding the planned purchase of 500 MW by GPU from Duquesne Light Company.

Public Service Commission of Wisconsin. Docket 05-EP-6. State Advance Plan. Testimony on the calculation of avoided costs and the structuring of payments to qualifying facilities.

State Corporation Commission, Virginia. Case No. PUE910033. Testimony on class rate of return and rate design for delivery point service. Northern Virginia Electric Cooperative.

State Corporation Commission, Virginia. Case No. PUE910048 Testimony on proper data and modeling procedures to be used in the evaluation of the annual Virginia Power fuel factor.

State Corporation Commission, Virginia. Case No. PUE910035. Evaluation of the differential revenue requirements method for the calculation of avoided costs.

Public Service Commission of Maryland. Case Number 8241 Phase II. Testimony related to the proper determination of avoided costs for Baltimore Gas and Electric.

Public Service Commission of Maryland. Case Number 8315. Evaluation of the system expansion planning methodology and the associated impacts on marginal costs and rate design, PEPCO.

1990

Public Utility Commission, State of California, Application 90-12-064. Analyses related to the contractual obligations between San Diego Gas and Electric and a proposed QF.

Montana Public Service Commission. Docket 90.1.1 Testimony and analyses related to natural gas transportation, services and rates.

State Corporation Commission, Virginia. Case No. PUE890075. Testimony on the calculation of full avoided costs via the differential revenue requirements methodology.

District of Columbia Public Service Commission. Formal Case 834 Phase II. Analyses and development of demand side management programs and least cost planning for Washington Gas Light.

State Corporation Commission, Virginia. Case No. PUE890076. Analyses related to administratively set avoided costs. Determination of optimal expansion plans for Virginia Power.

State Corporation Commission, Virginia. Case No. PUE900052. Analyses supporting arbitration of a power purchase agreement with Virginia Power. Determination of expansion plan and avoided costs.

Public Service Commission of Maryland. Case Number 8251. Analyses of system expansion planning models and marginal cost rate design for PEPCO.

State Corporation Commission, Virginia. Case No. PUE900054. Evaluation of fuel factor application and short term avoided costs.

Federal Energy Regulatory Commission. Northeast Utilities Service Company Docket Nos. EC90-10-000, ER90-143-000, ER90-144-000,ER90-145-000 and El90-9-000. Analyses of the implications of Northeast Utilities and Public Service Company of New Hampshire merger on electric supply and pricing.

Public Service Commission of Maryland. Re: Southern Maryland Electric Cooperative Inc. Contract with Advanced Power Systems, Inc. and PEPCO.

Puerto Rico Electric Power Authority, Office of the Governor of Puerto Rico. Independent evaluation for PREPA of avoided costs and the evaluation of competing QF's.

State Corporation Commission, Virginia. Case No. PUE890041. Testimony on the proper determination of avoided costs with respect to Old Dominion Electric Cooperative.

1989

Oklahoma Corporation Commission. Case Number PUD-000586. Analyses related to system planning and calculation of avoided costs for Public Service of Oklahoma.

Virginia State Corporation Commission. Case Number PUE890007. Testimony relating to the proper determination of avoided costs to the certification evaluation of new generation facilities.

Federal Energy Regulatory Commission. Docket RP85-50. Analyses of the gas transportation rates, terms and conditions filed by Florida Gas Transmission.

Circuit Court of the Fifth Judicial Circuit, Dade County, Florida. Case No. 88-48187. Analyses related to compliance with electric and thermal energy purchase agreements.

Florida Public Service Commission. Docket 880004-EU. Analysis of state wide expansion planning procedures and associated avoided unit.

1988

Virginia State Corporation Commission. Case No. PUE870081. Testimony on the implementation of the differential revenue requirements avoided cost methodology recommended by the SCC Task Force.

Virginia State Corporation Commission. Case No. PUE880014. Testimony on the design and level of standby, maintenance and supplemental power rates for qualifying facilities.

Virginia State Corporation Commission. Case No. PUE99038. Testimony on the natural gas transportation rate design and service provisions.

Montana Public Service Commission. Docket 87.8.38. Testimony on Natural Gas Transmission Rate Design and Service Provisions.

Oklahoma Corporation Commission. Cause Pud No. 00345. Testimony on estimation and level of avoided cost payments for qualifying facilities.

Florida Public Service Commission. Docket No. 8700197-EI. Testimony on the methodology for establishing non-firm load service levels.

Arizona Corporation Commission. Docket No.

U-1551-86-300. Analysis of cost-of-service studies and related terms and conditions for material gas transportation rates.

1987

Virginia State Corporation Commission. Case No. PUE870028. Analysis of Virginia Power fuel factor application and relationship to avoided costs.

District of Columbia Public Service Commission. Formal Case No. 834 Phase II. Analysis of the theory and empirical basis for establishing cost effectiveness of natural gas conservation programs.

Virginia State Corporation Commission. Case No. PUE860058. Testimony on the relationship of small power producers and cogenerators to the need for power and new generation facilities.

Virginia State Corporation Commission. Case No. PUE870025. Testimony addressing the proper design of rates for standby, maintenance and supplement power sales to cogenerators.

Florida Public Service Commission. Docket No. 860004 EU. Testimony in the 1986 annual planning hearing on proper system expansion planning procedures.

1986

Florida Public Service Commission. Docket No. 860001 EI-E. Testimony on the proper methodology for the estimation of avoided O&M costs.

Florida Public Service Commission. Docket No. 860786-EI. Testimony on the proper economic analysis for the evaluation of self-service wheeling.

U.S. Bankruptcy Court, District of Ohio. Testimony on capabilities to develop and operate wood-fired qualifying facility.

Public Utility Commission, New Hampshire Docket No. DR-86-41. Testimony on pricing and contract terms for power purchase agreement between utility and QFs. (Settlement Negotiations)

Florida Public Service Commission, Docket No. 850673-EU. Testimony on generic issues related to the design of standby rates for qualifying facilities.

Virginia State Corporation Commission. Case No. 860024. Generic hearing on natural gas transportation rate design and tariff terms and conditions.

Virginia State Corporation Commission. Commonwealth Gas Pipeline Corporation. Case No. 850052. Testimony on natural gas transportation rate design and tariff terms and conditions.

Bonneville Power Administration. Case No. VI86.
Testimony on the proposed Variable Industrial Power Rate for Aluminum Smelters.

Virginia Power. Case No. PUE860011. Testimony on the proper ex post facto valuation of avoided power costs for qualifying facilities.

Florida Public Service Commission. Docket No. 850004 EU. Testimony on proper analytic procedures for developing a statewide generation expansion plan and associated avoided unit.

1985

Virginia Natural Gas. Docket No. 85-0036. Testimony and cost of service procedures and rate design for natural gas transportation service.

Arkansas Louisiana Gas. Louisiana Docket No. U-16534. Testimony on proper cost of service procedures and rate design for natural gas service.

Connecticut Light and Power. Docket No. 85-08-08.
Assist in the development of testimony for industrial natural gas transportation rates.

Oklahoma Gas and Electric. Cause 29727. Testimony and system operations and the development of avoided cost measurements as the basis for rates to qualifying facilities.

Florida Public Service Commission. Docket No. 840399EU. Testimony on self-service wheeling and business arrangements for qualifying facilities.

Virginia Electric and Power Company. General Rate application No. PUE840071. Testimony on proper rate design procedures and computations for development of supplemental, maintenance and standby service for cogenerators.

Virginia Electric and Power Company. Fuel Factor
Proceeding No. PUE850001. Testimony on the proper use of the PROMOD model and associated procedures in setting avoided cost energy rates for cogenerators.

New York State Public Service Commission. Case No. 28962. Development of the use of multi-area PROMOD models to estimate avoided energy costs for six private utilities in New York State.

Vermont Rate Hearings on Payments to Small Power Producers. Case No. 4933. Testimony on proper assumptions, procedures and analysis for the development of avoided cost rates.

1984

Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-service procedures, class rate of return and rate design.

BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on theory and implementation of marginal cost rate design.

Virginia Electric Power Company. Application to Revise Rate Schedule 19 -- Power Purchases from Cogeneration and Small Power Production Qualifying Facilities. Case No. PUE830067. Testimony on proper PROMOD modeling procedures for power purchases and properties of PROMOD model.

Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-service procedures, class rate of return and rate design.

BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on the theory and implementation of marginal cost rate design, financial performance of BPA; interactions between rate design, demand, system expansion and operation.

1983

Northern Virginia Electric Cooperative. Case No. PUE830040. Testimony on class cost-of-service procedures, class rate of return and rate design.

Vermont Rate Hearings to Small Power Producers. No.4804. Testimony on proper use and application of production costing analyses to the estimation of avoided costs.

BPA Wholesale Rate Proceedings. Testimony on the theory and implementation of marginal cost rate design; financial performance of BPA; interactions between rate design, demand, system expansion and operation.

Idaho Power Company, PUC-U-1006-185. Analysis of system planning/production costing model play of hydro regulation and associated energy costs.

1982

Generic Conservation Proceedings, New York State. Case No. 18223. Testimony on the economic criteria for the evaluation of conservation activities; impacts on utility financial performance and rate design.

PEPCO, Washington Gas Light. DCPSC-743. Financial evaluation of conservation activities; procedures for cost classification, allocation; rate design.

PEPCO, Maryland PSC Case Nos. 7597-I, 7597-II, and 7652. Testimony on class rates of return, cost classification and allocation, power pool operations and sales.

1981

Pacific Gas and Electric. California PSC Case No. 60153. Testimony on rate design; class cost-of-service and rate of return.

Previous testimony before the District of Columbia Public Service Commission, Maryland PSC, New York Public Service Commission, FERC; Economic Regulatory Administration

NEPGA Exhibit 2

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and New England Power Pool	)	Docket No. ER10-787-___
New England Power Generators Association, Inc.	)	
	)	
v.	)	Docket No. EL10-50-___
	)	
ISO New England Inc.	)	
PSEG Energy Resources & Trade LLC, *et al.*	)	
	)	
v.	)	Docket No. EL10-57-___
	)	
ISO New England Inc.	)	

TESTIMONY OF ROBERT B. STODDARD
ON BEHALF OF NEW ENGLAND POWER GENERATORS ASSOCIATION

JULY 1, 2010

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

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

A My name is Robert B. Stoddard. I am a Vice President and the leader of the Energy & Environment Practice of Charles River Associates ("CRA") in its offices at 200 Clarendon Street, T-33, Boston, Massachusetts 02116.

Q PLEASE SUMMARIZE YOUR EXPERIENCE AND QUALIFICATIONS.

A I am an economist with extensive experience with, and knowledge of, electricity market design and operation. My work over the past decade has focused on electricity industry restructuring and on providing strategic analyses and testimony for utilities, generation owners, and governments regarding the financial implications of market design and structure, particularly regarding Regional Transmission Organizations ("RTOs") in New England, New York, the Mid-Atlantic, and the Midwest. As shown in NEPGA Exhibit 2-A, I have testified frequently before the Federal Energy Regulatory Commission ("FERC" or "Commission") and various States' legislatures and utility commissions on competitive market design and market power issues. I hold degrees in economics from Amherst College and Yale University.

Q WHAT ROLE HAVE YOU HAD IN THE DEVELOPMENT OF THE ISO NEW ENGLAND ("ISO-NE") FORWARD CAPACITY MARKET ("FCM") AND OTHER INSTALLED CAPACITY MARKET DESIGNS?

A My work in capacity markets in New England began in 2004 with affidavit in support of NextEra Energy Resources, LLC (f/k/a FPL Energy, LLC) on issues of locational capacity requirements in the *Devon* proceeding.[1] When the Commission set the matter

[1] *Devon Power LLC*, Docket No. ER03-563-030, Protest of FPL Energy, LLC, Affidavit of Robert B. Stoddard (Mar. 22, 2004).

for hearing, I was engaged by four of the largest generation owners in New England to testify in the *Devon* hearings regarding the development of a Locational Installed Capacity ("LICAP") market. In the ensuing settlement process, I continued to represent generation owners throughout the negotiations to develop the FCM settlement agreement. In support of the settlement agreement, ISO-NE filed my affidavit, along with affidavits from the other two lead economists in the settlement, Professor Peter Cramton, on behalf of ISO-NE, and Dr. Miles Bidwell, on behalf of the Connecticut Department of Public Utilities Control. Since the adoption of the FCM, I have continued as an active participant in FCM rule development and ongoing reviews of the market effectiveness, including participation in the FCM Working Group through much of 2009 on behalf of the New England Power Generators Association ("NEPGA"). I testified previously in the instant dockets, providing expert testimony that accompanied NEPGA's protest and complaint.[2]

I have testified about capacity market issues in every Commission-jurisdictional organized market. In addition to the work described above in New England:

a. In New York, I testified on behalf of Consolidated Edison Company of New York ("Con Ed") and other load interests. Prior to the start of the market in 1999, I worked with my colleague Dr. William Hieronymus to develop market power mitigation measures for New York City generation being divested by Con Ed. Later, I testified for Con Ed and others regarding the transition of NYISO markets from an "installed" to an "unforced" metric of capacity. I have continued to

[2] *ISO New England Inc.*, Docket No. ER10-787-000, Motion to Intervene and Protest of the New England Power Generators Association, NEPGA Exhibit 3, Affidavit of Robert B. Stoddard on Behalf of New England Power Generators Association, (Mar. 15, 2010) ("March Affidavit"); *New England Power Generators Assoc. v. ISO New England Inc.*, Docket Nos. EL10-50-000 & ER10-787-000, Complaint Requesting Fast Track Processing By NEPGA, NEPGA Supplementary Exhibit 2, Supplementary Affidavit of Robert B. Stoddard (Mar. 23, 2010).

monitor the New York markets closely on behalf of my commercial clients, including the City of New York.

b. In PJM, I represented Mirant and other generators throughout the settlement discussions that led to the development of the Reliability Pricing Model ("RPM") and have since testified frequently on needed reforms to that market design.

c. In the Midwest ISO, I have testified on behalf of Duke Energy and FirstEnergy on deficiencies in the Midwest ISO's "Module E" resource adequacy approaches and advocated a prompt transition from the monthly deficiency auctions to a more robust design.

d. Recently I also had significant roles in developing the California Forward Capacity Market ("CFCM") design in California Public Utilities Commission proceedings, where I represent a coalition of utilities (Southern California Edison and San Diego Gas & Electric) and generators (NRG Energy, RRI Energy, and NextEra Energy Resource). The CFCM approach received broad-based support, including that of the California ISO, energy retailers, and end-use customers.

Overseas, my team and I have worked on resource adequacy issues for the market operators of the Russian Federation, Portugal, and the Republic of Ireland.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A I have been asked by counsel for NEPGA to evaluate the rule changes to the FCM tariff filed in February 2010, *ISO New England Inc.*, Docket No. ER10-787-000, Various Revisions to FCM Rules Related to FCM Redesign (Feb. 22, 2010) ("FCM Revision"), and set for hearing by the Commission in its April 23, 2010 order in this docket, *ISO New England Inc.*, 131 FERC ¶ 61,065 (2010) ("Hearing Order"). Specifically, I address the key deficiencies in the FCM design related to (i) the Alternative Pricing Rule ("APR"), (ii) the definition and modeling of locational capacity zones, and (iii) the administrative Cost of New Entry ("CONE") for a new proxy unit. For each of these aspects of the FCM rules, I provide my view as an economist and as one of the principal architects of the FCM as to what rule changes are required for, and would be consistent with, sound economics, efficient market outcomes, and the overall market design to ensure resource adequacy in the long term.

II. BACKGROUND AND SUMMARY OF TESTIMONY

Q WHAT ARE THE KEY POINTS RELATED TO THE ITEMS IDENTIFIED IN THE HEARING ORDER THAT YOU WILL ADDRESS?

A My testimony addresses the key deficiencies in the current APR and the criteria that an adequately designed revised APR must satisfy. Within that context, I review the most recent ISO-NE proposal for APR revisions, as outlined in a June 15, 2010 presentation to stakeholders, which I generally support. *See* Bob Ethier *et al.*, Draft Response to FERC Order of April 23, 2010 (June 15, 2010), http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2010/final_prop_fcm_rev6_15_10.pdf. I understand that ISO-NE intends to submit its June proposal in this proceeding on July 1.

I also identify and address several deficiencies inherent in the current definition and treatment of Out-of-Market ("OOM") capacity. Specifically, I will discuss the changes to the rules that must be made to define effective conditions under which a resource should be treated as OOM. I also discuss the duration over which OOM treatment must apply and the appropriate carry-forward mechanism to account for multi-year impacts of OOM capacity. Finally, I discuss the provisions that must be applied to the prospective treatment of OOM resources that cleared in the first three FCAs to ensure that the capacity markets in New England produce prices that are adequate to incentivize new entry and retain existing needed generation over the long term without over-compensating or under-compensating suppliers.

With regard to locational capacity zones, my testimony discusses the number of zones that must be modeled and the importance of, whenever possible, modeling all zones in each FCA. I also discuss potential market power issues associated with modeling of zones and provide examples of the mitigation measures that could be implemented to address these issues.

Finally, I discuss why it is necessary for the administrative value of CONE for a new proxy unit to be reset, and I present the assumptions and parameters that should be used in determining the updated CONE value. I also discuss the importance of updating CONE and the potential deleterious effects of failing to reset it to a level reflective of actual costs of a new generating unit. In addition, I discuss why it is important to set some market parameters that are currently tied to CONE based on other metrics.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE APR.

A A properly functioning APR is essential to the sound operation of the FCM; as the Commission acknowledges, if "a low offer is not economically justified, it is reasonable to reset the clearing price to a level that would be expected in a competitive market that requires new capacity."[3]

The deficiencies in the existing APR rules have already led to serious problems. These issues need to be addressed in a coherent manner that provides a comprehensive,

[3] *Devon Power LLC*, 115 FERC ¶ 61,340 at P 114 (2006).

transparent framework for addressing the impacts of OOM resources in the FCM and the distortions to market prices associated with previous and future OOM entry.

The APR approach proposed by ISO-NE in its June presentation ("June APR"), which I understand will be the basis for its filing on July 1, provides a straightforward, comprehensive, and sound manner of addressing the presence of OOM resources and their concomitant effect on the market: whenever OOM resources are in the market (either because they were offered in the current year or are carried forward from a prior year), capacity prices paid to existing resources are reset to approximate the payments that would have occurred but for the OOM entry. Any rule short of this proposal will result in suppression of capacity prices by OOM resources, leading to inefficient price signals and the potential for exercise of buyer side market power, as well as making it likely that FCM prices will fall short—and perhaps far short—of the actual cost of new entry. This systemic artificial price suppression will over the long term eviscerate competitive capacity markets in New England, as many merchant generating facilities will not have the opportunity to recover their long-run marginal costs.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE SELECTION OF CAPACITY ZONES.

A The second group of proposed market rule changes that I will discuss is related to Capacity Zone determination and price separation. The FCM should be designed to procure sufficient resources to meet all resource planning criteria, thereby avoiding incremental procurements outside of the FCM framework. The FCM Revision, approved by the Commission in the Hearing Order, to use the higher of the Local Resource Adequacy Requirement or the Transmission Security Analysis Requirement, is a positive change that will improve the locational price signals in the FCA. However, additional changes are needed to ensure that locational zones are captured in the model appropriately, both in terms of scope and consistent treatment in each FCA.

First, the FCM design should be modified to *always* model Capacity Zones in the FCA, consistent with the practice of the New York Independent System Operator ("NYISO") and the PJM Interconnection ("PJM"), both of which model the defined capacity zones.[4] The only plausible rationale for more limited zonal modeling is a concern that market power mitigation may be inadequate in small zones, but this is an issue that can be dealt with directly. It does not otherwise justify a failure to correct the core deficiency in the market in the first place. I note that additional zones may or may not create additional price separation, depending on the details of market supply/demand balance and other fundamentals within each zone; conversely, if ISO-NE fails to model a zone, it cannot be priced separately from the rest of the pool even if the market fundamentals would justify such a separate locational price. It is better, therefore, to err on the side of modeling more zones, more often.

Second, the number of zones should be established based on a balance between, on the one hand, effectively capturing the electrical characteristics of the system and resulting transmission limits and, on the other hand, potential technical auction problems, if any, resulting from including a large number of small zones and providing adequate notice of the zones.

[4] The NYISO has not, however, been proactive in identifying additional zones that may be required. Because of software limitations, PJM is unable to determine locational capacity requirements when there is a sufficiently large surplus of capacity in a zone. Under that circumstance, the zone may not be modeled in the RPM auction.

If ISO-NE has information that indicates that some sub-zone is likely to be relevant in the FCA, it should establish that sub-zone, whether or not it is expected to be constrained, as an FCA zone with sufficient notice to ensure the opportunity for competitive entry, allowing new projects in that zone to be qualified. But if these sub-zones have not been identified in advance (which should be an unlikely event), the zones should not be determined on the fly, but rather be included for the next auction, when they will be known in advance with sufficient opportunity for developers to qualify new resources to compete. Nor should the question of whether a new zone will be created be subject to stakeholder vote; while stakeholders should review the methodology and assumptions used by the ISO to establish zones, determination of zones should be driven by data and analysis, not politics. To the extent that an auction outcome reveals a need for a new zone (because, for example, a de-list or retirement is denied due to local reliability concerns), that zone should be included in subsequent auctions for as long as it is relevant.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING CONE.

A The final group of topics I examine covers the administratively set value for CONE for a new proxy unit, and its application in the market design. An update to the ISO-NE administrative value of CONE is necessary to address the fact that the current value of CONE is, in the words of the Internal Market Monitor, "significantly below most estimates of the cost of new entry for generating resources."[5] I propose that ISO-NE should reset CONE to a level that reflects the long-run cost of new capacity, rather than its present, utterly arbitrary level bearing no relationship to the actual costs of the new

[5] *ISO New England Inc.*, Docket No. ER09-1282-000, Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements at 8 (June 5, 2009) ("Internal Market Monitor Report").

resources and that a periodic reset process be established to prevent such a substantial disparity between the ISO-NE CONE and actual costs from occurring again in the future. This necessarily means a cost to build active generation, for although demand resources and energy efficiency are valuable at the margin, you cannot operate an electric system with nothing but these resources. Something, somewhere, must produce electricity under the dispatch control of the RTO, and it is these dispatchable generation resources that ultimately must be maintained or replaced with other dispatchable generation. This generation-based CONE may not be appropriate for all purposes, however, and I will discuss some particular rules that currently use CONE that might appropriately be changed to another benchmark.

Q WHY IS IT VITAL TO PROPER FUNCTIONING OF THE FCM THAT APPROPRIATE RULE CHANGES BE IMPLEMENTED IN EACH OF THESE AREAS?

A The importance of remedying the flaws in the FCM design identified by ISO-NE's Internal Market Monitoring Unit cannot be overstated. When we began the FCM settlement discussions, we faced imminent capacity shortages in New England yet had next to no new resources in the interconnection queue, flat participation in demand response programs, and the risk of unexpected unit deactivations. Within a year of the adoption of the FCM, though, the situation had turned around. Without substantial changes in the FCM rules to correct the deficiencies that remain inherent in the current model, however, the FCM will fail to attract new resources and maintain existing needed resources over the long run, and we will see a reversal of the successes we achieved, leading to deactivation of some of the highest efficiency, cleanest generation facilities in the region, and a shift in the fundamental investment paradigm from a merchant model back to rate-based expansion. If this were allowed to occur, a major benefit of competitive markets would be lost: consumers, not shareholders, would, once again, be forced to shoulder the risk of this investment in the long run. These changes are also necessary to protect economically efficient demand-side participation. Capacity markets not only provide needed revenues to ensure reliability, they also guide investment (and disinvestment) in the region's generation and transmission infrastructure, in terms of both new units and necessary retrofits to existing units, including those needed to meet increasingly more stringent environmental requirements. Thus, flaws in the capacity markets not only inflict near-term harm on market participants; more importantly, from my perspective, these flaws inflict long-lasting harm by misdirecting investment in New England's energy infrastructure.

III. THE ALTERNATIVE PRICE RULE

A. Purpose of the APR

Q WHY WAS THE APR INCLUDED IN THE FCM MARKET DESIGN?

A A fundamental criterion for a sound market design is that, to the extent possible, it produces market clearing prices and quantities that are consistent with a competitive outcome. Over the long-term, the prices in a competitive market should fluctuate around, but trend towards, the long-run marginal cost of the product bought and sold in the market. For the FCM, this means that capacity auctions should result in prices that on average over time equal CONE. Another goal of the FCM design is to produce price stability around this long-run equilibrium price, so that small changes in supply or demand conditions do not result in dramatic swings between very high and very low prices. The APR, as one of several stabilizing factors built into the FCM design, was intended to ensure that the FCA price would reflect new entry costs when new entry was, in fact, occurring, even if the new entry is insensitive to the FCA clearing price because of contractual guarantees.

The APR serves as one of several necessary protections against market power, by reducing or eliminating the price impact of OOM capacity additions. Had it functioned as intended, the APR would therefore have largely eliminated any incentive for a load-serving entity ("LSE") to contract with new generation ahead of need for the purpose of lowering the capacity price at which the LSE would buy the remaining portion of its capacity requirement. The APR thus mitigates market power by reducing the price impact of uneconomic capacity additions. As the Commission previously has held balancing supply side mitigation provisions with load side mitigation provisions is critical to ensure that prices are neither artificially increased nor artificially suppressed.[6]

The Internal Market Monitor provides an excellent summary of the rationale for the APR:

> One of the FCM design goals is to ensure that the FCA clearing price reflects the cost of new entry (CONE) when new entry is needed. The Alternative Price Rule (APR) was included in the market design to help prevent OOM resources from setting artificially low prices. OOM entry includes self-supplied resources and other resources that remain in the auction no matter how low the price, typically because they have a contractual commitment that covers some or all of their costs. The APR provides for price adjustments when new entry is needed but is prevented from setting the price in the FCA because out-of-market entry is sufficient to meet the need. If the quantity of OOM capacity offered is greater than the quantity of new capacity required, prices are likely to be much lower than the market-based competitive cost of new entry … . This is

[6] *New York Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211 at P 1 (2008); *New York Indep. Sys. Operator, Inc.*, 118 FERC ¶ 61,182 at P 17 (2007).

important because the amount of new capacity needed is relatively small each year and can be exceeded by OOM capacity fairly easily.[7]

Q IN YOUR OPINION, HAS THE APR FUNCTIONED AS INTENDED?

A No. The results from the first three FCAs demonstrate why the APR, as originally specified, was critically flawed. Despite clearing prices well below most estimates of new resource costs, 5,356 MW of new resources cleared in the first three auctions, 2,005 MW of which were designated as OOM. As a result, the New England market has been left with an enormous surplus, totaling 5,061 after FCA #3, that could last another decade or longer. And despite this surplus, additional OOM capacity has continued to be added. For example, in FCA #3, 695 MW of additional OOM capacity cleared, despite a surplus of 4,448 MW already in the market.

ISO-NE was facing an immediate capacity need at the time the FCM design was approved. Under a well-functioning market, that need for new capacity should have translated into prices that reflected the cost of adding new capacity. Instead, each FCA has resulted in prices that reflect an administratively set price floor, divorced from the competitive forces and economic fundamentals. This was directly due to governmental actions that were taken to bring new capacity on line while—as reflected by the express terms of the RFPs that were used—at the same time suppressing the price. An APR, if properly structured, would have prevented precisely this outcome. Various flaws in the APR rules, however, prevented its effective operation. I discussed the flaws in the existing APR in my earlier affidavit in this docket.[8]

---

7 Internal Market Monitor Report at 5.

8 *See* March Affidavit ¶¶ 22-79.

Q WOULD REVISIONS TO THE APR PROPOSED BY ISO-NE IN THE FCM REVISION RESOLVE THESE PROBLEMS WITH THE ORIGINAL APR?

A No. As I discussed in my March Affidavit, several flaws remained in the February APR. The Commission acknowledged the concerns of multiple parties about the APR, noting that:

> [T]he concerns [about APR] raised by the [External Market Monitor] and the generators warrant further investigation and, therefore, we will require further proceedings, in the form of the paper hearing ordered herein, for the purpose of examining and resolving those concerns.[9]

Indeed, ISO-NE itself acknowledged the FCM Revision that additional revisions were needed in this area. In the next sections of my testimony, I lay out my views of the appropriate and necessary criteria for an effective APR. I then review a recent proposal for a revised APR that ISO-NE recently presented to stakeholders, which I support, in concept, subject to further review of the specific parameters that are contained in its filing. I also discuss a demand curve as an alternative means of supporting market stability, and note the importance of having such a mechanism in place if an effective APR cannot be established.

B. *Criteria for Adequate APR*

Q WHAT CRITERIA SHOULD BE APPLIED IN DEVELOPING A REVISED APR MECHANISM?

A In its Hearing Order, the Commission noted that

> APR is a market power mitigation rule intended to discourage buyers who have the incentive and ability to suppress market clearing capacity prices below a competitive level from doing so. We have previously accepted rules to address such uneconomic entry in the capacity markets of ISO-NE, as well as in NYISO and PJM. Our objective in accepting these

[9] Hearing Order at P 71.

> provisions has been to ensure that the prices in capacity markets reflect the market cost of new entry when new entry is needed.[10]

In order for a new APR rule to be effective and to meet these objectives, it must satisfy several criteria. First, it must adjust the price to the competitive level that would result in the absence of OOM capacity. Second, this adjustment must occur *whenever* the unadjusted clearing price is affected by OOM capacity offered into a past or present FCA, *regardless* of whether the competitive price is set by new or existing capacity. Third, the APR must fully correct for the impact of OOM, and remove all dampening price signals. Finally, the APR must effectively remove any incentive for net short entities to add uneconomic capacity in order to artificially suppress the price, while still allowing for entry of new resources that have been secured by market participants under economically efficient contracts.

Q LET'S CONSIDER EACH OF THE FOUR CRITERIA IN ORDER. WHY SHOULD THE APR ADJUST THE FCA CLEARING PRICE TO A COMPETITIVE LEVEL?

A The APR should reset the FCA clearing price to (or, at least, towards) competitive levels for both equity and efficiency reasons. As a matter of equity, investors who have committed capital to the New England market have a reasonable expectation that the markets will provide them an opportunity to earn a competitive return on that investment and that a periodic reset process be established to prevent such a substantial disparity between the ISO-NE CONE and actual costs from occurring again in the future; if market prices for capacity are artificially suppressed over the long term below the full economic cost of providing that capacity, they are denied this opportunity. Although this may be attractive to consumers in the short run, it is not an equitable outcome.

---

[10] Hearing Order at P 69 (footnote omitted).

Moreover, allowing price suppression ultimately promotes inefficient investments in the region. New capacity will be brought into the market—by contract—ahead of demand for the purpose of artificially suppressing capacity prices, which is inefficient. Existing resources may well have an offer in the auction below that of a new resource brought in under contract, yet that relatively cost-effective resource would be displaced without an effective APR. Furthermore, by suppressing capacity prices below the competitive level, needed existing suppliers will have a reduced incentive (and cash) to maintain their generation at high levels of reliability; "run to failure" becomes a realistic option when the net cash flow from a resource is low or negative.

Q PLEASE EXPLAIN YOUR SECOND CRITERION, THAT THE APR BE APPLIED WHENEVER OOM RESOURCES AFFECT THE MARKET CLEARING PRICE.

A If getting prices right is important, it ought to be important all the time. The current APR applies only when *all* required new entry comes from OOM resources newly offered in *that auction*. Neither of these limitations is sensible. If 500 MW of new capacity is needed, and 490 MW of that comes from OOM entry, the offer price of the remaining 10 MW of new supply could easily be much lower than the competitive market price of obtaining 500 MW of new supply. The supply curve for new and existing capacity slopes upward. Ignoring this fact, as the current APR does, leads to systematic under-pricing when OOM resources are in the offer stack. Furthermore, the issue of price suppression does not necessarily go away after the first year when an OOM resource enters the market. If more than a year's worth of new requirement is brought on-line, that over-supply will suppress prices until the over-supply is absorbed. Ignoring this fact creates the opportunity for buyers in the market to keep the market sufficiently long by adding new OOM resources so that the market price stays below the full cost of those new resources indefinitely. Permitting such an exercise of buyer market power is not sustainable over the long term, and should not be allowed by a sound market design.

Q PLEASE EXPLAIN YOUR THIRD CRITERION, THAT AN EFFECTIVE APR SHOULD RESET THE PRICE FULLY TO THE COMPETITIVE LEVEL.

A In competitive markets, prices are not merely a means of moving money from one side of the table to another. Prices serve as carriers of information. If market prices are distorted by out-of-market activities, the information in the market is also distorted. With bad information, market participants make inefficient investment choices. Because these choices in a capacity market are typically long-lived—for example, to build or retire a power plant—price distortions can have long-run adverse outcomes on the market.

Q FINALLY, PLEASE EXPLAIN YOUR FOURTH CRITERION FOR AN EFFECTIVE APR.

A My fourth criterion is that a sound APR should eliminate the incentive of buyers to contract for new builds that would not be economic but for their potential to suppress market prices, while at the same time protecting the ability of parties to get the direct benefit of any contracts they choose to make. This is a difficult balance to strike. In New York City, by contrast, OOM resources will not clear in an auction unless their mitigated price (based on a threshold of 75 percent of CONE, or a unit-specific standard for projects with documented lower costs) clears; it is possible, therefore, that a buyer has entered into a contract to buy energy and capacity from a new resource but finds that the new resource cannot supply the capacity. In New England, where there are many buyers who may not have market power, this rule is too draconian, in my judgment; even though it would provide a very sharp deterrent from the exercise of buyer market power, it may also have a chilling effect on "innocent" contracting that, at least in the judgment of the Internal Market Monitor, is uneconomic. Thus, for the New England market, the ideal APR would find this balance between removing the incentive to build for the purpose of suppressing prices, while still allowing contracts to clear when the supplying parties want them to do so.

Q HOW DO YOU STRIKE SUCH A BALANCE?

A Having given this issue further thought since my March Affidavit, I have concluded that the best way to accomplish this dual goal is to assign capacity supply obligations based on as-submitted offers, but to set a higher price for incumbent resources equal to the price that would have prevailed in the market but for the suppressing effect of OOM resources. This apparently is the same conclusion that ISO-NE reached, because it is the same basic APR design that ISO-NE presented in June.

C. ISO-NE's June 2010 Revised APR Proposal

Q HAVE YOU REVIEWED ISO-NE'S PROPOSED APR?

A Yes, I reviewed those materials provided by ISO-NE for the June 15, 2010 meeting that it conducted for stakeholders. This presentation is attached as NEPGA Exhibit 2-B. I understand that this is the position that ISO-NE intends to file contemporaneous with my testimony.

Q PLEASE SUMMARIZE THE APR PROPOSAL OF ISO-NE.

A As I understand it, ISO-NE proposes that the APR rule operate as follows:

- The Internal Market Monitor will construct a mitigated supply curve that includes new OOM resources (with unjustified offers below 0.8 times the relevant benchmark for the resource) and Carried Forward Excess OOM at offer prices equal to 0.9 times the relevant benchmark price for each resource.

- The FCA is conducted, and two prices are noted (for each relevant zone): the market-clearing price using the mitigated supply curve (computed in step 1), and the market-clearing price using as-submitted offers. Call the first price the "APR Price" and the second price the "FCA Price."
- All existing resources ("Tier 1 Resources") with offer prices below the APR Price are given Capacity Supply Obligations at the APR Price.
- All resources other than Tier 1 Resources ("Tier 2 Resources") that clear the FCA with as-submitted offers are given Capacity Supply Obligations at the FCA Price.

Q HOW DOES ISO-NE PROPOSE TO HANDLE THE "BETWEEN" RESOURCES PROBLEM THAT YOU DISCUSSED IN YOUR MARCH AFFIDAVIT?

A In order for any auction design to give the right incentives for participants, it must be the case that a bidder is content with its bid once the outcome is known. In particular, we want to avoid a design where capacity supply obligations are awarded to resources that were willing to stay in the auction to some low price, but then pay a higher price to those resources that ultimately clear. Resources that left the auction at prices below the final payment level will regret having stepped out of the auction, even though the price at which they left reflected their true reservation price. I call these resources "between resources," because their bid falls between the mitigated and unmitigated FCA prices.

ISO-NE addresses this issue cleanly: "between" Tier 1 Resources are given a capacity supply obligation at the mitigated APR Price.

Q DO YOU SUPPORT THIS PROPOSAL?

A Yes, I support this proposal as a framework for designing an effective APR. Important details of ISO-NE's proposal, such as the determination of the Carried Forward Excess OOM, were not fully developed in the June 15 meeting materials. My testimony on September 1, 2010, will provide a complete analysis of the new proposal and recommend any adjustments suggested by that analysis once I have had the opportunity to review the full proposal.

Q IN YOUR MARCH AFFIDAVIT YOU OUTLINED AN APR PROPOSAL. IN WHAT WAYS DOES YOUR MARCH PROPOSAL DIFFER FROM THE CURRENT ISO-NE POSITION?

A The ISO-NE proposal builds upon that proposal in constructive ways. Like my March proposal, ISO-NE now proposes to eliminate complex triggering rules and simply apply the APR whenever there are OOM resources—either newly offered or carried forward—in the supply stack and, consequently, potentially suppressing the FCA clearing price below its competitive and compensatory level.

Also similar to my March proposal, ISO-NE now proposes to construct a mitigated supply curve where all new and carried forward OOM resources are re-priced towards a level consistent with those resources' full net cost. ISO-NE proposes to establish technology specific benchmark prices, as I had proposed, and mitigate any unsupported offer that is below 0.8 times the applicable benchmark upwards to 0.9 times the applicable benchmark; in contrast, I had proposed that the mitigation should be to the full benchmark value. Restating the mitigated offer for an OOM resource is necessary if the APR Price from the auction is going to result in efficient short-term and long-term outcomes. Shading the price downward to 90 percent of the benchmark will result, in the short run, in the inefficient displacement of existing resources by more-costly new resources. In the long run, this systematic under-mitigation drives the expected long-run average FCA price below the level where it needs to be, namely at the full economic CONE value.[11]

Finally, ISO-NE now proposes, as I had in March, that the FCA be run to establish the APR Price, which reflects the price that would have arisen had all OOM resources been offered at (or near, under ISO-NE's proposal) their competitive value, but that resources clear based on their as-submitted offers.

Q DOES THE ISO-NE PROPOSAL USE THE APR PRICE IN THE SAME WAY THAT YOU PROPOSED IN MARCH?

A No. Under my March proposal, the APR Price (which I referred to as P*) would have set the total capacity payments. Specifically, if there were no binding locational constraints, the total capacity cost would be fixed at the APR Price times the Net ICR. With this cost fixed, I proposed that the FCA continue, but with a demand curve inserted to allow ISO-NE to procure a quantity greater than the NICR (or, within zones, the LSR); this demand curve would be constructed to maintain an unchanged cost to customers. In contrast, ISO-NE now proposes to pay all Tier 1 Resources this APR Price, provided that those resources remained in the FCA at that price.

---

[11] Any comparison to the energy market mitigation, which allows mitigated energy bids to include up to a 10 percent margin over the calculated marginal cost of the resource, would be specious. First, the 10-percent margin is intended to allow for some costs that are difficult to measure; it is not a license to overcharge consumers. Second, if a supplier is bidding above true cost, it can be displaced by competitive entry. In the capacity market, however, allowing OOM resources to be *under-priced* cannot be corrected by competitive entry; to the contrary, the under-pricing effectively precludes market-based, competitive entry.

Q WHICH APPROACH DO YOU NOW SUPPORT?

A I support the mechanism now proposed by ISO-NE. This approach elegantly solves two issues created by my earlier proposal, as well as addressing the deficiencies of ISO-NE's FCM Revision.

Q WHAT IS THE FIRST ISSUE THAT IT ADDRESSES?

A Under my March proposal, the price paid to existing resources was suppressed by OOM resources, even though the total cost was not suppressed. This violated the third criterion that I discussed above. Consequently, existing resources with low going-forward costs could be pushed out of the market by more costly OOM resources. This outcome is inefficient: the resource adequacy market outcome should not be driving low-cost existing resources from the market because they do not have contracts or subsidies. Under my March proposal, the mix of resources that cleared the auction was not necessarily the lowest cost mix.

Q WHAT IS THE SECOND ISSUE WITH YOUR MARCH PROPOSAL THAT THE ISO-NE PROPOSAL ADDRESSES?

A There is a subtle incentive issue created in my March proposal with respect to the offer prices from some resources. In a typical market, the incentive to economically withhold a resource by offering it above its true cost is tempered by the risk that this resource might not clear even when the market price is above its true cost. If this happens, the supplier loses a potential revenue source for that resource, which may or may not be offset by the increase in price from withholding that resource and higher earnings for other resources in the suppliers' portfolio. In the APR rule that I proposed in March, however, this tempering effect on economic withholding is weakened. Depending upon the circumstances of the auction and the information available to suppliers, resources that could be important in setting the APR Price might be very unlikely to clear. If these resources are part of portfolios that include resources that would benefit by having a higher total level of capacity payments in the market, then the competitive check on the bidding behavior of these suppliers is weakened. Although this weakening is not likely to be material, it does suggest that, instead of using the APR rule I proposed in March, another rule should be adopted that does not have this weakness.

Q HOW DOES THE ISO-NE PROPOSAL ADDRESS THESE CONCERNS?

A By clearing existing resources at the APR Price, the ISO-NE proposal squarely addresses both of these concerns simultaneously.

With respect to the first issue, existing resources are not pushed out of the market by new resources unless the offer prices for those existing resources are indeed higher than the full cost of bringing a new resource into the market. This is a sound outcome: the market should not be fostering costly capital expenses to build new resources unless those resources are indeed less costly than what is already available. Any other outcome is inefficient and raises the total cost of meeting the resource adequacy requirement over the long run.

With respect to the second issue, all resources now have the same incentive to bid competitively as they would without the APR rule. Although the FCA is, in effect, bifurcated, the Tier 1 Resources that could clear in the first phase of the FCA have a strong incentive to clear in that market and, consequently, to offer their resources at a price closely linked to actual costs. The incentive compatibility created by the ISO-NE proposal is discussed in more detail in the testimony of Professor David McAdams.[12]

Q WOULD YOU FAVOR INCLUDING COMPETITIVELY OFFERED NEW RESOURCES IN THE TIER 1 CATEGORY?

A Although there are some reasons to support that line of thinking, on net I believe it would be better for all new resources—assuming they are being correctly classified as new to the market—to be included in Tier 2. Clearing competitively offered new resources as Tier 1 Resources could encourage unneeded new builds in the market if OOM new entry is already committed and likely to enter into commercial operation regardless of the FCA outcome. Such "double builds" would be wasteful and create (or exacerbate) a capacity surplus. Second, if new entry deemed not to be OOM would receive a higher price than those tagged as OOM, the Internal Market Monitor's decision about the OOM status will have potentially enormous implications for new entrants and would place undue pressure on the Internal Market Monitor not to deem some new resources as OOM, especially if those resources are favored by state policies. Putting all truly new resources in the same tier addresses both issues.

Q ARE COSTS TO CONSUMERS HIGHER OR LOWER UNDER THE ISO'S APR PROPOSAL, COMPARED TO YOUR MARCH PROPOSAL?

A Consumers could pay more or less under the ISO's proposal relative to my earlier proposal. Under my March proposal, the ISO would collect from consumers the mitigated price (*i.e.*, the APR Price or P*) times the Net ICR quantity whenever the APR was in effect. This revenue would then be divided among the resources that cleared,

---

[12] Testimony of David L. McAdams on Behalf of New England Power Generators Association, attached as NEPGA Exhibit 4 ("McAdams Test.").

which would be a larger quantity but each receiving a lower price. Under the ISO's proposal, this APR Price is paid only to a portion of resources, the Tier 1 existing resources; Tier 2 Resources are paid the lower FCA Price. If there are no "between resources," then consumer costs are lowered. Specifically, they would save the product of the Tier 2 cleared quantity times the difference between the APR Price and the FCA Price. If there are "between resources," however, the payments to these resources at the APR Price reduce this savings or, if the quantity of between resources is large enough, could increase capacity payments. Some of this extra cost in the capacity market from procuring resources above the reliability requirement could be offset, though, by reduced prices in the energy market.[13]

Q HAVE YOU COMPLETED YOUR ASSESSMENT OF THE ISO'S NEW APR PROPOSAL?

A No. The ISO's June 15 presentation left several significant questions unanswered. Without knowing the ISO's complete proposal, filed contemporaneously with this testimony, I cannot complete my evaluation. Consequently, I will supplement my response in the second round of testimony on September 1.

Q WHAT AREAS IN PARTICULAR ARE LEFT OPEN BY THE ISO'S JUNE PRESENTATION?

A There are several open issues in the proposal, but, in particular, the ISO presentation was ambiguous as to the treatment of Carried Forward Excess Capacity. As I stated in my March affidavit, I believe it is essential that OOM capacity in excess of the amount of new capacity required in the year in which that OOM capacity is first offered needs to be

[13] *See PJM Interconnection, L.L.C.*, Docket Nos. ER05-1410-000, *et al.*, Settlement Agreement and Explanatory Statement Resolving All Issues, Attachment C, Supplemental Affidavit of Benjamin F. Hobbs (Sept. 29, 2006).

carried forward until such time that it is absorbed by the market, either through load growth or resource retirements. As this Commission previously has determined, any pre-defined time period is arbitrary and provides the load side with an opportunity to game the rule.[14] The end result will be that OOM entry will still have significant depressing effects on market prices and the core purpose of these rule changes will be evaded. Specifically, if the OOM quantity is sufficiently high, these OOM resources could effectively prevent the market from ever functioning as intended. On page 20 of its presentation, NEPGA Exhibit 2-B, ISO-NE appears to agree with this view: "Excess OOM MW will be carried forward each year until eroded by load growth and retirements." At page 34, however, ISO appears to contemplate a time limit for carrying Excess OOM forward.

The ISO is also ambiguous as to when a Tier 2 Resource becomes a Tier 1 Resource. In-market new resources (*i.e.*, those not designated as OOM) that clear in an FCA should become Tier 1 after their initial price commitment period. Prospectively, OOM new capacity resources, however, should continue in Tier 2 until they are no longer part of the Excess OOM MWs carried forward.

Q WHAT ARE THE RISKS TO THE MARKET IF AN APR RULE MEETING THE FOUR CRITERIA YOU HAVE DESCRIBED IS NOT IMPLEMENTED?

A If a revised APR meeting these four criteria in not implemented, the capacity market will fail over the run. Without a fully effective APR, the FCA clearing price will fall short—perhaps far short—of reflecting the true marginal cost of meeting resource adequacy requirements. This distortion leads to flawed investment and retirement decisions; for

---

[14] *See New York Indep. Sys. Operator*, 122 FERC ¶ 61,211 at P 114.

example, unnaturally low capacity prices will discourage efficient development of demand-side capability to curtail peak usage, or cause customers currently enrolled in such programs to abandon them. Distorted capacity prices also incorrectly skew the decision among generation technologies. For example, if off-shore wind farms have substantially higher capacity payments than on-shore wind farms, a depressed capacity price would understate the difference in value between those two options for meeting renewable portfolio standards.

Moreover, a flawed APR opens the door for capacity buyers to engage in actions calculated to suppress capacity prices below a competitive level. Actions that are uneconomic on their own merits, but profitable in the context of the portfolio benefits to the economic actor, are the hallmark of market manipulation. Because a sound market design must minimize the opportunities for price manipulation that moves the market outcome away from its long-run, efficient equilibrium, a sound APR mechanism must be adopted.

Q ARE THERE OTHER POTENTIAL OPTIONS TO MITIGATE IMPACTS OF OOM IF AN EFFECTIVE APR IS NOT IMPLEMENTED?

A Yes. The most effective remedy would be implementation of a demand curve. I discuss this option below in Section V.

IV. DEFINITION AND TREATMENT OF OOM

A. Definition of OOM Resources

Q IN YOUR OPINION, WHAT RESOURCES SHOULD BE TREATED AS OOM?

A The OOM definition that is adopted must ensure that any new resource that is offered at a price below its all-in costs, including engineering, procurement and construction costs, along with financing costs, net of earnings from the sale of the unit’s output, should be considered to be OOM. In other words, any resource bidding at a level below its all-in costs, including appropriate risk premium, ignoring subsidies or above-market contractual payments, but net of expected earning from the market-priced sale of its output, should be flagged as OOM and treated as such in the FCM clearing process.

Q WOULD YOU CLASSIFY SELF-SUPPLIED RESOURCES AS OUT-OF-MARKET?

A Yes. Self-supplied new capacity resources are intrinsically out-of-market, inasmuch as their offer price—which is effectively zero—has no necessary relationship to the full cost of that resource net of expected market-based earnings. Therefore, for most purposes in the FCA, self-supplied new capacity resources should be treated as OOM resources.

In order to preserve the self-supply option for new capacity in a meaningful form, certain clarifications are required in the ISO's June APR proposal:

First, self-supplied Tier 2 Resources (*i.e.*, self-supplied resources not yet categorized as existing) should be entered in the FCA with an offer price of zero. In the calculation of the Tier 1 price, these resources would be reflected at a price consistent with their cost of new entry.

Second, all resources with an offer price of zero should be guaranteed to clear. If the relevant FCA price is positive, a zero-offer resource will clear even without this rule. If the relevant FCA price is zero, however, that implies that there is at least as much capacity offered at a zero price as required. Rather than triggering some form of rationing, however, there is no reason not to clear all such resources, adding to the base of resources with capacity commitments at no net cost to consumers. Because self-supplied resources offset the *physical* capacity obligation of the supplying LSE, however, clearing surplus self-supplied new capacity resources will have the effect of shifting costs among LSEs.

Q WHAT REVENUES FROM THE SALE OF MARKET PRODUCTS SHOULD BE CONSIDERED WHEN EVALUATING THE APPROPRIATE OFFER LEVEL FOR NEW RESOURCES?

A Any net revenue from output of capacity resources, for which competitive payments are available to any resource willing to provide the product for a price at or below the competitive market clearing price, should be accounted for in determining the appropriate offer level for a new resource. The most common products are energy and ancillary services, but, in principle, revenues from the sale of other products could also be considered. For example, if payments are offered to resources with certain attributes that are desirable for meeting specific policy goals, and those payments are available to all resources with those attributes, the payments could legitimately be factored into the offer for a resource. However, if the payments are made selectively, to certain resources only, those payments should be treated as non-market subsidies and not used to offset costs when determining a competitive offer for a resource. For example, if a new resource receives and relies on a unique payment for a certain attribute, but a existing resource with the same attributes is not eligible for the same payment, the new resource should be flagged as OOM.

Q SHOULD SUBSIDIES AVAILABLE TO NEW UNITS BE ALLOWED TO OFFSET COSTS WHEN DETERMINING THE APPROPRIATE OFFER FOR THE RESOURCE?

A No. Subsidies should not be ignored for purposes of determining OOM. Where additional payments for other services are available to all equivalent resources, these additional payments would not be a cause for OOM. All such subsidies mask, but do not change, the underlying true cost of new resources and result in discriminatory treatment of existing resources providing the same product or service. Moreover, because resources are not treated as OOM so long as their offers are within a safe harbor range of the cost of new resources (75 percent under the current market rules, or 80 percent under the July ISO-NE proposal), small subsidies would not lead to OOM treatment, but rather would apply only in the case of subsidies that have a material effect on resource costs. Finally, subsidies are often available to new resources only, leading to a skewing of investment and retirement decisions among resource owners. With such subsidies in place, efficient, cost-effective existing resources may become artificially uneconomic not because of competitive market forces, but because of subsidies beggaring existing resources into penury or exit.

The only "bright line" test available in the evaluation of OOM resources is to discard all subsidies in the determination of competitive offers and evaluation of OOM. Resources that bid into an FCA at a low cost due to subsidies should be flagged as OOM and its competitive offer determined by its all-in costs, net of market payments for the products it provides.

Q DOES YOUR PROPOSED OOM TREATMENT RESTRICT POLICY MAKERS FROM ACHIEVING LEGITIMATE POLICY GOALS?

A No. Policymakers could achieve desired outcomes through efficient, market-based approaches rather than selective subsidies for "preferred resources." For example, rather than subsidizing new resources with a favorable carbon impact, policy makers could achieve a target for greenhouse gas reductions by implementing a carbon tax or cap-and-trade policy. Such a policy would not prejudge which resources could most cost-effectively achieve the desired reduction, but would rather leave it to market forces to identify the lowest cost solution. Similarly, a robust market for Renewable Energy Credits ("RECs") could achieve renewable energy targets through market forces rather than subsidies to new resources. In markets with capped REC prices, subsidies may be the only means to provide sufficient incentives for entry of sufficient renewable generation resources to meet renewable policy targets.

More generally, if policy makers wish to target a set of "preferred resources," doing so through a non-discriminatory, competitive procurement process will lead to a more efficient outcome than subsidizing a selected set of resources or contracting bilaterally with selected resources at above-market prices. Contracting with selected resources also increases the likelihood that a resource will be self-scheduled or bid in at a zero price, distorting the market price for remaining resources. Hence, subsidized projects and capacity resources that receive implicit subsidies through bilateral transactions should be flagged as OOM and prices reset based on their actual costs.

Even if regulators choose to buy preferred resources outside of market structures, the proposed APR rule accommodates such entry. The designation as OOM in the capacity market would simply mean that the subsidy offered to a preferred resource must be supported by its contribution to meeting the policy goal, and not based on any value of suppressing market prices. As discussed above, I would clarify ISO-NE's June APR proposal to guarantee that all self-supplied resources and other resources with an offer price of zero be granted a capacity supply obligation. These preferred resources would then displace any other Tier 2 Resources with offer prices greater than zero. Furthermore, if and when these preferred resources eventually shift from Tier 2 to Tier 1 status, they could displace existing capacity resources.

Q WILL OOM TREATMENT OF SUBSIDIZED RESOURCES UNDERMINE THE SELF-SUPPLY OR PURCHASE DECISIONS OF LSEs?

A No. In contrast to New York City, where new resources are subject to a hard offer floor that can prevent new resources from clearing in the market, the FCM design includes mechanisms by which an LSE can definitively clear a resource. Resources can be used as self supply (requiring resolving some additional issues), or bids at a price of zero can be submitted. Inclusion of these provisions is the result of a compromise reached in the development of the original FCM design, whereby the potential for self-supply and bilateral purchases are accommodated so that efficient contracting is not precluded, but as a result the market is subject to potential inefficiency and artificially low prices due to OOM entry. Implementation of a robust APR rule allows preservation of this ability to enter efficient supply and hedging contracts, while protecting against inefficient suppression of market prices due to contracted resources bidding in below all-in cost.

Q WILL A STRONG APR RULE AND DEFINITION OF OOM PREVENT STATES FROM IMPLEMENTING RENEWABLE PROGRAMS OR ENCOURAGING DEMAND RESPONSE?

A No. States are still free to use procurement procedures outside of the FCM to secure commitments from new renewables. The current APR mechanism allows these resources to clear even if their actual costs are higher than the FCA clearing price. With a robust APR, however, these offers would not suppress capacity prices for resources below the competitive level (*i.e.*, the level that would have prevailed had all resources been offered at competitive levels) and, consequently, the incentive to over-build the market for the purpose of suppressing capacity costs is largely eliminated. For example, an LSE might choose to contract to buy all products from a new wind farm, including products such as federal carbon credits that do not yet have an easily quantified value. The wind-farm owner would then logically offer its capacity into the FCA at zero, thereby guaranteeing that it clears; the LSE in turn receives either a physical or financial hedge on its capacity obligation (depending on whether the wind farm was offered as self-supply or as a price-taking resource). All Tier 1 Resources, though, would be paid a price that reflects the marginal cost on the mitigated supply stack, which is a more accurate representation of the true marginal cost to society of maintaining resource adequacy.

Demand resources also are not disadvantaged. To the contrary, maintaining capacity payments at levels consistent with the actual cost of meeting the Installed Capacity Requirement provides a clear price signal of value of demand response as a peak-load management resource. Allowing price suppression will require new subsidies, or increase the level of existing ones, to support the same level of demand response participation.

B. *Carry-Forward Mechanism for OOM Resources*

Q UNDER WHAT CIRCUMSTANCES SHOULD AN OOM RESOURCE BE CARRIED FORWARD TO SUBSEQUENT AUCTIONS?

A If an OOM resource does not clear in the FCA with its *mitigated* offer price, then that resource was uneconomic and not needed to meet resource adequacy. It may clear in the FCA at its *unmitigated* offer level; indeed, if it is self-supplied or offered at a zero price, my proposal would be that it would always clear. Regardless, though, this OOM resource was not economic in the FCA, and until it becomes economic, it should retain its designation as an OOM resource in subsequent FCAs.

Q FOR WHAT PURPOSES IN THE FCA WOULD YOU CARRY-FORWARD THE DESIGNATION AS OUT-OF-MARKET FOR SUCH UNECONOMIC RESOURCES?

A Assuming that a new OOM resource is actually built, I would apply this designation for all purposes. In particular:

- Its offer price would continue to be mitigated to the competitive offer price determined for the resource by the Internal Market Monitor in the first year when it cleared, and
- The resource would be treated as Tier 2 for purposes of which clearing price it received.

Q IF AN OOM RESOURCE HAS ALREADY BEEN BUILT AND CLEARED IN FCA #1 - #3, WOULD IT BE RECLASSIFIED AS A TIER 1, EXISTING RESOURCE?

A As Professor McAdams' testimony illustrates, payment of OOM resources at Tier 2 prices is important prospectively to discourage OOM bidding. As my earlier testimony indicates, the APR proposal does not preclude subsidized new entry, it simply mitigates that entry. If the sponsor of a new project wants to subsidize the resource, that is its choice, but the market design should not impose additional costs on other customers in the New England region by paying that sponsored resource the higher APR Price from the FCA. Likewise, the resource was offered into the market representing that it would be willing to accept this lower price, and thus, has no basis to assert that its expectations have been unfairly altered. However, for OOM resources cleared in FCA #1 - #3, the investments are sunk and disincentives for their entry are simply ineffective. In most cases, they are already built and, in some cases, already operating. While these resources should be accounted for in determining the amount of OOM capacity applied to triggering the APR, they could in principle be paid the Tier 1 or Tier 2 price without affecting incentives for new entry.

Q WOULD YOU APPLY THIS SAME RULE IF AN OFFERED OOM RESOURCE DOES NOT PROCEED WITH CONSTRUCTION, BUT IS SUBSEQUENTLY RE-OFFERED?

A If an OOM resource is offered but fails to clear in its initial FCA auction, and development of the resource does not proceed, then I would restart the evaluation if the same project is offered again in a later auction. In particular, it may be assigned a different mitigated offer.

C. Treatment of Historical OOM

Q IN YOUR OPINION, HOW SHOULD "HISTORIC OOM" CAPACITY BE TREATED IN FUTURE FCM AUCTIONS?

A As discussed earlier, significant amounts of OOM Capacity entered the market during the first three FCA. As noted by the Internal Market Monitor in his June 2009 report, "the triggering conditions [for APR] should be modified to properly account for multiyear effects of OOM resources that clear in a single year and eliminate the need for new entry in subsequent years."[15] In order to properly correct for the impacts of OOM and restore prices that would have occurred under a competitive outcome, the APR needs to account for all prior OOM, including that from the first three FCA.

If the "historic OOM" is not accounted for properly by including the carry-forward amount in future auctions, prices will remain artificially distorted from competitive levels for many years to come. These artificially low prices will lead to inefficient distortions in the capacity mix in New England. Cost-effective existing capacity may be forced to retire. Significant amounts of demand response resources may also leave the market. Demand response resources, in fact, are likely to be the most vulnerable to artificially low prices resulting from unmitigated OOM. Very few of the costs of providing demand resources are sunk; rather, these costs are almost entirely variable. So unlike existing generation, which may, because most of its costs are sunk, bid very low just to stay in the market, efficient bids for demand response will be higher. In fact the demand response most likely to survive in this scenario is the most heavily subsidized and therefore least cost effective resources. In particular, energy efficiency

[15] Internal Market Monitor Report at 6.

programs that do not depend on the benefits of avoided cost may be less affected, at the expense of efficient demand response that does not depend on subsidies.

Applying this standard to past OOM will not exclude it from the market. Under the proposed APR rule, the OOM resources will clear based on their unmitigated offers. Hence, in contrast to the New York market, in which new entrants in the market must submit mitigated offers and, as a result, may not clear some or all of their capacity, the historical OOM resources will not be prevented from clearing. For this reason, unlike the New York City market, where the Offer Floor was limited to new entrants, thus allowing past OOM resources to continue to effectively to submit zero bids and to clear but causing the market clearing price to remain artificially suppressed until this excess capacity was absorbed, historical OOM resources in ISO-NE can and should be used in determining when the APR will be applied and to what price it will reset the FCM price, without affecting whether those historical OOM resources clear in the market.

Q HOW SHOULD THE SET OF OOM CAPACITY RESOURCES FROM THE FIRST THREE FCAs BE IDENTIFIED?

A Capacity cleared in the first three FCAs should be evaluated under any revised standard for OOM applied in future auctions. Under this standard, in addition to the 2,005 MW of resources already designated as OOM by the Internal Market Monitor in the first three auctions, 586 MW of new resources exempted from review for FCA #1, and simply treated as existing, should be evaluated and treated as OOM if it meets the requirements under the prospective standard. The exemption for certain resources in FCA #1 was intended to allow new resources to be treated as existing. Nonetheless, those resources will still have an artificially suppressive effect on future clearing prices, pushing them below the levels that would have occurred under competitive conditions. In order to avoid this distortion to the price signals that are critical to guide new entry and avoid inefficient retirement of resources, the effects of this OOM capacity should be accounted for going forward. Additionally, the 2,867 MW of demand resources that were cleared through FCA #3, many of which were added under state- or utility-sponsored programs, should be reviewed and, if the requirements are met, treated as OOM under the revised APR. In particular, of the 2,867 MW of demand resources, 1,073 MW are passive demand response from energy efficiency, which is often secured through utility incentive programs that may be completely unrelated to the cost of supplying the resources and from the expected price in the FCA. Hence, these resources warrant careful review to determine whether they were, in fact, in-market. To the extent the cost of securing these resources exceeded the avoided cost of procuring other capacity through the FCA, they should be designated as OOM and carried forward as such in the calculation of the APR price adjustment.

Q HAVE YOU EVALUATED THE MAGNITUDE OF THE OOM ENTRY IN THE FIRST THREE FCAs?

A Determining the amount of capacity from the first three FCAs that should be carried forward as OOM requires a comprehensive evaluation by the Internal Market Monitor, applying the standards that I have already discussed. The full set of information that would be required to determine which resources should be flagged as OOM is simply not available publicly for many resources. However, I have evaluated the extent of potential OOM resources from the first three FCAs, as well as the qualified OOM resources for FCA #4 in order to illustrate the potential impact on the market if the historical OOM is ignored in the application of the APR going forward. I have also analyzed some example resources to show where there are indications that resources should have been flagged as OOM but were not.

Q CAN YOU SUMMARIZE THE CAPACITY THAT CLEARED IN THE FIRST THREE FCAs AND HOW OOM RESOURCES CONTRIBUTED TO THE RESULTING SURPLUS?

A FCA #3 set out to procure the Net Installed Capacity Requirement of 31,965 MW for the 2012-2013 Capacity Commitment Period[16] from a pool of 43,415 MW of qualified resources: 37,609 MW of Existing Capacity, 2,830 MW of New Generating Capacity Resources, 2,420 MW of New Import Capacity Resources, and 555 MW of New Demand Resources.[17] Of the new resources, "1,912 MW … sought approval to offer below 0.75 times CONE but were not accepted by the [Internal Market Monitor], and will be treated as out-of-market capacity … ."[18] Permanent, Static, and Administrative Export De-List bids totaled 1,196 MW, leaving 36,413 MW of Existing Capacity in FCA #3 (the price at which resources may submit Dynamic De-list Bids)—a surplus of 4,448 MW—prior to Dynamic De-Lists.

---

16 *ISO New England Inc.*, Docket No. ER09-1415-000, Filing of Installed Capacity Requirement, Hydro Québec Interconnection Capability Credits and Related Values for the 2012/2013 Capability Year (July 7, 2009), *accepted by* unpublished letter order issued on August 14, 2009.

17 *See ISO New England Inc.*, Docket No. ER09-1424-000, Informational Filing for Qualification in the Forward Capacity Market at 4-5, 20 (July 7, 2009) ("FCA #3 Informational Filing").

18 *Id.* at 5.

Table 1: Capacity Qualified in FCA #3

	Generating	Imports	Demand Resources	Grand Total
Existing Capacity	32,636	2,164	2,809	37,609
De-List Bids				1,196
Net Existing Capacity				36,413
New Resources				
OOM	1,623	0	290	1,912
In-market	1,208	2,420	265	3,894
Total	2,830	2,420	555	5,806
Total Qualified	32,228	1,900	2,898	43,415
Total After Static & Permanent De-Lists				42,219

Source: FCA #3 Informational Filing. Subtotals may not add due to rounding.

This surplus has its origin in both supply and demand conditions. Because of decreased load forecasts, Net ICR for 2012-2013 was 563 MW below Net ICR for 2011-2012. But the bulk of the surplus comes from surplus capacity cleared in FCA #1 and FCA #2, which included 1,310 MW of resources designated as Out-of-Market by the Internal Market Monitor, 586 MW of new capacity treated as existing in FCA #1 (and consequently was not subject to review as Out-of-Market), and 2,778 MW of Demand Resources, many of which would likely have been deemed Out-of-Market under the FCM Revision.[19] Taken together, these three categories of supply sum to 4,673 MW, almost the whole of the 4,755 MW of surplus resources cleared in FCA #2, and greater than the surplus Existing Capacity in FCA #3 (net of de-list bids). As shown in NEPGA Exhibit 2-C, but for these potentially uneconomic sources of entry in FCA #1 and

[19] *See* Internal Market Monitor Report at 2 (Table 1-1); *ISO New England Inc.*, Docket No. ER09-1282-000, Motion to Intervene and Comments of the New England Power Generators Association, Attachment A, Report on ISO New England Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements at 11 (June 26, 2009).

FCA #2, we would have entered FCA #3 needing to acquire 788 MW of new capacity resources.

In spite of this substantial surplus, FCA #3 saw significant net additions to the capacity base. A total of 37,026 MW cleared the auction, a surplus of 5,061 MW over the Net ICR. Table 2 below summarizes the cleared capacity by type.

Table 2: Capacity Cleared in FCA #3

	Generating	Imports	Demand Resources	Grand Total
Existing Capacity	30,558	1,083	2,588	34,230
New Resources				
OOM	575	0	119	695
In-market	1,095	817	190	2,102
Total	1,670	817	309	2,796
Grand Total	32,228	1,900	2,898	37,026

Sources: ISO-NE qualification filing, results spreadsheets[20]

Table 2 needs to be interpreted with some caution. Of the 575 MW of OOM new generating capacity, 422 MW is a bid reflecting the major capital expenditure for environmental compliance at Brayton Point 4. This offer replaced 435 MW of existing capacity from the unit, therefore reducing the amount of capacity surplus in the auction by 13 MW. (The bulk of the remaining OOM new generation is the 129.6 MW New Haven Peaking Project, which was selected to receive a long-term PPA by the Connecticut DPUC.[21]) Similarly, of the 1,095 MW of New Generating Capacity Resources that cleared in-market, 1,045 MW was capacity from Brayton Point 1 through 3 marked as "new" because of major environmental compliance costs, replacing 1,099

[20] *ISO New England Inc.*, Docket No. ER10-186-000, Forward Capacity Auction Results Filing, Attachment A (Oct. 30, 2009) ("ISO-NE FCA #3 Results Filing).

[21] *See* New Haven Peaking Project (2010), http://www.pseg.com/companies/fossil/plants/connecticut/newhaven_peaker.jsp.

MW of existing capacity from those resources. Therefore, on net, there was only 50 MW across five projects of new, in-merit generating capacity that cleared FCA #3.

Considering the 2,796 MW of "new" resources broadly, it appears that only a small fraction are entering in response to FCM price signals. All the Demand Resources are either Out-of-Market or sponsored by a utility or a state and, therefore, may have costs above the avoided capacity payments under FCM. Only 4 MW of the 1,670 MW of new Generating Capacity Resources appear be to truly new, in-market entry, with the remainder being explicitly Out-of-Market, sponsored by a utility or a state, or to be capacity associated with major capital expenses and so qualifying as "new." Finally, under the current rules, imports are treated as new resources. Nearly all of the "new" imports are from Hydro-Québec, which has historically been a significant capacity importer to ISO-NE; in fact, only 817 MW of the 1,397 MW of "new" capacity importers cleared, leaving excess transfer capability on both the New York and New Brunswick interfaces.

Q IS THERE REASON TO QUESTION WHETHER ANY OF THE NEW IN-MARKET RESOURCES THAT CLEARED IN THE FIRST THREE FCAs SHOULD HAVE BEEN DESIGNATED AS OOM?

A Yes. For example in FCA #3, three of the five new capacity projects were offered by entities that are net purchasers of capacity (Connecticut Municipal Electric, Public Service of New Hampshire, and the Vermont Public Power Authority), and the largest of the two other projects (Plainfield Renewable Energy, at 37.5 MW) is "supported by Connecticut's Clean Energy Fund" which "has committed significant development funding to insure its success."[22] These facts raise serious questions as to whether offers from even the limited amount of purportedly "in-market" new generation that cleared the auction represent those resource's long-run average costs.

Another set of examples comes from the new resources designated as existing for FCA #1. Among the 586 MW of new generating resources that fell into this category, at least 4 projects, totaling 278 MW of capacity were offered by, or secured through contracts with net purchasers of capacity.[23] The Thomas A. Watson project, for example, was reported to have debt coverage requirements of approximately $800,000/month and cost more than $1,000/kW to construct, implying costs well above the clearing price in the subsequent FCAs. While this plant may have been developed at a time when ISO-NE appeared to be facing looming new capacity needs, by the time construction began in April of 2008, the first FCA had already resulted in a significant surplus. Hence, while this unit may have been added with reasonable intentions, it turned out to be built ahead of need, and therefore was OOM capacity. Treating it as such in future FCAs would not displace its capacity from the market, but rather would allow prices to be adjusted to reflect that new entry, such as the Watson unit, has occurred and should eventually be reflected in the price.

Similarly, there is reason to question whether much of the "in-market" new Demand Resources that cleared in the first three FCAs would have been categorized as Out-of-Market under the FCM Revision. For example, in FCA #3, every kilowatt of "in-

---

22 *See* Connecticut's Renewable Energy Project (2010), http://www.prellc.net/.

23 These projects include the Thomas A. Watson peaking facility, offered by Braintree Electric Light Department, the Waterbury Generating Facility, awarded a contract under the Connecticut Energy Independence Act RFP, and two plants sponsored by CMEEC.

market" new Demand Resources had as its lead participant either a utility or a state entity, as shown in Table 3.

Table 3: In-Market New Demand Resources Cleared in FCA #3

Lead Participant	**MW**
NSTAR Electric	54.216
National Grid	50.328
Maine Public Utilities Commission	31.782
Northeast Utilities	30.583
Vermont Energy Investment Corp.[24]	11.597
United Illuminating	10.800
Commonwealth of Massachusetts	0.682
Grand Total	**189.988**

Source: ISO-NE FCA #3 Results Filing, Attachment A

Additionally, as mentioned above, a significant portion of the demand response cleared in FCM has come from energy efficiency resources, which are often subsidized or secured through utility programs that are independent of avoided market costs.

Q ARE YOU AWARE OF ANY EVIDENCE THAT CAPACITY BUYERS IN NEW ENGLAND MAY HAVE BEEN PARTICIPATING IN THE FCM WITH THE INTENT TO BENEFIT FROM THE PRICE SUPPRESSION EFFECT OF NEW, OUT-OF-MARKET ENTRY?

A Yes. In a pair of reports sponsored by a large coalition of New England capacity buyers, Synapse Energy Economics, Inc. clearly outlines a strategy for using out-of-market resources, with a focus on energy efficiency and other demand resources, to create an indirect benefit of suppressing the wholesale capacity prices.[25]

---

[24] Vermont Energy Investment Corp. administers a program under the auspices of the Vermont Public Service Board. *See* Vermont Energy Investment Corporation, Efficiency Vermont (2009), http://www.veic.org/Implementation_Services/Project_Profiles/Efficiency_Vermont.aspx.

[25] *See* Rick Hornby *et al.*, Avoided Energy Supply Costs in New England: 2007 Final Report, at 1-1 (Jan. 3, 2008), http://www.synapse-energy.com/Downloads/SynapseReport.2007-08.AESC.Avoided-Energy-Supply-Costs-2007.07-019.pdf ("2007 Report"); Rick Hornby *et al.*, Avoided Energy Supply Costs in New England: 2009 Report,

Q WHAT WOULD BE THE IMPLICATIONS OF NOT ACCOUNTING FOR THIS HISTORICAL OOM CAPACITY IN PROSPECTIVE APPLICATION OF THE APR?

A Although 491 MW of Existing Capacity, including 21 MW of Demand Resources, exited the market through Static De-List Bids, and an additional 1,119 MW, including 230 MW of Demand Resources, exited through Dynamic De-List Bids, the market—when the Historic OOM is included—remains untenably long in capacity. If historical OOM capacity is not accounted for, any reforms made to the APR or other market rules are likely to be moot for seven or more years to come or perhaps longer, as the existing stock of OOM resources will lead to very low—and perhaps zero—clearing prices and make the impact of re-pricing the offers of future OOM resources very small.

Q BASED ON THE NEW ENTRY YOU DISCUSSED ABOVE, APPROXIMATELY HOW MUCH HISTORICAL OOM SHOULD BE CARRIED FORWARD?

A As I already discussed, without more complete information, the exact amount of OOM resource cannot be determined definitively. However, at a minimum, 2,005 MW of capacity that cleared in the first three auctions has already been designated as OOM. Additionally, it is very likely that a significant portion of the 3,043 MW of new demand response cleared in the auctions and 586 MW of new generation capacity designated as existing in FCA #1 should appropriately be deemed OOM. Of the 3,043 MW of new demand response, 190 MW was added in FCA #3 by net short buyers, and 1,073 MW came from energy efficiency, which may have been subsidized, meaning there is reasonable concern that at least 1,263 MW of new demand response should have been treated as OOM. Moreover, we cannot rule out that some of the remaining demand

---

at 1-1 (Oct. 23, 2009), http://www.synapse-energy.com/Downloads/SynapseReport.2009-10.AESC.AESC-Study-2009.09-020.pdf ("2009 Report").

response was also OOM, especially in light of the clear incentive for adding OOM demand response identified in the Synapse study I discussed above. If the 1,263 MW of demand response and 564 MW of new resources treated as existing were added to the 2,005 MW of capacity already designated as OOM, 3,832 MW of historical OOM resources would be carried forward resulting in a significant offset of the 5,061 MW of surplus resulting from FCA #3. Even if the OOM designation were limited to the 2,005 MW already deemed to be OOM, effective reform from a revised APR would be delayed at least 5 years.[26]

V. A DEMAND CURVE AS A SUPPLEMENT TO MARKET STABILITY

Q EARLIER YOU DISCUSSED THE ROLE OF THE APR IN THE FCM MARKET DESIGN. WOULD YOU PLEASE SUMMARIZE YOUR VIEWS?

A Yes. The APR is one of several elements in the FCM design that is required to avoid large price swings from small changes in quantity. In particular, the APR was intended to make the outcome of the FCA fairly insensitive to whether new resources came into the market by contract or in-market, under the theory that the market price should reflect the *cost* of the resources in the market, rather than the bids from those resources unless those bids are consistent with the costs of the resources.

Q WHAT ARE SOME OF THE OTHER MECHANISMS THAT, WITH THE APR, WERE INTENDED TO PROVIDE A MEASURE OF PRICE STABILITY IN THE MARKET?

A The most important of these additional mechanisms is the forward procurement. If procurement of capacity resources happens close to the commitment period (as is done,

---

[26] Based on load growth forecasted at approximately 350 MW annually.

for example, by the NYISO and Midwest ISO), the potential supply of resources is quite inelastic, *i.e.*, the available supply can neither be increased nor decreased much by changes in price. By securing capacity commitments far enough in advance of the commitment year to allow new resources to be developed, or to allow incumbent resources to de-list or retire in an orderly fashion, the "forward" element of the FCM increases the elasticity of supply. This in turn means that changes in demand can be accommodated without massive swings in price. The first two panels of NEPGA Exhibit 2-D show how forward procurement enhances price stability.

Another important mechanism to promote price stability is the Dynamic De-List bid. As Dr. Shanker discusses at length in his accompanying testimony, successful capacity markets must be structured to return, on average over time, the full cost of new generation resources net of expected earnings in the energy and ancillary services markets. A direct corollary of this rule is that very low prices in one period must be compensated for by high prices in other periods. The only way for high prices (*i.e.*, prices much above the levelized cost of new entry) to arise in the FCM framework is for new entrants to place a risk premium on their levelized costs. By earning this premium over the initial years of their price commitment in the FCM, they can offset subsequent years when the capacity price may fall below CONE. The larger these downward price excursions are expected to be, and the more frequently they are expected to occur, the greater will be this risk premium demanded by new entrants before they would be willing to sink hundreds of millions of dollars of capital in the New England power market. Dynamic De-List bids provided suppliers a limited ability to moderate downward price swings in the event that there is a small amount of surplus, and thereby limit the need for higher prices in periods when new entry is required.

Q IS THERE ECONOMIC VALUE IN HAVING A WIDELY VARIABLE CAPACITY PRICE?

A No, not in my view. Capacity prices are primarily a signal to investors to increase or decrease the capital stock in the market. Because these investment decisions are long-lived, I believe it is best that the price informing these decisions should also reflect long-run fundamentals. By contrast, energy prices can and should fluctuate with short-term market conditions, because supply is very flexible; the decision to produce power on one day does not dictate the production decision in the following day (at least for most units). Although strongly fluctuating capacity prices may yield some minor benefits in cuing entry or exit of marginal capacity resources with flexible supply decisions, such as demand-side resources or imports, these benefits are more than offset by the cost of the substantial risk premium that capital would require to invest in such a market.

Q TWO OF THESE THREE STABILIZING MECHANISMS ARE AT ISSUE IN THIS CASE: THE APR AND DYNAMIC DE-LIST BIDS. IN YOUR VIEW, WHAT WOULD THE EFFECT ON THE MARKET BE IF THESE MECHANISMS FAIL TO MODERATE PRICE SWING EFFECTIVELY?

A I believe that an effective (*i.e.*, revised) APR and the current Dynamic De-List rules are a minimum requirement for the FCM to work as intended. The ISO's current proposal for APR appears, at least in my preliminary assessment, to be a sound modification that would restore the APR's ability to produce reasonable prices—at least, once the market has returned to a closer balance of supply and demand. I anticipate, however, that this comprehensive and effective rule will be vigorously opposed by some parties, and so some weaker, potentially ineffective rule may eventually be adopted.

Although ISO-NE has proposed a sound APR rule, it has also proposed not to address the adverse effects on *future* pricing of *past* OOM entry that occurred when the APR was clearly flawed. Thus, even if an effective APR rule is established going forward, the substantial amount of OOM entry that has occurred in FCA #1 through FCA #3, and may appear in additional FCAs prior to implementation of the new APR will continue to depress auction prices below the full cost of the marginal capacity resources serving load.

Even if APR is fixed going forward and it also accounts for past OOM entry by applying the revised provisions to it, the FCM Revision of mitigation of Dynamic De-List bids would materially weaken their intended effectiveness in moderating price volatility in the FCA.

Collectively, therefore, I am concerned that the ultimate result of this round of rule changes will be to eviscerate some of the important price stabilizers included in the original FCM design. If this were to occur, the FCM will not produce a sustainable structure over the long term.

Q IF A ROBUST SET OF PRICE STABILITY MECHANISMS IS NOT INCLUDED IN THE NEW FCM DESIGN, IS THERE ANY FURTHER CHANGE IN THE DESIGN THAT YOU WOULD RECOMMEND?

A Yes; in that circumstance, I would include a demand curve in the FCM. An administratively set, properly structured demand curve has proven to be an effective design element in the NYISO and PJM capacity markets. With a demand curve, these other markets have been able to implement small zones, combined with comprehensive buyer and seller bid mitigation (in zones without sufficient competition), and still realize locational prices that reflect the underlying supply and demand balance in each zone. For example, PJM models small sub-zones such as Public Service Electric & Gas - North and Delmarva Power and Light—South, while mitigating local market power and achieving sensible price separation.[27]

Q HOW WOULD A DEMAND CURVE PROMOTE PRICE STABILITY?

A We saw earlier that making the supply curve more elastic by procuring well in advance of the commitment year would result in smaller price swings. Similarly, increasing the elasticity (downward slope) of demand also moderates prices, therefore decreasing both risk to suppliers and prices to consumers. As shown in Panel 3 of NEPGA Exhibit 2-D, allowing the FCA to procure a variable quantity of capacity, dependent on the prices at which capacity is offered, moderates the price impact of any given change in the need for resources.

The demand curve also reduces reliance on the APR in a world where most or all new entry occurs under contract. With the demand curves implemented in NYISO and PJM, if the supply curve is entirely below the demand curve (that is, the two curves do not intersect), then the market-clearing price is set at the point on the *demand curve* at the total quantity of supply in the market. Therefore, even if every capacity resource is self-supplied or contracted to load, the market-clearing price for capacity will reflect the supply/demand balance in the market in unconstrained areas—if the market is balanced, prices will be near CONE. And this is the right outcome. With neither a demand curve

---

[27] *See* PJM 2013/2014 Base Residual Auction Results, http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/planning-period-parameters-report.ashx.

nor an (effective) APR, and with the proposed changes to Dynamic De-List bids, however, the FCA would clear well below this level or the actual full cost of the resources providing resource adequacy. In this case—where supply is tight but not necessarily offered at its full economic costs—the demand curve backstops the APR. See Panel 4 of NEPGA Exhibit 2-D.

Q HOW WOULD YOU DRAW THE DEMAND CURVE?

A During the LICAP proceedings prior to the FCM settlement, ISO-NE had proposed a methodology for establishing the parameters of the New England demand curve. This methodology was fully litigated and, with minor revisions, included in the Initial Decision that the administrative law judge sent to the Commission. This methodology would be a logical starting place for an FCM demand curve.

Q PLEASE SUMMARIZE HOW THE DEMAND CURVE PARAMETERS WOULD HAVE BEEN ESTABLISHED UNDER THE INITIAL DECISION IN THE LICAP PROCEEDING.

A Under the Initial Decision, the demand curve would have been designed to have the following properties:[28]

- The demand curve should consist of two downward-sloping line segments, with a common point at a "kink."
- The slope to the left of the kink is three times greater than the slope to the right of the kink.
- The target level of capacity (*i.e.*, the expected average level of installed capacity relative to the ICR) should be set to a standard whereby the level of actual

[28] *Devon Power LLC*, 111 FERC ¶ 63,063 at PP 39-41, 74, 130, 150, 165 (2005) ("Initial Decision") (demand curve design details).

installed capacity is expected to fall below ICR no more than 17.6% of the time, based on the historical distribution of the installed capacity as a percent of the capacity requirement.

- The point at which the demand curve hits the quantity axis (*i.e.*, the point at which the capacity price would reach zero) is 1.15 times the ICR.
- The maximum price is 2 times the estimated CONE value.

With these parameters set, it is possible to determine the unique level of capacity (as a percent of ICR) at which the kink point much be placed in order to set the expected average capacity price equal to the estimated CONE.[29]

Q WHAT LEVEL DID THE INITIAL DECISION DETERMINE WAS JUST AND REASONABLE FOR THIS KINK POINT?

A The "C_{target}" level was determined to be 105.4 percent of ICR, based on the historical average over 21 years of data.[30] In order for this level of capacity to exactly receive CONE over time the kink point developed by ISO-NE and recommended in the Initial Decision would be at 103.8 percent of ICR.[31]

Q HAVE YOU CONSIDERED HOW THIS KINK POINT WOULD BE AFFECTED BY INCLUDING DATA FROM YEARS SINCE THE LICAP PROCEEDINGS?

A Yes. Adding the additional five years of available data, from Summer 2004 through Summer 2009 inclusive, has relatively little effect on the determination of "C_{target}" or the kink point. C_{target} would be 105.48 percent of ICR. Given the updated standard deviation

---

[29] In the Initial Decision, the estimated CONE value is referred to as the Estimated Benchmark Capacity Cost, or EBCC.

[30] Initial Decision at P 130. The Initial Decision refers to Objective Capability, or OC; this concept has since been replaced by ICR.

[31] Initial Decision at P 198.

of 0.051, the kink point would be 102.9 percent of ICR, using the same calculation methodology used by ISO-NE in the LICAP proceeding.

Q THE INITIAL DECISION PLOTS THIS DEMAND CURVE WITH RESPECT TO THE ESTIMATED BENCHMARK COST OF CAPACITY. GIVEN THE REST OF THE FCM MARKET DESIGN, ARE ANY REVISIONS TO THIS BENCHMARK REQUIRED?

A Yes. ISO-NE had proposed that the estimated benchmark cost of capacity be a "gross" cost, *i.e.*, before deductions for potential profits from the sale of energy and ancillary services from the benchmark unit. ISO-NE proposed to make an after-the-fact adjustment to all capacity payments to remove the benchmark resource's estimated earnings in any given year. Although the FCM design retains this general concept in the Peak Energy Rent ("PER") deduction, the after-the-fact adjustment is based on a notional 22,000-heat-rate resource, rather than the reference resource for CONE. The benchmark price for setting the demand curve, therefore, would appropriately adjust the gross cost of new capacity downward by the expected earnings of the benchmark resource (yielding what is referred to as "net CONE") but then upward by the expected decrease in net revenues due to the PER costs.

Q ARE THE DEMAND CURVES IN OTHER CAPACITY MARKETS DRAWN USING A NET CONE VALUE?

A Yes, both NYISO and PJM construct their administrative demand curves for capacity using an estimate of net CONE, rather than gross CONE.

Q HOW DO THESE OTHER RTOS ESTIMATE NET CONE FOR THE PURPOSES OF DRAWING THEIR CAPACITY MARKET DEMAND CURVES?

A Both the NYISO and PJM use two steps to calculate net CONE. First, they estimate gross CONE based on fundamental engineering and construction costs, financing costs, and fixed operating costs of the reference resource. Second, they estimate the net earnings of the reference resource from the sale of energy and ancillary services, also called the E&AS Offset.

Q ARE THESE NET EARNINGS ESTIMATED IN THE SAME WAY IN NYISO AND PJM?

A No. PJM uses an average of a rolling three-year period of the notional earnings of a reference resource dispatched against historical LMPs.[32] In New York, an independent consultant estimates likely future earnings through a complex econometric analysis.[33]

Q WHICH APPROACH WOULD YOU RECOMMEND FOR NEW ENGLAND?

A Both approaches have their drawbacks, but on net I believe that the PJM approach is superior. It is predictable, readily reproducible by market participants, and well defined. Although history is not always a good predictor of the future, the PJM approach has the merit that, on average over the economic lifetime of an asset, the E&AS Offset is approximately equal to the actual earnings of the reference technology. The NYISO's forward-looking approach, by contrast, may be systematically wrong.

---

32 PJM OATT, Attachment DD § 5.10.

33 The approach is described in the NYISO Installed Capacity Manual, Section 5. The econometric methodology for the calculation was discussed in a presentation at the January 15, 2010 meeting of the NYISO ICAP Working Group. *See* Jonathan Falk, Econometric Model of NYISO LBMP: A Look Back and a Look Forward (2006), http://www.nyiso.com/public/webdocs/committees/bic_icapwg/meeting_materials/2010-01-25/Econometric_Model_of_NYISO_LBMP_2.pdf.

Q WHAT IS THE BENCHMARK RESOURCE YOU PROPOSE FOR THE NEW ENGLAND MARKET?

A As I will discuss later in my testimony, the appropriate benchmark resource is a generating unit. The benchmark unit should reflect the cost-effective peaking technology for the region, when considered in light of both capital costs and net revenues from the sale of its output.

Q WHAT E&AS OFFSET VALUE HAS PJM APPLIED IN CALCULATING NET CONE UNDER THIS METHODOLOGY?

A For its most recent capacity auctions, conducted for the 2013/14 Planning year, PJM applied an E&AS offset of $1.12/kW-month for the RTO.

Q ARE THERE ANY TECHNICAL ISSUES RAISED BY USING A DEMAND CURVE IN THE DESCENDING CLOCK AUCTION FORMAT OF THE FCA?

A No, there are no technical issues with implementing a demand curve in a descending clock auction. The FCA already includes one: the Quantity Rule, discussed below, allows ISO to modify the quantity it is seeking to purchase under certain conditions, and the new quantity it purchases is directly linked to the current clock price. Likewise, ISO-NE proposed in February to implement a demand curve when a resource's de-list bid was denied for reliability reasons.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING A DEMAND CURVE IN THE FCM DESIGN.

A In order for the current vertical demand curve to yield just and reasonable results, two key elements are required. First, a robust APR with appropriate recognition of historic OOM must be adopted in the current round of rule changes. Secondly, the Dynamic De-

List bidding must remain unaltered from its current design. If both elements are not incorporated in the design going forward, then a replacement price stabilization mechanism is needed to ensure economic pricing in the market. A demand curve is one such mechanism: its effectiveness has been proven, and its operation is well-understood from its use in PJM and NYISO. The hard work of designing the parameters for a New England demand curve has already been done in an adjudicated forum. Updating the parameters as discussed above, the LICAP demand curve applicable in the FCM is shown in NEPGA Exhibit 2-E.

VI. DEFINITION AND MODELING OF CAPACITY ZONES

Q WHAT ISSUES DID THE COMMISSION SET FOR PAPER HEARING REGARDING THE DESIGNATION OF CAPACITY ZONES WITHIN NEW ENGLAND?

A The Commission set four such issues for hearing:

(1) Whether zones should always be modeled

(2) Whether all de-list bids should be considered in the modeling of zones

(3) Whether a pivotal supplier test is necessary

(4) Whether revisions to the current mitigation rules would be necessary in order to model all zones[34]

Q DID THE COMMISSION PROVIDE ANY GUIDANCE IN THE HEARING ORDER ON THESE ISSUES?

A Yes, it provided comments and guidance on all four issues. On the question of whether all zones should be modeled, the Order states: "[t]he Commission believes that it is important to model zones wherever possible to set appropriate locational prices. We have cited the need for locational pricing in New England for many years, noting that its

---

[34] Hearing Order at P 18.

absence in the Installed Capacity ("ICAP") market (the predecessor to the FCM) was a significant flaw since 'location is an important aspect of ensuring optimal investment in resources.'"[35]

However, the Commission continues,

> While we believe that always modeling zones should be the ultimate goal, we agree with ISO-NE that such a change would require further analysis and is not required to be implemented prior to FCA # 4. Rather, we note that all parties have raised valid concerns on this issue, including whether the current mitigation rules are adequate to model zones at all times, whether all de-list bid types should be allowed to set a zonal price (*i.e.*, whether a "pivotal supplier" test is necessary, and whether it should have a market share threshold), and what, if any, corresponding revisions to the current mitigation rules are necessary. We believe that the proposed Rule Changes to consider additional de-list bids in the modeling of zones represent a first step to the zone modeling issue, and we will accept these revised rules on a transitional basis.[36]

Q HOW HAVE FCM ZONES BEEN MODELED IN THE AUCTIONS TO DATE?

A In the three FCA auctions held to date, only four potential zones have been considered: Connecticut, NEMA/Boston,[37] Maine, and Rest of Pool. These zones are a legacy from the LICAP proceedings. Connecticut and Boston are defined as import constrained and Maine is defined as export constrained. For each of the four zones, the local sourcing requirement is calculated and compared to the installed resource base in the zone. If the zone is not short of installed capacity relative to its Local Sourcing Requirement ("LSR"), it is not modeled. Also, if a zone is modeled in the auction and price separation with adjacent zones does not occur, the zone is eliminated. The auction first clears the import constrained zones (Connecticut and Boston), then the Rest of Pool zone, and

[35] Hearing Order at P 134.

[36] Hearing Order at P 135.

[37] NEMA is the Northeast Massachusetts area, of which Boston is a sub-zone.

finally the export constrained zone (Maine), assuming the zone(s) have been modeled. Certain modeling limitations are incorporated into the FCM design, primarily based on controlling or eliminating the exercise of market power and accommodating the descending clock auction ("DCA") format.

Q WHAT FLAWS HAVE YOU IDENTIFIED IN THE CURRENT FCM RULES THAT HINDER THE APPROPRIATE DEGREE OF ZONAL SEPARATION?

A There are numerous limitations and shortcomings in the current FCM locational zone modeling process, the principal flaw being that the resulting large zones make it difficult or impossible to adequately reflect important electrical constraints at a sub-zone level in the market clearing process. The rules for zone creation and elimination are so tight that they may preclude creation and/or modeling of sub-zones with barely adequate resources to meet the LSR; if any de-list bids are entered, however, they would have to be rejected to enforce local sourcing requirements in the sub-zone. (This situation occurred in FCA #1 when ISO-NE rejected the de-list bids from Norwalk Harbor and later denied the opportunity for any Connecticut resource to decrease its obligation.) Aside from the mandatory Maine zone, zones have not passed the "Market Modeling" test and have not been modeled in any FCA to date. Also, if price separation does not occur in the FCA, current rules do not allow for modeling zones in subsequent reconfiguration auctions to account for system changes. This can result in an inability to model changes that subsequently require local resources during the period from the forward auction through the reconfiguration auctions.

Another flaw in the current rules is an over-reliance on out-of-market rejection of de-list, bilateral, and pro-ration requests in order to enforce constraints and protect reliability. Both the Internal and External Market Monitors have identified these rejections as problematic and have indicated that in-market solutions to the reliability issue are preferable.[38] The Commission has also indicated a preference for in-market solutions.[39]

Finally, a particular weakness of the descending clock auction is its requirement for a pre-specified clearing order, a feature that renders it unable to model more realistic zone diagrams with bi-directional constraints or mesh networks.

Q WHAT UNRESOLVED ISSUES STILL REMAIN IN THE FCM ZONAL MODELING?

A This existing approach to modeling Capacity Zones has obvious shortcomings, discussed above. As it stands currently, even if ISO-NE is put on notice through a Non-Price Retirement Request or a Permanent De-List Bid that a capacity resource in a Capacity Zone is likely to retire, and even if that retirement would cause the stock of Existing Capacity in that zone to fall below the LSR, ISO-NE cannot model the zone in the FCA. But, lacking any locational capacity price, it would be pure happenstance if the FCA managed to procure the new resources required in that locality to offset the unit retirement. Given that the import constrained zones are likely to have substantially higher costs than Rest of Pool, it is highly unlikely that such happenstance, in the real world, would occur. ISO-NE has therefore sensibly proposed to exclude capacity associated with Non-Price Retirement Requests or Permanent De-List Bids when it evaluates whether there is sufficient Existing Capacity to meet the LSR.

---

[38] Internal Market Monitor Report at 41-43; *ISO New England Inc.*, Docket No. ER10-787-000, Motion to Intervene and Comments of Potomac Economics, Ltd. On Revisions to FCM Rules Related to FCM Redesign Filed by ISO New England at 12-16 (Mar. 15, 2010).

[39] Hearing Order at P 70.

Another shortcoming with the current approach is the fact that intrinsically higher resource costs in a Capacity Zone cannot be reflected except when the zone is absolutely short of capacity. It is likely that taxes and labor costs for generators are much higher in Connecticut than in New Hampshire. As Capacity Zones are currently modeled, these genuinely higher costs to provide service in those areas cannot manifest themselves in differential capacity prices.

Q WHAT IS YOUR OPINION ON THE QUESTION OF WHETHER ALL ZONES SHOULD BE ALWAYS MODELED IN THE FCM?

A Based on my extensive work in this area, I believe that it is very important. The FCM should be designed to procure sufficient resources to meet all resource planning criteria, thereby avoiding incremental procurements outside of the FCM framework. This is best achieved by requiring ISO-NE to *always* model relevant Capacity Zones in the FCA, consistent with the practice of the NYISO and the PJM, both of which model the defined capacity zones whenever possible.[40] Just as ISO-NE does not selectively omit major transmission limits from its security-constrained dispatch, modeling all zones would not selectively omit major capacity transfer limits from the FCM. Any residual concern about the potential exercise of seller market power in new small zones—which is already mitigated by the existing FCM rules—could be addressed directly by further bid mitigation, if needed.

---

[40] Because of software limitations, PJM is unable to determine locational capacity requirements when there is a sufficiently large surplus of capacity in a zone. Under that circumstance, the zone may not modeled in the RPM auction.

Q WHY ARE THESE CHANGES TO CAPACITY ZONE MODELING IMPORTANT FOR THE LONG-TERM EQUILIBRIUM OF THE FCM?

A These changes in modeling Capacity Zones are needed if the FCM is to send appropriate locational price signals for entry and exit. As we saw in FCA #1, when ISO-NE fails to model a reliability requirement in the FCA, its intra-round reliability review will lead it to reject de-list bids. This not only causes unhedgeable "uplift" costs for load, it also results in incorrect FCA prices everywhere. Capacity prices are too low in the import-constrained zone, and may be too high elsewhere, compared to prices that would result from proper zonal modeling. As a result, going forward consumers in the rest of New England may be subsidizing the locational needs of consumers located in these constrained areas. Consequently, suppliers cannot retain resources in import-constrained areas over the long term because the revenue that is received will be insufficiently low, nor do new resources have any price signal to enter price suppressed Capacity Zones. Failure to model zones when the underlying economics would require it leads to the perverse outcome of erasing the locational price signal for both new *and existing* capacity that was the *raison d'être* for a new capacity market under the *Devon* orders.

Q WILL THE FCM REVISION ADDRESS THIS DEFICIENCY?

A No. Even if the FCM Revision had been in effect for all prior FCAs, there would have been no zonal price separation. In FCA #1, the Norwalk Harbor bids would not have triggered the modeling of a Connecticut capacity zone because they were Dynamic De-List Bids. In FCA #3, the Salem Harbor bids would not have triggered the modeling of a NEMA/Boston zone because those resources were not needed to meet that zone's LSR.

If this market is to have economically efficient zonal pricing, the FCM rules must now move to model all relevant zones, all the time.

Q UNDER WHAT CIRCUMSTANCES DO YOU RECOMMEND THAT A PARTICULAR ZONE BE MODELED FOR APPLICATION OF THE APR?

A ISO-NE should model all relevant zones all of the time. As discussed elsewhere herein, the evidence from PJM shows the risk of failing to model zones when fundamentals, such as cost and supply/demand balance, differ sharply across zones. On the other hand, properly modeling a zone, in and of itself, does not necessarily create price separation with adjacent zones. Only differing market fundamentals when constraints bind create price separation.

Furthermore, the existence of sufficient installed resources overall cannot be presumed to lead to sufficient capacity resources in constrained areas if the pool-wide market price continues to stand. Only with undistorted zonal capacity prices can each relevant local zone have a reasonable expectation of attracting the requisite level of local capacity resources that are needed to serve consumers in those areas.

Q HOW SHOULD THE APPROPRIATE NUMBER OF ZONES TO BE INCLUDED IN THE FCM MARKET BE DETERMINED?

A Ideally, a nodal capacity market would yield appropriate price signals at every node within a region based on the local marginal cost of capacity—just as the ISO-NE energy markets do for energy. While this granular localized approach is theoretically desirable and possibly even achievable,[41] practical considerations require that capacity zones be

---

[41] *See* Aleksandr Rudkevich *et al.*, A Market-based Approach to Power System Expansion Planning and Technical Appendix, Presentation at the FERC Technical Conference on Planning Models and Software (June 10, 2010), http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=5183&CalType=%20&CalendarID=116&Date=&View=Listview.

somewhat larger groups of nodes, ideally defined by natural electric grid transmission constraints to represent zones that could be expected to exhibit price separation under normally-occurring conditions. To be an effective tool, such transmission constraints must include both thermal and voltage based constraints.

The proper determination of capacity zones thus is an engineering issue, whose basis can be prescribed by a bright-line rule specified in clear mathematical text. It should not be subject to partisan stakeholder votes, although the methodology itself should be presented and explained to stakeholders from the outset. The division of a region into capacity zones is then accomplished via analysis applying such methodology, not by subjective and malleable criteria or votes cast by those with vested interests.

Once a constrained capacity zone is identified, it must be modeled until there is a structural change (*e.g.*, transmission upgrades or additional generation within the constrained area) that renders that sub-zone no longer relevant.

Q ARE THERE ANY POTENTIAL PROBLEMS WITH MOVING TO SMALLER ZONES UNDER FCM DESIGN?

A Yes, small zones raise certain issues that need to be addressed under FCM design, including the potential for market power concerns to arise. First, there is the possibility that constrained locations for potential competition to interconnect may not serve as a sufficient discipline on pricing. If a zone has few potential interconnection points, potential competition may have difficulty finding a suitable location for new development. In such circumstances, it may be appropriate to monitor offers from existing capacity resources in the sub-zone more closely. Additionally, more entities may have localized structural market power, so a review of the mitigation standards may be warranted. However, absent a demand curve, heavily mitigated offers may fail to signal the tight supply conditions to indicate future need for new entry. The introduction of demand curves, as discussed in Section V, would help alleviate this issue.

Q IN YOUR OPINION, ARE THERE ANY OTHER MARKET POWER CONCERNS THAT MIGHT PRECLUDE MODELING A PARTICULAR ZONE?

A No, market power concerns should not preclude modeling a zone. For one thing, pre-announced zones should be able to attract sufficient new resources, if needed, to result in competitive results. In any case, appropriate offer mitigation for existing supply, if and where needed, is the direct and correct way of addressing market power concerns. The alternative is to systematically create incorrect prices and consequently significant mis-pricing that will skew investment/retirement decisions, and ultimately, a capacity market that is not sustainable over the long term because adequate prices were not set in the constrained areas.

Q WHAT WOULD BE THE IMPLICATIONS OF CHANGING THE COMPOSITION OF CAPACITY ZONES FROM AUCTION TO AUCTION?

A The existence of changing and uncertain capacity zones raises additional issues under FCM design. First, the uncertainty makes it more challenging and costly to qualify a full set of new resources to meet potential needs for locational reliability because developers are unlikely to have enough information to choose optimal sites for development. Second, any creation of zones "on the fly" would be detrimental, denying market participants and developers the crucial advance notice required in order to encourage timely development of qualified new resources to meet potential reliability needs.

Q CAN YOU SUGGEST A MIDDLE PATH BETWEEN NODAL PRICING AND SUPER-REGIONAL ZONES?

A Yes, I think the proper balance is struck by modeling zones (and announcing that these zones will be modeled with sufficient lead time) that include:

- All high-level market zones as permanent zones, *e.g.*, Connecticut, NEMA/Boston and Maine, *and*
- Zones that would be likely to be constrained if key (large) "at risk" resources were to de-list, *and*
- Zones that were identified as relevant in a previous FCA if the triggering reliability issue has not already been addressed by new resources or new transmission.

For example, in FCA #3, the Salem Harbor 3 and 4 units were not allowed to de-list for local reliability concerns in the NEMA/Boston region, yet this did not trigger the modeling of that region as a separate Capacity Zone. This event should have triggered such a Capacity Zone creation, which should then remain in place unless and until the reliability concern was resolved, ideally through economic new entry. As noted above, modeling a separate zone does not create price separation if it doesn't bind in the auction—but failure to model that zone guarantees that price separation cannot occur when warranted.

Q WHAT OTHER FCM CHANGES, IF ANY, WOULD YOU RECOMMEND IN CONCERT WITH A MOVE TO AN INCREASED NUMBER OF SMALLER ZONES?

A More complex zonal models would also likely require a shift in the auction format. One option would be a sealed-bid auction format, as used by PJM and NYISO. A sealed-bid auction allows the ISO more time to analyze and react to bids before posting the results. As ISO-NE has noted, the current descending clock auction format is not suited to the more complex zones envisioned due to the interconnected mesh nature of the grid and bidirectional constraints. Shifting to a sealed-bid format, however, would vitiate much of the design features of Dynamic De-List bids, which I view to be an important pricing stability mechanism.

Q WHAT IS YOUR OPINION ABOUT THE NOTION OF ALIGNING CAPACITY ZONES WITH THE ISO-NE ENERGY ZONES?

A As noted by Mark Karl with respect to the FCM Revision, the use of energy zones only "*partially* coincides with the natural electrical boundaries that would be consistent with 'pure' capacity reliability zones."[42] He appears to believe, however, that the cost of this partial inconsistency is offset by unquantified benefits from commercial or political simplicity in having capacity zones aligned with other boundaries. I disagree. Ignoring *de minimis* deviations from the natural electric boundaries might be acceptable, but ignoring important physical realities is not. For example, the transmission congestion into the NEMA/Boston sub-zone should be a primary consideration when evaluating the de-list bids for the Salem Harbor units discussed above. If such congestion is sufficient to warrant a de-list denial and a Reliability-Must-Run ("RMR") contract, it is likely sufficient to trigger the creation of a new zone.

Nor is this the practice in other RTOs. PJM's RPM Locational Deliverability Areas can (and do) span or slice the utility franchise areas (which also serve as the energy pricing zones), or even combine sub-areas of several energy zones when appropriate. For

---

[42] Filing letter accompanying FCM Revision ("Filing Letter"), Attachment 4, Prepared Testimony of Mark G. Karl at 5:21-23 (emphasis added).

example, the PSEG North and DPL South capacity zones are smaller than the corresponding energy zones. PJM stakeholders debated a "Central PJM" Locational Deliverability Area that would include portions of several utility franchise areas, based on the electrical realities of the PJM grid,[43] reflecting the fact that natural electrical boundaries, considered from a reliability standpoint, may need to sub-divide some energy areas while simultaneously combining sub-regions across utility boundaries. RTOs were intended to erase utility boundaries for the purposes of system planning and operation; to institutionalize these boundaries in the FCM is unnecessary and unwise.

Q WHAT ARE THE POSSIBLE CONSEQUENCES OF FAILING TO PROPERLY MODEL A CAPACITY ZONE?

A The consequence of the failure to model Capacity Zones can be better understood through an example. Suppose that all Demand Resources in Connecticut require $5.00/kW-month, while Demand Resources in Rest of Pool require $4.00/kW-month; assume further that all Existing Generation Resources require less than $4.00/kW-month. Further, suppose existing Demand Resources make up 10 percent of each utility area's capacity requirements (presumably capacity clearing prices in prior FCAs had equaled or exceeded $5.00). Connecticut's LSR is, hypothetically, 8,000 MW, so there are 800 MW of Demand Resources in the state. Finally, suppose that Connecticut's stock of Existing Capacity (including these 800 MW of Demand Resources) is 8,100 MW, and that across the region the Net ICR is 32,000 MW with 35,000 MW of Existing Capacity. Note that, because Connecticut has sufficient Existing Capacity to meet its LSR, the Connecticut

---

[43] *See, e.g.*, Paul McGlynn, LDA Analytic Method Update (Jan. 18, 2008), http://www.pjm.com/~/media/committees-groups/committees/pc/20080116/20080116-item-05-lda-update.ashx.

Capacity Zone is not modeled, that is, the market price paid to Connecticut resources cannot be higher than the price for resources elsewhere.

What happens in this hypothetical in the next FCA? As the FCA starts, there are 3,000 MW of surplus existing resources plus some amount of new resources. Assume that the new resources all drop out above $5.00/kW-month, leaving now only the surplus of existing resources. Until the price falls below $5.00, nothing leaves. As soon as we reach $4.99, however, all 800 MW of Connecticut's Demand Resources de-list. This now leaves Connecticut net short of capacity; with 800 MW gone from its 8,100 MW base, only 7,300 MW remains, which is less than the required 8,000 MW. Regionally, however, we are still long; the initial 3,000 MW surplus has been trimmed only to 2,200 MW. The price would need to fall to $4.00 to eliminate this overall system excess. The upshot of this market is that the Connecticut resources that have their de-list bid rejected for reliability get paid those bids, while all other Connecticut resources get paid the lower $4.00 clearing price. However, both kinds of resources were providing exactly the same reliability service to ISO-NE. This outcome is clearly discriminatory. It is also economically inefficient because prices do not reflect costs, skewing short-term consumption choices and long-term investment decisions.

Q CAN YOU SUGGEST A BETTER MARKET OUTCOME IN THIS EXAMPLE?

A Yes. The efficient market outcome would be for the capacity clearing price in a Capacity Zone to be set by the marginal resource needed to meet the LSR there, regardless of whether that resource is existing or new. In the example above, the Connecticut capacity price should have been $5.00, and the Rest of Pool price something below $4.00, as determined by the Dynamic De-List Bids of generators.[44] There are no RMR payments needed for resources in import-constrained zones, and clear market signals are sent to potential entrants as to the constrained locations for development of new generation or demand resources.

This issue is not just hypothetical. Initially PJM did not model capacity zones unless internal resources were below 105 percent of the local sourcing requirement.[45] PJM's Independent Market Monitor determined that, had the eastern region of PJM been modeled and allowed to price-separate from the western region, (a) there would have been no need for RMR contracts and (b) prices would have risen in the east but fallen in the west.[46] Because PJM mitigates all capacity offers from existing resources, this price separation reflects fundamental cost differentials, not an exercise of local market power. With the strong support of its Independent Market Monitor, PJM has since increased the likelihood that capacity zones will be modeled in the auctions.

Q HOW SHOULD ISO-NE RESPOND IF AN FCA OUTCOME INDICATES THE NEED FOR A NEW CAPACITY ZONE?

A Ideally, ISO-NE would recognize the need for the new zone prior to the auction, announcing it in time for developers to respond with new project proposals. Realistically, however, it is difficult to anticipate all of the reliability issues and define a

---

[44] Because the surplus in Rest of Pool is greater than the Demand Resources there, all of the Demand Resources must de-list and some amount of additional generation (which, by hypothesis, has a reservation price below $4.00).

[45] *PJM Interconnection, L.L.C.*, Docket No. ER09-412-000, Amendments to PJM Open Access Transmission Tariff and Reliability Assurance Agreement at 51-52 (Dec. 12, 2008). PJM maintained that this was because of technical difficulties modeling transfer limits and local sourcing requirements when the supply/demand ratio was high, though, rather than because of any economic rationale or market design philosophy.

[46] Monitoring Analytics, LLC, Analysis of the 2011/2012 RPM Auction at 20-21 (Sept. 12, 2008, revised Oct. 1, 2008), http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf.

full set of potentially relevant zones in each year. In each auction, however, ISO-NE should do their best to define all needed and proper capacity zones, and the latest ISO-NE proposal is moving in that direction.

If ISO-NE fails to anticipate a relevant zone, which is subsequently revealed as needed in an auction, I would recommend that in the first year the constraining unit (presumably a request for de-list) be retained in the pool, denying any de-listing for local reliability reasons. Such a unit cannot set the clearing price, but would be paid its de-list bid (or in the case of a Permanent De-List bid, it would receive an RMR contract on a cost-of-service basis). There would be no immediate change to the zone structure, but all parties would be on notice that in the subsequent year ISO should model that area as a separate zone, creating the largest possible sub-zone containing that resource and for which the remaining units within the new sub-zone resolve the reliability constraint. This new zone should be modeled for all subsequent years, as long as the zone is demonstrably needed in the analysis.

Q IF ONLY ONE CRITICAL RELIABILITY UNIT HAS OFFERED A DE-LIST BID IN SUCH A NEW ZONE, HOW IS YOUR APPROACH DIFFERENT FROM JUST PAYING THAT UNIT WHAT IT OFFERED?

A If it is possible to compete the de-list candidate unit away with new entry, we would want to create the new zone, allowing price signals to encourage that new entry development. Even a high-priced new entrant might fill the void. That may be cheaper than retaining that resource with an RMR or Out-of-Merit contract. If a relevant sub-zone is not modeled in the FCA, however, we will never find out whether any such economic replacement exists.

Doing otherwise, by failing to model the new zone and paying high prices to the de-list candidate is discriminatory, because the other resources in the sub-zone would be paid the (lower) FCA clearing price for providing the same reliability services as the retained de-list candidate unit. It is also discriminatory in that, absent a new zonal definition, the only way to remove the constraint is through rate-based transmission upgrades, denying new units or suppliers of demand response the correct price signals to enter the (new) zone, meeting the need and "competing away" the marginal de-list unit. Clearly it would be more efficient to create the new zone and allow newer, cheaper resources to replace the older unit. Retaining the de-list unit with high payments is thus inefficient as well as discriminatory.

Q NEW ENGLAND CURRENTLY HAS A SURPLUS OF EXISTING CAPACITY (INCLUDING OOM RESOURCES) OF ABOUT 5,000 MW. TO CORRECT FOR THIS OVERHANG, SHOULD SOME OR ALL OF THE SURPLUS CAPACITY BE RETIRED?

A Simply retiring the highest-cost resources may not be the optimal solution because many of those resources may serve important reliability functions that have not been modeled to date in the FCAs. The presence of a large surplus, whether caused by OOM or in-market entry, does not mean that proper zone modeling is not needed, or that wholesale retirement of older units is the right remedy. Marginal units in New England that need higher capacity payments to survive (*e.g.*, Salem Harbor, Mystic 7, Norwalk Harbor, and potentially some modern combined-cycle plants), may seek to de-list and retire. But because they are needed for local reliability, they have historically been retained with RMR contracts or Out-of-Merit treatment. However, allowing a sudden expansion of

RMR contracts is contrary to FERC policy, as articulated in the *Devon Power* case, in which significant increases in RMR contracts caused the Commission to order an overhaul.[47]

The surplus may or may not be well-located to serve local capacity needs, but without creating new, properly defined capacity market zones, no price signals will be sent to spur developers to locate new entry resources in the proper zones that actually need additional capacity. Regardless of whether new entry occurs under contract or is dependent on market prices, if ISO-NE fails to model relevant capacity zones, new entry projects in constrained (but unmodeled) locales will only be constructed under OOM contracts, shifting substantial risks from shareholders to consumers. Among East Coast RTOs, we generally observe that transmission congestion occurs most often near the most expensive zones for building new capacity. This is not surprising, as the lowest cost development sites are usually far removed from major demand nodes.

Q IS YOUR POSITION ON THIS QUESTION CONSISTENT WITH THE DRAFT RESPONSE PRESENTED BY ISO-NE ON JUNE 15, 2010? PLEASE COMMENT ON ANY DIFFERENCES.

A From the limited details presented to date by ISO-NE, I believe that its proposals are generally in agreement with my positions, and certainly moving in the right direction. ISO-NE agrees with the goals of modeling "all zones all the time" and allowing de-list bids to set the price. The ISO proposal also aims to eliminate, to the extent practicable, the out-of market rejection of de-list, bilateral and pro-rating requests, and it offers changes to substantially reduce these OOM rejections. ISO-NE notes that substantial

---

[47] *Devon Power LLC*, 103 FERC ¶ 61,082 at P 29 (2003).

changes to the FCA clearing engine will be needed "to accommodate the additional complexity."[48]

ISO-NE proposes to initially identify capacity zones through the system planning stakeholder process in advance of the auction. For FCA #6, ISO-NE suggests starting with the eight energy market zones (VT, NH, ME, CT, RI, WMASS, SMASS, and NEMA/Boston). These capture most, but not all, of the relevant constraints. Some of these zones may be irrelevant in the foreseeable future, but there is no harm in modeling them: if they are not relevant in a given auction, then no price separation will occur. I am concerned, however, that there may be *smaller* zones than these eight energy zones that are potentially constrained. Apparently to respond to this potential issue, ISO proposes to "develop explicit criteria for zonal modeling, and evolve the model prospectively through the system planning process,"[49] although it is unclear how much of the modeling criteria will be developed through the stakeholder process.

I would rather implement these changes sooner, and develop and utilize the "explicit criteria" and "effective mitigation" as soon as possible, preferably by FCA #5 rather than waiting until FCA #6. While the window has closed for modifying FCA #4, I see no reason why these steps cannot be implemented in time for FCA #5 (as long as the de-list bidding deadlines are extended so that suppliers know the rules of the road before submitting de-list bids).

---

48 ISO-NE's June 15 presentation at 22.

49 ISO-NE's June 15 presentation at 51.

Q SHOULD DE-LIST BIDS BE CONSIDERED IN THE MODELING OF ZONES, AND ALLOWED TO SET CAPACITY ZONE PRICES?

A Yes. There is no sound rationale for excluding any Static De-List Bid or Administrative Export Bid from consideration in modeling or pricing Capacity Zones. All Static De-List Bids have been thoroughly scrutinized by the Internal Market Monitor and then filed with the Commission for its review. As last year's experience with Salem Harbor demonstrates, this review process is rigorous and open. The definition of the allowed Static De-List Bid price is set by formula in the ISO-NE Tariff and has been accepted by the Commission as just and reasonable. Even if a market participant has substantial local market power, the exacting review to ensure that any Static De-List Bid does not exceed the level allowed by Tariff provides sufficient safeguards against the exercise of that market power. Even if the Internal Market Monitor believes itself incapable of making an accurate determination of whether a Static De-List Bid conforms to the Tariff requirements, the fact that the Commission has full review authority moots that concern.

All de-list bids from incumbents above 0.8 times CONE are subject to a cost-based review by the Internal Market Monitor and the Commission; consequently, these bids are already adequately mitigated and should be accepted for all purposes in the FCM regardless of whether they are pivotal. When supply is very tight, however, even market participants with small shares will be deemed pivotal. In the extreme, if new capacity is required, *all* existing supply will be deemed pivotal and disallowed from setting the zonal clearing price under the FCM Revision and the rules that are in place for FCA #4. But when supplies are tight, capacity prices *should* be near CONE. It would not be unreasonable, therefore, under these circumstances to allow Dynamic De-List Bids from suppliers to create and price a Capacity Zone, consistent with the object of price stability and protection against large price swings from a small capacity surplus. The Commission has historically used a structural screen of 20 percent for such purposes.[50] (I address NEPGA's proposal for mitigating dynamic de-list bids below.)

As it stands today, ISO-NE may end up denying de-list bids in the FCA from resources not because they are needed for resource adequacy (as measured by the LRAR), but because they are needed under the zonal TSA. In order for the FCM to send sensible, locational price signals, what is *bought* and what is *priced* must line up. This alignment is now achieved via the FCM Revision specifying the purchase of the higher of the LRAR or the TSA. ISO-NE has maintained that a reliability review of de-list bids is essential; therefore, if this premise is accepted *arguendo*, it follows that this "higher of" approach is also essential.

It follows that the market pricing mechanism must be robust enough to handle these requirements that are identified only during, and not before, the auction. As I discussed earlier in my testimony, the set of zones that can reasonably be anticipated as potential constrained areas should be included in every auction, whether they are likely to bind in that auction or not. In the unlikely event that a transmission constraint is encountered that is not captured by the predetermined zones, it should be modeled in all future auctions, limiting the need for out-of-merit payments to that one auction. Otherwise, as overall supply conditions tighten, we will likely continue to end up with units' de-list bids being rejected, resulting in above-market payments to generators and

[50] *See, e.g.*, *AEP Power Mktg., Inc.*, 107 FERC ¶ 61,018 at P 8 (2004) ("While the Commission did not employ a bright-line test, it looked to a benchmark for generation market power of whether a seller had a market share of 20 percent or less in each of the relevant markets.").

unhedgeable "uplift" costs to serve load. Avoiding these Reliability Must Run issues was precisely why the Commission found that ISO-NE must be started down the path of fundamental reforms in *Devon*.[51]

Q WHY SHOULD STATIC DE-LIST BIDS BE ALLOWED TO SET THE MARKET PRICE?

A The FCM Revision had the curious effect of implying that its oversight process on Static De-List Bid prices is robust enough to set the payment to the supplier, but not robust enough to set a market price—notwithstanding the further review process at the Commission. No other capacity market has this dichotomy. PJM's Independent Market Monitor reviews all offers from existing capacity resources, mitigates them consistent with Attachment DD to the PJM Tariff, and then allows the as-mitigated bids into the market, setting price if marginal.[52] Likewise, in the Midwest ISO, capacity offers are subject to mitigation by the Independent Market Advisor, Potomac Economics (which is the Independent Market Monitor for ISO-NE and NYISO) but, once mitigated, are allowed to set the capacity clearing price. The NYISO capacity market also has no "mitigate but ignore" rule in its In-City market such as ISO-NE proposed in the FCM Revision. As all these other RTOs recognize, there is no need for such a rule: once the market monitor has applied the tariff-specified mitigation to a bid, the bid is valid for all purposes in the market. The fact that ISO-NE's mitigation decisions undergo a further round of direct review by the Commission provides a second layer of protection not

---

[51] *Devon Power LLC*, 103 FERC ¶ 61,082 at P 29.

[52] PJM OATT, Attachment DD § 5.14(h). Technically, the Independent Market Monitor only mitigates bids if a market power screen failure occurs. In practice, the screen failure has occurred in every Base Residual Auction to date and will almost surely occur in all future Base Residual Auctions.

found in any other capacity market and even more basis for permitting the mitigated bid to set price.

Q WHY SHOULD ADMINISTRATIVE EXPORT DE-LIST BIDS BE INCLUDED AND ALLOWED TO SET MARKET PRICES?

A Administrative Export De-List Bids are entered by ISO-NE as a bookkeeping entry to account for multi-year exports of capacity. The current market rules always exclude Administrative Export De-List Bids from the stock of Existing Capacity.[53] The FCM Revision sought to limit this exclusion only to those Administrative Export De-List Bids entered on behalf of non-Pivotal Suppliers.[54] There is no economic rationale for this change. The fact that this export contract was entered into some time in the past, when the current year's market conditions could not be easily predicted and the cost of economic withholding against an uncertain future is high, suggests that there is little economic ground for ignoring these contracts for the purposes of modeling and pricing Capacity Zones. More importantly, the capacity for these resources has already been contractually committed elsewhere and is not recallable by ISO-NE. To ignore that basic fact is to risk locational capacity deficiencies or the need for inefficient RMR contracts.

Q WHY SHOULD DYNAMIC DE-LIST BIDS BE INCLUDED AND ALLOWED TO SET CAPACITY PRICES?

A To address this question, I will first parse this group into two categories, depending on whether the supplier possesses structural market power.

---

[53] ISO-NE Tariff § III.13.1.2.3.1.4.

[54] Filing Letter at 9-10.

There is no sound economic rationale for excluding Dynamic De-List Bids from suppliers without structural market power. Moreover, removing the ability of these suppliers to set prices excludes a large portion of the supply from effective participation in the market. NEPGA Exhibit 2-F shows the market structure in FCA #2 for the two most-concentrated import-constrained Capacity Zones, Connecticut and NEMA/Boston. As the exhibit shows, there is a large amount of capacity in these zones offered by market participants with very small market shares, including utilities, municipals, government agencies, and small Demand Resource suppliers.[55] In Connecticut, 53 percent of the qualified capacity was from suppliers with less than a 10 percent market share, and only one supplier had a market share in excess of 20 percent (NRG, with 27.4 percent), a threshold the Commission has used in other contexts for determining whether suppliers have structural market power. Similarly in NEMA/Boston, 27 percent of the qualified capacity was from suppliers with less than a 10 percent market share, and again there was only one supplier above the 20 percent mark. If ISO-NE fails to consider the cost information embedded in the offer prices from these numerous, small participants in the market, it will lose substantial market efficiency with no offsetting gain from mitigating (non-existent) market power.[56]

Even if a supplier has structural market power, ignoring Dynamic De-List Bids is contrary to the underlying market design adopted in the FCM Settlement Agreement. The Dynamic De-List Bid threshold at 0.8 times CONE was not justified because it represented the one-year going-forward cost of capacity, but instead because the FCM

[55] As noted above, I include both existing and new resources in my analysis.

[56] The D.C. Circuit has outright rejected newly proposed market power mitigation measures when they were unjustified by a prior showing of the existence of market power, much less the exercise thereof. *See, e.g.*, *Edison Mission Energy, Inc. v. FERC*, 394 F.3d 964, 968-70 (D.C. Cir. 2005).

price should equal, on average over time, the long-run average cost of capacity (net of market earnings for energy and other products). If the market rules drive prices to short-run marginal cost whenever there is a surplus, there will be two adverse consequences to the market. First, entrants will bid new capacity at a premium to earn, on average over time, a sufficient return. Second, those entrants will also price in a risk premium to account for the greater volatility in cash flows from the capacity market. With no demand curve to add price stability to the FCA, the relatively looser review standards for supply priced below an agreed level—0.8 times CONE—was designed as the stabilizer on the low side. (New entry into a readily contestable market is the stabilizer on the high side.) By not allowing all Dynamic De-List Bids to set clearing prices, ISO-NE would undermine this important leg in the market design in precisely those import-constrained markets where developing new capacity resources is the most costly and challenging. As Dr. Bowring observed about the restrictions limiting the modeling of capacity zones in PJM's RPM auctions:

> That rule should be removed from the tariff as it inappropriately prevents locational price differences based on the economic fundamentals of the capacity market from being revealed in the auction. The result is to suppress appropriate locational price signals that reflect the relative shortage of capacity in specific locations. Getting those locational price signals right was one of the key elements of the RPM design.[57]

Q HAS THE DRAFT RESPONSE PRESENTED BY ISO-NE ON JUNE 15, 2010 ADDRESSED YOUR CONCERN ABOUT DYNAMIC DE-LIST BIDS?

A No. Although ISO-NE apparently agrees with the goal of allowing de-list bids to set the price, it also is proposing to mitigate de-list bids to a substantially lower level than

[57] Monitoring Analytics, LLC, Position of Independent Market Monitor for PJM on RPM Market Design Issues (Sept. 29, 2008), http://www.pjm.com/~/media/committees-groups/committees/cmec/20080929/20080929-item-00-imm-cmec-position.ashx.

allowed under the current rules. As I stated above, the current rules governing Dynamic De-List bids serve an important price-stabilizing function in the market design. Because the full details of the ISO's new mitigation proposal are not available until ISO files its brief and testimony concurrent with this testimony, and because what has been presented raises significant implementation questions with respect to the calculation of opportunity costs based on the NYISO capacity market, I will limit my comments to the following observations, subject to further comments on September 1, 2010.

First, resources in New England should certainly be allowed to offer capacity at a price at least as high as the opportunity costs as determined by the export potential to NYISO Rest-of-State, but that standard is not a good replacement for the current 0.8 time CONE threshold. As I discussed earlier, the current rule was intended to add market stability. Anchoring mitigation to a the NYISO Rest-of-State price could result in the potential for the clearing price swings the current rule was designed to prevent. Recent NYISO Rest-of-State prices have averaged between approximately $2/kW-month and $3/kW-month over recent history, and in some months fallen as low as $0.30/kW-month. Moreover, if the ISO-NE market is tight, then prices should be near CONE, and allowing prices to fall to this level would not be reasonable as applied to the ISO-NE market.

Second, there are practical limitations to this approach. The NYISO market is a short-term, monthly market, not a forward, annual market like ISO-NE. Hence, the mitigation would either need to be tied to a forecast of NYISO prices, which would be difficult to establish with any reasonable consensus, or to contemporaneous prices, which could be completely disconnected from the market conditions expected three years hence.

Q WHAT IS YOUR OPINION ON THE QUESTION OF WHETHER A PIVOTAL SUPPLIER TEST IS NECESSARY TO EVALUATE DE-LIST BIDS, AND IF SO, WHETHER IT SHOULD HAVE A MARKET SHARE THRESHOLD?

A If the Commission accepts any contention that a test for structural market power is needed, it should incorporate two critical parameters: First, it must consider not only *existing* capacity, but also new capacity. Secondly, it should consider the absolute market share of the supplier's portfolio in determining when to apply the test. NEPGA has proposed a threshold of 5 percent for this test. NEPGA has also proposed any supplier with only a single resource in a zone not be deemed pivotal. Such a supplier would be unable to benefit from withholding that resource from the market.

Q EARLIER YOU PRESENTED EVIDENCE ABOUT THE CONCENTRATION OF SOME LOCAL AREAS UNDER A 20 PERCENT STANDARD. HAVE YOU CALCULATED SIMILAR STATISTICS FOR THE 5 PERCENT STANDARD THAT NEPGA HAS PROPOSED?

A Yes, I have. This standard is much more restrictive, but even so shows that there is a considerable "competitive fringe" of suppliers that can discipline pricing. In Connecticut, 24.4 percent of the qualified capacity was from suppliers with less than a 5 percent market share, with six suppliers with a market share in excess of 5 percent. Similarly in NEMA/Boston, 26.8 percent of the qualified capacity was from suppliers with less than a 5 percent market share, with three suppliers with a market share in excess of 5 percent mark. These statistics, I should note, include supply from both existing and qualified new supply in FCA #2.

Q WHY SHOULD A TEST FOR MARKET POWER INCLUDE NEW RESOURCES?

A When the FCA occurs, the relevant universe of supply is not just *existing* resources. ISO-NE will have qualified *new* resources as well, and that capacity is a perfect substitute for incumbent capacity from a reliability service standpoint. We designed the FCM to allow new capacity to compete against existing capacity directly; this principle of "contestability" is critical to ensuring the reasonableness of the market outcomes. By ignoring this competition—even after it has transformed from a theoretical competitive force into qualified capacity—lacks any foundation in economics. The theory of contestable markets postulates that the threat of new entry is sufficient to check the pricing behavior of incumbents.[58] In the case of the FCA, there is more than a hypothetical threat of new entry; competing projects have been reviewed and qualified by the ISO-NE and therefore stand ready, willing, and able to displace incumbent suppliers.

There is simply no basis to discriminate between the competition created by an existing supplier and the competition created by a qualified new supplier. Incumbents do not necessarily have a lower cost; in every FCA to date, new capacity not marked as out-of-market by the Internal Market Monitor has been accepted even as existing supply is de-listed.[59] The FCA clearing mechanism treats an offer from qualified new supply perfectly symmetrically with an offer from Existing Capacity. It is unfounded and illogical, therefore, to ignore the competitive pressures created by qualified new supply in defining an FCM Pivotal Supplier.

---

[58] *See* William J. Baumol, John C. Panzar & Robert D. Willig, *Contestable Markets and the Theory of Industry Structure* (1982).

[59] As I discussed earlier, however, there is reason to believe that the entry of much of this supposedly in-market capacity was not dependent on the level of the FCA clearing price.

VII. ADMINISTRATIVE COST OF NEW ENTRY

A. Current CONE is Well Below the Cost of New Generation

Q IS THE CURRENT ISO-NE VALUE OF ADMINISTRATIVE CONE A REASONABLE ESTIMATE OF THE LONG-RUN NET COST OF BUILDING NEW CAPACITY IN NEW ENGLAND?

A No. CONE should be reset to a value that reasonably represents the full cost of new generation resources in the locational capacity zones and Rest of Pool, net of expected earnings from the sale of energy and other products. As the Internal Market Monitor has observed, the current administratively set value of CONE of $4.918/kW-month is "significantly below most estimates of the cost of new entry for generating resources."[60] For example, the Commission has recently approved Net CONE values of $6.70/kW-month in PJM (Zone 4), $9.06/kW-month in PJM (RTO), and $8.92/kW-month in New York—respectively 59%, 84% and 81% above ISO-NE's current CONE value.[61] This price, as applied to the locational zones, is even farther below the actual CONE value in these areas. For example, the CONE value for the constrained New York City zone is $11.93/kW-month. There is no reason to think that the cost of new power plant construction in New England is materially different than in these other, nearby regions.

---

[60] Internal Market Monitor Report at 8.

[61] *PJM Interconnection, L.L.C.*, Docket No. ER10-366-000, Revisions to Open Access Transmission Tariff and Reliability Assurance Agreement at 6 (Dec. 1, 2009), *accepted by* unpublished letter order issued January 22, 2010; *New York Indep. Sys. Operator, Inc.*, Docket No. ER08-283-000, Tariff Revisions to Implement Revised ICAP Demand Curves for Capability Years 2008/2009, 2009/2010, and 2010/2011, Affidavit of David Lawrence at Table 4 (Nov. 30, 2007), *accepted by* 122 FERC ¶ 61,064, *order on reh'g*, 125 FERC ¶ 61,299 (2008), compliance filing *accepted by* unpublished letter order issued July 30, 2009. Furthermore, any escalation of that $16.00/kW-month starting price or the $8.00/kW-month value of CONE upon which it would be based, should begin now and not be delayed, as the Filing Parties had proposed for their FCM Auction Staring Price. Values cited are for PJM CONE Region 4 (MetEd/PPL/Penelec areas) and NYISO Rest of State, which I judge to be most similar to New England overall, and PJM RTO (rest of pool) for comparison. I treat the FCM CONE as a "Net CONE" value, which is conservative inasmuch as it excludes the expected cost of the PER deduction, which has no counterpart in either the PJM or NYISO market design.

Moreover, while increases in the cost of building new power plants since the approval of the FCM market design are well documented, the ISO-NE CONE has fallen from $7.50/kW-month to 4.918/kW-month by virtue of the mechanistic operation of the current rules.[62]

In other RTOs, the Commission has approved the development of CONE values through engineering and economic analyses performed by independent consultants. Such an update should be undertaken for ISO-NE as well. As I will discuss in more detail below, there are several deleterious effects for the market if CONE is set too low. Hence, failure to update CONE to a value that reflects a reasonable estimate of the costs of building new generation to meet the long-term needs of ISO-NE, and its locational zones, is likely to force prices well below actual cost levels, eviscerating the ability of the market design to produce fair and reasonable outcomes and precluding any reasonable chance that new capacity needed for reliability purposes will be added through market-based outcomes.

Q DOES THE DECOUPLING FROM CONE OF THE STARTING VALUE FOR THE AUCTION CHANGE THE NEED OR IMPORTANCE OF UPDATING CONE TO A VALUE MORE REFLECTIVE OF CURRENT POWER PLANT CONSTRUCTION COSTS?

A No. In fact, the concern that the starting value for the auction at two times CONE may be too low is further evidence that CONE itself is unreasonably low. The very fact that twice CONE is viewed as being potentially too low to provide sufficient incentives for capacity to remain in the descending clock auction is a telling indication that CONE must

---

62 FCA #3 Informational Filing at 3 n.8; *see also ISO New England Inc.*, Docket No. ER08-633-000, Forward Capacity Auction Results Filing at 2, 8 (Mar. 3, 2008).

certainly be too low to encourage new entry. Hence, the FCM Revision's decoupling of the starting price of the Forward Capacity Auction from CONE are entirely appropriate. But ISO-NE is treating the symptom, not the disease. As Dr. Ethier noted in his February affidavit, auction theory tells us that starting a descending clock auction at a very high price has no effect on the expected outcome.[63] The risk, correctly identified by Dr. Ethier, is that the descending clock auction starts too low, and potentially begins with inadequate supply. The current market rules start the Forward Capacity Auction at two times CONE. Because CONE is—or, at least, is intended to be—the price at which new capacity is willing to enter, starting at a level two times higher should provide more than enough headroom in the auction. The real problem here is not that two times CONE is insufficiently high, but rather that ISO-NE currently uses an unrealistic value for CONE itself. In fact, as compared to the figures approved by the Commission for the NYCA Curve—not the higher priced NYC Curve—the existing New England CONE price may very well be nearly 100% too low. Thus, two times CONE is, in actuality, barely CONE itself—a result directly driven by the collective rules that remain in place in New England at this time.

Q IS THERE A SOUND ECONOMIC BASIS FOR HOW THE CURRENT LEVEL OF CONE WAS SET?

A No. The current level of CONE is the result of a purely mathematical calculation, unlinked from any market reality. Today's CONE of $4.918 is equal to $1.88 plus 75% of the average clearing price in FCA #1 and FCA #2, but the clearing prices in those two auctions was simply 60% of the relevant CONE values, each of which was also set by

---

[63] Filing Letter, Attachment 3, Prepared Testimony of Robert G. Ethier at 22.

formula. Contrary to the intent of the FCM framework, the CONE value now has *no information* from any competitive supply offer about the actual revenue requirements of the resources supporting system reliability. Given the market design goal of utilizing this information to set CONE, the Commission should require ISO-NE to reset CONE using a "bottoms up" accounting analysis, as NYISO and PJM do and as ISO-NE did prior to the FCM.

B. An Updated Estimate of CONE Should Reflect Costs of New Merchant Generation

Q WHAT IS THE APPROPRIATE BENCHMARK UNIT FOR ESTABLISHING CONE?

A The conceptually appropriate benchmark for setting administrative CONE is the all-in cost of a new gas-fired combustion turbine. In the long run, new *generating* capacity will be needed in order to meet demand and operate the system to reliability standards, meaning new power plants must be added to the system, not just demand resources or energy efficiency. In other words, once the "low-hanging fruit" in the form of low-cost demand response or unit uprates has been exhausted, new peaking capacity will be the long-run marginal entrant. Hence the appropriate long-run price signal should be consistent with this technology.

While, in theory, the marginal entrant at any point in time could be a combined-cycle plant or other technology, rather than a peaking unit, there are two reasons why a gas turbine peaking unit remains an appropriate benchmark unit. First, there is very sound economic theory as to why all economic resources will have very similar net CONE values, and therefore all be close to marginal. As a result, using a peaking unit as the reference technology should lead to, at worst, small errors relative to the net CONE for the marginal technology. In order to understand why, suppose, for a simple example, that there were only two kinds of units: baseload and peakers. If baseload units had systematically lower net CONE values, it must be the case that their E&AS earnings are offsetting a larger portion of their capital costs than it is for peakers. Baseload units would therefore out-compete peakers in the FCA, and the mix of resources on the system would shift towards baseload. In so doing, though, the E&AS earnings of baseload units would decline. As a result, the payment needed from the capacity market to cover the all-in costs of new baseload units would increase, which would in turn increase the total earnings for a new peaker, reflecting the relative abundance of the former and scarcity of the latter. Eventually the mix of resources would be such that the differentials in E&AS earnings between baseload and peaker units exactly offset the capital cost differences, and their net CONE values are equal. And, in order to maintain that level of E&AS earnings, there would have to be an alternating back and forth over time between peakers clearing and baseload units clearing the capacity markets. So, any deviation of net Cone values of one unit class from another is corrected by the resulting shift in the fleet mix. Using the net CONE value for a peaker is therefore a reasonable proxy for the net CONE of any efficient technology (and more reliably estimated, since the most difficult portion to estimate—the future E&AS earnings—is small relative to the capital costs).

The second reason is that changing the benchmark unit over time in response to shifts in the relative economics of various unit classes will lead to systemically under-compensating new entrants. To understand why, consider again the example of a two-technology world with peakers and baseload units only. Suppose in one year, baseload capacity has the lowest net CONE and it enters the market expecting the clearing price to exactly return the net CONE required for new baseload capacity each year, leaving the unit owner exactly fully-compensated for its all-in costs. If, however, in the next year the energy market earnings for baseload units fall such that peakers have the lower net CONE, and the CONE value is adjusted accordingly, the baseload unit will no longer receive a payment sufficient to cover its net CONE. More generally, if the unit with the lowest new CONE changes from year-to-year, adjusting the administrative CONE in response will lead to CONE values over time that under-compensate *all* technologies, since each type of unit will receive a value equal to or *lower than* its levelized cost. Because the FCM market does not typically clear with a demand curve, and under the current rules, prices are not anchored to a demand curve, the harm from this systematically low CONE may be limited. But relying on the peaking technology as the benchmark units is nonetheless still appropriate.

Q SHOULD CONE REFLECT THE COST OF DEMAND RESPONSE, SUBSIDIZED RENEWABLES, UNIT UPRATES, OR OTHER LOW COST NEW RESOURCES THAT HAVE ENTERED THE MARKET IN THE FIRST THREE FORWARD CAPACITY AUCTIONS?

A No. While the net CONE for some new resources that cleared the New England market during the first three FCAs may have been below the net CONE of a new peaking unit, the amount of capacity that can be added through low-cost upgrades is limited and in the long run will be exhausted. For example, while FCM has created an incentive for some generation owners to make investments to uprate units, the number of such cost-effective projects is limited and certainly not sufficient to meet all capacity needs in the long-term. Additionally, though some demand resources may also have relatively low costs, physical generation is needed on the system and there are finite limits to the amount of peak demand that can be met by reductions in load. Further, the price of demand resources reflects the price at which customers elect not to have capacity supply purchased on their behalf, but does not reflect the cost to meet that incremental demand with new capacity. Moreover, to the extent some new resources appear to be low cost, if subsidies are driving that cost advantage, those resources should be treated as OOM, as discussed earlier in my testimony.

Q SHOULD THE COSTS OF FINANCING USED TO CALCULATE CONE REFLECT THE FINANCING OF A MERCHANT UNIT OR CONTRACTED UNIT?

A The CONE values should be determined based on financing assumptions consistent with the risk profile of a new merchant unit. While it may turn out that some, or even most, new capacity that clears in the FCM is under long-term contract, that outcome is not relevant to pricing of the product in the FCM, which comes with no long-term commitment from buyers. The purpose of the market is to secure one-year (or up to five-year for new capacity) supply obligations for the Commitment Period covered by each FCA. With a shorter commitment period, most of the market risk remains with suppliers rather than consumers. This allocation of risk, therefore, should be reflected in FCM prices. If buyers in the FCM market have a preference for paying a lower capacity price in exchange for bearing the market risk associated with entering longer-term contracts for capacity, they are free to enter longer-term contracts with either new or existing capacity resources. But that decision is independent of the capacity market design, since the product the market is designed for is short-term merchant capacity. Designing the market to produce prices for a product other than what is being bought and sold will produce neither efficient nor equitable outcomes.

This point can be illustrated with an analogy to the energy market. In the energy market, an LSE may opt to enter long-term contracts for power with new generators. By making a long-term commitment and taking on the associated long-term risk, the LSE may pay a lower price for the energy than if they purchased it in the ISO spot markets. If generators can manage that risk at lower cost, however, such a discount may not be available, and the LSE will instead purchase from the spot markets. But in either case, it would be inappropriate to administratively adjust the spot market prices to reflect the pricing under a long-term contract. The product being purchased in the spot markets comes with a different risk allocation and the price appropriately reflects that difference. Targeting an FCM price based on the risk allocation of long-term contracts would be just as inappropriate.

To summarize, allowing CONE to be determined based on the lower cost of debt and equity that would be available to a resource with a long-term contract will produce a market structure that is not sustainable over the long term, for several reasons. First, designing the market to produce long-term, equilibrium pricing based on units with long-term contracts would be presupposing that buyers, rather than sellers, will always bear the long-term market risk. Setting the CONE to a value below what could support new merchant entry, effectively steering the long-term market price towards that value, will result in a self-fulfilling prophecy that all new resources will require contracts because the CONE revenues will be insufficient to support new un-sponsored merchant entry. Consumers will no longer have the choice about whether or not to bear the long-term market and technological risk. If instead CONE is set to the higher value, enabling merchant units without long-term contracts to compete, consumers will have a choice about whether to meet new capacity needs through FCM, leaving the risk with suppliers, or entering contracts and taking on the risk. In this scenario, the risk will be allocated efficiently by the market outcome, rather than predetermined by the market design and administrative auction parameters.

Second, even if all new capacity resources are under contract, it is likely that most existing capacity, which comprises most of the market, will be supplied on a merchant basis, with a one-year commitment. That means that suppliers will bear the long-term risk for most of the capacity product being supplied through FCM, and the price paid to those suppliers should thus continue to reflect the long-run marginal cost of capacity with that risk allocation. In the long run, that price will be determined by the all-in cost of a new merchant generator, not a unit with a long-term contract. If consumers can bear the long-term market risk at a lower cost than suppliers of existing capacity resources, then they could opt to purchase some or all of the capacity of existing resources through long-term contracts rather than FCM. But that decision should not be predetermined by the choice of CONE, rather, just as for new resources, it should be left to the market.

Finally, from a practical perspective, there are several reasons to expect that at least some new entry will occur on a merchant basis. At least at the time of the FCM Settlement Agreement, there was ample reason to believe that long-term contracts would not be the sole, or even the primary, means for new capacity resources to enter the market. Most electric utilities in New England have statutory limits on their ability to enter into such long-term contracts; the majority of load in the region is served either by non-utility retailers or under competitively tendered "default supply" contracts that run for six months to three years. Furthermore, New England saw a large amount of "merchant" entry by independent power producers throughout the ten years prior to the FCM Settlement Agreement, and there was little reason at the time to forecast a radical change in that pattern.

Hence, just as it would not be appropriate to set CONE based on the cost of an exhaustible resource type, it is likewise not appropriate to assume long-term pricing will be set by new resources with contracts.

Q WHAT ARE APPROPRIATE ASSUMPTIONS FOR FINANCING COSTS TO APPLY WHEN CALCULATING CONE?

A The financing costs used to set CONE should reflect the financing terms available to new, project financed merchant generators. While a traditional assumption applied in the calculation of CONE has been a 50/50 split between debt and equity, conditions in the financial markets have changed, making that degree of leverage unlikely for a true merchant project. Based on conversations with merchant generation owners and my understanding of current financing requirements of banks and lending institutions, a conservative estimate in the current financial climate would be 55 percent equity. The cost of equity also should reflect the level of risk associated with a merchant project. In order to estimate the cost of equity for a merchant project, I have relied on data published by Bloomberg Financial. As shown in NEPGA Exhibit 2-G, Bloomberg reports the following cost of equity values for several merchant power companies:

- Calpine: 15.03 percent
- Dynegy: 13.78 percent
- Mirant: 13.33 percent
- NRG: 12.77 percent

- RRI Energy: 19.53 percent.

The average cost of equity across these companies is 14.88 percent. However, the cost of equity values shown applies to a diversified company with a portfolio of assets, which will have inherently lower risk than an individual project. Hence 15 percent is a conservative estimate of the cost of equity for a merchant project. The actual cost of equity for a new, project-financed capacity resource would likely include an additional risk premium beyond that reflected in the 15 percent figure.

For cost of debt, the yield on B rated corporate bonds, currently 8.84 percent, provides a reasonable estimate for a project financed merchant project. Based on discussions with business persons from merchant power companies operating in New England, it is my understanding that a single B rating would be typical for such a project. Moreover, while balance-sheet financing may allow a lower cost of debt, such as would be available for BBB rated bonds, which is not an appropriate rate in my opinion. The cost of debt should reflect the risk of the project, rather than the risk of the diversified corporate entity, since no company will not have unlimited access to its balance sheet for financing, at least not without facing a re-rating to lower-grade debt. Balance sheet financing therefore comes at an opportunity cost which should be reflected in the assumed financing costs.

Q WHAT IS AN APPROPRIATE AMORTIZATION PERIOD FOR COMPUTING LEVELIZED COSTS WHEN ESTIMATING CONE?

A Based on my experience working with developers of new capacity and financing institutions, projects are typically evaluated with a 20-year amortization period. This amortization period is also generally consistent with CONE calculations conducted in

NYISO and PJM. This amortization period reflects the typical economic life that is considered when generation investment decisions are made. Twenty years therefore is a reasonable assumption for most estimates of CONE, provided the other financing assumptions are consistent with what I discussed in my previous answer. In some cases, the amortization period has been used as a means to capture merchant risk. For example, my understanding is that the CONE calculation for New York City uses a shorter amortization period to account for risk. Where the cost of capital does not reflect the full merchant risk, such an adjustment may be appropriate.

Q HAVE YOU REVIEWED THE ESTIMATE OF CONE PREPARED BY SARGENT AND LUNDY ON BEHALF OF NEPGA?

A Yes. As discussed in the testimony of Christopher Ungate, under the financing assumptions I have described and Sargent and Lundy's indicative estimates of the overnight capital cost for illustrative gas turbine units assumed to be built in Western Massachusetts and Boston using the GE Frame 7FA technology to provide an apples-to-apples comparison with the current CONE level, the estimated CONE values are $13.72/kW-month, and $15.20/kW-month, respectively.

C. Failure to Revise CONE Would Have Adverse Effects.

Q HOW ARE MARKET OUTCOMES UNDER FCM AFFECTED WHEN CONE IS SET TOO LOW?

A While ISO-NE's concern with the auction starting price is well placed, there are many other elements of the FCM design that also rely on CONE, that are just as broken, if the administratively set level of CONE is badly out of line with the true level of CONE. In addition to the starting price, CONE serves several functions in terms of setting auction parameters. NEPGA Exhibit 2-H provides a listing of all of these functions. As long as CONE is skewed, none of these rules works as intended.

Q WHY IS LINKING THESE PARAMETERS TO AN ARTIFICIALLY LOW CONE PROBLEMATIC?

A Each of these parameters plays an important role in steering the market towards competitive outcomes and providing long-term price stability near the long-run economic cost of new capacity. If CONE is not set to a level that appropriately reflects this long-run expected price, these built-in stabilization mechanisms may actually push the market towards inefficient pricing, resulting in inefficient and undesirable market outcomes. The alternative to resetting CONE would be to revisit each use of CONE and consider what changes, if any, are required to ensure that the rule operates reasonably. Such a change would, in effect, make CONE irrelevant. In particular, there are three rules that, absent a CONE reset, need urgent attention. I discuss these three as examples of why the continued use of an administrative estimate of CONE that is far removed from commercial reality undermines the sound operation of the FCM.

Q WHAT IS THE FIRST OF THESE THREE IMPORTANT USES OF CONE?

A The most important of these is the standard of review for offers of new capacity to determine if they are Out-of-Market. Currently, any offer of new capacity priced at 75 percent of CONE or above is exempt from review and may set the capacity clearing price. This rule was intended to provide a “safe harbor” for competitive bids. But, with the CONE estimate now 63% of the NYISO value and only 61% of the PJM East value, a resource can bid less than half of a realistic CONE value without triggering review as a potentially Out-of-Market resource.

Q IS RESETTING CONE THE ONLY FIX AVAILABLE FOR THE STANDARD OF REVIEW FOR OOM CAPACITY?

A No. There are two reasonable fixes for this problem. However, both require the use of recent, reliable, and reasonable estimates of costs to build new capacity. First, one could increase CONE to a level that actually reflects the cost of building new generation, in line with PJM and NYISO. As an alternative and likely preferred approach, ISO-NE could adopt asset class-specific standards of review for new resource offers, as PJM does in its Minimum Offer Price Rule, which I also propose to be used in the APR. Under this second approach, the Internal Market Monitor would periodically develop a benchmark CONE for a range of various technologies, for example, 2-on-1 F7A combined cycle, LMS100, and GE H System combined cycle. A proposed project's offer price would be compared to the estimated asset class for its type, if applicable, or to CONE if the entry is not within an asset class for which the Independent Market Monitor had established a benchmark. This class-specific approach would ensure that offers from all resources were evaluated against a relevant benchmark, even if the value of CONE diverged from that resource's actual costs. It is my understanding, based on the June 15, 2010 presentation, that ISO-NE now proposes to reset the threshold for OOM resources based on unit class benchmarks for estimated CONE. I support ISO-NE's revised proposal in concept.

Q WHAT IS THE SECOND RULE THAT WOULD NEED TO BE ADDRESSED IF CONE IS NOT RESET?

A A second rule that requires revision absent a CONE reset is the Dynamic De-List Bid threshold, set at 0.8 times CONE. As this threshold has dropped over the first three

FCAs, from $6.00/kW-month in FCA #1 to $3.93 in FCA #3, even while the market-based CONE has likely risen during this time, more capacity suppliers facing high risk-adjusted going-forward costs will be required to file Static De-List Bids for review by the Independent Market Monitor in order to be able to bid these costs into the market. This not only increases the administrative burden on the supplier and the Internal Market Monitor, but more importantly increases the risk to the supplier. First is a regulatory risk that the Internal Market Monitor or the Commission will disagree with the supplier's assessment of its revenue requirements from the capacity market. Second is a timing risk that market conditions will have shifted markedly between the time the Static De-List Bid must be filed and the time of the FCA. Once submitted, the price in a Static De-List Bid is binding, so the supplier's ability to set his bid consistent with market conditions at the time of the FCA is impaired. It is my understanding that instead of restoring this threshold to levels originally contemplated by the FCM design to provide price stability, ISO-NE proposes an alternative threshold. As I stated above, I will reserve further comment on this element of the ISO-NE's proposal in the hopes that more details will be included in the ISO-NE July 1 filing.

Q WHAT IS THE THIRD RULE FOR WHICH THE CONE RESET OR OTHER ADJUSTMENT IS CRITICAL?

A Finally, the "Quantity Rule" that applies when Static or Permanent De-List Bids are accepted does not work as intended with the current, low value of CONE. Although the FCA does not, on its face, have a sloped demand curve, the market rules create circumstances in which the FCA will procure less than the full quantity of capacity required. Depending on the clearing price in the FCA, expressed as a percentage of

CONE, ISO-NE may defer the purchase of replacement capacity for cleared de-list bids until an incremental auction. The following table summarizes the rule:

FCA Clearing Price as a % of CONE	*Percentage of Permanent De-Listed Capacity Replaced*	*Percentage of Static De-Listed Capacity Replaced*
≥ 150%	0%	0%
150% to 125%	0% to 100%, increasing linearly	0%
125% to 120%	100%	0%
120% to 80%	100%	0% to 100%, increasing linearly

Q WHAT IS THE PURPOSE OF THE QUANTITY RULE?

A This rule was intended as a further check on the potential for economic withholding by suppliers. By creating what amounts to a demand curve, activated only when there are accepted de-list bids, the quantity rule reduces the price impact of the de-list bid on the FCA clearing price if there is not effective competition from new entrants and, consequently, reduces the profitability of economic withholding. But, with ISO-NE's CONE value so far below a reasonable estimate of the costs of new generation construction for ISO-NE, this rule could easily backfire. There might be ample new supply resources available to replace higher-cost resources, offered at prices reflecting their actual costs. At that price level, none of the Permanent or Static De-List Bid capacity would be replaced in the FCA, even if there is an infinite supply of new, efficient capacity priced at cost. Instead, ISO-NE would attempt to procure this additional needed capacity in a subsequent Incremental Auction. This outcome stands the rule on its head. The rule was supposed to apply only when new capacity did not provide sufficient competition to moderate prices close to cost, but if CONE is not a reasonable estimate of those costs, the rule begins to work against consumer interests by making the new entrant appear incorrectly uneconomic. An important rationale for having a Forward Capacity Market was to create enough lead time for economic entry. Delaying needed purchases of new resources by a year likely will only increase procurement cost and run the risk of insufficient capacity being available at all. There is no obvious remedy for this rule besides getting CONE reset to a plausible level.

Q DO YOU AGREE WITH ISO-NE'S RECENT PROPOSAL TO ELIMINATE THE QUANTITY RULE?

A Yes, I do. As noted by ISO-NE in their draft response, the Quantity Rule has never been invoked to date and should be eliminated. This rule, which defers purchasing replacement capacity for high-priced de-list bids from the FCA to the reconfiguration auctions, unduly complicates the FCA design and suppresses efficient pricing. The rule has not been invoked because there have been no high-priced Static or Permanent De-List bids. It also increases reliability risks through reducing the new capacity development timeline. It is not needed, and it should be eliminated. If market participants want to purchase systematically less capacity when prices are higher than some benchmark, then the capacity market should simply include a demand curve.

Q WHAT OTHER RULES ARE AFFECTED BY THE CONE VALUE?

A While the three rules just discussed are the most problematic in terms of the impact of an artificially low value for CONE, there are other aspects of the FCM market also affected. First, payments under the Inadequate Supply and Insufficient Competition rules, which are intended to set prices at a level sufficient to signal a need to new resources to enter and compete in subsequent FCA, will be too low. Second, the price cap applied for replacement resources will also be too low. Finally, the collateral requirements for resources participating in FCM will be lower than intended when the rule was set, creating the potential for inadequate credit requirements.

Q WHAT CHANGES ARE NECESSARY TO RESTORE THESE RULES TO THEIR ORIGINAL FUNCTION?

A For both the first and second rules (payments under Inadequate Supply or Insufficient Competition, and the price cap for replacement resources), the CONE benchmark should be replaced by the net cost of a new benchmark generation resource. Although I support the concept that low-cost demand resources should be allowed to set the capacity clearing price when they are the marginal capacity resource, only active generation can be caused to enter in effectively uncapped quantities at a basically constant cost. In the first case, when we don't have sufficient resources offered competitively, we have presumably accepted all offered, economic demand-side resources—if more resources are needed, therefore, it must be from economic generation. In the second case, if the replacement price is capped below the cost of new generation, then we are precluding participation of new generation to provide replacement reserves, even when those reserves are strictly needed to meet reliability requirements.

For the third rule, relating to collateral requirements, the benchmark would more logically be set at the clearing price of the auction in which the resource obtained its capacity supply obligation, as it is this price that would be paid to the resource, not some notional benchmark at CONE or any other value.

Q DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A Yes. However, as noted above, I anticipate submitting further comments/testimony in September, after reviewing the final form of June APR and other filings made on July 1.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and New England Power Pool	))	Docket No. ER10-787-000
New England Power Generators Association Inc. v. ISO New England Inc.	)))))	Docket No. EL10-50-000
PSEG Energy Resources & Trade LLC, PSEG Power Connecticut LLC, NRG Power Marketing LLC, Connecticut Jet Power LLC, Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, and Somerset Power LLC v. ISO New England Inc.	)))))))))	Docket No. EL10-57-000

I, Robert B. Stoddard, being duly sworn, depose and state that the contents of the foregoing Testimony on behalf of the New England Power Generators Association is true, correct, accurate and complete to the best of my knowledge, information, and belief.

Robert B. Stoddard

Robert B. Stoddard

SUBSCRIBED AND SWORN to before me this 30 day of June 2010.

Suzanne M. Walsh

(Notary Public)

My commission expires: 2/25/2011

SUZANNE M. WALSH
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
February 25, 2011

CRA Charles River Associates

ROBERT STODDARD

Vice President

Ph.D. (ABD) Economics
Yale University

M.A., M.Phil Economics
Yale University

B.A. Economics and Music
Amherst College

Mr. Stoddard heads CRA's Energy & Environment practice. He has twenty years of experience assisting clients in defining, analyzing, and interpreting the economic issues involved with competition and product valuation in energy and other markets. His recent work has focused on electricity industry restructuring and on providing both strategic analyses and testimony for utilities, generation owners, and governments regarding the practical implications of market design and structure, particularly in New York, New England and PJM. He has submitted testimony to the Federal Energy Regulatory Commission as well as to the utility commissions and legislatures of several states on competitive market design and market power issues, and he as testified in civil litigation and arbitration on the interpretation of, and damages relating to, energy contracts. He recently was the lead economist for capacity suppliers in developing the New England capacity market, played a central role in negotiating the settlement of the PJM Reliability Pricing Model, and developed the leading proposal for the design of a capacity market for California. In related areas, Mr. Stoddard has served as the special economic counsel to the Rhode Island House of Representatives for electricity restructuring as acted as overseer for Connecticut's standard-offer energy auction, devised an energy trading strategy audit and strategy redesign for a major northeastern utility; conducted a comprehensive review of operating flaws within the structure of an ISO; designed a market-based transfer pricing system for the distribution, trading, and generation subsidiaries of a leading western utility; and managed the federal and state regulatory filings for several large utility mergers and asset sales.

EXPERIENCE

Mr. Stoddard has been a consultant on electric market issues to Abrams Capital, ArcLight Capital Management, Astoria Generating, Bangor Hydro-Electric Company, Boston Generating, California Independent System Operator, Citibank, City of New York, ConEdison Energy, Connecticut Department of Public Utility Control, Consolidated Edison Co. of New York, Constellation Energy Commodities Group, Dayton Power & Light, Devon Canada Corp., Dominion, Dominion North Carolina Power, Duke Energy, Edison Mission Energy, Electricity Supply Board of Ireland, Energia dos Portugal, Energy Capital Partners, Energy East, Entergy Nuclear, FirstEnergy, FirstLight, International Power, J. Aron & Company, Maine Energy Recovery Co., MASSPower, Midlands Cogeneration Venture, Mirant Corporation, Morgan Stanley Capital Group, Morris Energy Group, NextEra Energy Resources (formerly FPL Energy), New England Power Generators Association, New York City Economic Development Corporation, New York Energy Buyers Forum, NextEra Energy Resources, Northeast Utilities, NRG Energy, Orange & Rockland Utilities, Pepco Energy Services, Pinnacle West, Powerex Corporation, Rhode Island Speaker and House of Representatives, RRI Energy, San Diego Gas & Electric, Southern California Edison, Sunoco, Tenaska, Tonbridge Power, USGen New England, USPowerGen, Virginia Electric and Power, and Williams Power.

Electricity Market Design

- Project director and testifying expert for capacity market design litigation and settlement negotiations for the New England and PJM markets, representing coalitions of the major generation owners in the region.
- Principal author of SDG&E and California Forward Capacity Market Advocates' proposal for a centralized capacity market structure to address resource adequacy needs of the California electricity markets.
- Working with other CRA experts, prepared a white paper on capacity market design for Energia dos Portugal.
- Principle drafter of the current form of the utility restructuring laws in Rhode Island, implementing improved retail market access.
- Project director for a major policy initiative by a major generation owner to review key flaws in modern RTO design that distort competitive pricing and outcomes.
- Project manager and testifying expert for litigation regarding the market rules governing use of Phase Angle Regulators between New York and PJM. Subsequently, assisted the negotiated design of these rules pursuant to the FERC orders.
- In the redesign of the wholesale power market for the Republic of Ireland, responsible for development of rules regarding demand-side integration, interconnection management, financial transmission rights and transmission loss representation.
- Testified on behalf of a major importer into the California electricity market on the allocation of financial transmission rights across external interties.
- Project director for a review for the California Independent System Operator of transmission rights allocations in the proposed California wholesale market.

Market Power Analysis and Mitigation

- Testifying expert and project director supporting the integration of Virginia Electric and Power (Dominion) into the PJM marketplace.

- Project manager for an acquisition of generation assets in Connecticut by a competing supplier, using detailed hourly analyses of power flows and potential future competition, the results of which Mr. Stoddard presented to the FERC, U.S. Department of Justice and the Connecticut Office of the Attorney General.

- Project manager for a market power analyses needed to obtain federal and state regulatory approval of the merger of the leading natural gas transporter and distributor in the eastern U.S. with a vertically integrated utility with substantial gas holdings.

- Project manager for study of the potential competitive effects of the divestiture of substantially all the New York City utility generation to independent power producers, including detailed behavioral modeling that took account of the complex transmission system and design of market power mitigation measures for the energy and capacity markets.

Electricity Contracts

- Provided expert testimony supporting the reliability must-run (RMR) applications of over 2 GW of generation in New England, documenting need for RMR contracts to maintain the financial viability of needed resources. The case resulted in a settlement agreement that provided for significant support payments for these resources during the transition to compensatory market payments.

- Prepared testimony for a bankruptcy court regarding damages arising from a power purchase agreement that had been rejected at the time of bankruptcy.

- Testified in arbitration proceedings to determine the product specification and price of the capacity product contracted for in a period of regulatory change.

- Testified in arbitration proceedings about the interpretation of, and damages owed under, the electricity section of a contract for the purchase of a large petrochemical refinery and resale of the refinery's output.

- State-appointed auditor of Connecticut's utilities' first Standard Offer power procurement auction, reviewing reasonableness of pricing and the terms and conditions of contract offers to supply essentially all of the state's power needs for a three-year period.

- Testified on fuel costs adders reasonably allowable in a long-term power contract between NRG and Connecticut Light & Power, and attendant retail rate design to fairly allocate the incremental costs.

- Assisted Consolidated Edison Co. of New York negotiate the sale of its nuclear facilities and linked buy-back of power for the license-life of the units.

- Worked with Pinnacle West staff to develop options-based contracts to transfer power between its generating, trading and distribution affiliates to preserve appropriate performance incentives.

- Project manager for bankruptcy evaluation of a New England cooperative, involving assessment of value of hydroelectric, nuclear assets and long-term contracts.

Strategy

- Directs the development of the master energy infrastructure strategy for the City of New York, working with key stakeholders to develop a strategy to develop the infrastructure needed to meet the city's future energy needs economically and reliably.
- Developed a detailed forecasting model for capacity prices in PJM resulting from the new capacity market design and, using this information, worked with a major market participant's strategy and financing staff to identify under-valued assets for acquisition.
- With senior management of a major utility, developed a transmission investment strategy to reflect shifting competitive opportunities, RTO market design, and state and federal regulation. Identified key opportunities to leverage and redirect capital expenditures to significantly decrease cost of delivered power and increase rate of return to corporate shareholders.
- Developed a competitive bidding strategy for a complex hydroelectric generation asset to recognize opportunity costs, limitations of market rules, and effects of key transmission constraints in a two-settlement, locational pricing regime.
- Assisted a leading provider of utility outsourcing services to develop a comprehensive regulatory strategy for its service offerings to a major utility.

TESTIMONY AND REPORTS

Richard Blumenthal, Attorney General for The State of Connecticut v. ISO New England Inc., Brookfield Energy Marketing Inc., et al. FERC Docket No. EL09-47-000, and *The Connecticut Department of Public Utility Control and the Connecticut Office of Consumer Counsel v. ISO New England Inc., Brookfield Energy Marketing Inc., et al.*, FERC Docket No. EL09-48-000. Prefiled testimony on behalf of Brookfield Energy Marketing Inc. regarding scheduling of capacity imports. June 2009. Answering Testimony, February 2010.

Pepco Energy Services, Inc. v. Constellation Energy Commodities Group, Inc. (ad hoc arbitration); expert report on behalf of Constellation on alleged mis-payment under a bilateral contract for PJM capacity, April 2008; testimony, October 2009.

Application of MidAmerican Energy Company for the Determination of Ratemaking Principles, IUB Docket No. RPU-2009-0003. Rebuttal testimony on behalf of NextEra Energy Resources, June 2009; surrebuttal testimony, July 2009, live testimony, August 2009.

Midwest Independent Transmission System Operator Inc., FERC Docket Nos. ER08-394-007 and -009. Affidavit regarding monitoring and mitigation of resource adequacy auctions on behalf of Duke Energy Corp., July 2009.

Calpine Corporation, Citigroup Energy Inc., Dynegy Power Marketing, Inc., J.P. Morgan Ventures Energy Corporation, BE CA, LLC, Mirant Energy Trading, LLC, NRG Energy, Inc., Powerex Corporation, and RRI Energy, Inc. v. California Independent System Operator Corp., FERC Docket No. EL09-62-000. Affidavit on behalf of complainants, June 2009; reply affidavit, July 2009.

Report on ISO New England Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements, prepared for New England Power Generators Association, Inc. and filed in *ISO New England, Inc.*, FERC Docket No. ER09-1282-000 (June 2009).

Richard Blumenthal, Attorney General for Connecticut, v. ISO New England Inc. et al., FERC Docket Nos. EL09-47-000 and EL09-48-000. Prefiled testimony on behalf of Brookfield Energy Marketing Inc. regarding scheduling of capacity imports. June 2009.

Master Transmission Plan for New York City, report prepared for the New York City Economic Development Corporation, April 2009.

California Independent System Operator Corporation, FERC Docket No. ER09-589-000. Affidavit on behalf of Powerex Corp. regarding changes to the CAISO credit policy regarding unsecured credit, February 2009.

"Contracting and Investment: A Cross-Industry Assessment" Report filed with Post-Conference Comments of Reliant Energy, Inc., *Credit and Capital Issues Affecting the Electric Power Industry*, FERC Docket No. AD09-002-000, January 2009.

PJM Interconnection, LLC FERC Docket No. ER09-412-000. Affidavit and reply affidavit on behalf of Mirant, Edison Mission Energy, International Power, and FPL (NextEra Energy Resources) regarding omnibus changes to the PJM RPM capacity market tariff, January 2009.

Midwest Independent System Transmission Operator, Inc. FERC Docket Nos. ER08-394-000, -003, -007. Affidavit on behalf of Duke Energy protesting the market monitoring standards proposed for the voluntary capacity auction in Midwest ISO, January 2009.

Devon Canada Corp. et al. v. Pittsfield Generating Company LP, et al. Expert report for defendant regarding damages from alleged breach of natural gas supply contract to a reliability must-run electric generator, December 2008.

Maryland Public Service Commission v. PJM Interconnection, L.L.C., FERC Docket Nos. EL08-34-000 and EL08-47-000. Affidavit on behalf on Mirant Parties on appropriate structural and behavioral market power tests in PJM, October 2008; reply affidavit, November 2008.

ISO New England, Inc., FERC Docket No. ER08-1209-000. Affidavit on behalf of the New England Power Generation Association on compensation to reliability resources, July 2008; reply affidavit, September 2008..

Midwest Independent Transmission System Operator, Inc. FERC Docket No. ER08-1169-000. Affidavit on behalf of FPL Energy, LLC, regarding revisions to Generation Interconnection Procedures, July 2008.

RPM Buyers v. PJM Interconnection, L.L.C., FERC Docket No. EL08-67-000. Affidavit on behalf of PJM Power Providers opposing *ex post* changes to initial RPM auction results, June 2008.

Assessment of Maine's Continued Participation in ISO New England and Alternatives, Expert report in Maine Public Utilities Commission Docket No. 2008-156, prepared on behalf of Bangor Hydro-Electric Company, June 2008; testimony to the MPUC, October 2008.

Reliability at Stake: PJM's Reliability Pricing Model. Report prepared for PJM Power Providers in conjunction with FERC technical conference to discuss the operation of forward capacity markets in New England and the PJM region (FERC Docket No. AD08-4-000), May 2008.

Estimation of Indian Point 2 Fair Market Value Using a Statistical Analysis of Comparable Transactions, Testimony in *Consolidated. Edison Co. of New York v. United States*, No. 04-0033C (Fed.Cl.), February 2008.

Critique of the APPA/CMU Study "Do RTOs Promote Renewables?" (with David Riker) commissioned by Electric Power Supply Association, January 2008.

Midwest Independent Transmission System Operator, Inc. Electric Tariff Failing Regarding Resource Adequacy, FERC Docket No. ER08-394-000. Affidavit on behalf of Duke Energy Corp. and FirstEnergy Services Co. on the urgency of implementing a uniform resource adequacy requirement, January 2008.

Mirant Energy Trading, LLC, et al. v PJM Interconnection, L.L.C., FERC Docket No. EL08-8-000. Affidavit on the flaws in the market power mitigation rules for the Third Incremental Auction of the PJM Reliability Pricing Model capacity market., November 2007.

Wholesale Competition in Regions with Organized Electric Markets, FERC Docket Nos. RM07-19-000 and AD07-7-000. Affidavit on role of demand-side resources in organized electric markets on behalf of Duke Energy Corp., September 2007.

Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program, California PUC Rulemaking 05-12-013. Principal author of SDG&E Track 2 Resource Adequacy Program Proposal, March 2007; principal author, Joint Pre-Workshop Comments of the California Forward Capacity Market Advocates, May 2007, and Proposal for a Forward California Capacity Market, August 2007.

People of the State of Illinois, ex rel. Illinois Attorney General Lisa Madigan v. Exelon Generating Co., LLC et al., FERC Docket No. EL07-47-000. Affidavit assessing reasonableness of outcomes in the Illinois power procurement auction on behalf of J. Aron & Company and Morgan Stanley Capital Group. July 2007.

PJM Interconnection, L.L.C., FERC Docket Nos. EL03-236-000 *et al.* Affidavit regarding three-pivotal-supplier market power test and scarcity pricing in PJM's energy markets on behalf of Mirant Energy Trading, *et al.*, May 2007.

Midwest Independent Transmission System Operator, FERC Docket No. ER07-550-000. Affidavit regarding resource adequacy issues in ancillary services market design on behalf of Duke Energy Co., March 2007.

PJM Interconnection LLC, FERC Docket No. EL05-148-000 *et al.* Affidavit regarding redesign of the long-run resource adequacy market in PJM on behalf of the Mirant Parties, October 2005; supplemental affidavit on behalf of the Mirant Parties, NRG and Williams Power Co., November 2005; presentation to FERC Technical Conference, February 2006; prefiled comments to FERC Technical Conference Panel 1, May 2006, on behalf of the Mirant Parties, Williams Power Co., and Dayton Power & Light; prefiled comments to FERC Technical Conference Panel 2, May 2006, on behalf of the Mirant Parties; supplemental affidavit on behalf of the Mirant Parties, June 2006; affidavit and reply affidavit supporting settlement agreement, September & October 2006.

Mystic Development, LLC, FERC Docket No. ER06-427-000. Affidavit analyzing future revenues in support of RMR filing, December 2005; supplemental affidavit, September 2006.

In re USGen New England, Inc. Debtor. United States Bankruptcy Court for the District of Maryland, Case No. 03-30465. Expert Report on damage resulting from PPA rejection, on behalf of USGen New England, March 2006; supplemental report, September 2006.

California Independent System Operator Corporation, FERC Docket No. ER06-615-000. Joint affidavit with Paul Kevin Wellenius regarding FTR allocations under new CAISO market design, on behalf of Powerex Corp, June 2006

Fore River Development, LLC, FERC Docket No. ER06-822-000. Affidavit analyzing future revenues in support of RMR filing, December 2005.

Assessment of the New York City Electricity Market and Astoria, Gowanus, and Narrows Generating Stations. Report prepared for Morgan Stanley Senior Funding, Inc. related to financing for US Power Generating Co. and Madison Dearborn Capital Partners IV, L.P., January 2006.

Review of Initial Execution of Protocol for Implementation of Commission Order No. 476. Report to FERC in Docket EL02-23-000, regarding operation of controllable lines between NYISO and PJM, on behalf of Con Edison, September and December 2005.

Honeywell International Inc. v. Sunoco, Inc. AAA Case No. 13 181 Y 02588 04. Expert report, deposition and live testimony on contract energy pricing in petrochemicals, May 2005.

Con Edison Energy, Inc. v. ISO New England, Inc. and New England Power Pool, FERC Docket No. EL05-61-000. Affidavit on behalf of complainant, February 2005, regarding bidding rules in capacity deficiency auction.

KeySpan Ravenswood LLC v. New York Independent System Operator, Inc., FERC Docket No. EL05-17-000. Affidavit on behalf of Consolidated Edison Company of New York, Inc., November 2004, regarding retroactive damage claims from a capacity market.

Devon Power LLC, et al., FERC Docket No. ER03-563-030. Affidavit and rebuttal affidavit regarding design of locational installed capacity markets on behalf of FPL Energy, April and May, 2004; answering testimony on behalf of Capacity Suppliers, November 2004; cross-answering testimony, December 2004; supplemental cross-answering testimony, January 2005; deposition and hearing testimony, February-March 2005; affidavit supporting Settlement Agreement, March 2006.

Application of Dominion North Carolina Power to Join PJM as PJM South, North Carolina Utilities Commission, Case No. E-22 SUB 418. Direct testimony and cost-benefit study on behalf of applicant, April 2004; rebuttal testimony, December 2004; examination, January 2005.

Application of Virginia Electric and Power Company to Join PJM as PJM South, State Corporation Commission of Virginia Case No. PUE-2000-00551; direct testimony and cost-benefit study on behalf of applicant, June 2003; supplemental direct testimony, March 2004; rebuttal testimony, September 2004; examination, October 2004.

Consolidated Edison v. Public Service Electric and Gas Co. et al., FERC Docket No. EL02-23-000 (Phase II); direct testimony on behalf of Consolidated Edison Company of New York, Inc., June, 2002 regarding transmission facilities contracts. Remand testimony, January—March 2003.

In the Matter of the Siting of Electric Transmission Facilities Proposed to be Located at the West 49th Street Substation of Consolidated Edison Company of New York, Inc. et al., New York State Public Service Commission Case Nos. 02-M-0132, 01-T-1474, 02-T-0036, 02-T-0061; testimony on behalf of Consolidated Edison Company of New York, Inc., April 2002 (direct) and May 2002 (rebuttal).

Testimony before the Rhode Island Special Legislative Commission on the Quonset-Davisville Steamplant, January and April 2002.

Testimony before the Committee on Corporations, Rhode Island House of Representatives, regarding 2002 House Bill 7786, *An Act Relating to Public Utilities and Carriers,* April 2002.

Keyspan-Ravenswood, Inc. v. New York Independent System Operator, FERC Docket No. EL02-59-000, direct testimony on behalf of Consolidated Edison Company of New York, Inc., March 2002, regarding implementation of market power mitigation in installed capacity markets.

DPUC Investigation Into Viability of Power Supply Contracts to the Connecticut Light and Power Company and the United Illuminating Company, Connecticut DPUC Docket No. 01-12-05, direct testimony on behalf of NRG Energy, Inc. and affiliates, February 2002.

Joint Study by the Department of Public Utility Control and the Office of the Consumer Counsel Regarding Electric Deregulation and How Best to Provide Electric Default Service After January 1, 2004, Connecticut DPUC Docket No. 01-12-06, direct testimony on behalf of NRG Energy, Inc. and affiliates, January 2002.

The Narragansett Electric Co. Rate Changes for January 1, 2002, *Rhode Island PUC Docket No. 3402, direct testimony on behalf of the Hon. John B. Harwood, Speaker of the House of Representatives, State of Rhode Island and Providence Plantations, December 2001.*

Wisvest-Connecticut, LLC et al., FERC Docket No. EC01-70-000, technical conference presentation on behalf of NRG Energy, Inc. and affiliates, September 2001.

New York Independent System Operator, Inc., FERC Docket No. ER01-2536-000, affidavit on behalf of Consolidated Edison Co. of New York, the City of New York, the New York Energy Buyers Forum, and the Association for Energy Affordability, Inc., July 2001.

Testimony before the Committee on Corporations, Rhode Island House of Representatives regarding electricity restructuring; various dates, 2001.

Consolidated Edison Co. of New York, Inc., FERC Docket Nos. EL01-45-000 and ER01-1385-000, affidavit and rebuttal affidavit (joint with William H. Hieronymus) on behalf of Consolidated Edison Co. of New York, March and April, 2001.

Joint Petition of Consolidated Edison Co. of New York, Inc. and Entergy Nuclear Indian Point 2, LLC, for Authority to Transfer Certain Generating and Related Assets and for Related Relief, NYSPSC Case 01-E-0040, technical conference presentation on behalf of applicants, February 2001.

PROFESSIONAL HISTORY

2009–Present	*Vice President and Practice Leader*, Charles River Associates, Boston, MA
2003–2009	*Vice President*, Charles River Associates, Boston, MA
2001–2003	*Principal*, Charles River Associates
1995–2001	*Managing Consultant*, PA Consulting Group, Cambridge, MA PA purchased PHB Hagler Bailly, formed by the merger of Hagler Bailly and Putnam, Hayes & Bartlett, where Mr. Stoddard had been a Principal.
1993–1995	*Senior Health Economist and Acting Managing Director*, Benefit Research USA, a Quintiles company, Cambridge, MA.
1990–1993	*Senior Associate*, Charles River Associates, Boston, MA
1985–1990	*Teaching and Research Fellow*, Department of Economics, Yale University

1983–1985 *Assistant Economist*, Federal Reserve Bank of New York.

Draft Response to FERC Order of April 23, 2010

Bob Ethier, Mark Karl, Dave LaPlante
Chantale LaCasse, NERA

June 15, 2010

Outline

- Background
- FERC Order for Paper Hearing
  - FERC Guidance
- Summary of Proposed ISO Response
- Detailed Proposal for the Alternative Price Rule (APR)
- Detailed Discussion of Out-of-Market (OOM) Determination
- Detailed Proposal for Modeling Capacity Zones
- Detailed Proposal for Mitigation

Background: Internal Market Monitor Report

June 5, 2009

- FCM Settlement required report on results of first two FCAs by the Internal Market Monitoring Unit (IMMU)
- IMMU's FCM assessment:
  - Concluded FCM met overall objective by procuring capacity for region
  - Provided recommendations for certain improvements to the FCM:
    - Address the reliability criteria used for determining capacity zones and evaluating de-list bids
    - Modify the Alternative Price Rule
    - Change Cost of New Entry in determining starting price for each FCA

Background: FCMWG Created

Summer 2009

- Forward Capacity Market Working Group (FCMWG) created at request of state regulators
- FCMWG specifically created to provide a forum for a coordinated and comprehensive discussion of potential FCM changes
- Collaborative effort of NECPUC, NEPOOL and ISO
  - Each had representative serve as a tri-chair
- FERC Facilitator participated

Background: Scope of Work for FCMWG

July – December, 2009

- A dozen issues identified by stakeholders as potential issues
- Two issues, APR and zones, required immediate attention due to obligations associated with ISO tariff
- Of all the issues identified by stakeholders, given time constraints, resources, and importance of issues, FCMWG decided to focus efforts on APR and Zonal Issues
- FCMWG produces a Design Basis Document that describes many changes to the FCM, including changes to the APR, zones and the definition of OOM
- DBD used to develop market rule changes

Background: FCA Capacity

- FCA #3 Excess Capacity at price floor: 5,031 MW
- FCA #4 Qualified New OOM Capacity: 1,527 MW
- Forecast Peak Load Growth: (RSP 09)

Background: ISO & NEPOOL Filing

February 22, 2010

- ISO and NEPOOL jointly filed set of FCM rule changes
  - This filing included enhancements to:
    - The Alternative Price Rule
    - Out of Market (OOM) determinations for new, low-priced resources
    - Capacity Zone modeling in the Forward Capacity Auction
- Filing emphasized commitment to future stakeholder discussions
  - ISO Proposed an up-to 18 month stakeholder process

"…a number of Participants have sought input from the External Market Monitor on the APR, and zonal formation, and other parties seek further discussion on APR pricing and the definition of out-of-market capacity. Accordingly, a stakeholder process will be commenced as soon as practicable to continue to examine these important issues…."

Background: Responses to February 22 Filing

March 15, 2010

- ISO and NEPOOL's February 22 filing was opposed by the generation sector
- Generator sector believes that the proposed reforms are inadequate to fix the APR, zonal modeling, and the calculation of the Cost of New Entry, and would not send the proper long-term price signals
- Generator sector asserted that proposed FCM rules are not just and reasonable

Background: Responses to February 22 Filing

March 15, 2010

- Load interests filed comments with FERC, which in general were supportive of the FCM reforms included in 2/22 filing
- External Market Monitor filed comments with FERC:
  - "ISO's proposed changes to the FCM will improve the performance of the market by increasing the efficiency of FCM prices"
  - "If judged against the objectives of the APR rules to minimize the price effects of OOM capacity, the APR provisions fall well short"
  - "While the amendments improve the FCM design, more is needed to allow the prices in capacity zones to more fully reflect the system's capacity needs"

Background: ISO's Response to Comments

March 30, 2010

- ISO filed answers to generators' comments and protests
- ISO urged FERC to approve:
  - Proposed changes in February 22 filing and reject generators' complaints and requests
  - A more expedited stakeholder process than the one referenced in February 22 filing (request to shorten future stakeholder process from 18 to 9 months)
- Various load parties filed opposition to generator filings

Background: FERC Order

April 23, 2010

- FERC accepted ISO's filing, but only on a temporary basis, and set for a Paper Hearing the following issues:
  - APR
  - OOM determinations
  - Zones
  - Calculation of CONE

- FERC established Paper Hearing Schedule
  - First briefs due July 1
  - Second briefs due September 1

Background: FERC Order

April 23, 2010

- FERC's order provides perspective on stakeholder process

Excerpt from April 23 FERC Order, 131 FERC ¶ 61,065

Docket No. ER10-787-000, *et al.* - 65 -

3. <u>Commission Determination</u>

183. As discussed above, we are setting many of the questions that the parties raise here for paper hearing. Given that extensive stakeholder proceedings up to this point have not fully resolved these heavily-contested issues, we will not require ISO-NE or NEPOOL to continue with stakeholder processes. However, we encourage the parties to continue stakeholder discussions in light of the guidance provided by this order, if they believe such a process will be useful and may lead to a negotiated resolution.

FERC Description of Issues for Paper Hearing

- Issues Relating to Alternative Price Rule
  - Triggering Conditions, if any, for the APR
  - Treatment of OOM resources that create capacity surpluses for multiple years
  - Appropriate price adjustment under APR
- Modeling of Capacity Zones
  - Whether zones should always be modeled
  - Whether all de-list bids should be considered in the modeling of zones
  - Whether a pivotal supplier test is necessary
  - Whether revisions to the current mitigation rules would be necessary in order to model all zones
- Proper Value of Cost of New Entry
  - Whether the value of CONE should be reset
- There were also other issues identified in the Order (e.g. what to do with past OOM)

Guidance in April 23 Order

- FERC provided significant guidance in its April 23 Order, including:
  - The APR should seek to fully correct for OOM entry
  - Zones should be modeled whenever possible

Guidance On APR

- On the APR: “Our objective in accepting these provisions has been to ensure that the prices in (the) capacity markets reflect the market cost of new entry when new entry is needed. We agree with the EMM and the commenter's that ISO-NE’s existing APR does not fully meet this objective. For example, the existing APR provides a price adjustment of OOM resources only when there is a need for new capacity as reflected by an ICR that exceeds all existing capacity. … Moreover, we also agree with commenters that OOM resources can affect prices even when no new capacity is needed, by displacing what would otherwise be the marginal, price-setting existing resources. And we agree with commenters that the price adjustment under the existing APR does not always fully correct for the effect of OOM resources on the capacity price. That is, the existing APR does not establish the price that would have arisen had all of the OOM resources offered at prices that reflect their full entry costs net of in-market revenues. Thus, when OOM resources are offered into the market, the existing APR does not ensure that capacity market prices reflect the market cost of new entry when new entry is needed.” paragraph 69-70

Guidance On Zones

- On zones: "The Commission believes that it is important to model zones wherever possible to set appropriate locational prices. We have cited the need for locational pricing in New England for many years, noting that its absence in the Installed Capacity (ICAP) market (the predecessor to the FCM) was a significant flaw since 'location is an important aspect of ensuring optimal investment in resources.'" paragraph 134

Discussion Draft

Guidance on Mitigation

- On mitigation: "While we believe that always modeling zones should be the ultimate goal, we agree with ISO-NE that such a change would require further analysis and is not required to be implemented prior to FCA # 4. Rather, we note that all parties have raised valid concerns on this issue, including whether the current mitigation rules are adequate to model zones at all times, whether all de-list bid types should be allowed to set a zonal price (i.e., whether a "pivotal supplier" test is necessary, and whether it should have a market share threshold), and what, if any, corresponding revisions to the current mitigation rules are necessary." paragraph 135

Summary of Draft ISO Response

ISO Response to FERC Guidance

- FERC rejected proposed stakeholder process and ordered a paper hearing to resolve the issues

- The ISO's draft response differs from the February filing:
  - The ISO's response reflects guidance provided by the Commission in its April 23 Order
  - In sum, the guidance was that the February filing did not go far enough in enhancing the APR and zonal modeling

Summary of Draft Response: APR

- New resources, both OOM and non-OOM, would be paid the FCA clearing price
  - Paid the initial year FCA price for 3-5 years in years APR is triggered
- In each year with OOM MW, the ISO would calculate an APR price as if the OOM MW had offered competitively into the FCA
  - Competitive offers for OOM resources based on the IMMU benchmark
  - The APR price would be higher than the FCA clearing price because the OOM resources would be included at their higher, competitive offer levels
  - This APR price would be paid to existing resources that had not delisted at that price
  - This two-tiered pricing is intended to send appropriate signals to new investors about the need for new capacity, while in the long term insulating investors from the risk that OOM resources will inappropriately depress clearing prices
- Excess OOM MW will be carried forward each year until eroded by load growth and retirements

Summary of Draft Response: OOM

- The market monitor will develop a benchmark offer for each new resource technology type
  - New resources seeking to offer below 80% of the benchmark must provide data to justify their offers
    - The benchmark approach is similar to that used by the PJM market monitor
  - If data do not support the low offer, resource deemed OOM
- Will not consider OOM from first three FCAs
- No change to definition of OOM

Summary of Draft Response: Zones

- Model all zones all the time, and allow all de-list bids to set price
  - Initially, these will be the eight defined load zones
  - System planning will develop criteria for identifying future zones
- This requires substantial modification to the FCA clearing engine to accommodate the additional complexity
  - During the auction the price impact of underlying constraints will not be apparent, so bidders will be unable to estimate the clearing price impact of their actions
  - For example, in advance of the auction, participants would know of the existence of a western Massachusetts zone, but that zone might not have a separate price as the auction is run, and the remaining quantity for that zone might not be reported intra-round
  - Consistent with approaches used in certain wireless spectrum auctions
  - Objective function would be to maximize social welfare

Summary of Draft Response: Mitigation

- Changes being made to support the modeling of zones in the auction
- Threshold for Dynamic De-list Bids will be changed to opportunity cost of selling to Rest of System in New York
- Static De-list Bid levels will be modified
- Permanent De-list Bids will become Priced Retirement Bids
- Propose elimination of the Quantity Rule based on experience in the first 4 FCAs and revised mitigation rules

Summary of Draft Response: CONE

- Many of the uses of CONE are eliminated with the revised mitigation and OOM rules, and with the elimination of the Quantity Rule. The remaining uses can reasonably be indexed either to the cost of developing backstop capacity (a gas-fired peaker) or to the FCA clearing price
  - The remaining uses appear to be of less interest to stakeholders than the Dynamic De-list bid threshold and the OOM review threshold price
  - Remaining uses include: price at which ISO will buy replacement capacity in reconfiguration auctions, price paid to existing resources when there is inadequate supply or insufficient competition in the FCA, and to set the level of financial assurance required for new capacity clearing in an FCA
- Propose elimination of CONE and use of appropriate values for specific purposes

Proposal Details

- The next sections provide more detail on draft changes to:
  - APR
  - OOM
  - Zones
  - Mitigation

Detailed Proposal for the Alternative Price Rule

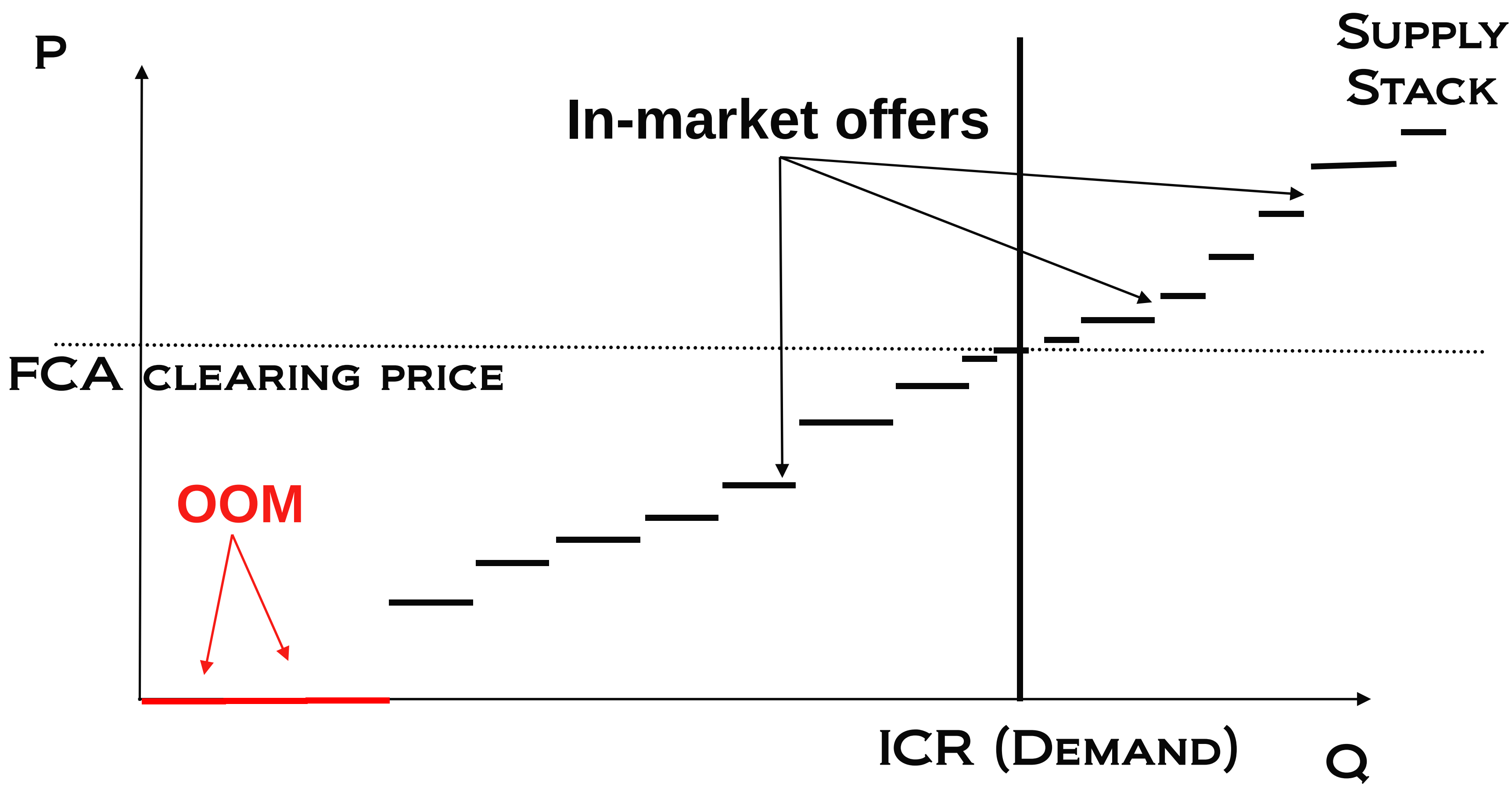
Proposed APR Responsive to the FERC's Guidance

- APR adjusts the price when OOM resources depress the capacity price (not only when new entry is needed)
- APR fully corrects for the effect of OOM resources on the capacity price
- APR takes into account that OOM resources may continue to depress the capacity price after entry
- APR set prices that reflect the market cost of new entry when new entry is needed

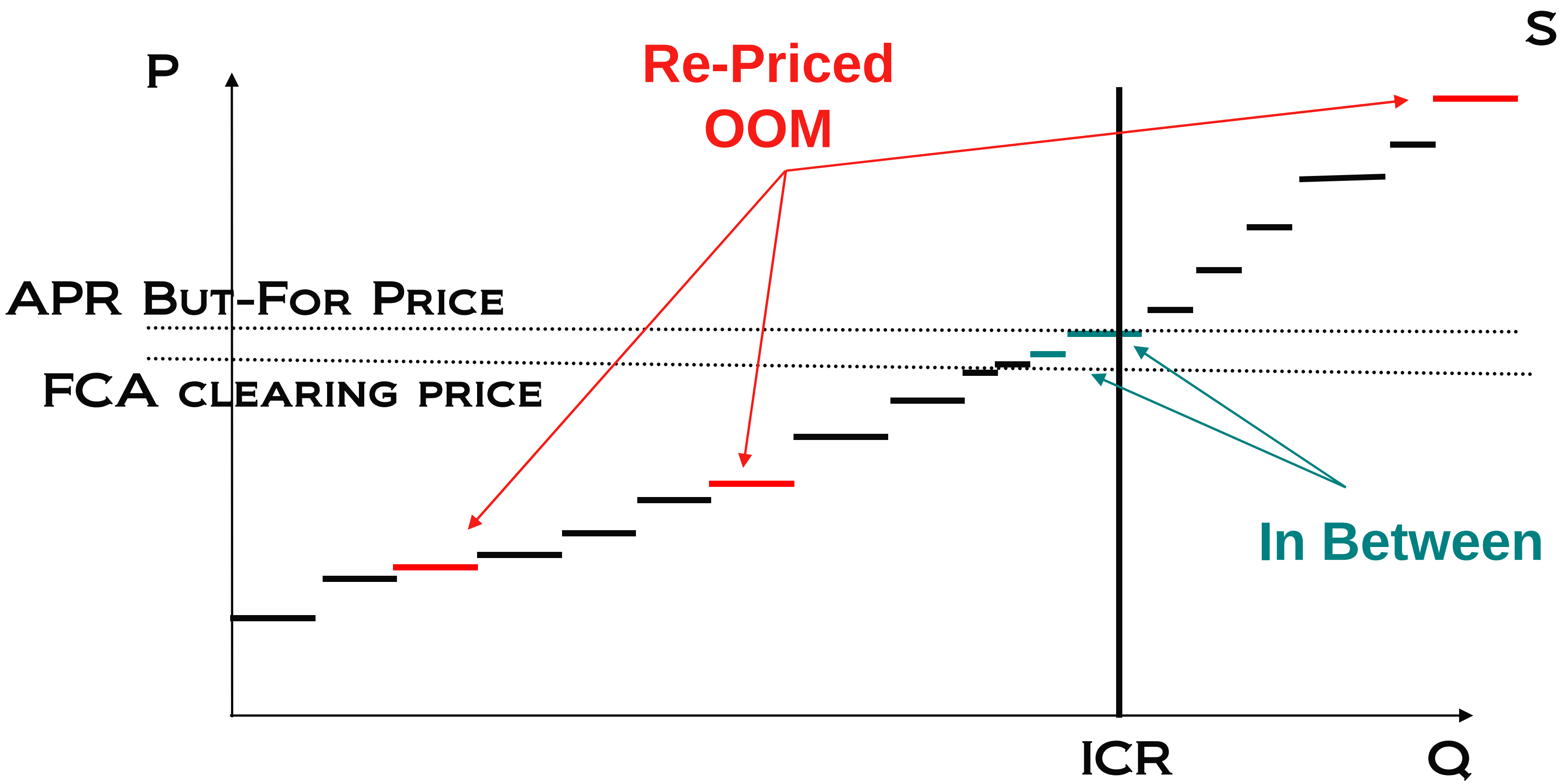
Proposed Approach Is a Single APR

- APR aims to fully correct for the effect of OOM resources on the capacity price
- The FCA is conducted to determine the FCA clearing price
- The APR is triggered if there are OOM resources (new or "carried-forward")
- The APR calculates the clearing price that would have prevailed had the OOM resources offered competitively into the FCA
  - IMMU imputes a competitive offer to each OOM resource
  - For all other resources, FCA offers are used
- The price under the APR is a "but-for price" – a price that would have cleared the FCA "but for" some resources being OOM

Descending Clock Auction Is Run



OOM Resources Are Re-Priced



Alternative Price Higher Than FCA Clearing Price

- FCA clearing price takes all OOM resources at a zero bid and clears to accept only as many resources as are needed to meet the ICR
- OOM resources are re-priced to calculate alternative price
- Expect that some or all of the OOM resources may not clear in the but-for/alternative price calculation
- When OOM resources are “out of the money”, additional, higher priced resources set the alternative price
- This results in an alternative price that is higher than the FCA clearing price

Payments Based on Two Price Tiers: Alternative Price and FCA Clearing Price

- In-between resources are those that did not clear the FCA but that would clear when OOM resources are re-priced
- *First Tier:* These resources are paid the alternative, but-for price:
  - Existing resources that clear the FCA
  - Existing resources that are "in-between"
- *Second Tier:* All other resources that clear the FCA are paid the FCA clearing price (including new OOM resources and new in-market resources)
- New resources become existing after term of initial FCA pricing expires (will propose a specific term of 3 to 5 years)
- May set limit to period during which resources get the alternative price
- For that time period existing in-market resources are protected from the risk of future OOM depressing the capacity price

ISO new england

Capacity Payments Under APR Higher than Under FCA Clearing Price

- The capacity payments are higher than the capacity payments that would be made without an APR
- The total capacity payments may be higher or lower than the capacity payments that would be needed to cover the ICR at the alternative price
- Compared to paying the alternative price to all resources that clear at the FCA clearing price:
  - OOM resources and in-market new resources are paid the FCA clearing price (instead of the alternative price), reducing payments
  - In-between existing resources are paid the alternative price (instead of not being paid), increasing payments

Trigger for APR Includes Carry-Forward

- Calculation of alternative price is triggered when there are new or “carried-forward” OOM resources
- An OOM resource that enters in a given auction triggers the application of the APR. The resource is re-priced by the IMMU for purposes of calculating a but-for price
- In an auction after entry, the same resource would still be an OOM resource as long as a combination of load growth and retirements in the zone had not yet exceeded the OOM resources that cleared in the auction in which the resource first entered
  - Considering tying payment of the FCA clearing to the length of carry-forward
- May be appropriate to impose a time limit such that the resource would no longer be considered OOM even if load growth had not exceeded the OOM resources by that point

Discussion Draft

Detailed Discussion of OOM Determination

Benchmark Offers for APR and OOM

- A Benchmark Offer is what a resource would offer into the capacity market so that the resource would break even over the project life, after accounting for revenues from other wholesale electricity markets
- Benchmark Offers will be calculated by resource type for different types of generation and demand resources.
- Resources with unsupported offers below .8*Benchmark will be declared out of market and put into the APR calculation at .9*Benchmark.

OOM Determination - Past OOM

- ISO and IMM generally agree with the Commission Finding in a similar NYISO Case;
  - In the *NYISO* case, the Commission found that mitigation policy should be directed at avoiding inefficient and unneeded entry. Whether or not the entry of past resources was efficient or needed, their entry and their associated costs could not now be avoided, so mitigation would no longer be effective. (p. 80 FCM redesign order)
- The Revised Proposal will not carry forward any OOM Capacity from FCA 1 – FCA3

OOM Determination -- FCA4 and Forward

- In the FCM Redesign Order, Commission asked several questions on this topic:
  - The briefs should include a discussion of how APR mitigation can be constructed so that load is able to hedge its capacity obligation outside of ISO-NE's capacity market with bilateral contracting while ensuring that such bilateral contracting does not distort the capacity market clearing price.
  - Similarly, parties should address whether or how APR mitigation might accommodate OOM capacity introduced for resource adequacy or to satisfy public policy goals, such as the integration of renewable and demand response resources.

OOM Determination – Key Issues

- Should OOM Capacity Clear in the Capacity Market ?
  - The Revised Proposal continues the current practice of clearing all OOM Capacity in the market. This is different from NYISO rules which prevent resources that bid below a threshold from clearing for 3 years, but similar to PJM's practice.
- Which resources will be determined to be OOM?
  - The Revised proposal makes no change to the rules for determining which resources are out-of-market.

OOM Determination - Bilateral Contracts

- The current rules treating self supply as OOM meet the Commission standards expressed in the redesign order:
    - … load is able to hedge its capacity obligation outside of ISO-NE's capacity market with bilateral contracting while ensuring that such bilateral contracting does not distort the capacity market clearing price. (p. 77 FCM redesign order)
- The Self Supply Option enables load to hedge its obligation outside of the capacity market
- Treating new Self-Supply as OOM prevents it from distorting the capacity market price

OOM Determination – Policy Objectives

- The FERC asked:
  - … whether or how APR mitigation might accommodate OOM capacity introduced for resource adequacy or to satisfy public policy goals, such as the integration of renewable and demand response resources (p. 77 FCM redesign order)
- Maintaining current rules for OOM determination accommodates the development of resources to meet policy objectives by including that capacity in the market.

OOM Determination – Policy Objectives

- Treating capacity with unsupported offers below .8*Benchmark as OOM helps ensure that another Commission objective is met:
  - Mechanisms that fail to address OOM capacity surpluses do not provide the long term price signals that support efficient private investment. (p. 87 FERC Redesign Order)
- Allowing capacity with unsupported offers to clear supports the policy objective, while treating it as OOM prevents price distortion.

Detailed Proposal for Modeling Capacity Zones

FCM Zones and Zone Modeling

- Modeling FCM Zones in Auctions to Date:
  - Each FCA has considered four potential zones: Connecticut, NEMA/ Boston, Maine, and Rest of Pool
    - These zones are a legacy from the LICAP proceedings.
    - Connecticut and Boston are defined as import constrained and Maine is defined as export constrained.
    - Local sourcing requirement calculated and compared to installed resource base in the zone. If the zone is not short, it is not modeled.
    - If a zone is modeled in the auction and price separation does not occur, the zone is eliminated.
    - The auction clears the import constrained zones (Connecticut and Boston) first, then Rest of Pool, and finally the export constrained zone (Maine), if the zone(s) have been modeled.
    - Modeling limitations are primarily based on controlling or eliminating market power and accommodating the DCA format.

ISO new england

Discussion Draft

FCM Zones and Zone Modeling

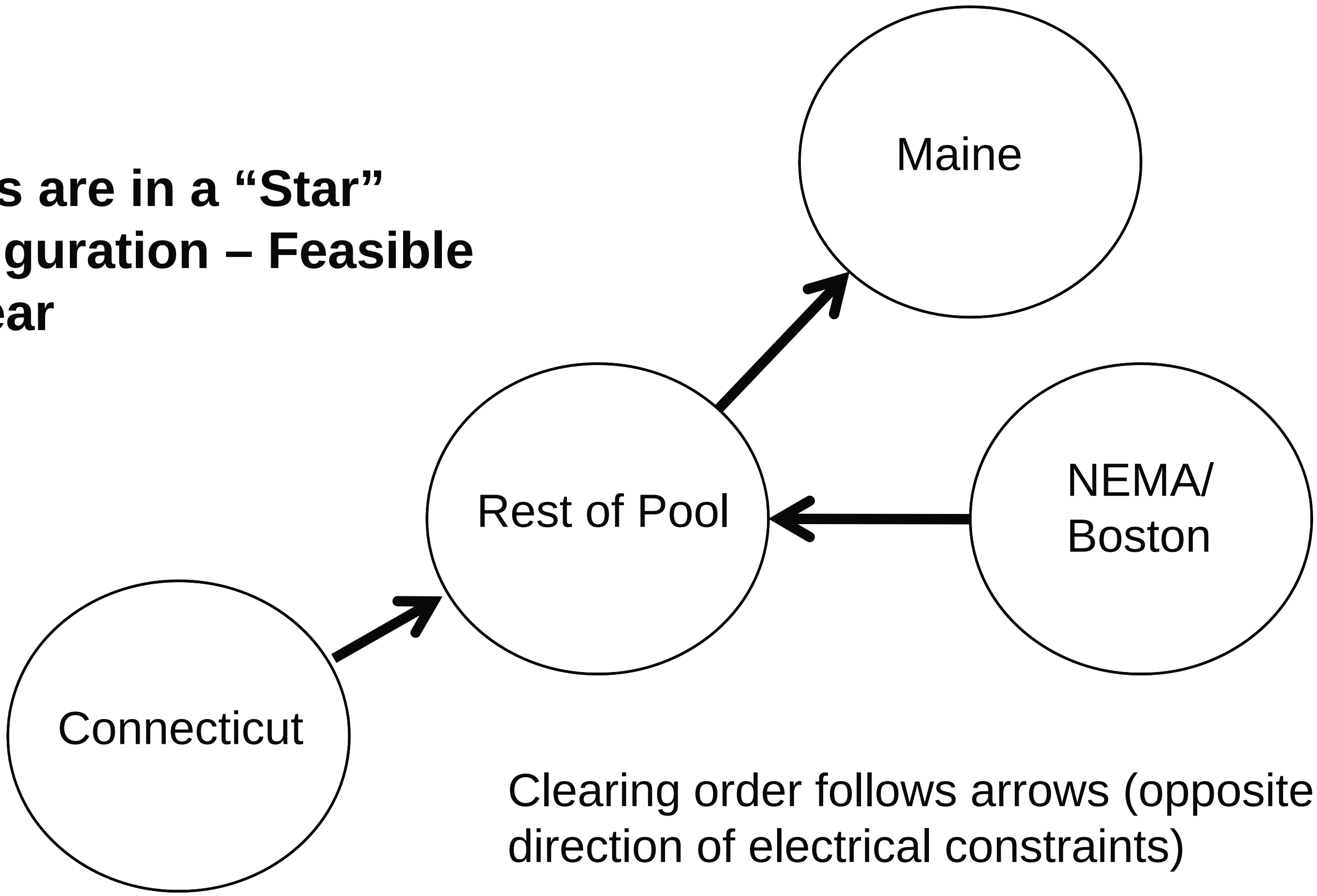
- Limitations and Shortcomings of the Current Modeling Process:
  - Large zones make it difficult or impossible to adequately reflect important electrical constraints in market clearing.
  - Constraints are enforced and reliability protected through out of market rejection of resource de-list requests.
  - Zonal modeling test may preclude modeling of a zone with barely adequate resources resulting in de-list rejection to enforce local sourcing requirement of a zone not modeled.
  - If price separation does not occur in the FCA, current rules do not allow for modeling zones in subsequent reconfiguration auctions to account for system changes.
    - Elimination of a zone without price separation after the FCA results in an inability to model changes that subsequently require local resources.
  - The descending clock auction requires a pre-specified clearing order and is unable to model bi-directional constraints or mesh networks.

FCM Zones – Recent Rule Changes

- In response to identified shortcomings and as part of the FCMWG process, ISO filed changes to zonal modeling:
  - Local purchase requirements are set at the higher of the adequacy and the security requirement.
  - The zonal modeling process starts with the eight energy market zones rather than the four LICAP zones.
    - The zonal process provides for subdivision of energy zones. but subdivision must first be vetted through the system planning stakeholder process.
- Unresolved issues include:
  - Zonal market modeling test may still preclude zonal modeling.
  - Zones are still eliminated if price separation does not occur in the FCA.
  - Clearing order requirement of the descending clock auction still precludes modeling of bi-directional constraints and mesh networks.
  - Practical impact is that at most only the four LICAP zones will be modeled.

FCM Zonal Configurations - Current

Zones are in a "Star" Configuration – Feasible to clear

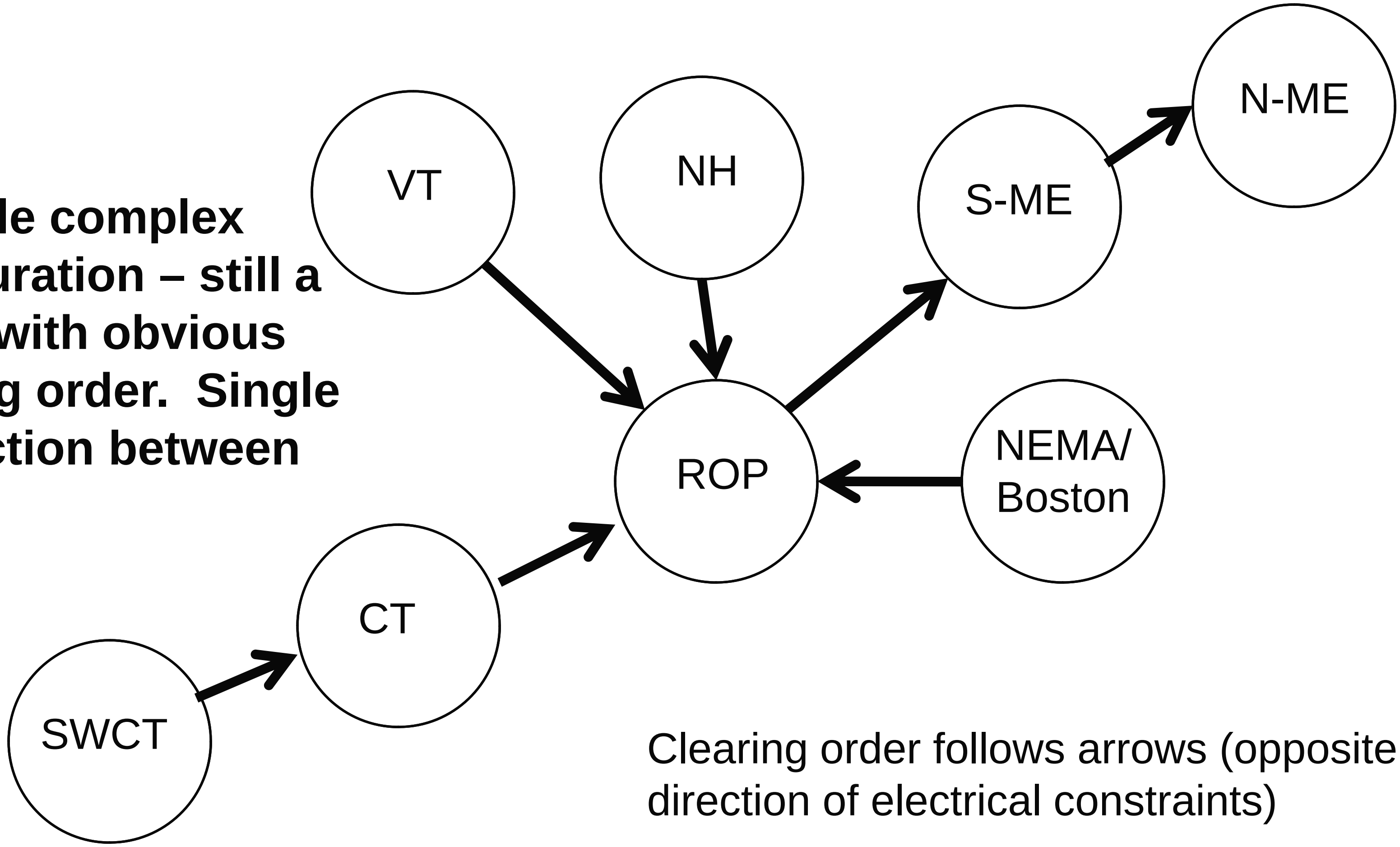


Clearing order follows arrows (opposite direction of electrical constraints)

ISO new england

FCM Zonal Configurations - Possible

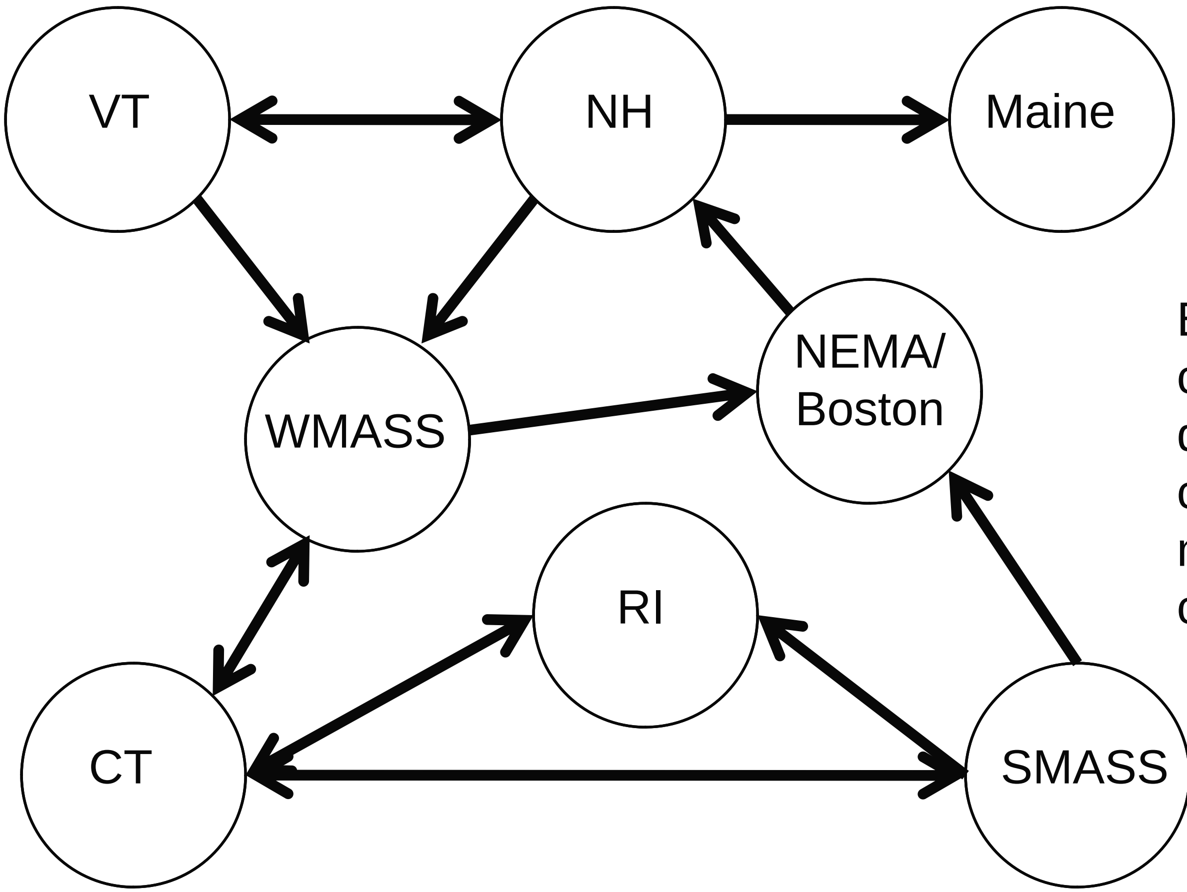
Possible complex configuration – still a "Star" with obvious clearing order. Single connection between zones.



Clearing order follows arrows (opposite direction of electrical constraints)

Discussion Draft

FCM Zonal Configurations – Likely Actual



Bi-directional constraints indicated by double arrows, multiple connections create a mesh. No determinate clearing order.

FCM Zones – Summary of the Task

- For the most part, zones have not passed the “Market Modeling” test and have not been modeled in the auction.
  - Resources without a CSO have no energy market participation obligation.
  - Reliability has been protected by out-of-market rejection of de-list, bilateral, and pro-ration requests.
  - Both the Internal and External Market Monitors have identified these rejections as problematic and have indicated that in-market solutions to the reliability issue are preferable.
  - The FERC has also indicated a preference for in-market solutions.
- The ISO proposal regarding zones takes as a given that the goal is to eliminate, to the extent practicable, the out-of market rejection of the requests identified above.
  - Stated differently, the proposal answers the question: “what changes are required to substantially reduce out-of-market actions by ISO in FCM?”

FCM Zones – ISO Proposal

- Identify capacity zones through the system planning stakeholder process in advance of the auction
  - Initially, for FCA6, use the eight energy market zones. These capture most, but not all, relevant constraints.
  - Develop explicit criteria for zonal modeling, and evolve the model prospectively through the system planning process.
  - Once identified, and given effective mitigation starting with FCA6, drop the market model test and model the zones for all relevant purposes for the capacity commitment period
- Modify the FCA to accommodate the model configuration
  - Retain the descending clock for bid collection
  - Develop a clearing engine able to respect model constraints and find the optimal solution (Most likely an LMP type model)

Detailed Proposal for Mitigation

Change the Threshold for Dynamic De-List Bids

- Dynamic De-list Bids enable existing resources to leave the market when the descending clock reaches .8*Cone (now about $3.93/kw-mo)
- This is a negotiated number and is not representative of a resource's going forward or opportunity cost.
- If a resource remains in the energy market, its primary opportunity cost is the ability to sell capacity into the Rest-of-System in New York
- We propose to change the de-list bid threshold to the capacity price for the rest of system in New York.

Modification to Static De-list Bids

- Static De-list Bids are capped by a resource's going forward or opportunity costs
  - Current rules calculate going forward costs assuming resource leaves both capacity and energy markets
    - This is incorrect. Rules do not require resources to leave the energy market and none have done so
- Base assumption will be changed to assume that resource remains in the energy market; therefore appropriate going forward cost is zero
- If resource commits to leave energy market, use going forward costs
- Non-zero bids possible for opportunity cost of selling to New York or of deactivating the resource, e.g. for repowering

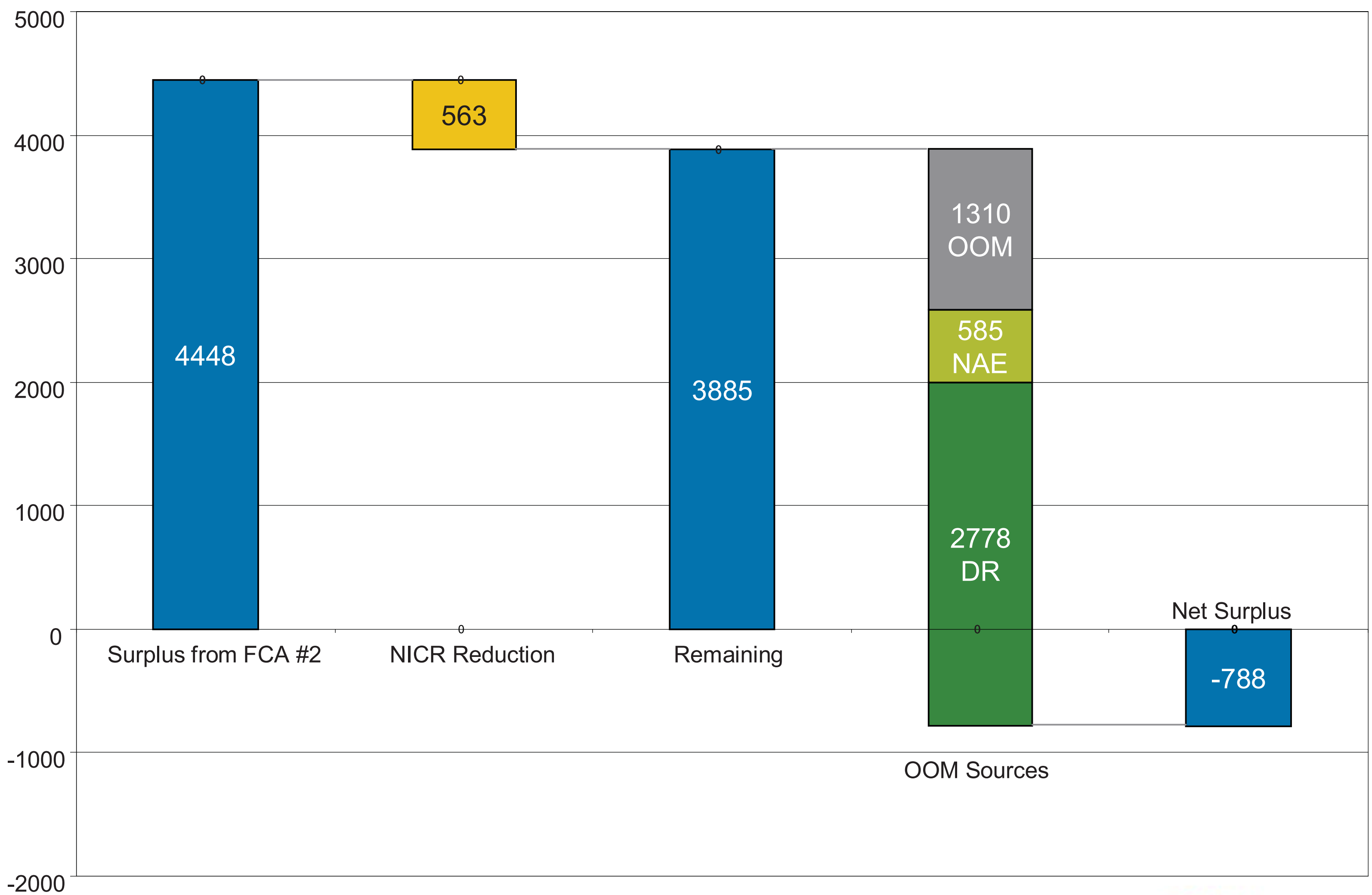
Changes To Permanent De-List Bids

- Permanent De-list Bids will continue to be based on going forward or opportunity costs.
- Permanent de-list bids currently give resource the option of leaving capacity market permanently while remaining in the energy market.
- Aside from exporting capacity (which can be done using static and administrative export bids) there seems to be no need to preserve the option for a permanently de-listed resource to remain in the energy market and interconnected to the system.
- A resource submitting a Permanent De-list Bid that is accepted must retire at the beginning of the commitment period.

Elimination of the Quantity Rule

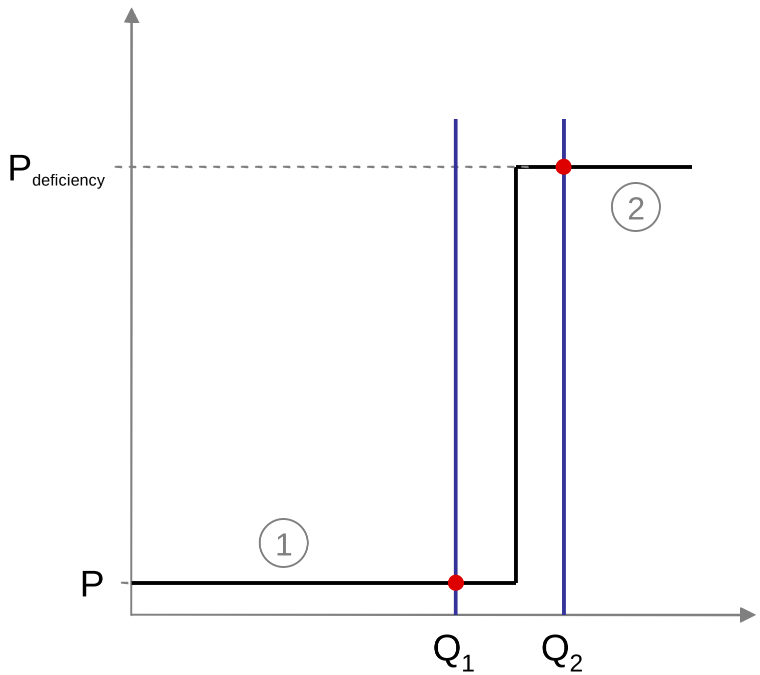
- The Quantity Rule defers purchasing replacement capacity for high priced de-list bids from the FCA to the reconfiguration auctions
- The rule has not been invoked to date
- There have been no high priced static or permanent de-list bids
- Changes to the other mitigation rules make high priced de-list bids even less likely
- Therefore, there is no need for the rule, which creates significant complications for auction design and execution, suppresses efficient pricing, and reduces the new capacity development timeline, which increases reliability risks

Decomposition of FCA #2 Surplus into FCA #3



NEPGA Exhibit 2-D - Panel 1

With fixed supply, small changes in demand cause large swings in price



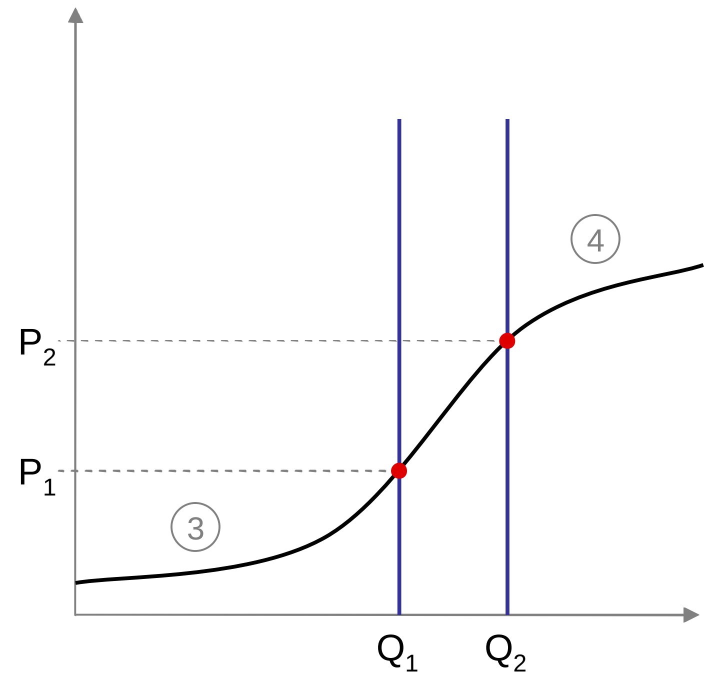
Close to commitment year:

1 existing capacity cannot avoid fixed costs by de-listing; hence cost is low; and

2 new capacity cannot enter even if price is high.

NEPGA Exhibit 2-D - Panel 2

With elastic supply, price changes are moderated



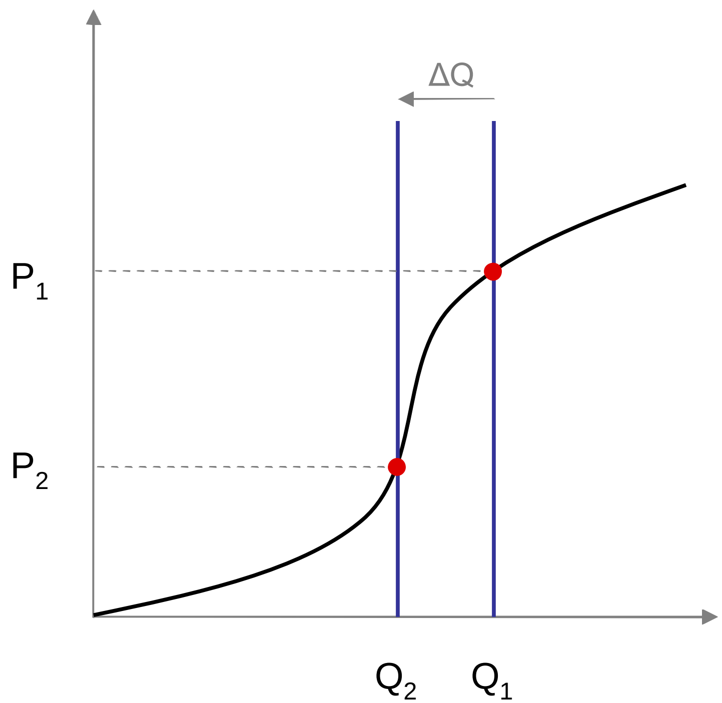
With commitment well in advance:

3 existing capacity can avoid fixed costs by de-listing; hence offers in at avoidable cost; and

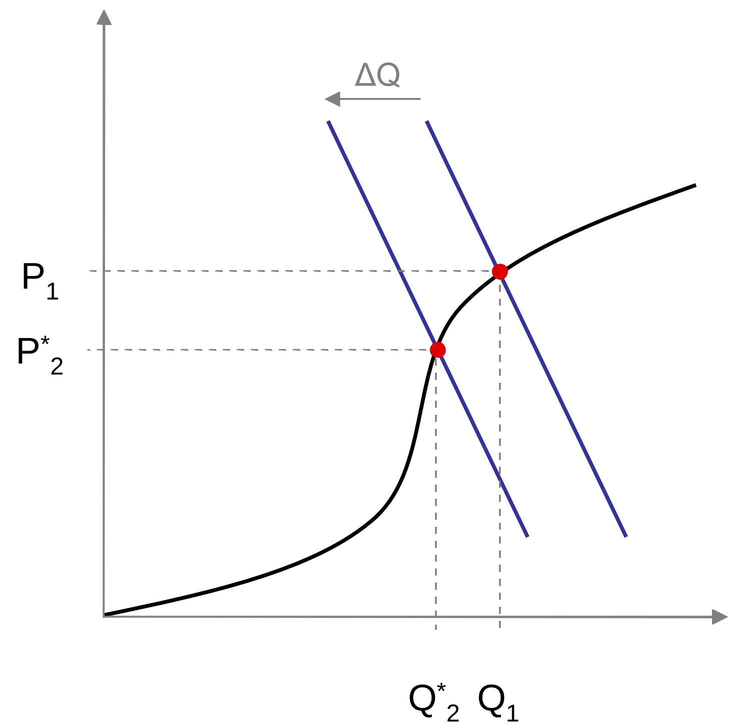
4 new capacity can be built in time, and offers at its cost of entry.

NEPGA Exhibit 2-D - Panel 3

Impact of a ΔQ reduction with inelastic demand



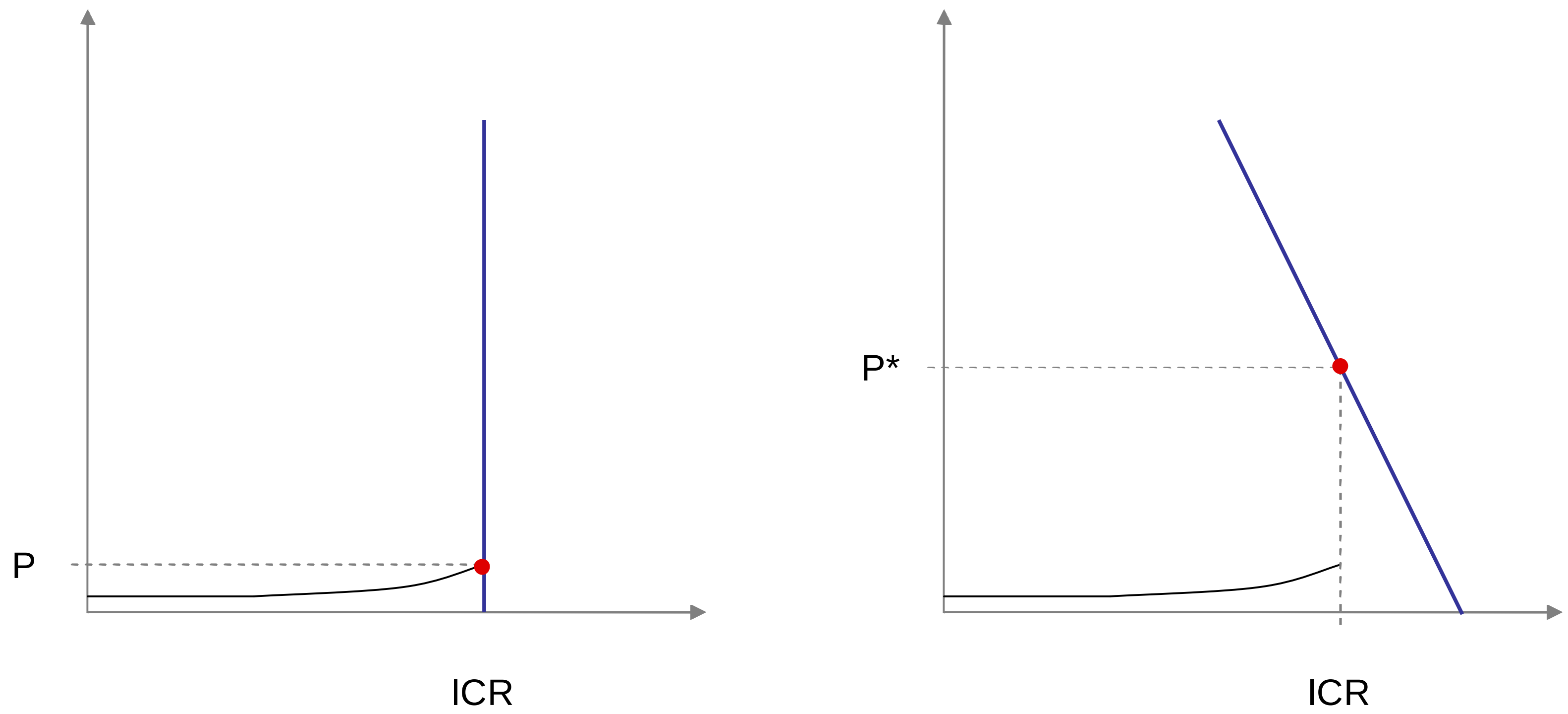
Impact of same ΔQ reduction with elastic demand



NEPGA Exhibit 2-D - Panel 4

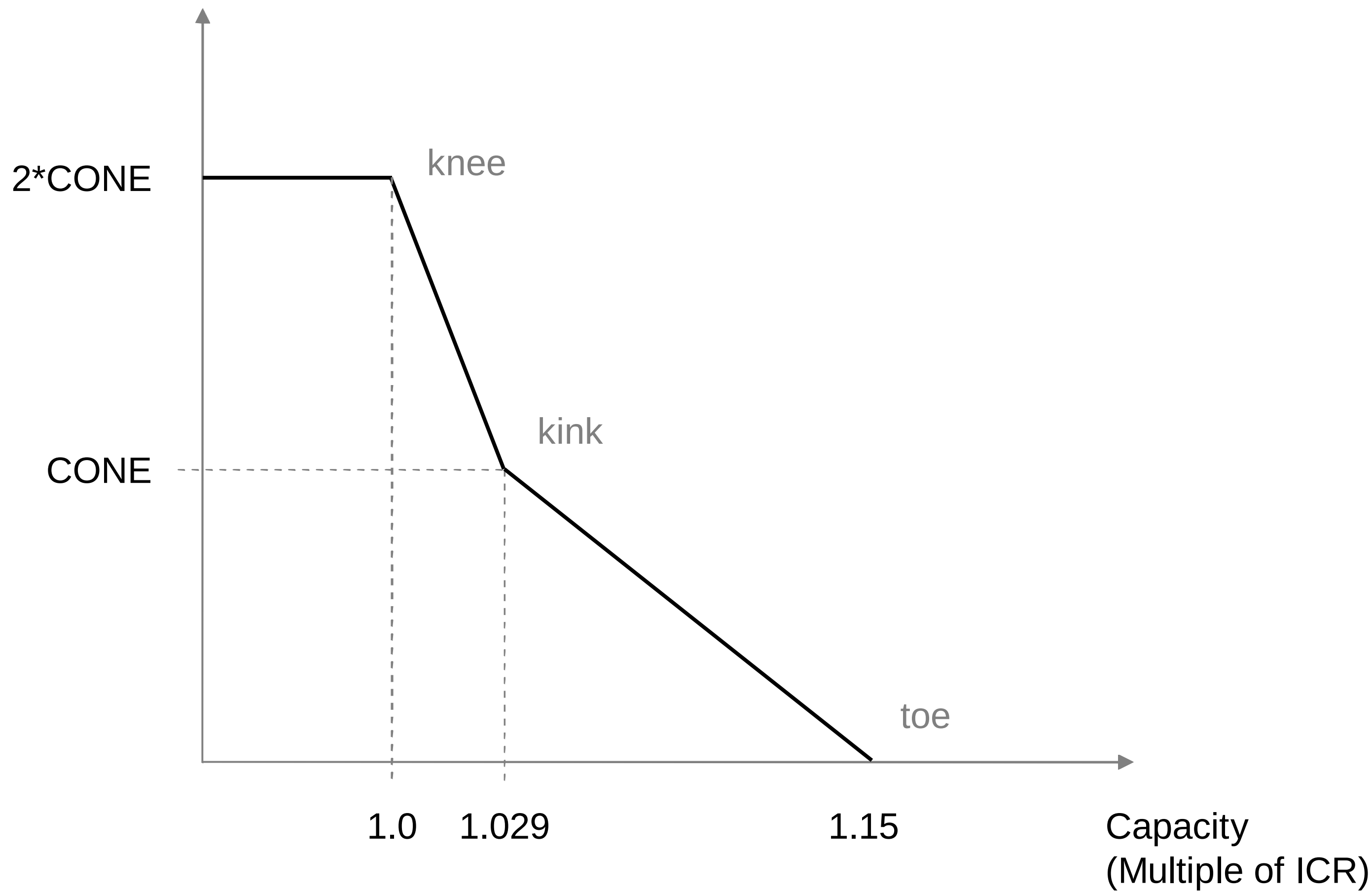
FCA without APR, in balance but with no merchant entry

Same FCA, but with demand curve



NEPGA Exhibit 2-E

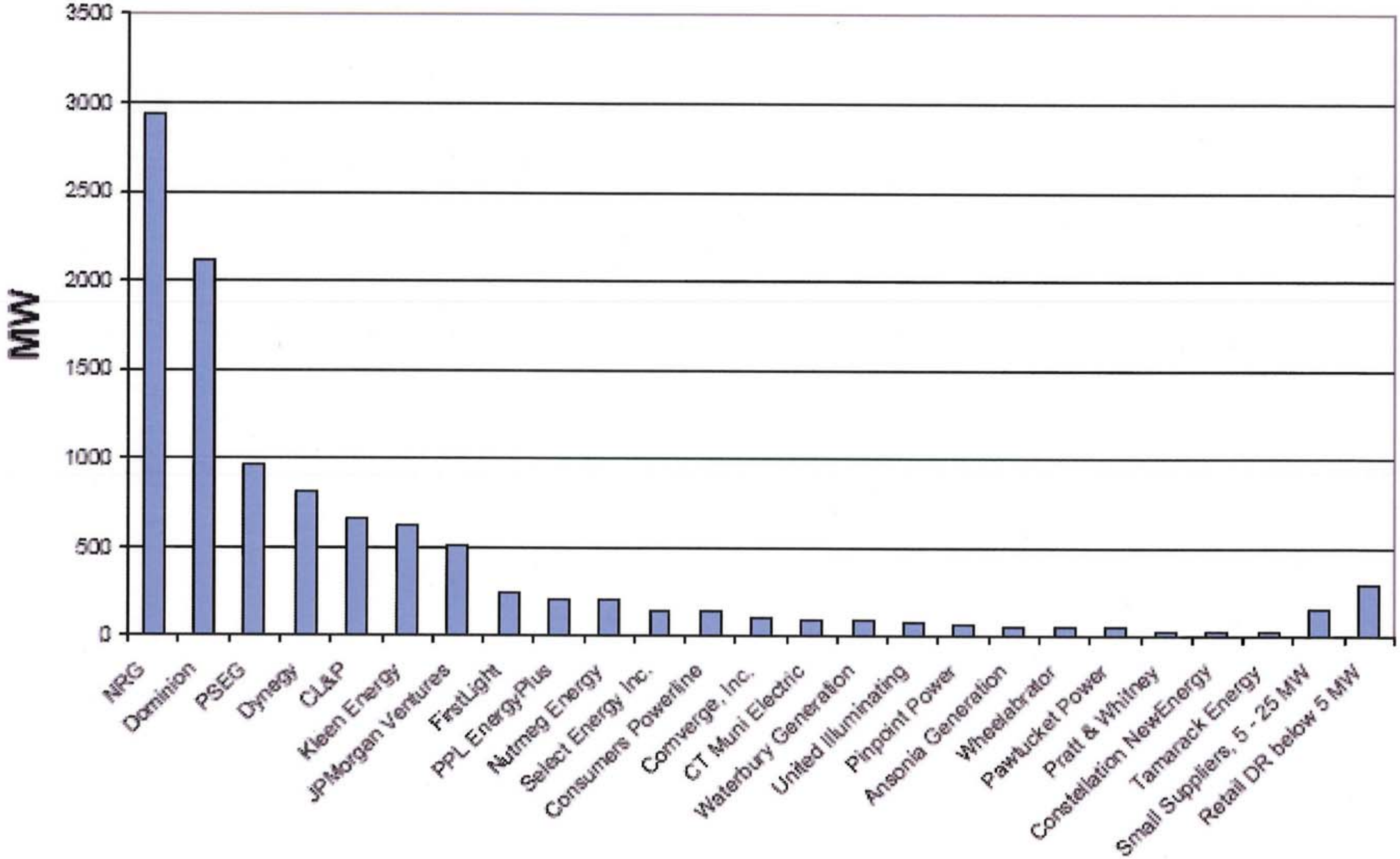
Proposed FCA Demand Curve



Load Pockets Had Ample Competition in FCA #2

- Connecticut
  - 6,817 MW LSR
  - 10,777 MW qualified, including 1,166 MW of DR (366 MW new DR)
  - 9,159 MW cleared
  - 3,960 MW surplus
  - 2,940 MW from largest supplier (NRG)
    - Of which 1,066 MW was *new* (374 MW OOM)
  - *NO Pivotal Supplier*
  - *ONE Supplier > 20% share*
    - *NRG had 20.5% share excluding new generation*
  - *53% of qualified capacity from suppliers with <10% market share*

Figure 1: Distribution of Qualified Connecticut Capacity among Lead Participants, FCA #2

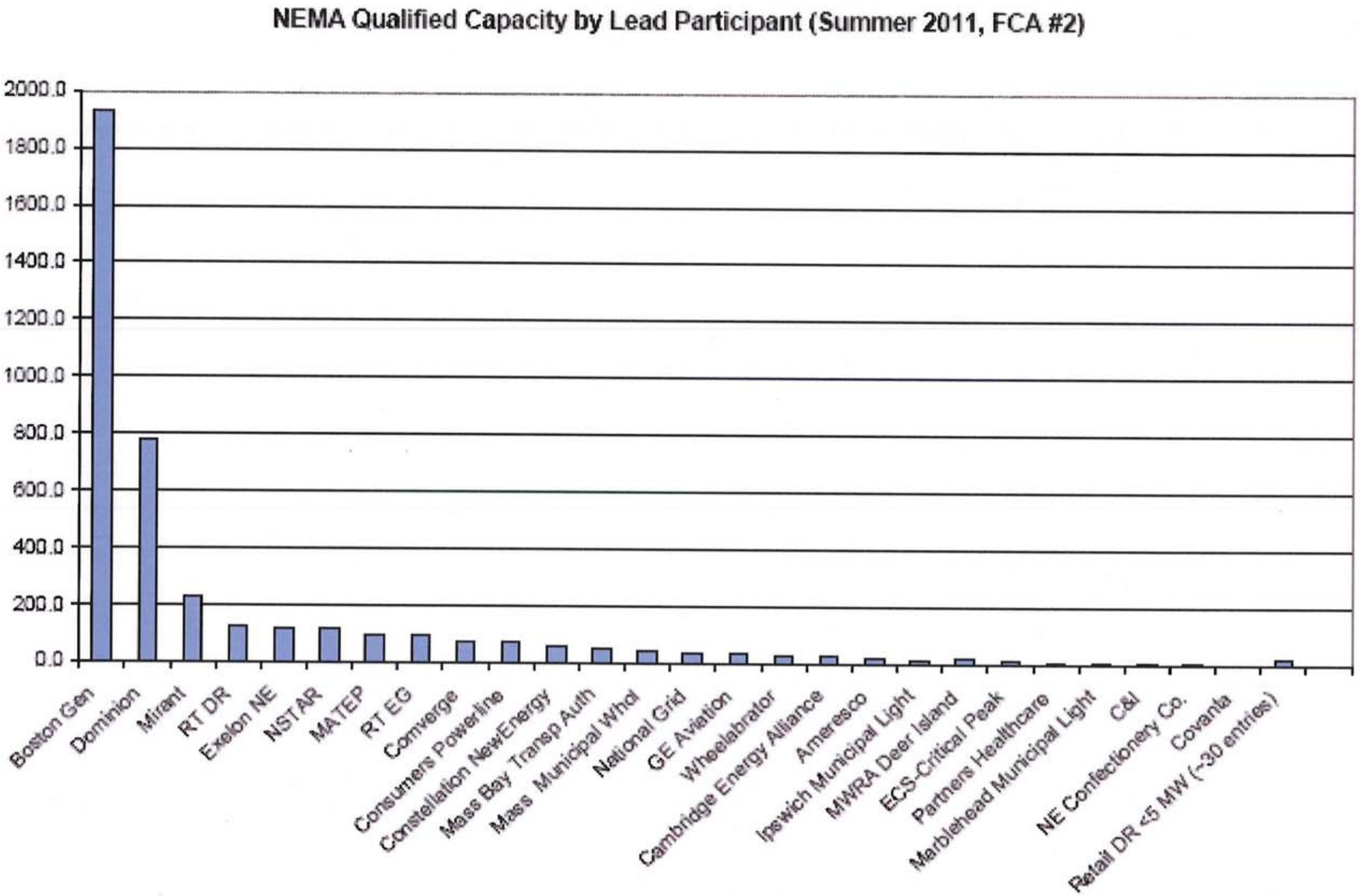


CRA Charles River Associates

Load Pockets Had Ample Competition in FCA #2

- NEMA / Boston
  - 2,016 MW LSR
  - 4,019 MW qualified, including 717 MW of DR (349 MW new DR)
  - 3,892 MW cleared
  - 2,003 MW surplus
  - 1,934 MW from largest supplier (Boston Gen)
  - *NO Pivotal Supplier*
  - *ONE Supplier > 20% share*
    - *Boston Gen held 48% share*
  - *32% of qualified capacity from suppliers with <10% market share*

Figure 2: Distribution of Qualified NEMA-Boston Capacity among Lead Participants, FCA #2



<HELP> for explanation. Index **HP**

99) Actions USD US Industrial B BFV Curve Historical Rates

From 06/01/06 to 06/01/10 Range 10Y - 30Y Market Mid/Tr Period Quarterly

Dates	10Y	15Y	20Y	25Y	30Y
6/10	8.8418	9.1369	9.3343	9.4831	9.6136
3/10	8.7968	9.0503	9.2623	9.3935	9.5339
12/09	9.2137	9.5093	9.7438	9.7971	9.9162
9/09	9.3442	9.6579	9.8652	9.9030	9.9731
6/09	12.5249	12.8483	13.040	13.0960	13.1635
3/09	14.6162	15.0371	15.284	15.3188	15.3371
12/08	15.1836	15.7097	15.792	15.6530	15.4823
9/08	10.3608	10.7756	10.894	10.8796	10.8550
6/08	9.3059	9.7108	9.9240	9.8218	9.9232
3/08	9.7329	10.7307	10.864	10.8014	10.9599
12/07	9.2981	9.9758	10.041	9.9660	10.0999
9/07	8.6567	9.2104	9.2394	9.1537	9.2824
6/07	8.0993	8.6153	8.5993	8.4975	8.6376
3/07	7.7892	8.2254	8.3255	8.2495	8.3757
12/06	7.8128	8.1763	8.2519	8.1632	8.2320
9/06	8.1077	8.4476	8.5445	8.4585	8.5288
6/06	8.2474	8.5702	8.6475	8.5016	8.5037

EquityWACC

Enter #<GO> for details

Dynegy Inc

Weighted Average Cost of Capital

Weighted Average Cost of Capital

Q1 2010

	1) Equity	2) Debt	3) Pref. Eqty
Weight	13.60%	86.40%	0.00%
Cost	13.78%	6.30%	0.00%
W x C	1.87%	5.44%	0.00%

WACC 7.32%

Capital Structure

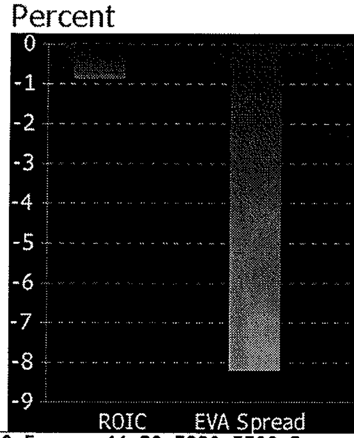
	Millions of USD
Market Cap	761.67
ST Debt	63.00
LT Debt	4,775.00
Pref. Eqty	0.00
Total	5,599.67

13.60% 1.13% 85.27% 0.00%

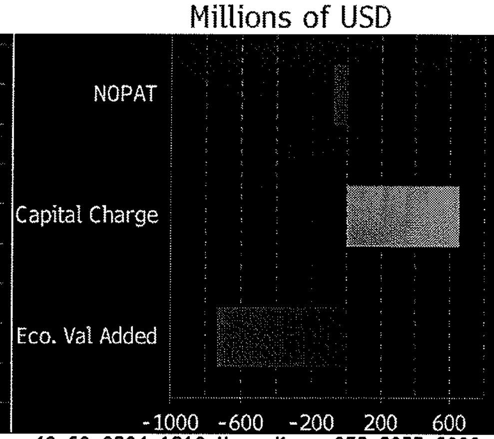
Economic Value Added

4) Net Op. Profit	316.00
5) Cash Op. Taxes	394.71
NOPAT	-78.71
6) Total Inv. Cap.	8,965.00
Capital Charge	656.16
Eco. Val Added	-734.87
ROIC	-0.88%
EVA Spread	-8.20%

Percent



Millions of USD



<HELP> for explanation, <MENU> for similar functions. EquityWACC
Enter #<GO> for details

Mirant Corp

Weighted Average Cost of Capital

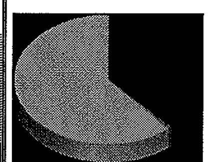
Weighted Average Cost of Capital

Q1 2010

	1) Equity	2) Debt	3) Pref. Eqty
Weight	38.11%	61.89%	0.00%
Cost	13.33%	7.74%	0.00%
W x C	5.08%	4.79%	0.00%

WACC 9.87%

Capital Structure



Millions of USD

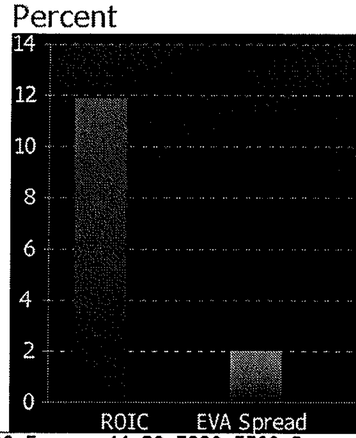
Market Cap	1,579.09
ST Debt	26.00
LT Debt	2,538.00
Pref. Eqty	0.00
Total	4,143.09

38.11% 0.63% 61.26% 0.00%

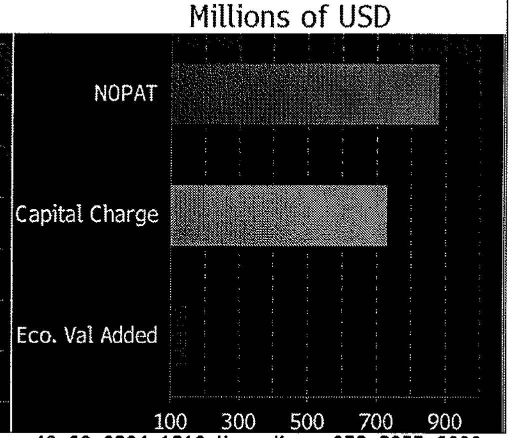
Economic Value Added

4) Net Op. Profit	887.00
5) Cash Op. Taxes	6.76
NOPAT	880.24
6) Total Inv. Cap.	7,401.00
Capital Charge	730.67
Eco. Val Added	149.57
ROIC	11.89%
EVA Spread	2.02%

Percent



Millions of USD



<HELP> for explanation, <MENU> for similar functions. **EquityWACC**
Enter #<GO> for details

NRG Energy Inc — Weighted Average Cost of Capital

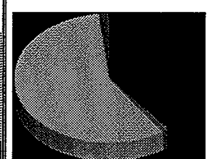
Weighted Average Cost of Capital

Q1 2010

	1) Equity	2) Debt	3) Pref. Eqty
Weight	39.29%	58.89%	1.82%
Cost	12.77%	4.75%	8.50%
W x C	5.02%	2.80%	0.15%

WACC 7.97%

Capital Structure



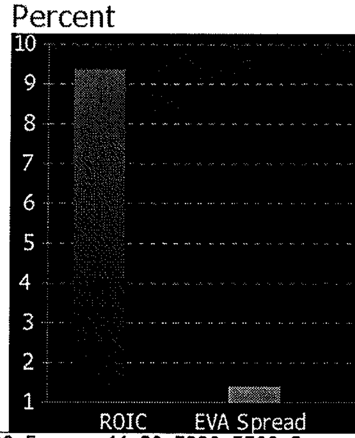
	Millions of USD
Market Cap	5,336.03
ST Debt	152.00
LT Debt	7,846.00
Pref. Eqty	247.00
Total	13,581.03

39.29% 1.12% 57.77% 1.82%

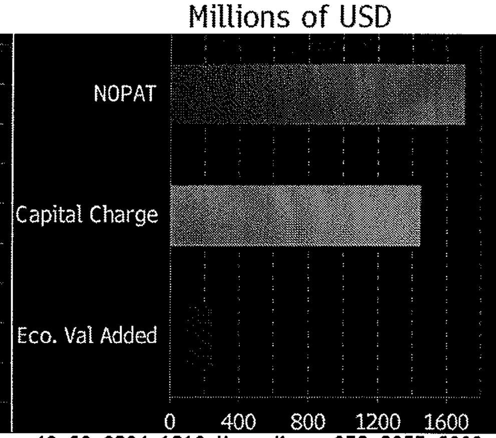
Economic Value Added

4) Net Op. Profit	1,798.00
5) Cash Op. Taxes	91.83
NOPAT	1,706.17
6) Total Inv. Cap.	18,212.00
Capital Charge	1,451.13
Eco. Val Added	255.04
ROIC	9.37%
EVA Spread	1.40%

Percent



Millions of USD



<HELP> for explanation, <MENU> for similar functions. EquityWACC

Enter #<GO> for details

RRI Energy Inc

Weighted Average Cost of Capital

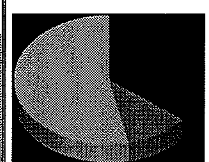
Weighted Average Cost of Capital

Q1 2010

	1) Equity	2) Debt	3) Pref. Eqty
Weight	35.68%	64.32%	0.00%
Cost	19.53%	8.16%	0.00%
W x C	6.97%	5.25%	0.00%

WACC 12.22%

Capital Structure



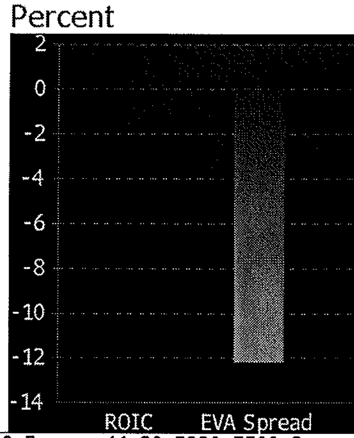
	Millions of USD
Market Cap	1,304.10
ST Debt	401.09
LT Debt	1,949.74
Pref. Eqty	0.00
Total	3,654.93

35.68% 10.97% 53.35% 0.00%

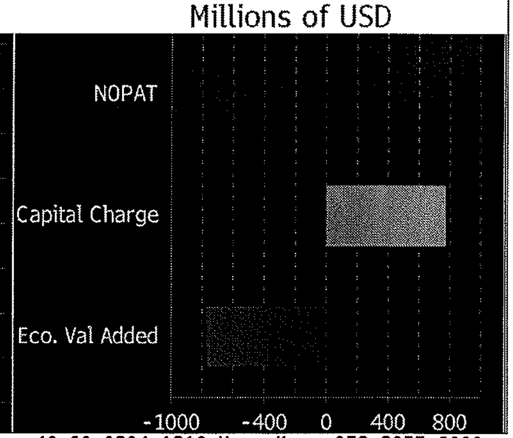
Economic Value Added

4) Net Op. Profit	-6.63
5) Cash Op. Taxes	-8.39
NOPAT	1.75
6) Total Inv. Cap.	6,322.64
Capital Charge	772.57
Eco. Val Added	-770.81
ROIC	0.03%
EVA Spread	-12.19%

Percent



Millions of USD



<HELP> for explanation, <MENU> for similar functions. EquityWACC
Enter #<GO> for details

Calpine Corp Weighted Average Cost of Capital

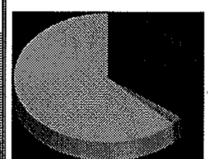
Weighted Average Cost of Capital

Q1 2010

	1) Equity	2) Debt	3) Pref. Eqty
Weight	35.63%	64.37%	0.00%
Cost	15.03%	6.93%	0.00%
W x C	5.35%	4.46%	0.00%

WACC 9.81%

Capital Structure



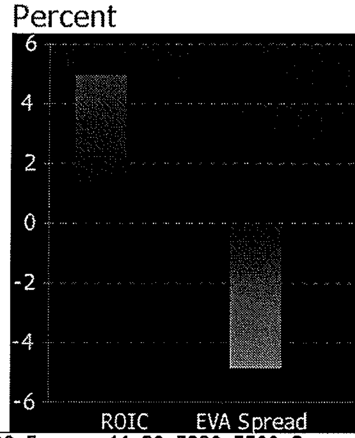
	Millions of USD
Market Cap	5,281.84
ST Debt	305.00
LT Debt	9,239.00
Pref. Eqty	0.00
Total	14,825.84

35.63% 2.06% 62.32% 0.00%

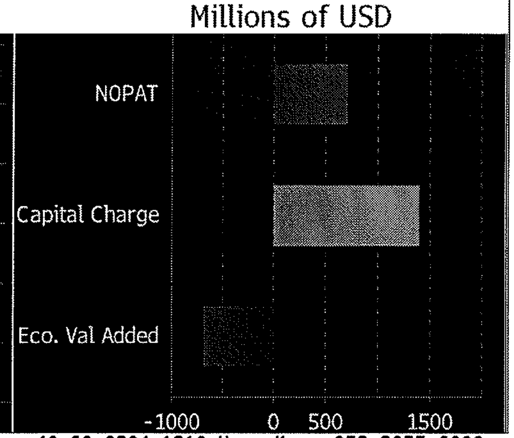
Economic Value Added

4) Net Op. Profit	939.00
5) Cash Op. Taxes	231.33
NOPAT	707.67
6) Total Inv. Cap.	14,248.00
Capital Charge	1,398.40
Eco. Val Added	-690.72
ROIC	4.97%
EVA Spread	-4.85%

Percent



Millions of USD



Uses & Associated Values of CONE

MIRANT

	FCA #1	FCA#2	FCA#3	FCA#4	FCA#5
CONE	$7.50	$6.00	$4.92	$4.92	???
Floor	$4.50	$3.60	$2.95	n.a.	n.a.
Clear Price	$4.50	$3.60	$2.95		
Auction Start Bid	$15.00	$12.00	$9.84	$9.84	???
Delist Bid of 2xCONE Required for Existing Summer Capacity in Excess of Winter Capacity	$15.00	$12.00	$9.84	$9.84	???
Allowed Static Delist Bid for Capacity at Risk Between 90F and 100F	$15.00	$12.00	$9.84	$9.84	???
Price at Which DR must offer to Permanently Delist Unverified Capacity Cleared in the Prior Auction	$15.00	$12.00	$9.84	$9.84	???
Price at Which ISO Offers to Purchase Capacity in an ARA to Replace a Cleared Delist Bid That was Rejected for Reliability	$15.00	$12.00	$9.84	$9.84	???
Price at Which ISO-NE Offers to Buy Replacement Capacity for A New Generator that, by the 3rd ARA, Is NOT Expected to be Available to Full Awarded Capacity Supply Obligation	$15.00	$12.00	$9.84	$9.84	???
Price at Which ISO-NE Offers to Buy Replacement Capacity to Cover a Significant Decrease in Capacity That Has No Viable Plan to Achieve Ability to Cover Full CSO.	$15.00	$12.00	$9.84	$9.84	???
Permanent Delist Bid Threshold Above 125% CONE Subject to IMMU Review	$9.38	$7.50	$6.15	$6.15	???
Price Above Which Static or Permanent Delist Capacity in a Constrained Zone Will not be Replaced	$9.00	$7.20	$5.90	$5.90	???
If System has Inadequate Supply but Zone has Adequate Supply, Zone Price Capped at 1.1x CONE	$8.25	$6.60	$5.41	$5.41	???
If the an Auction has Insufficient Competition, Payments to Existing Resources Capped at 1.1x CONE	$8.25	$6.60	$5.41	$5.41	???
Collateral Required, per KW, Before Demonstration of Commercial Operations Capability	$7.50	$6.00	$4.92	$4.92	???
Static Delist Bid Threshold @ or above 80% CONE	$6.00	$4.80	$3.93	$3.93	???
Dynamic Delist Bid Threshold @ 80% CONE	$6.00	$4.80	$3.93	$3.93	???
Price Below Which 100% of Static or Permanent Delist Capacity in a Constrained Zone will be Replaced	$6.00	$4.80	$3.93	$3.93	???
New Capacity Bid Review to Determine if OOM for APR if Below 75% CONE	$5.63	$4.50	$3.69	$3.69	???
Price Threshold Below Which New Generation, DR, or Imports may not offer more capacity than submitted in Qualification Package	$5.63	$4.50	$3.69	$3.69	???

NEPGA Exhibit 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and New England Power Pool	)	Docket No. ER10-787-___
New England Power Generators Association, Inc.	)	
	)	
v.	)	Docket No. EL10-50-___
	)	
ISO New England Inc.	)	
PSEG Energy Resources & Trade LLC, *et al.*	)	
	)	
v.	)	Docket No. EL10-57-___
	)	
ISO New England Inc.	)	

TESTIMONY OF CHRISTOPHER D. UNGATE
ON BEHALF OF NEW ENGLAND POWER GENERATORS ASSOCIATION

JULY 1, 2010

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

A My name is Christopher Ungate. I am a Senior Principal Management Consultant with Sargent & Lundy LLC. My business address is 401 Chestnut Street, Suite 500, Chattanooga, TN 37402.

Q PLEASE DESCRIBE, BRIEFLY, YOUR EDUCATIONAL AND EMPLOYMENT BACKGROUND.

A I have Bachelor and Master of Science degrees in Civil Engineering from the Massachusetts Institute of Technology in 1973 and 1974, respectively, and a Master of Business Administration from the University of Tennessee at Knoxville in 1984.

My consulting practice at Sargent & Lundy focuses on the areas of integrated resource planning, financial modeling and analysis for the assessment of power generation technologies, project development, asset transactions, operational reviews, and facility modifications and refurbishment projects. I also perform due diligence reviews of new technology development, new projects, modification and refurbishment of existing facilities, asset transactions, and operational assessments. I managed Sargent & Lundy's efforts with respect to the update of the New York Independent System Operator (NYISO) Demand Curves for Capability Years 2008/09, 2009/10 and 2010/11, and am currently engaged in the update for Capability Years 2011/12, 2012/13 and 2013/14. As part of that work, I guided the estimation of capital costs, fixed operations and maintenance costs, and other fixed costs for quantifying the cost of new entry in New York City, Long Island, and Rest of State.

Before joining Sargent & Lundy in 2006, I was employed for 31 years by the Tennessee Valley Authority in several positions in engineering, planning and management. My work experience included management of generation resource planning for a 30,000 MW portfolio of nuclear, coal, hydro and gas generation, providing annual power supply plans, monthly cost forecast updates, and system reliability analyses; hydro operations business planning; re-engineering and process improvement initiatives in utility planning and operations; and laboratory and prototype testing for hydro and thermal generating plants.

My resume is attached hereto as NEPGA Exhibit 3-A.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A The cost of new entry (CONE) is a reference point used in the management of the ISO-NE Forward Capacity Market. As noted by the Independent Market Monitor, the CONE value in ISO-NE is well below the net CONE values in both NYISO and PJM. The New England Power Generators Association, Inc. (NEPGA) has argued that current CONE values are unlinked from any market information about the actual revenue requirements of new capacity resources. To provide an order of magnitude basis for comparing New England CONE values to current costs, Sargent & Lundy was asked to prepare an estimate of the gross CONE[1] for a peaking unit technology, the GE 7FA, in two locations within the ISO-New England (ISO-NE) area based on current costs of development, labor, materials and equipment, and representative costs of financing a new peaking capacity project. This testimony reflects my estimate of what the actual development costs would be for the gross CONE for a new two-unit GE 7FA peaking plant located on a greenfield site in New England.

---

[1] That is, "gross" (*i.e.*, not net of earnings available from energy and ancillary service markets). The CONE figures reported for both PJM and NYISO are used to set the prices on Demand Cures in place in the respective markets and are reported out on a net CONE basis.

Q HOW IS THE COST OF NEW ENTRY CALCULATED?

A The general approach for estimating a levelized value for gross CONE is to estimate the revenue requirement that an owner would require each year to recover a return on, and of, its investment associated with the new generation, as well as fixed operations and maintenance (O&M) expenses. An annual levelized charge reflecting the cost of new entry is calculated based on the sum of the annual capacity charges and annual fixed O&M costs associated with installing and operating a new two-unit combustion turbine plant on a greenfield site at an identified location. Capital investment costs are converted to annual capacity charges using annual carrying charge rates. The annual carrying charge rate multiplied by the original capital investment yields the annual carrying charges. Carrying charges typically include all annual costs that are a direct function of the capital investment amount: principal and interest payments on project debt, equity returns, income taxes, property taxes, and insurance.

Q HOW IS THE BALANCE OF YOUR DIRECT TESTIMONY ORGANIZED?

A My testimony is structured as follows. First, I present the assumptions for the GE 7FA technology and locations used to prepare our cost of new entry estimate. Second, I present the total installed costs of the two unit GE 7FA peaking plant at each location, and how these costs were estimated. Third, I present the fixed operating and maintenance costs for each location. Fourth, I present the methodology and assumptions for calculating the annual carrying charges. Fifth, I present the levelized cost of new entry for each location.

Q WHAT COMBUSTION TURBINE TECHNOLOGY WAS CHOSEN FOR THIS ESTIMATE?

A At the request of NEGPA, I investigated the GE 7FA technology configured as a two unit simple cycle peaking plant for comparison to the CONE figure currently in place for New England. Current PJM CONE values are based on the GE 7FA heavy duty frame combustion turbine unit. Current NYISO CONE values are based on the GE 7FA in the Rest of State region to establish the NYCA Curve. The use of GE 7FA technology for my estimate is not meant to pre-determine the technology that should be used to set CONE for ISO-NE markets, but to provide a reasonable comparison to current ISO-NE CONE values.

Heavy-duty frame units like the GE 7FA are large-scale combustion turbines oriented to industrial and utility applications with lower capital costs (on a $/kW basis) and higher operating costs (on a $/MWh basis). The 7FA combustion turbine is capable of operating on 100% natural gas or 100% fuel oil. Major overhauls are scheduled based on the number of starts or operating hours and the duty cycle experienced in operations. General Electric's installed fleet of more than 950 'F' technology combustion turbines has reached 27 million hours of commercial operation in power plants worldwide. The reliability of the 7FA gas turbine has been consistently 98% or better.

The GE 7FA is configured for this estimate to operate primarily on natural gas with fuel oil as a backup to comply with the reliability requirements of ISO-NE. The capacity of each unit is 200 MWs, based on ISO conditions (59^{o}F temperature, 60% relative humidity, and 14.7 psia atmospheric pressure), evaporative cooling, and 0.85

power factor. The heat rate is 10,190 Btu/kWh (HHV), and the exhaust temperature is 1109°F.

Aero-derivative units like the GE LM6000, GE LMS100, or Rolls Royce Trent 60 could also be considered as technologies for the purpose of estimating the cost of new entry of a peaking unit. The process of determining CONE should review alternative technologies in identifying the least cost, established technology to calculate the gross CONE values.

Q WHAT LOCATIONS WERE ASSUMED FOR THE COMBUSTION TURBINE UNITS?

A The cost of constructing a combustion turbine unit will be affected by site conditions, local labor rates, and local materials costs. Installed costs would be expected to be higher in a large urban area with higher land costs, property taxes and labor costs, as compared to a smaller city or rural area. To demonstrate the range of CONE values in ISO-NE, cost estimates were prepared assuming that the 7FA technology was sited in Boston, MA, as representative of a large urban center, and Springfield, MA, as representative of a smaller city. NEPGA Exhibit 3-B summarizes the key assumptions made for each location.

Q HOW MANY UNITS WERE ASSUMED AT EACH LOCATION?

A A two unit installation was assumed for each technology at this location. This allows for reasonable scale economies consistent with actual market installations of peaking units. The installed cost per kilowatt of new capacity is reduced if two units are constructed and share the burden of the common facility costs, such as support buildings and the switchyard.

Q WHAT POLLUTION CONTROL EQUIPMENT WAS ASSUMED FOR THIS TECHNOLOGY?

A Because much of the New England area is non-attainment for NOx, the 7FA cost estimate included dry low NOx combustors to reduce NOx emissions. For the limited purpose of providing this illustrative cost analysis, we also assumed that an SCR (selective catalytic reduction) would be installed on the GE 7FA to further reduce NOx emissions. While fitting an SCR on an "F" class combustion turbine is not a widely accepted practice due to the risks that it poses, it has been done.[2] PJM's CONE value also is based on a 7FA with an SCR so this provides an additional data point for review of these figures.[3]

The operating risk associated with an SCR system on an "F" class combustion turbine in simple-cycle mode is that the SCR could be damaged by the turbine's very high exhaust gas temperature unless the exhaust temperatures are reduced. The upper end operating temperature of SCR systems is typically 850°F, which is several hundred degrees below the exhaust temperature of the GE 7FA combustion turbine. It is technically feasible to design and install a system of ductwork, and air dampers to lower the exhaust temperature of an "F" class turbine by mixing it with ambient air before introducing the exhaust air to an SCR sized to handle the larger gas flow rate. However, to date there are very few examples of SCRs installed on "F" class turbines in simple

---

[2] Permit to Construct Application, Bridgeport Peaking Station, Bridgeport, CT, prepared for Bridgeport Energy II, LLC, by Earth Tech, Inc., June 2007, at 4-6 to 4-7, http://www.ct.gov/csc/lib/csc/pendingproceeds/petition_841/attachment_f_bulk_exhibit_air_permit_app_june07.pdf.

[3] Cost of New Entry Combustion Turbine Power Plant, Revenue Requirements, Additional CONE Area Evaluation, prepared for PJM Interconnection, LLC, by Pasteris Energy, Inc., November 16, 2009, at 13, http://www.pjm.com/~/media/committees-groups/committees/cmec/postings/20091130-cone-ct-revenue-requirements-report.ashx.

cycle with only limited hours of operating success.[4] It is assumed appropriate operating controls and procedures will be designed and implemented to assure successful operation of the SCR on the 7FA turbine.

Q HOW WERE THE CAPITAL COSTS OF THIS TURBINE TECHNOLOGY AT EACH LOCATION ESTIMATED?

A Cost estimates were prepared for the construction of a new greenfield two-unit simple-cycle combustion turbine peaking plant at Boston, MA and Springfield, MA. These estimates reflect plant features typically found in modern peaking facilities and are intended to reflect representative costs for new plants of this type, in year 2010 dollars. The estimates are conceptual and are not based on preliminary engineering activities for any specific site. The estimates reflect projects awarded on an Engineering, Procurement and Construction (EPC)[5] contract basis, with combustion turbines and SCR systems purchased directly by the owner.

The study is based on greenfield site conditions to incorporate all of the normally expected costs to develop a new entrant peaking plant. Scope includes all site facilities for power generation and distribution, including a switchyard and interconnection costs. Use of rental trailer-mounted water treating equipment was assumed. Potable water is assumed to be available from a municipal supply. Wastewater treatment is not included; contaminated wastewater will be collected locally for tanker truck disposal. A control/administration building is included. Costs associated with all of these assumptions were included.

[4] Permit to Construct Application, Bridgeport Peaking Station, *supra* note 2, at 4-6 to 4-7.

[5] Use of an EPC contract transfers some of the construction risk from the owner/developer to the EPC contractor, who is rewarded for taking on this risk with higher fees. A capital cost estimate assuming an EPC contract will be higher than an estimate that assumes the owner/developer assumes all the construction risk.

All equipment and material costs are based on Sargent & Lundy in-house data, vendor catalogs, or publications. Labor rates have been developed based on union craft rates in 2010. Costs have been added to cover FICA, fringe benefits, workmen's compensation, small tools, construction equipment, and contractor site overheads. Work is assumed to be performed on a 50-hour work week by qualified craft labor available in the plant area. An allowance to attract and keep labor has been included. A labor productivity adjustment[6] of 1.30 has been applied to Boston and 1.10 for Springfield based on the 2010 Global Construction Cost Yearbook published by Compass International. Materials costs are based on data for Springfield and Boston.

A contingency allowance consistent with industry custom and practice is added to cover undefined variables in both scope definition and pricing that are encountered within the original scope parameters. Contingency should always be treated as "spent money." Examples of where it is applied would include nominal adjustments to material quantities in accordance with the final design, items clearly required by the initial design parameters that were overlooked in the original estimate detail, and pricing fluctuations like the recent run-up in copper prices. A contingency of 10% was applied to the total of direct and indirect project costs, which is typical for construction projects of this type and the same level that was used in CONE estimates in both NYISO and PJM that have been approved by the Commission.

---

[6] Labor productivity can vary from one site or geographic area to another due to congested working conditions, weather, work rules, etc. Labor productivity values are multiplied by a standard number of hours for installation of each plant component to determine the total labor hours required to construct the plant at each site.

Q WHAT IS THE CAPITAL INVESTMENT COST FOR THIS COMBUSTION TURBINE TECHNOLOGY AT EACH LOCATION?

A Capital investment costs for the peaking unit at each location include direct costs, owner's costs, financing costs during construction, and working capital and inventories. Direct costs are costs typically within the scope of an EPC contract. Owner's costs include items not covered by the EPC scope such as owner's development costs, oversight, legal fees, financing fees, startup and testing, and training. Social justice costs are not included. Financing costs during construction refer to the cost of debt and equity required over the periods from each construction expenditure date through the plant in-service date. These costs have been calculated from the monthly construction cash flows associated with the capital cost estimates, and the cost of debt and equity. A 20 month construction period is assumed, with cash flows peaking in the 14th month. Over 70% of the total cash flow occurs in the second half of the construction period. Working capital and inventories refer to the initial inventories of fuel, consumables, and spare parts that are normally capitalized. It also includes working capital cash for the payment of monthly operating expenses. On the basis of recent independent power projects, these costs have been estimated as 2% of direct capital costs.

Capital investment costs for this combustion turbine option at each location are summarized in Table 1 and NEPGA Exhibit 3-C.

Table 1. Total Investment Cost (2010$) – New Entrant Peaker

	Western MA	Boston
$ million	$348	$380
$/kW	$923	$1,004

Q WHAT ARE THE FIXED OPERATING AND MAINTENANCE COSTS?

A Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance).

Design-related costs were derived from a variety of sources, including the State-of-the-Art Power Plant Combustion Turbine Workstation, v 8.0, developed by the Electric Power Research Institute (EPRI), data for existing plants reported on Federal Energy Regulatory Commission (FERC) Form 1, and confidential data from other operating plants.

Site leasing costs are equal to the annual lease rate ($/acre-year) multiplied by the land requirement in acres. Property taxes are equal to the unadjusted property tax rate for the given jurisdiction, multiplied by an assessment ratio, and multiplied by the total investment cost of the plant. The assessment ratio is the percentage of market value applied in the tax calculation. Insurance costs are estimated to be 0.30% of the initial capital investment, escalating each year with inflation, on the basis of actual data for recent independent power projects.

The fixed cost assumptions for this cost estimate are summarized in NEPGA Exhibit 3-D. The fixed O&M cost estimates are presented in Table 2 and NEPGA Exhibit 3-E.

Table 2. Total Annual Fixed O&M Costs (2010$) – New Entrant Peaker

	Western MA	Boston
$/year	$12,113,000	$14,547,000
$/kW-yr	$32.15	$38.30

Q WHAT IS AN ANNUAL CARRYING CHARGE?

A The annual carrying charge is the uniform annual cost of the capital investment in the two unit peaking plant over the assumed amortization period. Carrying charges typically include all annual costs that are a direct function of the capital investment amount: principal and interest payments on project debt, equity returns, income taxes, property taxes, and insurance.

Q HOW ARE ANNUAL CARRYING CHARGES CALCULATED?

A Annual carrying charges are equal to the sum of the following components:

Principal. Based upon mortgage style amortization.

Interest. Equal to the cost of debt multiplied by the loan balance for the given year.

Target Cash Flow to Equity. Equal to the initial equity investment multiplied by an annuity factor over the amortization period, using the cost of equity as the annuity rate.

Income Taxes. Calculated by the formula: [t/(1-t)] x [Target Cash Flow to Equity + Principal – Annual Tax Depreciation], where t = Composite Tax Rate. Annual tax depreciation is based on 15-year MACRS depreciation in accordance with the federal tax code for a simple-cycle combustion turbine.

Property Taxes. The effective property tax rate multiplied by the original capital investment amount, escalating year with inflation.

Insurance. The insurance rate multiplied by the original capital investment amount, escalating each year with inflation.

Q WHAT IS THE LEVELIZED CARRYING CHARGE?

A The levelized carrying charge is equal to the annual carrying charges over the amortization period converted to an annuity using the after-tax weighted average cost of capital (WACC).[7] In other words, the annual carrying charges summed for each year are considered to be "revenue requirements" that are discounted at the after-tax WACC. The real levelized carrying charges are expressed in 2010 price levels. Carrying charges for future years are equal to the 2010 value escalated by the inflation rate of 2.00 %/year.

The nominal and real levelized carrying charge rates as are shown in NEPGA Exhibit 3-F.

Q WHAT ARE THE INCOME TAX AND FINANCING ASSUMPTIONS USED IN CALCULATING ANNUAL CARRYING CHARGES?

A Income tax and financing assumptions for each location are summarized in NEPGA Exhibit 3-F. Income taxes are a significant component of carrying charge rates. A portion of these charges must be grossed up to account for the income taxes due on plant

[7] Weighted average cost of capital is the average of the interest rate for debt and the return on equity weighted using the percentage of each source that is used to finance the total cost of investment.

revenues to ensure that the desired return on equity is achieved. Income taxes include the federal corporate tax rate of 35.00% and the Massachusetts corporate tax rate of 8.75%. The composite tax rate is the sum of these rates, reduced by the portion that is deductible from taxable income.

The financial assumptions used to estimate the gross cost of new entry were provided by NEPGA witness Robert Stoddard. The financing of the plant is assumed to have a 45:55 ratio of debt to equity. The cost of equity is assumed to be 15.00% and the cost of debt is assumed to be 8.84%. The amortization period is assumed to be 20 years. Financing assumptions are identical for each location. The costs of debt and equity are shown on a nominal basis and a real basis. Real rates are derived by removing the estimated inflation component of 2.00%,[8] and are subsequently used to calculate the real WACC and the real levelized carrying charge rates.[9] The carrying charge rates are different for each location due to different property tax rates (*see* NEPGA Exhibit 3-D).

Q WHAT ARE THE ESTIMATED LEVELIZED GROSS COSTS OF NEW ENTRY?

A The estimated "gross" CONE values for this technology at these two locations based on the above assumptions and methodologies are shown in Table 3 and NEPGA Exhibit 3-G.

---

[8] Based on Second Quarter 2010 Survey of Professional Forecasters, Federal Reserve Bank of Philadelphia, May 14, 2010.

[9] See response to previous question for a definition.

Table 3: Gross Cost of New Entry (2010$) – New Entrant Peaker

	Western MA	Boston
$/kW-yr	$164.59	$182.34
$/kW-mon	$13.72	$15.20

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and New England Power Pool	))	Docket No. ER10-787-000
New England Power Generators Association Inc. v. ISO New England Inc.	)))))	Docket No. EL10-50-000
PSEG Energy Resources & Trade LLC, PSEG Power Connecticut LLC, NRG Power Marketing LLC, Connecticut Jet Power LLC, Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, and Somerset Power LLC v. ISO New England Inc.	)))))))))	Docket No. EL10-57-000

I, Christopher D. Ungate, being duly sworn, depose and state that the contents of the foregoing Testimony on behalf of the New England Power Generators Association is true, correct, accurate and complete to the best of my knowledge, information, and belief.

Christopher D. Ungate

Christopher D. Ungate

SUBSCRIBED AND SWORN to before me this 28th day of June 2010.

Paul Weeks

(Notary Public)

PAUL WEEKS NOTARY PUBLIC AT LARGE HAMILTON CO., TN

My commission expires: 9/29/2010

CHRISTOPHER D. UNGATE
Senior Principal Management Consultant
Sargent & Lundy Consulting

Sargent & Lundy LLC

EDUCATION

University of Tennessee, Master of Business Administration, 1984
Massachusetts Institute of Technology, M.S. Civil Engineering, 1974
Massachusetts Institute of Technology, B. S. Civil Engineering, 1973

REGISTRATIONS

Professional Engineer - Tennessee

EXPERTISE

Resource Planning
Business and Strategic Planning
Process Improvement and Re-engineering
Market Analysis and Price Forecasting
Decision Analysis
Asset Valuation and Due Diligence
Generation Portfolio Analysis
Risk Analysis

RESPONSIBILITIES

Mr. Ungate is accountable for Sargent & Lundy offerings in the Utility Planning business segment. He develops and evaluates integrated resource plans and associated analyses to identify and evaluate the optimum power supply options. He reviews and evaluates power supply planning and procurement options such as generation options available in the region (potential greenfield or plant expansion options), the viability of siting and permitting new nuclear, coal, gas, wind, solar, biomass or other alternative generation, the prospects for purchase of existing assets, and the potential for partnering with other load serving entities or power generators. He also assesses the potential and/or required renewable energy resource options, the state of transmission planning and upgrade programs, recent wholesale prices in the Client's load zone, and the fuel market and transportation capacities. He assures consistency with the Client's long-term plans and objectives and Client-specific economic factors (such as standard inflation, inflation, discount, or escalation rates).

Mr. Ungate develops financial models and analyses utilized in the assessment of power generation technologies, project development, asset transactions, operational reviews, and facility modifications and refurbishment projects. He bases the models on appropriate economic, project, operating, and client-specific inputs related to base-case scenarios, as well as associated sensitivity analyses. He also reviews existing financial models and analyses to determine if they are reasonable and appropriate, and to evaluate or develop resulting conclusions and recommendations. He also performs forward pricing analyses and evaluations, system reliability studies, load forecasting, and electric market forecasts and projections in support of power supply planning or other Client needs.

Mr. Ungate also performs due diligence reviews of new technology development, new projects, modifications and refurbishment of existing facilities, asset transactions, and operational assessments. He evaluates and develops plans to optimize the utilization of conventional hydropower plants and pumped storage plants with thermal generating units.

EXPERIENCE

Mr. Ungate has over 35 years of experience in engineering and planning for electric utilities. Since joining Sargent & Lundy in 2006, his assignments have included:

ALTERNATIVES ANALYSIS

- **San Miguel Electric Cooperative**
  - Conducted study of generation alternatives to meet federal and state requirements for justification of new coal project.

- **CPS Energy**
  - Developed cost and performance assumptions for alternative technologies for use in integrated resource planning studies. Compared published estimates of costs for new nuclear plants.

- **Entegra Power Services**
  - Conducted a planning study of adding 300 MW of natural gas-fired peaking capacity to an existing power station in the southwest US. Estimated capital costs, operating performance, and operations and maintenance (O&M) costs for three aeroderivative combustion turbine models with and without selective catalytic reduction (SCR), and two frame combustion turbine models without SCR.

- **South Mississippi Electric Power Association**
  - Reviewed renewable energy alternatives for this G&T cooperative in anticipation of future Renewable Portfolio Standard requirements. Directed the evaluation of responses to an RFP for renewable energy and capacity.

- **Department of Energy and Sandia Renewable Energy Laboratory**
  - Updated the 2003 report, “Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts” with the Dish technology.

RISK ANALYSIS

- **Various Clients**
  - Analyzing the risks associated with the cost, schedule, and performance impacts of proposed projects.

- **Globaleq**
  - Identified and quantified key drivers of increases in capital estimates for coal fired power plants.

- **American Electric Power**
  - Identified and compared key characteristics of new nuclear plant technologies. Assessed the risk of each technology relative to client objectives.

- **Allegheny Energy**
  - Developed a comprehensive risk analysis model to determine the expected outage days, generation and costs for a fleet of supercritical coal-fired units based on a high level condition assessment. The objectives were to assess the impacts of the risk issues and associated mitigation projects and to provide support the development of capital spending plans.

PLANNING AND PROJECT SUPPORT

- **PSEG**
  - Developed the need for power and energy alternatives analyses to satisfy the NUREG 1555 requirements for Environmental Reports associated with an Early Site Permit Application for a new nuclear plant project.

- **Tennessee Valley Authority, PSEG**
  - Developed the need for power analysis to satisfy the NUREG 1555 requirements for Environmental Reports associated with a Combined Operating License Application for a new nuclear plant project.

- **New York Independent System Operator**
  - Estimated the cost of new entrant peaking units used in the formulation of demand curves for capacity market. Estimated going forward costs of existing generation used in determining need for market power mitigation.

- **Eskom**
  - Surveyed major equipment suppliers with capabilities to support a large coal-fired project in Africa to assess the potential effect of current and projected production capacity, resource availability, and transportation requirements on project schedule, quality, and costs.

- **EPB**
  - Conducted seminars on selected generation, transmission and electricity market topics to prepare senior management on current trends and issues.

Prior to joining Sargent & Lundy, Mr. Ungate had over 30 years of experience at the Tennessee Valley Authority in a variety of engineering and planning assignments. Examples of assignments include the following:

POWER SUPPLY PLANNING

- Directed supply planning for 30,000 MWs of nuclear, coal, gas, renewable, and hydro generation, and determined peak season power purchase requirements. Directed the preparation of power supply plans, and the valuation of capacity additions, major projects, product offerings, and bulk power transactions. Plans provided the basis for purchase and sale decisions; fuel purchase and inventory decisions; and hedging strategies for the commodity book.

- Led environmental controls optimization study to determine least cost approach to meeting CAIR/CAMR requirements for TVA's 15,000 MW coal generation portfolio. Alternatives included mothballing of units; increased allowance purchases; modified capital improvement programs; re-powering; and replacement with capacity and energy purchases from gas-fired units. Developed approach that resulted in reduction of projected end of period debt by more than $1 billion.
- Provided cost analysis for product pricing for industrial customers. Determined analytical approach and oversaw analyses to determine value of interruptible products, standby power, customer co-generation, long vs. short term contracts, and dispersed power products.

BUSINESS AND STRATEGIC PLANNING

- Directed business planning for portfolio of 109 conventional hydropower units at 29 sites and four pumped storage units. Portfolio supplies 10-15% of company sales with 5000 MWs of capacity. Forced outage rates, recordable injury incident rates, and reportable environmental events were increasing over the previous six years. Developed a five year business plan to increase resources to facilitate the transition to a process management maintenance strategy, and to integrate plant modernization and automation projects to change technology and workflow at the plants.
- Directed the first reassessment of the operating policies of Tennessee Valley Authority reservoirs since the system was designed in the 1930's. Stakeholders were concerned about water quality issues affecting the reservoirs and about the adverse impact of lake levels on property values and recreation-oriented businesses. Led initiative to redefine operating policies, examine environmental concerns, expand public interest and support, and more effectively meet the needs of multi-state customer base. Directed the development of an operating scheme that preserved hydropower value while improving summer lake levels for recreation and increasing minimum flows for water quality.
- Developed competitive analysis for an electric utility. Customers seeking choice of energy suppliers created need for a credible competitive analysis for electric utility monopoly. Price to customers was above competitive energy suppliers. Loss of customer load would create the risk of not recovering the high fixed costs of generation built to serve former customers. Quantified the competitive threat, and identified the circumstances under which loss of customers was most likely.

PROJECT ENGINEERING

- Directed 40-50 engineers, technicians and building trades conducting laboratory and prototype testing of thermal and hydro plant performance problems. Responsible for daily operating management, laboratory safety, quality assurance, human resources, technology acquisition and facilities management.
- Conducted field tests and physical modeling studies on the effects of thermal generating plants on rivers and reservoirs. Contributed to preparation of several environmental statements impacting authorizations for plant operations and discharge.

MEMBERSHIPS

Board of Examiners, Tennessee Quality Award, 1997-99

PUBLICATIONS

"Baseload Generation Capital Cost Trends," Electric Power Conference, May 2007.

"Resolving Conflicts in Reservoir Operations: Some Lessons Learned at the Tennessee Valley Authority," American Fisheries Society symposium, 1996.

"Tennessee Valley Authority's Clean Water Initiative: Building Partnerships for Watershed Improvement," Journal of Environmental Planning and Management, 39(1), 1996.

"'Equal Consideration' at TVA: Changing System Operations to Meet Societal Needs," Hydro Review, July 1992.

"Reviewing the Role of Hydropower in TVA Reservoir Operations," with Douglas H. Walters, Waterpower '91, An International Conference on Hydropower, Denver, Colorado, 1991.

"TVA's Lake Improvement Plan: Reviewing the Operating Objectives of TVA's Reservoir System," National Conference on Hydraulic Engineering, Nashville, Tennessee, July 1991.

"Tennessee River and Reservoir System Operation and Planning Review, Final Environmental Impact Statement," with TVA staff, December 1990.

"Field and Model Results for Multiport Diffuser Plume," with Charles W. Almquist and William R. Waldrop, American Society of Civil Engineers Specialty Conference on Verification of Mathematical and Physical Models, University of Maryland, August 1978.

"Mixing of Submerged Turbulent Jets at Low Reynolds Number," with Gerhard Jirka and Donald R. F. Harleman, M.I.T. Ralph M. Parsons Laboratory, Report No. 197, February 1975.

Key Characteristics of Site Locations		
Feature	**Non-Urban (Springfield, MA)**	**Urban (Boston)**
Site area	4.5 acres	3.5 acres
Gas pressure at site	450 psig	250 psig
Electrical interconnection	345 kV available at site	138 kV available at site
Foundation conditions	Spread footings	Piles
Switchyard requirements	Normal breaker separation	Gas insulated breakers

Capital Investment Costs (2010$)		
	Western Massachusetts	**Boston**
	2 x 7FA.05 (SC)	**2 x 7FA.05 (SC)**
Direct Costs	288,406,000	316,177,000
Owner's Costs	31,724,000	34,779,000
Financing Costs During Construction	22,019,000	24,139,000
Working Capital and Inventories	5,768,000	6,324,000
Total	347,917,000	381,419,000
Net Degraded Plant Capacity - Summer Qualified@90^{o}F (MW)	376.8	379.8
Net Degraded Heat Rate - Summer Qualified@90^{o}F (Btu/kWh)	10,453	10,453
$/kW	$923	$1,004

Fixed O&M Assumptions (2010$)		
	Western Massachusetts	Boston
	2 x GE 7FA.05	2 x GE 7FA.05
Average Labor Rate, incl. Benefits ($/hour)	$57.00	$69.00
Operating Staff (full-time equivalents)	4	4
Maintenance Staff (full-time equivalents)	3	3
Routine Materials and Contract Services	$390,000	$390,000
Administrative and General	$350,000	$350,000

Other Fixed Operating Assumptions (2010$)		
	Western Massachusetts	Boston
Lease Rate ($/acre-year)	18,000	129,000
Property Tax Rate	2.707%	2.938%
Insurance Rate	0.30%	0.30%

Operating Cost and Performance Summary (2010$)		
	Western MA	**Boston**
Combustion Turbine Model	2 x GE 7FA.05	2 x GE 7FA.05
Plant Performance (per Unit)		
Net Capacity (MW)		
Summer	196.5	198.7
Winter	220.4	221.2
ISO Conditions	198.9	200.6
Summer Qualified @90^{o}F	188.4	189.9
Net Heat Rate (Btu/kWh)		
Summer	10,345	10,337
Winter	10,118	10,131
ISO Conditions	10,229	10,229
Summer Qualified @90^{o}F	10,453	10,453
Fixed O&M - Routine ($/year)		
Labor - O&M	830,000	1,005,000
Materials & Contract Services	390,000	390,000
Administrative and General	350,000	350,000
Subtotal Fixed O&M - Routine	1,570,000	1,745,000
$/kW-year	**4.17**	**4.59**
Other Fixed Costs ($/year)		
Site Leasing Costs	81,000	452,000
Subtotal Fixed O&M – Routine & Other	1,651,000	2,197,000
$/kW-year	**4.38**	**5.78**
Property Taxes (without abatement)	9,418,000	11,206,000
Insurance	1,044,000	1,144,000
Total Fixed O&M ($/year)	12,113,000	14,547,000
$/kW-year	**32.15**	**38.30**

Income Tax Assumptions		
	Western Massachusetts	**Boston**
Federal Tax Rate	35.00%	35.00%
State Tax Rate	8.75%	8.75%
City Tax Rate	0.00%	0.00%
Composite Tax Rate *	40.69%	40.69%

* Federal Tax Rate + State Tax Rate – (Federal Tax Rate x State Tax Rate), to account for deductibility of state taxes from federal taxable income.

Financing Assumptions		
	Western Massachusetts	**Boston**
Equity Fraction	0.55	0.55
Debt Fraction	0.45	0.45
Cost of Equity (nominal)	15.00%	15.00%
Cost of Debt (nominal)	8.84%	8.84%
Cost of Equity (real)	12.75%	12.75%
Cost of Debt (real)	6.71%	6.71%
Weighted Average Cost of Capital		
Before-Tax (nominal)	12.23%	12.23%
After-Tax (nominal)	10.61%	10.61%
Before-Tax (real)	10.03%	10.03%
After-Tax (real)	8.80%	8.80%
Amortization Period (years)	20	20
Tax Depreciation	15-year MACRS	15-year MACRS
Inflation Rate	2.00%	2.00%
Levelized Fixed Charge Rate		
Nominal	20.16%	20.42%
Real	17.35%	17.58%

Levelized Cost of New Entry - Summary (2010$)		
	Western MA	**Boston**
Combustion Turbine Model	2 x GE 7FA.05	2 x GE 7FA.05
Net Summer Qualified Capacity @90^{o}F (MW)	378.4	376.4
Capital Charges		
Capital Investment Cost ($ millions)	347.9	381.4
Levelized Fixed Charge Rate (Real)[1]	17.35%	17.58%
$/year ($ millions)	60.4	67.1
$/kW-year	**160.21**	**176.56**
Fixed O&M – Routine & Other		
$/year ($ millions)	1.7	2.2
$/kW-year	**4.38**	**5.78**
Levelized Cost of New Entry		
$/year ($ millions)	62.0	69.2
$/kW-year	**164.59**	**182.34**
$/kW-month	**13.72**	**15.20**

Notes:
1. Includes property taxes and insurance

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

<table>
<tr><td>ISO New England Inc. and New England Power Pool</td><td>)</td><td>Docket No. ER10-787-___</td></tr>
<tr><td>New England Power Generators Association, Inc.

v.

ISO New England Inc.</td><td>)
)
)
)
)</td><td>

Docket No. EL10-50-___</td></tr>
<tr><td>PSEG Energy Resources & Trade LLC, et al.

v.

ISO New England Inc.</td><td>)
)
)
)
)</td><td>

Docket No. EL10-57-___</td></tr>
</table>

TESTIMONY OF DAVID L. MCADAMS PH. D.
ON BEHALF OF NEW ENGLAND POWER GENERATORS ASSOCIATION

JULY 1, 2010

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

A My name is David McAdams. I am Associate Professor of Business Administration and Economics at Duke University. My business address is Fuqua School of Business, Duke University, Durham, NC 27708.

Q PLEASE DESCRIBE, BRIEFLY, YOUR EDUCATIONAL AND EMPLOYMENT BACKGROUND.

A I have a Bachelor of Science degree in Applied Mathematics from Harvard University in 1996, a Masters in Statistics from Stanford University in 2001, and a Ph.D. in Business from Stanford University in 2001. In 1999, I was Special Assistant to the Director, Bureau of Economics, Federal Trade Commission. From 2001-2008, I served on the faculty at the Massachusetts Institute of Technology Sloan School of Management. In 2008, I joined the Duke faculty in the Fuqua School of Business and in the Economics Department. My theoretical and empirical research on multi-unit auctions[1] (of which capacity auctions are an example) has been supported by the National Science Foundation and published in the leading journals of economics. My curriculum vitae is attached hereto as NEPGA Exhibit 4-A. This is my first prepared testimony before the Commission.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A I am an economic theorist and auctions expert. The purpose of this testimony is to evaluate the ISO New England ("ISO-NE") Forward Capacity Market ("FCM") auction process, especially the proposed modifications to the Alternative Price Rule ("APR")

[1] Multi-unit auctions are auctions of multiple identical objects (*e.g.*, electricity, Treasury bonds, stocks), as opposed to so-called multi-object auctions of dissimilar objects (*e.g.*, FCC spectrum, task assignment). My dissertation was titled "Essays in Multi-Unit Auction Theory," and a project funded by the National Science Foundation ("NSF") from 2003-2006 was titled "Ordinal Structure in Multi-Unit Auctions."

outlined by ISO-NE staff in a June, 15 2010 presentation.[2] In brief, my main conclusions are as follows. *First*, the February APR proposed by ISO-NE in a February 22, 2010 filing is flawed for several reasons, and needs to be improved. *Second*, the June APR outlined by ISO-NE staff resolves several of my concerns with the February APR, and represents a substantial step forward. *Third*, I find one of the most novel aspects of the June APR—its two-tiered pricing structure whereby new resources are paid a different price than existing resources—to be sensible and economically sound.

Q AS AN ECONOMIST WITH AUCTION EXPERTISE, CAN YOU PLEASE PROVIDE AN OVERVIEW OF AUCTION ECONOMICS, AND WHY AUCTION THEORY IS RELEVANT FOR PRACTICAL AUCTION DESIGN?[3]

A Auctions have been a very active area of research in economics—indeed, one of the most active areas of research—for over two decades. To an outsider, this may seem rather odd. Auctions are certainly interesting and important mechanisms for the facilitation of trade in many important markets—such as stock exchanges, bonds sales, business-to-business procurement, and so on—but there are many other sorts of transactions as well. Why such focus on auctions? In my mind, there are four main reasons.

First, auctions shed light on the role of *private information* in markets. The canonical neo-classical model describes the good properties of markets when there are many buyers and sellers, firms cannot abuse market power and there is no hidden information about

[2] Three APRs are relevant to my testimony. The "Historic APR" is contained in the ISO's Transmission, Markets, and Services Tariff (FERC Electric Tariff No. 3). The "February APR" revised the Historic APR and is described in an ISO-NE filing: *ISO New England Inc.*, Docket No. ER10-787-000, Various Revisions to FCM Rules Related to FCM Redesign (Feb. 22, 2010) ("FCM Revision"). The "June APR" is outlined in a publicly available presentation by ISO-NE staff: Bob Ethier *et al.*, Draft Response to FERC Order of April 23, 2010 (June 15, 2010) ("ISO-NE Response") http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2010/final_prop_fcm_rev6_15_10.pdf.

[3] This summary of auction economics builds upon a private correspondence that I received from Professor Patrick Bajari. Another excellent discussion is contained in "Empirical Models of Auctions" by Susan Athey and Phil Haile, an invited lecture prepared for the Ninth World Congress of the Econometric Society.

the goods being bought and sold. The celebrated welfare theorems in some sense formalize the intuition of Adam Smith: despite the fact that market participants are self interested, their very self interest may generate socially beneficial outcomes since it generates an efficient use of resources. However, it is well known that if agents possess private information about the objects being sold, markets may break down or fail to function properly. The Nobel prizes awarded to Akerlof, Spence, Stiglitz, Hurwicz, Maskin and Myerson were in large part for their analysis of private information. The Nobel Prize awarded to Vickrey was specifically for the analysis of private information in auctions.

A large volume of literature has demonstrated that private information is important in both economic theory and in real markets. Much of this research has a pessimistic tone about the ability of markets to generate socially desirable outcomes. Auctions are a laboratory for studying private information because the fundamental motivation for holding an auction is to get bidders to compete against each other in order to reveal their private information. One of the key *positive* messages of auction theory is that competition can achieve efficient outcomes even in the presence of private information. Therefore, if there is private information, you can sometimes restore the "good" properties of the welfare theorems by holding an auction. However, the rules of the auction and the form of private information are central to whether or not efficiency will be obtained through decentralized competition via bidding.

Second, auctions have very high-quality data. Academic researchers typically have access to precise descriptions of what is being sold. In the best case, they have approximately the same public information that is available to bidders. Also, prices in auctions typically have no measurement error. In other markets, the researcher may have only error-prone measures of prices, quantities and product characteristics.

Third, auctions have highly structured formal rules that provide a close link between game theory and actual market institutions. In many other settings, the "rules" of competition are unclear. By contrast, in an auction, the strategies that bidders may use and how markets clear are precisely specified. As a result, it is much easier and more compelling to bring the theory to the data. This makes auctions a highly attractive testing ground for game theory and economic theory more generally.

Finally, since the "auction game" is clearly specified and known to all players, auction theory may do a relatively good job of describing real-world behavior—including by anticipating strategic behaviors that may undermine the performance of the auction.[4] Because of this, auction theory and academic auction theorists have played an important role in the design of many important real-world auctions, including everything from the sale of FCC spectrum and Treasury bonds to the assignment of environmental permits.

PART ONE: CONCEPTS AND TERMS USED IN THIS TESTIMONY

Q ARE THERE ANY SPECIALIZED ECONOMIC TERMS OR CONCEPTS THAT YOU WILL USE IN YOUR TESTIMONY?

A Yes, I will refer to some economic and game-theory concepts that may not be familiar to some readers, and utilize certain terms commonly used in this proceeding. Accordingly, I will begin by defining and discussing the following concepts and terms:

a. economic cost;

[4] In many high-stakes auctions, such as those used in recent FCC spectrum auctions, many bidders have hired auction theorists to help them decide what to bid. In such cases, one may expect an even closer correspondence between the predictions of auction theory and actual bidding behavior.

b. stand-alone economic cost;

c. economic CONE (vs. annualized CONE vs. administrative CONE);

d. single-price auction;

e. uniform-price auction;

f. truthful bidding;

g. lowest-cost allocation;

h. marginal economic resource;

i. economic price;

j. OOM;

k. Nash equilibrium; and

l. weakly dominant strategy.

This is not a complete list of all significant terms used in this testimony. When other significant new terms are introduced in later parts of the testimony, I will indicate that by underlining and italicizing the term in question.

Q THE FIRST TERM ON YOUR LIST IS "ECONOMIC COST." WHAT DO YOU MEAN BY THIS?

The "economic cost" of an economic decision—such as the decision to enter with a new resource or continue operation with an existing resource—is, quite simply, the *unprofitability* of that decision. After all *future* benefits and costs of this decision are accounted for, including any out-of-market subsidies from third-parties, how much money is lost by making this decision? That amount is the economic cost of the decision.

Q WHAT IS "STAND-ALONE ECONOMIC COST"?

A When a resource is deciding whether to enter or continue operating in the FCM, there are all sorts of future benefits and costs associated with this decision that have nothing to do with the economic operation of that particular resource. For example, if the owner of the resource in question has buyer-side market power and entry will decrease current and/or future FCA prices, then such exercise of market power constitutes a benefit. Similarly, if the resource has been subsidized or guaranteed a positive return by some third-party, then prospective subsidy payments from this third-party constitute a benefit. Finally, the prospect of future FCA auction payments constitutes a benefit.

The "stand-alone economic cost" of a decision to enter or continue operation is the unprofitability of that decision, when accounting only for the revenues and costs associated with the economic operation of that resource *plus* FCA auction payments. Namely, this includes all revenues earned in energy markets, all costs of operation and (if the decision in question is whether to enter the auction before investment costs have been sunk) all costs of investment. Stand-alone economic cost does *not* account for any benefits from the exercise of market power nor for any subsidies received from third-parties—other than FCA payments.

Q WHAT IS "ECONOMIC COST OF NEW ENTRY (CONE)"?

A I will use the term "economic CONE" to refer to the *stand-alone* economic cost of new entry. To re-iterate an earlier definition, then, a resource's economic CONE is the *unprofitability* of that resource, after accounting for all investment costs, the present value of profitability after entry[5] and all future FCA auction payments. In other words, a

[5] Profitability after entry includes not just expected revenues and costs of operation, but also the option value associated with being able to temporarily or permanently cease operations.

resource's economic CONE is the FCA auction payment that it needs *now*, in order to make new entry of that resource profitable on a stand-alone basis, *i.e.*, not including any prospective subsidies or benefits related to the exercise of market power.

Q PLEASE EXPLAIN WHAT YOU MEAN BY "ANNUALIZED CONE" AND "ADMINISTRATIVE CONE."

A In my reading of the record of this proceeding, I have noticed two common uses of the term "CONE" that are different from economic CONE. (By contrast, I have rarely seen the term "CONE" used to refer to the stand-alone economic cost of new entry.) *First*, this term is used to refer to what one might call "annualized CONE," corresponding to the annualized stand-alone unprofitability of a resource. In other words, if the FCA were to provide the same auction payment every year over a resource's lifetime, annualized CONE is the annual payment that that resource needs to make new entry profitable on a stand-alone basis. *Second*, "CONE" is used to refer to an administratively-determined cost of new entry ("administrative CONE") that plays a role in the rules of the FCA.

Q WHAT IS A "SINGLE-PRICE AUCTION"?[6]

A In a "single-price auction" of reserve capacity obligations, each bidder announces a price at which it is willing to supply different quantities of reserves. (Each bidder may be viewed as submitting a supply curve listing the price that it demands for every quantity that it might be asked to supply.) Obligations are awarded to all those who submit bids less than the "market-clearing price," *i.e.*, the lowest price at which more quantity is

[6] The term "single-price auction" is not standard in the auction theory literature. However, for this testimony, it will be useful to distinguish auctions in which all winners receive the same price ("single-price auctions") from those in which all winners receive the same price *and* this price equals the market-clearing price ("uniform-price auctions").

offered than needed to meet the Net Installed Capacity Requirement ("Net ICR"), and all winners are paid the "auction price" for all quantity supplied.

Q WHAT IS A "UNIFORM-PRICE AUCTION"?

A A "uniform-price auction" is a single-price auction in which the auction price is equal to the market-clearing price. As I will explain in more detail in Part Three, the FCA under the February APR is a single-price auction but *not* a uniform-price auction, because its auction price is not always equal to the market-clearing price.

Uniform-price auctions are most commonly implemented via sealed bids or via a "descending clock" process. In the descending clock variety, announced prices decrease over time until the quantity supplied no longer exceeds the Net ICR, and the "bid" on a given unit of supply corresponds to the price at which that unit is withdrawn from the auction.

Usually, we expect uniform-price auctions to perform well as a means to generate meaningful price signals and efficient allocations. For instance, uniform-price auctions are routinely used around the world in electricity procurement auctions, Treasury bond sales auctions, and to open trading each day on stock exchanges. The reason is that, as long as all bidders are "small enough" relative to the overall market to view themselves as unable to influence the price, each bidder has an incentive—technically, a "weakly dominant strategy" (defined below)—to bid the maximal price at which it is willing to buy (if a buyer) or the minimal price at which it is willing to sell (if a seller).

Q WHAT DO YOU MEAN BY "TRUTHFUL BIDDING"?

A A resource is "bid truthfully" if its bid is equal to its stand-alone economic cost.

Q WHAT IS A "NASH EQUILIBRIUM"?

A In any Nash equilibrium of a game, each player's strategy is a best response to the strategies of the other players. In the context of the FCA, this means that each bidder would not gain from changing its bid, were it to learn the bidding strategies of all others in the auction.

Q WHAT IS A "WEAKLY DOMINANT STRATEGY"?

A A strategy is weakly dominant if it is a best response to others' strategies, no matter what those strategies may be. The adjective "weakly" in weakly dominant strategy captures the possibility that there may be some circumstances in which a player is indifferent between various strategies. For example, in the context of the FCA, a resource whose cost is so high that it has no chance of clearing in the auction finds every bid that doesn't clear to be a best response. Such a bidder is indifferent between all such losing bids because all of them are payoff-equivalent: the bidder gets nothing, regardless of which losing bid it makes.

Q WHAT IS A "LOWEST-COST ALLOCATION"?

A A lowest-cost allocation of reserve obligations is one in which obligations are assigned to those resources having the lowest stand-alone economic costs. Any allocation of obligations that fails to meet this standard—*i.e.*, in which the stand-alone economic costs of some resources that receive an obligation are greater than the stand-alone economic costs of some resources that do not receive an obligation—is manifestly inefficient. Namely, efficiency could be increased (while holding fixed the supply of reserve capacity) by displacing high-cost resources that received an obligation with lower-cost alternatives that did not.

Any single-price auction results in a lowest-cost allocation *if* all bidders bid truthfully.

The uniform-price auction has the extra advantage of incentivizing every resource to submit a bid equal to its economic cost. In particular, all "stand-alone resources" whose economic cost is equal to their stand-alone economic cost have an incentive—technically, a weakly dominant strategy—to bid truthfully. (By contrast, bidders with market power will shade their bids away from stand-alone economic cost in order to distort market outcomes to their advantage. Similarly, bidders with access to subsidies will bid less than stand-alone economic cost in order not to forego those outside payments.)

Q WHAT IS THE "MARGINAL ECONOMIC RESOURCE"?

A Suppose that the FCA achieves a lowest-cost allocation. The "marginal economic resource" is the lowest-cost resource that fails to receive an obligation under this allocation.

Q WHAT IS THE "ECONOMIC PRICE"?

A The "economic price" of reserve capacity is the stand-alone economic cost of the marginal economic resource. The economic price of reserve capacity can be interpreted as the marginal social value provided by each unit of reserve capacity in the FCM, should the lowest-cost resources be those that satisfy the Net ICR. To see why, suppose that the lowest-cost resources satisfy the Net ICR, but that one of these resources were forced to exit. The most economical way to replace this lost resource would be with the marginal economic resource, at a marginal social cost equal to the stand-alone economic cost of the marginal economic resource.

Q WHAT IS "OOM"?

A Broadly construed, "out-of-market (OOM)" is a phrase used to describe resources whose economic costs are *less* than their stand-alone economic cost. Thus, resources may be OOM for a wide variety of reasons, including buyer-side market power and subsidies for entry and/or operation received from a third-party.[7]

The term "OOM" is also commonly used to refer to a category of resources that are administratively labeled as OOM. For instance, under the February APR, a new resource is designated as OOM when (a) its bid is less than a pre-designated threshold and (b) this bid is not appropriately justified with the market monitor ahead of the auction, or when its de-list bid is rejected for reliability reasons.

Following the convention established in the record of this proceeding, I will use the term "OOM" in my testimony to refer *both* to resources that have stand-alone economic costs less than their economic costs, as well as to resources that are administratively labeled as being "out-of-market" in the FCA.

PART TWO: STATEMENT OF THE PROBLEM

Q WHAT IS THE PURPOSE OF THIS PART OF YOUR TESTIMONY?

A In this part of my testimony, I will discuss why an Alternative Price Rule ("APR") is needed in the Forward Capacity Auction ("FCA").

---

[7] Another category of OOM resources are those that have sunk investment costs prior to the FCA. Such resources would bid in the FCA without regard to these sunk costs, bidding less than the FCA payment that they would need to make entry profitable *prior* to their investment decision to sink these costs. However, as Mr. Stoddard notes in his testimony, gas-fired resources, unit up-rates, and demand-side resources can all move from advanced development to commercial operation in the three years between the FCA and the beginning of the commitment year. Resources of these types constitute all of the new resources that have been qualified in the FCAs to date. Consequently, ignoring sunk-cost resources for the sake of this testimony appears to be without too much loss. (That said, should longer lead-time resources such as nuclear be viewed as an important source of potential new entry in the future, the problem of how properly to incentivize such resources should be carefully revisited.)

Q PLEASE DESCRIBE HOW THE FCA WOULD PERFORM IF THERE WERE NO APR.

A The FCA is a descending-clock procurement auction. Owners of qualified capacity participate in the auction and "bid" by deciding at what price to withdraw from the auction. I will discuss two of the alternative price rules—the February APR and the June APR—at length later in this testimony. However, for now suppose that there were no APR. In particular, suppose that the FCA operated as a uniform-price auction. In this hypothetical scenario, (i) capacity obligations would be awarded to all those who submitted bids less than the "*FCA clearing price*," *i.e.*, the lowest price at which more quantity is offered than needed to meet the Net ICR, and (ii) all clearing resources would be paid the FCA clearing price.

If all resources had economic costs equal to their stand-alone economic costs, such an auction would achieve the best possible outcome from an efficiency perspective.

Q PLEASE ELABORATE.

A A basic fact about uniform-price auctions is that bidders have a weakly dominant strategy to bid their economic cost.[8] Consequently, if all resources have economic cost equal to their stand-alone economic cost, the FCA would generate Nash equilibrium outcomes[9] in which (i) the Net ICR is met through a lowest-cost allocation and (ii) resources that receive an obligation are paid the economic price of reserve capacity. From an efficiency

---

[8] "Weakly dominant strategy," "economic cost," "stand-alone economic cost," "Nash equilibrium," "lowest-cost allocation," and "economic price of reserve capacity" are defined in Part One. Please recall that economic cost includes benefits from the exercise of market power, and that a lowest-cost allocation only results when bids are equal to *stand-alone* economic costs.

[9] In theory, there might be Nash equilibria in which some players do not play their weakly dominant strategy. However, such equilibria typically fail to meet even the weakest sorts of stability criteria. My judgment is that little is lost by focusing on the Nash equilibrium in which all bidders in the FCA adopt their weakly dominant strategy, should they all have weakly dominant strategies.

stand-point, this is the best possible outcome: (i) the Net ICR is met at minimal cost and (ii) capacity resources are paid their marginal social value, incentivizing efficient investment and disinvestment decisions.

Q WHY MIGHT SOME RESOURCES' ECONOMIC COST ***NOT*** EQUAL STAND-ALONE ECONOMIC COST?

A As noted above, a uniform-price auction would induce efficient outcomes in the FCM if all resources had economic cost equal to stand-alone economic cost. Unfortunately, there are two potentially important reasons why the economic cost of some resources may be *less* than stand-alone economic cost. *First*, the owners of some resources might have buyer-side market power (discussed below),[10] in which case they would receive the benefit of lower FCA prices should those resources clear. *Second*, some resources might receive benefits from third-parties (discussed below) should they enter and/or operate.

If, for these or other reasons, a substantial fraction of resources in the FCM have economic costs substantially below their stand-alone economic cost, a uniform-price auction could induce very inefficient outcomes in the FCM. In particular, resources whose economic cost is artificially depressed by market power and/or third-party benefits would be inefficiently *over-represented* in the FCM. Consequently, the Net ICR would not be procured at minimal total economic cost and the FCA price would not provide a meaningful signal of the marginal social value of reserves, distorting investment decisions. Indeed, should market power or third-party benefits differentially benefit one class of energy resources over another, the FCA could even distort incentives for the

[10] Seller-side market power is also a concern, if unmitigated. Resources controlled by those with seller-side market power will have economic cost *greater* than stand-alone economic cost.

Research and Development needed to advance the most promising nascent energy technologies.

Q IN THIS EXPLANATION, YOU REFER TO "MARKET POWER." CAN YOU EXPLAIN HOW YOU ARE USING THIS TERM?

A Yes. A bidder that has the ability to influence the auction price through its bid is said to have "market power" in the auction. Unlike traditional notions of market power which are typically based on market share ownership or control, the ability to influence price in an auction can also depend on the auction rules. In poorly-designed auctions, even relatively small bidders may be able to influence the market price.

Any bidder with market power has an incentive to use that power to distort auction outcomes to its advantage. (Some bidders may prefer higher auction prices, while others may prefer lower auction prices.)

Q YOU ALSO REFER TO "THIRD-PARTY BENEFITS" IN YOUR RESPONSE. PLEASE EXPLAIN WHAT YOU MEAN BY THAT.

A Even absent market power, a resource's economic cost can be less than its stand-alone economic cost if a third party has committed itself to pay for all or part of the resource's costs (*e.g.*, by providing a subsidy) or has made avoidance of these costs impossible (*e.g.*, by requiring entry or continued operation) regardless of the auction price that results. Such a resource will be willing to accept an auction price low enough to make entry or continued operation profitable, given only those costs that remain discretionary. (A new or existing resource's discretionary costs are those that could be avoided if it were not selected to be a reserve capacity resource.)

Q WITH THE BENEFIT OF THE ABOVE CLARIFICATIONS AND EXPLANATIONS, CAN YOU SUMMARIZE YOUR VIEW OF WHY AN ALTERNATIVE PRICE RULE, OR APR, IS NEEDED IN THE FORWARD CAPACITY AUCTION?

A The appeal of uniform-price auctions is that they can harness the power of competition to achieve efficient allocations and prices. However, such benefits only accrue when bidders' incentives in the auction reflect underlying *stand-alone* economic costs. In the FCM, there are important reasons to be concerned that this pre-condition for efficiency may fail to be satisfied. In particular, some bidders' incentives in the auction may be distorted by market power and/or third-party benefits. Because of this, an unmitigated uniform-price auction would most likely *not* function well in the FCM. Market power mitigation is needed to correct for the effect of market power, while APR mitigation is needed to correct for the effect of third-party benefits.

PART THREE: FEBRUARY APR

Q WHAT IS YOUR VIEW OF THE FEBRUARY APR?

A My view is that the February APR needs to be improved.

Q EXPLAIN THE BASIS FOR THIS VIEW.

A The aspiration of the APR is to restore the FCA outcome to something that *approximates*, as closely as possible, the efficient market outcomes and efficient market incentives that would have been generated in a uniform-price auction had there been no "out-of-market (OOM)" capacity. In this part of my testimony, I will discuss some important reasons why the February APR needs to be improved in order to achieve that objective more fully.[11] Understanding some of the flaws of the February APR helps one better to appreciate the design of the June APR. In Part Four of this testimony, I will discuss the June APR and how/why it improves on the February APR.

Q PLEASE BEGIN BY DESCRIBING THE FEBRUARY APR.

A The FCA under the February APR is very complicated. Here I will simply sketch some of the features of the February APR that are most salient to my testimony. There are three separate triggering events—APR-1, APR-2, and APR-3—in each of which the February APR pays all clearing resources an "APR price" instead of the FCA clearing price.

Q WHEN YOU REFER TO "TRIGGERING EVENTS," WHAT EXACTLY ARE YOU TALKING ABOUT?

A The February APR is designed to have an effect on auction outcomes in certain circumstances, and designed *not* to have any effect in other circumstances. The "triggering events" are those circumstances in which the APR establishes a different auction outcome than what would otherwise have occurred in a uniform-price auction.

Q NOW, PLEASE DESCRIBE THE SPECIFIC TRIGGERING EVENTS MENTIONED ABOVE, APR-1, APR-2 AND APR-3.

A These triggering events are as follows: [12]

APR-1 applies "when new capacity is needed in the Forward Capacity Auction … but that need is completely met by new OOM megawatts in the current Forward Capacity Auction."

---

[11] My discussion of this issue is not exhaustive. For a more thorough discussion of this topic, see especially the March 2010 testimony of Mr. Robert Stoddard and Dr. Roy Shanker.

[12] Quotes here are from the FCM Revision, Attachment 3, Prepared Testimony of Dr. Robert Ethier at 5-6.

APR-2 applies "when new capacity is not needed in the Forward Capacity Auction, but would have been needed if not for the entry of OOM megawatts in previous Forward Capacity Auctions."

APR-3 applies "when new capacity is not needed in the Forward Capacity Auction even without the OOM megawatts that entered in previous FCAs, but when the FCA price is depressed as a result of de-list bids that are rejected for reliability reasons." These triggering events depend on which resources are designated as being OOM, a process that depends in part on bidding in the auction. Namely, a new resource is designated as OOM when (a) its bid is less than a pre-designated threshold and (b) this bid is not appropriately justified with the market monitor ahead of the auction, or its delist bid is rejected for reliability reasons.

Under APR-1 and APR-2, the APR price is computed to equal the *lower* of an administratively-determined CONE or one penny below the offer price of the lowest-bid new in-merit resource that does not clear. (To keep this testimony as brief as possible, I will not discuss APR-3.)

Q YOU STATED ABOVE THAT THE FEBRUARY APR NEEDS TO BE IMPROVED. EXPLAIN WHAT YOU MEAN.

A I will focus here on two weaknesses of the February APR. *First*, the triggering events are incomplete. *Second*, when APR-1 or APR-2 is triggered, the APR price will typically not equal the economic price of reserve capacity.[13]

[13] The "economic price of reserve capacity" is defined in Part One, as the market-clearing price that results when all resources bid their stand-alone economic cost.

Q WHY ARE THE TRIGGERING EVENTS OF THE FEBRUARY APR INCOMPLETE?

A The presence of OOM always has a potential to suppress auction prices, since OOM resources have an incentive to bid less than their stand-alone economic costs. However, there are circumstances in which OOM is present but the APR is not triggered. For example, when new capacity is needed, there is some new in-merit entry, and there is some OOM capacity in the auction, none of APR-1, APR-2 or APR-3 is triggered despite the potentially price-suppressing effect of that OOM.[14]

Q WHY MIGHT THE APR-1 AND APR-2 PRICE NOT BE EQUAL TO THE ECONOMIC PRICE OF RESERVE CAPACITY?

A The economic price of reserve capacity (or, more simply, "economic price") is the stand-alone economic cost of the marginal economic resource or, equivalently, the market-clearing price that would result if all resources were bid at their stand-alone economic cost. By contrast, recall that the APR-1 and APR-2 price is equal to the *lower* of CONE or one penny below the offer price of the lowest-bid new in-merit resource that does not clear.

The APR-1 and APR-2 price will tend not to equal the economic price for several reasons, two of which I will highlight here.

First, in those events when the APR-1 and APR-2 price is less than CONE, the lowest-bid new in-merit resource that does not clear is typically not the marginal economic resource. Consequently, *even if* all in-merit resources were to bid truthfully, the APR-1 and APR-2 price would not equal the economic price. This effect can cause the APR-1 and APR-2 price to be higher or lower than the economic price. For instance,

[14] *See* Section IV-B, especially ¶¶ 32-33, of Mr. Stoddard's Affidavit, filed with NEPGA's Protest in Docket ER10-787-000 on March 15, 2010.

consider a situation in which the marginal economic resource is a new in-merit resource that does not clear, but not the *lowest-cost* new in-merit resource that does not clear. In this case, the APR-1 and APR-2 price would be lower than the economic price under truthful bidding by all in-merit resources. Or, consider a situation in which (i) the marginal economic resource is an existing in-merit resource and (ii) all new in-merit resources cost more than this existing resource. In this case, the APR-1 and APR-2 price would be higher than the economic price under truthful bidding.

Second, even in-merit resources—that lack market power and receive no third-party benefits—may have an incentive to bid less than their stand-alone economic costs under the February APR. (I refer to such untruthful bidding by in-merit resources as "*innocent bid-shading*."[15])

Q WHY MIGHT IN-MERIT RESOURCES HAVE AN INCENTIVE TO SHADE THEIR BIDS BELOW THEIR STAND-ALONE ECONOMIC COSTS?

A Here is a scenario in which an in-merit bidder would strictly benefit by bidding less than its stand-alone economic cost. Suppose that bidding is such that (i) APR-1 is triggered and (ii) there are some existing in-merit "between" resources whose going-forward economic cost is less than the APR price but greater than the FCA clearing price. ("Between" resources are illustrated in Exhibit RBS-3 of Mr. Stoddard's March 2010 testimony.) Were these in-merit "between" resources to bid truthfully, they would not clear because their stand-alone economic cost exceeds the FCA clearing price. However, they would strictly prefer to clear since their stand-alone economic cost is less than the

[15] Such bid-shading is "innocent" because the bidder has no market power and hence cannot manipulate the price. Rather, innocent bid-shading is a response to distorted incentives created by the auction rules.

APR price. Thus, these in-merit resources strictly prefer to deviate from truthful bidding with a bid that is less than or equal to the FCA clearing price, so as to clear.

By contrast, I am aware of no situation under the February APR in which an in-merit resource strictly prefers to bid *more* than its stand-alone economic cost.

PART FOUR: JUNE APR

Q DO YOU HAVE A VIEW REGARDING THE JUNE APR?

A Yes. In this part of my testimony, I will discuss the June APR and make two main points. *First*, I will show how the June APR resolves some of the weaknesses inherent in the February APR. *Second*, I will argue that the two-tiered pricing structure introduced in the June APR is sensible and economically sound.

Q PLEASE DESCRIBE THE BASIS FOR THE VIEWS YOU WILL ARTICULATE REGARDING THE JUNE APR.

A At the time when I developed this testimony, some details of the June APR are not known. Earlier in June 2010, ISO-NE staff presented an outline of the June APR, but details will be offered in a July filing contemporaneous with mine. (At that point, presumably, the fully-known APR proposal will be referred to as the *July* APR, to distinguish discussion of ISO-NE's formal filing in July from discussion of its informal presentation in June.) Nonetheless, I will venture here to sketch what appear to be some of the June APR's most salient features.

Q WITH THAT CAVEAT, PLEASE DESCRIBE YOUR UNDERSTANDING OF THE JUNE APR.

A *First*, the June APR is triggered automatically whenever any OOM is present. *Second*, not all clearing resources are paid the same price. New resources and all OOM resources (new and carried-forward) are paid the FCA clearing price while existing resources are paid the APR price. *Third*, not all resources clear equally. New resources must bid less than the FCA clearing price to clear, while existing resources must bid less than the APR price to clear. *Fourth*, the APR price is computed by replacing the FCA bids of all OOM resources with administratively-determined estimates of their stand-alone economic costs. *Finally*, OOM is determined as under the February APR.

Q WHAT KIND OF BIDDING INCENTIVES DOES THE JUNE APR CREATE?

A Under the June APR, every bidder has a weakly dominant strategy to bid its economic cost.[16] (By contrast, I showed in Part Three that bidders sometimes stand to gain by bidding less than economic cost under the February APR.) There are two steps to the argument why. *First*, under the June APR, every bidder has bidding incentives *as if* in a uniform-price auction. *Second*, in any uniform-price auction, every bidder has a weakly dominant strategy to submit a bid equal to its economic cost on each unit of capacity.

Q PLEASE WALK US THROUGH THIS ARGUMENT. FIRST, WHY DOES EVERY BIDDER HAVE BIDDING INCENTIVES *AS IF* IN A UNIFORM-PRICE AUCTION?

A New resources must bid less than the FCA clearing price in order to clear and, when they clear, new resources are paid the FCA clearing price. Thus, new resources face the same strategic bidding problem *as if* in a uniform-price auction in which all resources' bids are equal to their bids in the FCA.

Existing resources must bid less than the APR price in order to clear and, when they clear, existing resources are paid the APR price. Thus, existing resources face the same strategic bidding problem *as if* in a uniform-price auction in which (i) all non-OOM

---

[16] "Weakly dominant strategy" and "economic cost" were defined in Part One.

bids are equal to their bids in the FCA and (ii) all OOM bids are equal to administratively-determined estimates of their stand-alone economic costs. (Given such bids, the market-clearing price is equal to the APR price under the June APR.)

Q SECOND, WHY DOES EVERY BIDDER IN A UNIFORM-PRICE AUCTION HAVE A WEAKLY DOMINANT STRATEGY TO BID ITS ECONOMIC COST ON EVERY UNIT OF CAPACITY?

A When a bidder submits a bid equal to its economic cost, that bidder will clear when the market-clearing price that it will be paid is greater than its economic cost, and not clear when the market-clearing price that it would have been paid is less than its economic cost. Thus, the resource in question clears when it is profitable to clear and avoids clearing when it is unprofitable to do so. In particular, bidding economic cost is always a best response, regardless of others' bids.

Q WILL THE JUNE APR INDUCE A LOWEST-COST ALLOCATION?[17]

A Since in-merit resources have an incentive—indeed, a weakly-dominant strategy—to submit bids equal to their stand-alone economic costs and OOM resources' bids are replaced with administrative estimates of their stand-alone economic costs when computing the APR price, my judgment is that the June APR will tend to come *closer* to reflecting a lowest-cost allocation than the February APR does.

However, there are circumstances in which the June APR will not achieve a lowest-cost allocation.

[17] "Lowest-cost allocation" and other terms used in the following discussion—such as "economic cost" and "stand-alone economic cost"—were defined in Part One.

Q CAN YOU PROVIDE AN EXAMPLE OF A SITUATION WHERE THE JUNE APR WILL NOT ACHIEVE A LOWEST-COST ALLOCATION?

A Yes. Consider the following scenario: (i) some new OOM resource bids less than the FCA clearing price; and (ii) this OOM resource has stand-alone economic cost greater than some in-merit resource that does not clear. This OOM resource is bid low enough to clear, but it is more costly than some resource that did not clear. Thus, the allocation does not minimize total cost.

Q UNDER THE JUNE APR, WILL THE APR PRICE EQUAL THE ECONOMIC PRICE OF RESERVE CAPACITY?[18]

A Given that a lowest-cost allocation is not always realized, the June APR will also not always set the APR price equal to the economic price of reserve capacity. Nonetheless, since OOM bids are replaced with estimates of their stand-alone economic costs—rather than left in the bid-stack and the APR set to the lower of CONE or one cent below the price of the lowest-bid new in-merit resource that did not clear—it is my judgment that the June APR will likely generate an APR price that more closely reflects the economic price than the February APR does.

Q UNDER THE JUNE APR, NEW RESOURCES ARE PAID LESS THAN EXISTING RESOURCES. DOES THIS TWO-TIERED PRICING STRUCTURE PROVIDE SOUND INCENTIVES FOR EFFICIENT ENTRY AND EXIT?

A Yes. I find the two-tiered pricing structure of the June APR to be economically sound.

To incentivize efficient investment and disinvestment in capacity resources, ideally we would like the FCA to generate a stream of auction payments, over each resource's

[18] The "economic price of reserve capacity" was defined in Part One.

lifetime, equal to the economic price of reserve capacity in every period. However, by design, the June APR only pays an APR price approximating the economic price of reserve capacity when a resource is "existing." "New" resources are paid the FCA clearing price, which tends to be lower than the APR price.

The advantage of paying existing resources a price that more closely reflects the economic price is that doing so—if one were to do so for the rest of a unit's operational lifetime—will allow existing in-merit resources to better internalize the future societal benefit of their continued operation.

Conversely, because new resources are paid a "too-low" price, in-merit resources have relatively weak incentives to enter. However, this may actually be a strength of the June APR. When OOM is *unavoidably* present in the FCM and it causes the supply stack to exceed the cumulative incremental installed capacity needs, it is *efficient* to provide in-merit resources with weaker incentives to participate in the FCM. This may sound paradoxical, so let me explain. Should all participants in the FCM be "efficiently incentivized" to participate by payments equal to the economic price, such incentives will coordinate their behavior so as to maximize social welfare. However, when some market participants—such as OOM resources—have "more-than-efficient" incentives to participate, social welfare is typically maximized by giving other market participants "less-than-efficient" incentive to enter.

Q PLEASE SAY MORE ABOUT WHY PAYING NEW RESOURCES LESS THAN THE APR PRICE MAY ACTUALLY BE A STRENGTH OF THE JUNE APR.

A If OOM resources are in ample supply, it is *prospectively* uneconomic to build new in-merit supply just because such supply would have been more economical ex ante. If new resources were paid the APR price, in-merit resources would have an incentive for such prospectively inefficient entry caused by the higher APR price. Instead, the June APR's two-tier pricing approach has the effect of minimizing the cost charged *through the ISO* for new capacity: if some new resources receive side payments outside of the FCA, those resources are allowed to displace another new resource, even if that other new resource would have been more efficient but for the side payments.

Q PLEASE RECAP YOUR VIEW ON THE TWO-TIERED PRICING STRUCTURE OF THE JUNE APR.

A The June APR's approach of paying new resources the FCA clearing price and paying existing resources the APR price is sound and sensible, for several reasons. *First*, should there be no OOM capacity, the FCA clearing price will be equal to the APR price and there will be no distortion of new in-merit bidders' incentives to enter. *Second*, when the presence of OOM depresses the FCA clearing price below the APR price, the June APR still provides some incentive for new in-merit resources to enter, but only if their cost of new entry is sufficiently low. Such reduced new entry incentives are appropriate to more efficiently rationalize the capacity mix in the FCM.[19] *Finally*, when the presence of OOM depresses the FCA clearing price below the APR price, paying the FCA clearing price could dissuade some high-cost OOM resources from inefficiently entering.

[19] Further, new resources are allowed to displace existing resources, potentially in two ways. *First*, if a new resource is bid below the FCA clearing price, that new resource will clear and an existing resource will no longer clear. (Put differently, such a low bid by a new resource will lower both the FCA clearing price and the APR price.) *Second*, if a new resource is bid between the FCA clearing price and the APR price, it will cause an existing resource to fail to clear—reducing the "overhang" of capacity supplied beyond Net ICR—while failing to clear itself.

PART FIVE: OTHER ISSUES

Q ARE THERE ANY OTHER ISSUES YOU WOULD LIKE TO ADDRESS IN YOUR TESTIMONY?

A Yes, there are two more issues that I would like to address. *First*, in their presentation on June 15, 2010, ISO-NE staff mentioned the possibility that they may "limit [the] period during which resources get the alternative price." Such a time-limit creates several potential problems. *Second*, because of some bidders' incentive for what I shall call "OOM evasion," some resources designated as "in-merit" could actually be OOM. If so, the APR price determined by the June APR could be substantially suppressed below the economic price of reserve capacity.

Q WHAT IS THE EFFECT OF PUTTING A LIMIT ON HOW LONG A RESOURCE IS QUALIFIED TO RECEIVE THE APR PRICE?

A Such a time limit creates several potential problems. First and most important, when new entry is needed, potential entrants will not be able to count on future auction payments equal to the future economic price of reserve capacity, reflecting the marginal social value of reserves. With lower anticipated future auction payments, their stand-alone economic costs in each individual auction will be higher.[20] In particular, new resources will demand an *initial* auction payment strictly in excess of what they would have demanded had there been no limit on how much time they would enjoy the APR price, after they have qualified as "existing" and become eligible to receive the APR price.[21] Indeed, putting a time-limit on when resources can receive the APR price will not have

---

20 "Stand-alone economic cost" was defined in Part One.

21 The economic cost of a new entrant accounts for expected future FCA payments. Decreasing future auction payments by $1 just increases by $1 how much that new entrant will demand up-front.

the effect of decreasing the lifetime auction payments that need to be paid to capacity resources. Instead, such a rule will simply "move the payments forward" to when a resource is first needed. This could increase the volatility of the FCA clearing price and, indeed, require the price sometimes to substantially *exceed* "administrative CONE" before new resources are incentivized to enter—even if administrative CONE is sensibly chosen to reflect what otherwise would be a reasonable estimate of economic CONE.[22] If risk-aversion is a significant factor for some resources, such volatility could also increase the expected cost of maintaining sufficient capacity

Q WHAT IS "OOM EVASION"?

A Under the June APR, a resource is designated as OOM when (a) its bid is less than 0.8 times the Benchmark Offer for that resource (what I will call its "OOM threshold") for that resource (see pg 36 of ISO-NE Presentation) and (b) this bid is not appropriately justified to the market monitor ahead of the auction, or when its delist bid is rejected for reliability reasons. Thus, a "truly OOM" resource whose economic cost is less than its OOM threshold could in principle avoid being designated as OOM by bidding its OOM threshold, instead of bidding its economic cost.

Q WHY MIGHT A BIDDER WANT TO EVADE BEING DESIGNATED AS OOM IN THIS WAY?

A For purposes of determining the APR price, its bid will be 0.8 times the Benchmark Offer. By contrast, if it submits a lower bid and is designated as OOM, its bid will be replaced by a higher bid equal to 0.9 times the Benchmark Offer. Thus, a bidder with

22 "Economic CONE" and "administrative CONE" were defined in Part One.

buyer-side market power—who stands to gain when the APR price is lower—may have an incentive to engage in OOM evasion.

Given OOM evasion, the set of resources designated as "out-of-market" could be biased *not* to include "truly OOM" resources controlled by bidders with buyer-side market power. In other words, the set of resources designated as "in-merit" could include some "truly OOM" resources that enjoy substantial market power. If so, bidders with buyer-side market power could, using the defined OOM threshold, successfully suppress the APR price below the economic price of reserve capacity.

The possibility of OOM evasion by those with buyer-side market power is not new to the June APR. Under the February (and Historic) APRs, bidders with buyer-side market power also have the ability to potentially lower the APR price via OOM evasion.

Q IS "OOM EVASION" MORE OR LESS OF A CONCERN UNDER THE JUNE APR?

A On balance, OOM evasion by bidders having buyer-side market power appears to be less of a concern under the June APR than under the February APR. The reason is that, in the June APR, raising one's bid to the OOM threshold has an additional cost for such bidders of raising the FCA clearing price. Thus, any benefit from lowering the APR price paid to existing resources could be partially offset by the cost of raising the FCA clearing price paid to new resources.

PART SIX: CONCLUSION

Q CAN YOU PLEASE SUMMARIZE THE MAIN POINTS OF YOUR TESTIMONY?

A In my testimony, I have tried to emphasize a few main points.

First, the June APR represents a substantial improvement over the February APR, in terms of generating an APR price that reflects the cost of new entry when new entry is needed or when the need for new entry has been deferred due to carry-forward OOM resources. *Second*, the two-tier pricing approach introduced in the June APR is sensible and economically sound. *Third*, some features that ISO-NE is considering adding to the June APR—such as a limit on how long resources can qualify as "existing" to receive the APR price—may undermine its performance.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and New England Power Pool	))	Docket No. ER10-787-000
New England Power Generators Association Inc. v. ISO New England Inc.	)))))	Docket No. EL10-50-000
PSEG Energy Resources & Trade LLC, PSEG Power Connecticut LLC, NRG Power Marketing LLC, Connecticut Jet Power LLC, Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, and Somerset Power LLC v. ISO New England Inc.	)))))))))	Docket No. EL10-57-000

I, David L. McAdams, being duly sworn, depose and state that the contents of the foregoing Testimony on behalf of the New England Power Generators Association is true, correct, accurate and complete to the best of my knowledge, information, and belief.

David McAdams

SUBSCRIBED AND SWORN to before me this 24th day of June 2010.

(Notary Public)

My commission expires: May 10, 2014

David McAdams

Associate Professor of Business Administration and Economics
Duke Fuqua School of Business and Department of Economics
Durham, NC 27708
david.mcadams@duke.edu

Degrees

BS 1996, Applied Mathematics, Harvard University.

MS 2001, Statistics, Stanford University.

PhD 2001, Business, Stanford University.
Dissertation: "Essays in Multi-Unit Auction Theory".
co-Advisors: Professors Paul Milgrom and Robert Wilson.

Experience

Duke Fuqua School of Business and Department of Economics.
Associate Professor (with tenure), since 2008.

MIT Sloan School of Management, Applied Economics.
Associate Professor (without tenure), 2007-2008.
Cecil and Ida Green Career Development Professor, 2006-2008.
Assistant Professor, 2001-2007.

Federal Trade Commission.
Special Assistant to the Director, Bureau of Economics, May – December 1999.
Consultant, January – May 2000.

Honors

National Science Foundation, Economics Program, Research Grant #SES-0820051 for "Endogenous Exit from a Stochastic Partnership", 2008-2011.

National Science Foundation, Economics Program, Research Grant #SES-0241468 for "Ordinal Structure in Multi-Unit Auctions", 2003-2006.

Stanford Institute for Economic Policy Research, Olin Dissertation Fellowship, 2001.

State Farm Dissertation Award in Business, 2001.

Jaedicke Scholar, Stanford Graduate School of Business, 1997.

Harvard National Scholar, 1992.

Journal articles

[1] "Isotone Equilibrium in Games of Incomplete Information", *Econometrica*, August 2003, 71(4), 1191-1214.

[2] "Monotone Equilibrium in Multi-Unit Auctions", *Review of Economic Studies* October 2006, 73(4), 1039 - 1056.

[3] "Monotonicity in Asymmetric First-Price Auctions with Affiliation", *International Journal of Game Theory*, February 2007, 35(3), 427-453

[4] (with Michael Schwarz) "Credible Sales Mechanisms and Intermediaries", *American Economic Review*, March 2007, 97(1), 260-276.

[5] "Adjustable Supply in Uniform Price Auctions: Non-Commitment as a Strategic Tool", *Economics Letters*, April 2007, 95(1) 48-53.

[6] (with Michael Schwarz) "Perverse Incentives in the Medicare Prescription Drug Benefit", *Inquiry*, Summer 2007, 44(2), 157-166.

[7] "Uniqueness in Symmetric First-Price Auctions with Affiliation", *Journal of Economic Theory*, September 2007, 136, 144-166.

[8] (with Michael Schwarz) "Who Pays When Auction Rules are Bent?", *International Journal of Industrial Organization*, October 2007, 25(5), 1144-1157.

[9] "On the Failure of Monotonicity in Uniform-Price Auctions", *Journal of Economic Theory*, November 2007, 137, 729-732.

[10] "Partial Identification and Testable Restrictions in Multi-Unit Auctions", *Journal of Econometrics*, September 2008, 146(1), 74-85.

Conference proceedings, etc.

[11] (with Yuzo Fujishima and Yoav Shoham) "Speeding Up the Ascending-Bid Auction". *International Journal Conference in Artificial Intelligence (IJCAI) Proceedings 1999*, pp. 554-559.

[12] (with James Chapman and Harry Paarsch) "Bounding Revenue Comparisons across Multi-Unit Auction Formats under epsilon-Best Response", *American Economic Review, Papers and Proceedings*, May 2007, 97(2), 455-458.

Working papers

[13] (with Ali Hortacsu) "Mechanism Choice and Strategic Bidding in Divisible Good Auctions: An Empirical Analysis of the Turkish Treasury Auction Market".

[14] "Performance and Turnover in a Stochastic Partnership". [Previous version titled "Dynamics in an Evolving Partnership".]

[15] “Discounts for Qualified Buyers Only” [Previous version titled “Endogenous Monopoly Market Segmentation”.]

[16] (with Yingyao Hu and Matthew Shum) “Nonparametric Identification of Auction Models with Non-Separable Unobserved Heterogeneity”.

[17] (with James Chapman and Harry Paarsch) “Bounding Best Response Violations in Discriminatory Auctions with Private Values”.

[18] (with Giuseppe Lopomo, Leslie Marx, and Brian Murray) “Carbon Allowance Auction Design”

Invited Presentations

Federal Energy Regulatory Commission [5], 1999

International Journal Conference in Artificial Intelligence [11], 1999

U. Maryland Economics [5], 1999

Carnegie-Mellon GSIA [2], 2001

Harvard Kennedy School of Government [2], 2001

MIT / Harvard Economics [1], 2001

MIT Sloan School of Management [2], 2001

Northwestern Economics [2], 2001

NYU Stern School of Management [2], 2001

WUSL Olin School of Business [2], 2001

Yale Economics / School of Management [2], 2001

CalTech Economics [2], 2002

U. Chicago Economics [1], 2002

Duke/U. North Carolina Economics [2], 2002

IO Theory Conference (at Texas) [1], 2002

U. Iowa Tippie College of Business [2], 2002

U. Maryland Economics [2], 2002

U. Michigan Economics [2], 2002

Midwest Theory Conference [1], 2002

MIT / Harvard Economics [3], 2002

Penn State Economics [2], 2002

Society of Economic Design Conference [5], 2002

Stony Brook Game Theory Conference [2], 2002

American Mathematics Society Annual Meetings [1], 2003

UC Berkeley Economics [3], 2003

UC Energy Institute [5], 2003

CalTech Economics [3], 2003

U. Chicago Economics [2], 2003

Econometric Society Annual Winter Meetings [1], 2003

International IO Conference [9], 2003

Northwestern Economics [3], 2003

Ohio State Economics [2], 2003

Princeton Economics [3], 2003

Stanford Institute for Theoretical Economics [2], 2003

U. Arizona Economics [7], 2004

U. Chicago Economics [10], 2004

Econometric Society Annual Summer Meetings [2], 2004

U. Illinois Economics [7], 2004

MIT / Harvard Economics [10], 2004

Northwestern Economics [5], 2004

Northwestern Kellogg School of Management [10], 2004

Pitt Economics [7], 2004

Rutgers Economics [7], 2004

WBZ Berlin "Advances in Auction Theory" Conference [7], 2004

UC Berkeley Economics [10], 2005

U. Chicago GSB [4], 2005

CIREQ Conference on Auctions [10], 2005

Columbia Economics / GSB [4], 2005

Penn Economics [4], 2005

Penn State Economics [10], 2005

Stanford Economics / GSB [4], 2005

Econometric Society Annual Winter Meetings [5], 2006

Econometric Society Annual Summer Meetings (by co-author) [4], 2006

U. Maryland Economics [4], 2006

U. Minnesota Economics [17], 2006

NYU Stern School of Management [4], 2006

U. Texas Economics [4], 2006

U. Wisconsin Economics [4], 2006

Yahoo! Research [8], 2006

American Economic Association Annual Winter Meetings (by co-author) [12], 2007

CalTech Economics [14], 2007

UCLA Economics [14], 2007

Duke/U. North Carolina Economics [10], 2007

Harvard/MIT Economics [14], 2007

IO Theory Conference (at Duke) [14], 2007

Johns Hopkins Economics [14], 2007

U. Michigan Economics [14], 2007

MIT Economics (IO Lunch) [13], 2007

Northwestern Kellogg [14], 2007

NYU Economics [14], 2007

Penn State Economics [14], 2007

GAMES 2008, Third World Congress of Game Theory Society [14] (talk canceled for personal reasons), 2008

Econometric Society Annual Winter Meetings [14], 2009

NBER Conference on Relational Contracts [14], 2009

UCLA Economics [15], 2009

Washington U. St. Louis [14], 2009

Utah Winter Business Economics Conference [14], 2010

Ohio State Economics [15], 2010

Invited Presentations, by institution: U. Arizona [2004], UC Berkeley [2003,2005], UC Energy Institute [2003], UCLA [2007,2009], CalTech [2002,2003,2007], Carnegie-Mellon GSIA [2001], U. Chicago [2002,2003,2004,2005], Columbia [2005], Duke/U. North Carolina [2002,2007], Federal Energy Regulatory Commission [1999], Harvard/MIT [2001*2,2002,2004,2005,2007], U. Illinois [2004], U. Iowa [2002], U. Maryland [1999,2002,2006], U. Michigan [2002,2007], U. Minnesota [2006], Northwestern [2001,2003,2004*2,2007], NYU [2001,2006,2007], Ohio State [2003,2010], U. Penn [2005], Penn State [2002,2005,2007], U. Pittsburgh [2004], Princeton [2003], Rutgers [2004], Stanford [2005], U. Texas [2006], Washington U. St. Louis [2001,2009], U. Wisconsin [2006], Yahoo! Research [2006], Yale [2001]

Professional Activities

Associate Editor, *International Journal of Industrial Organization*, since 2006.

Associate Editor, *Review of Economic Design*, since 2008.

Referee for *American Economic Review*, *Econometrica*, *Games and Economic Behavior*, *International Journal of Industrial Organization*, *Journal of Economic Literature*, *Journal of Economic Theory*, *Journal of the European Economic Association*, *Management Science*, *National Science Foundation*, *RAND Journal of Economics*, *Review of Economic Design*, *Review of Economic Studies*