UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England, Inc. and New England Power Pool Participants Committee	)	Docket No. ER10-787-000
New England Power Generators Association 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

DIRECT TESTIMONY OF JAMES F. WILSON
IN SUPPORT OF FIRST BRIEF OF
THE JOINT FILING SUPPORTERS

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I. Introduction

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

A: My name is James F. Wilson. I am an economist, principal of Wilson Energy Economics, and affiliate of LECG, LLC. My business address is 4800 Hampden Lane Suite 200, Bethesda, MD 20814.

Q 2: Have you previously submitted testimony in this proceeding?

A: Yes. My direct testimony on behalf of the Connecticut Department of Public Utility Control ("DPUC") was submitted in this proceeding on March 30, 2010 ("March Testimony"). (Direct Testimony of James F. Wilson on Behalf of the Connecticut Department of Public Utility Control, Exhibit DPUC-1 to Motion to Answer and Answer of the Connecticut Department Of Public Utility Control, the Vermont Public Service Board, the Vermont Department of Public Service and The Northeast Utilities Companies, *ISO New England Inc. and New England Power Pool*, Docket No. ER10-787-000 filed March 30, 2010). A description of my experience and qualifications was included in the March Testimony, and my CV, listing past testimony, was attached to it.

Q 3: Please describe the purpose of this stage of the proceeding.

A: On April 23, 2010, the Federal Energy Regulatory Commission ("FERC" or the "Commission") issued an order ("April Order") with regard to the revisions to the Forward Capacity Market ("FCM") capacity construct ("Joint Filing") filed on February 22, 2010 by ISO New England Inc. ("ISO-NE") and the New England Power Pool ("NEPOOL"). The April Order set certain issues for paper hearing and called for parties to file First Briefs addressing these issues.

Q 4: What is the scope of your testimony at this time?

A: The April Order set three elements of the FCM design for paper hearing: the Alternative Price Rule ("APR"); the provisions pertaining to definition and formation of capacity zones; and FCM's "Cost of New Entry" ("CONE") parameter and related parameters. I was asked by counsel for the DPUC to address some aspects of each of the three topics.

II. Summary and Conclusions

Q 5: Please summarize your testimony regarding the Alternative Price Rule.

A: The April Order stated that the APR is a market power mitigation rule (P 69) and suggested that it should apply to resources that are inappropriately suppressing prices (P 77). The April Order also noted that Commission precedent requires bright-line measures (P 77). In my testimony I propose a bright-line test, consistent with the guidance provided in the April Order, that would identify 1) buyers that may have an incentive and ability to attempt to suppress market prices; 2) resources offered by such buyers that were subsidized, contracted or acquired for the purpose of suppressing market prices and, therefore, should be mitigated; and 3) offers for other new resources of net buyers that may be so low as to indicate an attempt to suppress market prices and, therefore, may also warrant mitigation. I explain why the latter part of the test should focus on net going-forward cost, not net long-run average cost, which would lead to mitigation of resources that are not being used to suppress market prices. The APR should be triggered only by resources failing this bright-line test (which I refer to as the Mitigated Out-of-Market, or "MOOM", resources), and if the APR pricing rule will entail removal or re-pricing of some resources in the auction, only the MOOM resources identified according to the bright-line test should be removed from the auction or re-priced.

Q 6: Please summarize your testimony regarding the FCM CONE parameter.

A: The only issue identified by the April Order was the 0.75 CONE threshold for possible OOM identification, and this threshold is no longer needed if a bright-line test is used in the APR. No reset of the CONE parameter is needed.

FCM rules call for updating the FCM CONE parameter based on auction clearing results when there is a need for new resources, and this is an appropriate mechanism that will keep the parameter close to clearing results, as it needs to be. There is no justification for raising the FCM CONE parameter, and this would have the effect of allowing exercise of market power to raise FCA prices above the levels at which they would clear absent market power.

Q 7: Please summarize your testimony regarding the modeling of capacity zones.

A: The April Order set for paper hearing the question of whether zones should always be modeled and some issues about market power mitigation. In my testimony, I suggest that the approach to expansion of zonal capacity pricing should be cautious (as reflected in the Joint Filing), and I identify a number of reasons for concern that more extensive modeling of capacity zones may reduce rather than increase the efficiency of New England's capacity market.

1. Zonal capacity pricing has been used extensively in PJM, extending over seven delivery years. There is now an accumulation of evidence that, contrary to theory, higher zonal capacity prices do not attract and retain relatively more capacity into the higher-priced zones. There are three principal reasons for the failure of zonal capacity pricing to achieve its objectives. First, the zonal prices have been highly volatile, and apparently the markets have not found them to be credible price signals.

Second, zonal pricing creates strong incentives for incumbents to withhold existing and incremental capacity from the zones, incentives that do not exist if zones are not defined, and the capacity must compete in the broader, more competitive "Rest of RTO" region. Third, the constrained areas tend to be the relatively developed regions where it can be more difficult to identify sites and obtain all regulatory approvals to build new capacity and uncertain, volatile zonal prices are not sufficient to offset those difficulties.

2. Zonal capacity pricing creates strong incentives for entities with portfolios of capacity located in zones to withhold (de-list) capacity from the zones to attempt to raise zonal prices. New England's zones are generally quite small, and capacity ownership in them is concentrated. Zonal pricing will create much stronger incentives to withhold than exist when capacity is sold into the broader ISO New England market area.

3. Mitigation of the incentive and ability to withhold from New England's zonal capacity markets can only be partially effective. Incentives are generally not mitigated, and the ability to withhold incremental capacity is also generally not mitigated. Approaches to mitigating the ability to withhold existing capacity are only partially effective.

4. Zonal capacity pricing can also reduce efficiency if the local sourcing requirements are overly conservative, as this will raise zonal capacity prices above efficient levels and suppress capacity prices in surrounding areas below efficient levels.

5. In addition, the FCM descending clock auction approach, in combination with the fact that sellers submit de-list bids in real-time and the directions of capacity flows

between zones are not known until such de-list bids are submitted, pose some unique challenges not faced in other regions that have applied zonal capacity markets. While an effective solution approach can probably be designed, this should not be rushed, especially in light of the questionable impact and benefits of zonal capacity pricing.

III. Alternative Price Rule

Q 8: What issues did the April Order set for paper hearing with respect to the Alternative Price Rule (APR)?

A: The April Order set three issues for paper hearing (P 18):

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 the APR.

I will address the first and third of these issues in this testimony.

A. Triggering Conditions for the APR

Q 9: What guidance did the Commission provide with regard to the triggering conditions for the APR?

A: The Commission stated (P 69) that the "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." With regard to the triggering conditions for the APR, the April Order suggested some guiding principles:

- "The APR should be triggered when a buyer is in a position to exercise market power. A critical element is the determination of resources that are OOM because these are the resources that buyers might subsidize and offer non-competitively in order to suppress market-clearing prices." (P 75).
- "However, it may be reasonable to exempt OOM resources from mitigation when it is shown that they are not being used as a market power tool." (P 76).
- "It would not be reasonable to trigger APR market power mitigation for an existing OOM resource in a given year if that resource has not inappropriately suppressed the market clearing price in that year." (P 77).

- "Thus, some limitations on when an OOM resource may trigger APR mitigation may be reasonable, in order to identify situations where an OOM resource is likely to inappropriately suppress the market price." (P 77).
- "In general, Commission precedent requires bright-line measures or tests to distinguish OOM capacity that should trigger APR mitigation (i.e., that used as a tool for price suppression) from capacity that should not trigger such mitigation because it does not inappropriately suppress market-clearing prices below a competitive level." (P 77) (internal citation omitted).

Q 10: Do you agree with these principles for the determination of the APR triggering conditions?

A: Yes, these are the right principles for identifying the circumstances under which resources should be mitigated. To summarize, based on this guidance, the triggering conditions should have the following characteristics:

1. Be a "bright-line" test;
2. Distinguish *buyers* who might have the incentive and ability to suppress Forward Capacity Market ("FCA") prices from other market participants who clearly lack such incentive and ability, and whose offers, therefore, do not raise concerns about buyer market power;
3. Identify any new *resources* offered by such net buyers that were purchased, contracted or subsidized with the primary purpose of suppressing FCA prices (and, therefore, should be mitigated) from other resources that were acquired or subsidized for legitimate purposes;
4. Identify any new resources offered by net buyers that, while the resource was not acquired or subsidized to suppress FCA prices, the resource's *offer price* might reflect an inappropriate attempt to suppress the FCA price and should be mitigated.

In addition, the bright-line test should be capable of administration mechanically without requiring the market monitor to exercise significant subjective judgment; the Commission has rejected market rules that afford market monitors substantial discretion in these matters. *See PJM Interconnection, L.L.C.,* 119 FERC ¶ 61,318 (2007) at P 180; *PJM Interconnection, L.L.C.,* 117 FERC ¶ 61,331 (2006) at P 115.

Q 11: Is the definition of OOM currently in the ISO-NE Tariff ("the Tariff") consistent with these principles?

A: No, not at all. The existing definition of OOM casts much too wide a net, and fails to identify the subset of OOM resources that should be mitigated consistent with the April Order.

As the April Order notes (P 40), the Tariff presently defines "OOM capacity" as capacity whose offer price, in the opinion of the Internal Market Monitor ("IMM"), is "below the resource's long-run average costs net of expected non-capacity market revenues" (citing the ISO-NE Tariff § III.13.1.1.2.6). Although the Joint Filing "clarified" this definition, it did not change its substance. Prepared Testimony of David LaPlante on behalf of ISO New England Inc., February 22, 2010 in ER10-787-000, p. 3. This definition of OOM – an offer below the resource's long-run average cost – was developed in conjunction with rules that would trigger the APR only infrequently, and have a limited impact on price when triggered. If the APR is revised to be applicable more frequently or with greater impact on price, it should be triggered consistent with the principles set forth in the April Order summarized above and should apply to only those resources where there is evidence that they were offered into the FCA in order to affect the clearing price.

To be clear about the distinction between out-of-market resources as presently defined in the Tariff ("OOM" resources), and the subset of the out-of-market resources that, according to the Commission's guidance and an appropriate bright-line test based on that guidance, should trigger the APR and be mitigated, I will refer to the latter as "Mitigated Out-of-Market" resources, or "MOOM" resources. Only MOOM resources, not all OOM resources, should trigger the APR rule and be mitigated.

Q 12: Why should the bright-line test distinguish buyers who are likely to have the ability and incentive to use new resources to suppress FCA clearing prices from other market participants lacking such ability and incentive?

A: Including this element in the bright-line test is important for two reasons. First, it prevents inappropriately mitigating competitive offers from market participants who remain in the auction at low prices out of a desire to clear in the auction, not because they have any intent to suppress the clearing price. As I explained in the March Testimony (at 13:1 – 15:19), even merchant capacity resources that receive no subsidies and have no bilateral contracts may nevertheless be offered into the FCA at low prices. For instance, a resource that is already under construction at the time of the FCA may rationally, competitively, and legitimately stay in the descending clock auction at prices down to the level of its net going-forward or opportunity cost. Such resources have no intention to lower the FCA price and are not being used to exercise buyer market power. Their low offers represent competitive behavior that should not be mitigated.

Second, this part of the test is also important to prevent manipulation of the APR rule by a capacity seller attempting to *raise* the FCA price. A capacity seller might prefer that its new resources be designated MOOM in order that they be mitigated, resulting in a higher APR-based price earned by the seller's other capacity resources. That would of course be contrary to the purpose of the rule, and limiting MOOM to resources owned by net buyers eliminates the potential for such abuse of the APR rule.

Q 13: How should the bright-line test distinguish buyers who are at all likely to have the ability and incentive to use new resources to suppress FCA clearing prices?

A: The rules should exclude from possible MOOM designation any resource that is not owned by or contracted to a net buyer of capacity. Only net capacity buyers would potentially have an incentive to attempt to lower FCA prices.

An example of a bright-line test for a net buyer is found in PJM's Minimum Offer Price Rule ("MOPR"), a rule that is intended to serve the same purpose as FCM's APR. The MOPR excludes from mitigation any resource unless its owner has a "net short position" that exceeds a threshold (ten percent of the reliability requirement in smaller zones, five percent in larger zones). PJM Tariff, Attachment DD, §5.14(h)(3)(iii).

To ensure that this part of the test does not inappropriately exclude from possible MOOM classification resources whose offers may reflect an attempt to suppress prices, the test should recognize that under some circumstances an entity may not be a net buyer, but may essentially be acting as a net buyer, due, for instance, to a regulatory of legislative action applicable to the entity. For example, if state legislation required a load-serving entity to contract for resources and offer them into FCM in order to suppress the clearing prices, the resulting resources should be classified MOOM even if the entity happens to not be a net buyer of capacity. The bright-line test should include language to address such circumstances.

Q 14: How could a bright-line test distinguish resources of net buyers that are being offered in an attempt to inappropriately suppress the FCA price from others that are not?

A: If a resource is receiving an incentive (subsidy), has a bilateral contract with a net buyer, or is owned by a net buyer, and a primary purpose of the incentive, contract, or purchase was to lower FCA prices, the resource would be classified MOOM. The resource, or some part of its offer price, would be subject to mitigation.

A new resource that is receiving an incentive, has a bilateral contract, or was purchased by a net buyer should not be classified MOOM, however, solely on the basis of the existence of the incentive, contract, or purchase if the incentive, contract or purchase had

a legitimate purpose. For instance, if the incentive, contract or purchase was authorized or required by a state legislative or regulatory policy to provide local resource adequacy, environmental benefits, fuel diversity, or to attract renewable or demand response resources, then the presence of the resulting resources in the auction reflects fulfillment of a legitimate public policy purpose and does not constitute an attempt to suppress FCA prices. Such resources should not be treated as if they were being used to suppress FCA prices.

Note that this part of the test considers the acquisition or subsidization of the resource, not the price at which the resource is being offered, which I propose should be a separate part of the test.

Q 15: Finally, how should the bright-line test identify any new resources offered by net buyers that, while not acquired or subsidized to suppress the FCA price, are being offered at low prices that might reflect an inappropriate attempt to suppress the FCA price, and, therefore, may warrant mitigation?

A: The test should compare the resource's offer price to the resource's estimated net going forward cost, a concept already defined in the ISO-NE Tariff (§ III.13.1.2.3.2.1.2). New resources owned by net buyers or net sellers may be offered at prices close to net going-forward cost, and such offers may simply represent competitive conduct and a desire to clear in the auction. As long as the auction clears at a price above a resource's net going-forward cost, the resource can operate profitably under a capacity supply obligation.

If the sponsor believes the project will be profitable over its lifetime and has decided to go forward with it, or if the sponsor is largely committed to building the project due to a bilateral contract or already-sunk construction costs, the sponsor might rationally offer the project into the FCA for the first year of operation and be satisfied with any

contribution to paying down the fixed costs that the auction might offer. To express this strategy, the project would be offered at its first year net going-forward cost, and to the extent the auction clears at a higher price, the project will earn something toward recovery of the fixed construction cost. Indeed, under some competitive circumstances the sponsor of a resource might offer it at a price even below its net going-forward cost, for instance, if the sponsor is concerned that other, competing generation or transmission projects will be more likely to proceed if the resource fails to clear in the FCA.

For example, suppose the project's first-year net going-forward cost is $3/kW-month. If it de-lists from the auction at $5/kW-month and the auction clears at $4/kW-month, the sponsor has missed the opportunity to earn $1/kW-month over its net going-forward cost toward fixed cost recovery. If the sponsor has decided to go forward with the project (for whatever reasons), it makes no sense to pass up this opportunity; the resource should have been offered at $3/kW-month (unless, of course, there is another, more attractive opportunity, for instance, to sell the capacity into an adjacent RTO market at a higher price).

Q 16: How would the estimated net going-forward cost of a new resource be determined for the purpose of the bright-line test?

A: The Tariff already calls for new resources to provide cost information for the purpose of OOM evaluation (§ III.13.1.1.2.6). Similar language would allow determination of net going-forward cost.

Under some circumstances, a resource's net going-forward cost may be zero. The Tariff defines going-forward cost as "costs that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the

Capacity Commitment Period…" (§ III.13.1.2.3.2.1.2). If a resource has been contracted and is required to operate to meet a legitimate public policy requirement (for instance, a renewable resource target), then shutting down may not be an option, few if any costs may be avoidable, and net going-forward cost may be zero. In this example, the resource would legitimately be offered as a price-taker at a zero price (or a somewhat higher price if there are costs associated specifically with the capacity supply obligation).

The information required to determine a resource's first-year net going-forward cost is much simpler and more straightforward than required by the existing OOM definition, which requires estimation of long-run average cost and revenue. However, to reduce the administrative burden for market participants and the internal market monitor, the internal market monitor could develop estimated net going-forward costs by resource type, with offers above these levels not subject to the more detailed review (*i.e.*, serving a function similar to the 0.75 CONE threshold presently in the Tariff).

Q 17: In determining a resource's net going-forward cost, how would any subsidies or contractual revenues that the resource expects to receive, and that reduce the net going-forward cost, be treated?

A: Such revenues would be reflected in (subtracted from) the estimated net going-forward cost, if those revenues are being provided in fulfillment of legitimate purposes, and not to suppress FCA prices. For example, if a renewable resource has a net going-forward cost of $4/kW-month, and receives contract revenues of $1/kW-month that were allotted to the resource through state legislation to encourage development of renewable resources, the resource's net going-forward cost would be $3/kW-month. The existing OOM definition contains language that allows for consideration of such revenues, and similar

language would be appropriate to reduce net going-forward cost based on the amount of subsidies or contract revenues paid pursuant to legitimate policy objectives.

Q 18: Would it be appropriate to use the comparison between a resource's offer price and its net long-run average cost (as under the current OOM definition) as part of a bright-line test for whether an offer should be classified as MOOM and mitigated?

A: No, it would not. This test rests on the fallacious concept that a resource acting competitively should be expected to offer into the FCA at a price based on its net long-run average cost. I explained the flaw in this concept in my March Testimony (at 13:6 – 15:19) and in Section 5 of the attached paper, *Forward Capacity Market CONEfusion*, June 2010 (Exhibit DPUC-22). As explained above, the sponsor of a new resource – whether a net seller or net buyer – acting competitively may remain in the auction as long as price exceeds net going-forward cost or opportunity cost.

Q 19: Does applying some multiplier (such as 0.8) to long-run average cost address the problem you have identified with using this value in a bright-line test?

A: No, not at all. Any such multiplier is arbitrary and unrelated to the economics of the situation. For some types of resources, net going-forward cost could be a low percentage of the calculated long-run average cost, and a multiplier such as 0.8 would preclude a competitive offer based on net going-forward cost.

Q 20: Are there other reasons why long-run average cost is not an appropriate value to use for the bright-line test?

A: Yes. In addition to long-run average cost being the wrong economic concept, there could be many reasons a sponsor could calculate a very different long-run average cost than the IMM may estimate. The sponsor may choose to evaluate the project using a longer project useful life or lower expected interest rates than the IMM. Or the sponsor may elect to use a lower discount rate for levelizing costs and revenues and determining long-run averages when costs and revenues change over time. The sponsor may be more

optimistic about future market conditions and anticipate rising energy and ancillary services revenues or capacity revenues over time, such that the project can earn little or nothing toward its fixed costs in the first years of operation and still expect to be profitable over the life of the project. Starting with an estimate of a resource's "long-run average cost" and uncertain projections about future revenues as the basis for the test requires that the IMM exercise substantial discretion to ensure that offers are not inappropriately mitigated. By contrast, net going-forward cost can be and is relatively precisely defined.

Q 21: Can you cite any examples familiar to the Commission where project sponsors are willing to go forward with major fixed investments despite lacking assurance of earning long-run average cost in the first years of operation?

A: Yes. The sponsors of new natural gas pipeline projects often enter into agreements for discounted rates below the average cost-based rates that would provide full cost recovery. This is not interpreted as meaning that the sponsor is planning to lose money or is attempting to suppress the market price for gas transmission capacity. The sponsor most likely believes that over the long-run there will be additional opportunities for cost recovery. The sponsor may also be reacting to competitive pressures if there are proposals for competing pipeline capacity.

Q 22: If all new resources are required to de-list based on net long-run average cost, what would the result be for New England's capacity market?

A: To have all sellers offer their new capacity based on net long-run average cost is roughly what a sellers' cartel (an organization or agreement among firms expressly formed to limit competition) would attempt to achieve. Under that arrangement, some market participants would be prevented from offering their new capacity at legitimate, competitive prices, and some of the resources that participants are willing to provide to

the market would fail to clear. Capacity sellers would always earn net long-run average cost while in some years when capacity is tight they would earn higher prices, making the market supra-profitable for all.

Q 23: Please summarize your testimony with regard to the triggering conditions for the APR.

A: A bright-line test should be used for determining the subset of the OOM resources that should be mitigated (the mitigated Out-of-Market resources, or MOOM resources). The bright-line test should have the following elements:

1. Only resources of net buyers may be classified as MOOM; resources owned by or contracted to entities that are not net buyers should not be classified as MOOM;

2. Resources receiving an incentive, contracted, or purchased by a net buyer with a primary purpose of suppressing the FCA are classified as MOOM; resources that are in the FCA due to legitimate public policy purposes should not be classified as MOOM on the basis of the subsidy or contract.

3. Resources of net buyers may be designated MOOM and mitigated if their offer prices are below their net going-forward cost. The calculation of net going-forward cost should reflect any subsidies or contractual revenues provided for legitimate purposes, but not revenues provided with intent to suppress FCA prices.

B. Price Adjustment Under the APR

Q 24: Turning now to the pricing provisions of the APR, what guidance did the April Order provide in that regard?

A: The April Order did not provide specific guidance as to the pricing approach, but directed the parties to address "whether further changes are necessary to the price adjustment aspects of the APR." (P 87). The April Order also "encourage[d] the development of

mitigation mechanisms that result in market clearing prices that do not reflect the exercise of market power." (*Id.*).

Q 25: If the APR pricing rule will calculate the APR price after removing from the auction or re-pricing certain resources, which resources should be treated in this manner?

A: If the APR pricing rule will operate in this manner, it should remove or re-price only the resources that should be mitigated (MOOM resources), identified according to the bright-line test I described in the preceding paragraphs.

Q 26: Why is it appropriate to apply the APR pricing rule only to MOOM resources, not all OOM resources?

A: As I described earlier, the Tariff's definition of OOM casts much too broad a net and would result in mitigation of offers that do not represent attempts to inappropriately suppress FCM prices. The April Order recognized that OOM resources are the resources "that buyers *might* subsidize and offer non-competitively in order to suppress market-clearing prices" (P 75, emphasis added) and that "it may be reasonable to exempt OOM resources from mitigation when it is shown that they are not being used as a market power tool." (P 76).

Q 27: The April Order also states (P 70) that the existing APR "does not ensure that capacity market prices reflect the market cost of new entry when new entry is needed," suggesting this is a goal of the APR. How should this goal be understood?

A: The FCM is designed to allow prices to rise to the level necessary to clear sufficient capacity when new capacity is needed. With a revised APR that mitigates MOOM resources, the FCA clearing prices will not reflect any inappropriate attempts to suppress them.

However, as I explained in the March Testimony (at 13:1 to 15:19), we should not expect new resources to be offered into the FCAs at prices that reflect their net long-run average

cost or their levelized net cost of new entry. New entry offer prices may be above or below such levels, reflecting the circumstances and expectations of each project sponsor. The results of the capacity auctions in New England and PJM show that new capacity is not offered at prices based on net long-run average costs (March Testimony at 16:12-17, and Forward Capacity Market CONEfusion, Section 3).

Exhibit DPUC-4 shows the remaining supply by round in the first three FCAs, showing that very little capacity exited the auctions between the first and last rounds. Of the capacity that did exit, some unknown portion was existing capacity. Of the 905 MW that exited FCA 3 between the first and final round, over two-thirds exited in the round in which the price crossed the 0.8 CONE threshold, suggesting that much or all of it was existing resources that dynamically de-listed at prices near the 0.8 CONE threshold for such bids. Thus, although the public data is not sufficient to identify the precise amount of new capacity available within a wide range of prices such that the auction might determine whether or not it would clear, it is clearly very low.

Exhibits DPUC-5, DPUC-6 and DPUC-7 depict supply curves from the capacity auctions under PJM's RPM capacity construct, and show the same phenomenon: The supply curves are steep, suggesting that very little capacity is offered at prices such that the auction will determine whether or not it will clear. As in New England, of the small amount of capacity offered into RPM at prices that put clearing in any question, much of it is existing capacity.

Because the sponsors of new resources will likely have widely varying estimates of their costs and future market revenues, and because in any case they generally will not offer their new resources at prices based on net long-run average costs even when entry is

needed, the FCA supply curves will not include a significant amount of capacity at some "cost of new entry" level, and the auctions are not going to discover and reveal a cost of new entry.

IV. Proper Value of CONE and Related Parameters

Q 28: What issues did the April Order set for paper hearing with respect to the FCM CONE parameter?

A: The April Order set the following issue for paper hearing (P 18): "Whether the value of CONE should be reset."

Q 29: What guidance did the Commission provide with regard to CONE?

A: The April Order recognized that the FCM CONE parameter serves as the basis for several parameters in the FCM rules (P 142), but identified only the threshold for OOM determinations (0.75 CONE) as an issue:

> "Therefore, as the CONE value is intrinsically tied to the OOM determinations that are part of the APR Issue, we will require the Filing Parties and others to address in their First Briefs in the paper hearing, above, the issue of the proper CONE value." (P 151).

The Commission rejected the notion that the current value of CONE has been influenced by OOM entry (P 150), which some parties had asserted as a basis for resetting CONE.

Q 30: Please summarize the most important FCM parameters linked to the FCM CONE parameter.

A: The most important parameters linked to the CONE parameter are thresholds pertaining to seller and buyer market power mitigation.

1. Permanent de-list bids are reviewed by the IMM if they exceed 1.25 times CONE; Static and Export de-list bids are reviewed if they exceed 0.8 times CONE; and Dynamic de-list bids are not reviewed but must be less than 0.8 times CONE.
2. New capacity offers are reviewed for possible OOM classification if they are below 0.75 times CONE.

FCM's "Quantity Rule", which can result in deferring replacement of some or all de-listed resources to reconfiguration auctions, also uses thresholds linked to the CONE parameter. There are several other, less important references to the CONE parameter in the Tariff.

Q 31: A reset of CONE would override the current provisions in the Tariff for updating the FCM CONE parameter based on auction results. Would it be appropriate to reset CONE and override these provisions?

A: No. The FCM rule for updating the CONE parameter (the 70%/30% formula) is designed to keep the parameter, and all parameters linked to it, close to the FCA clearing prices over time. This approach is appropriate, because the various parameters linked to the CONE parameter need to remain close to the FCA clearing price to effectively fulfill their functions.

Q 32: Please elaborate as to why the FCM CONE parameter needs to remain close to FCA clearing prices.

A: The most important reason is that the seller market power mitigation thresholds are linked to it. Sellers are permitted to submit dynamic de-list bids that are not reviewed by the market monitor if those bids are less than 0.8 CONE. Thus, any time the FCA clearing price, absent market power, would be less than 0.8 CONE, exercise of market power to raise the clearing price is permitted and not mitigated as long as the clearing price is not raised to or above 0.8 CONE.

If CONE is close to the FCA clearing price that would occur absent exercise of market power, this threshold will prevent the exercise of market power that raises the clearing price. If, instead, CONE is well above the clearing price that would occur absent the exercise of market power, the threshold for dynamic de-list bids set at 0.8 CONE will not prevent the exercise of market power to raise the clearing price up to this level.

For example, suppose the clearing price absent market power would be $4/kW-month and CONE is $6/kW-month. Then dynamic de-list bids are allowed up to just under $4.80/kW-month, allowing existing suppliers to raise the FCA clearing price up to just under $4.80/kW-month. If CONE were reset to $10/kW-month, however, dynamic bids would be allowed up to just under $8/kW-month, permitting existing suppliers to exercise market power to increase the clearing price to just under $8/kW-month when the competitive clearing price would be only half that amount. The primary impact of resetting CONE to a high value, as some parties have promoted, would be to allow unmitigated market power to raise FCA clearing prices well above the level that would occur absent the exercise of market power. This is the most important reason CONE needs to remain close to the likely clearing price.

Q 33: With respect to the threshold for OOM designations, if it is too low does this justify a reset of CONE?

A: No. If the Commission implements a bright-line test for identifying the out-of-market resources to be mitigated, as the April Order suggests, the 0.75 times CONE threshold, and the OOM definition to which it is linked, will no longer be needed. If the Commission determines, however, to keep the current OOM definition and concludes the 0.75 times CONE threshold is too low, it may be appropriate to decouple the threshold for possible OOM designation from the CONE parameter, as has been done with the auction starting price and the floor price.

I have suggested an alternative screen for MOOM designation, based on estimates of net going-forward cost by resource type as part of a bright-line test. In any case, it would inappropriate to reset the FCM CONE parameter in order to give a higher value to the

threshold for OOM evaluation because that would raise other thresholds and render seller market power mitigation ineffective, as I described above.

Q 34: Is a comparison of the FCM CONE parameter's value to the CONE values in the NYISO or PJM tariffs meaningful?

A: No. Indeed, the FCM CONE parameter is a misnomer; the parameter is updated based on FCM clearing prices when new capacity is needed (otherwise it is updated based on a construction cost index), and over time becomes an average of recent clearing prices when new capacity is needed. The FCM CONE parameter is not used directly, but is the base price around which various market power thresholds are defined.

As I described in the March Testimony (at 51:1-17), the "CONE" values in NYISO and PJM play entirely different roles in those market designs, with the most important being as the price parameter in a sloped capacity demand curve. FCM does not use a sloped capacity demand curve and has no need for such a CONE parameter.

Q 35: How have PJM's CONE values compared to recent RPM clearing prices?

A: The most recent capacity auctions under PJM's RPM capacity construct (for the 2012/2013 and 2013/2014 delivery years) cleared at $16.46/MW-day and $27.73/MW-day, respectively, in the RTO Region. The applicable Net CONE values were over 16 times and 11 times higher than these clearing prices, respectively. The disconnect between those Net CONE values and supply offer and clearing prices led to clearing a very large amount of excess capacity, which will contribute to lower clearing prices in future RPM auctions.

In FCM terms ($/kW-month), the two recent RPM clearing prices were $0.50/kW-month and $0.84/kW-month, several times lower than the FCM CONE value of $4.918/kW-

month. To reset the FCM CONE parameter to a higher value would render it even more out of touch with current market conditions in either market area.

Q 36: Should the Commission be concerned that the FCM CONE parameter is well below the estimated levelized cost to build a combustion turbine, net of estimated average energy and ancillary services revenues?

A: No. The FCM CONE parameter is not intended to reflect or approximate that value, despite the name; its update mechanism is designed so that the value will reflect clearing price trends when new capacity is needed. The FCM auction mechanism is designed to set a higher price when necessary to clear sufficient capacity, and the value of the FCM CONE parameter does not limit FCM's ability to do this.

V. Modeling of Capacity Zones

A. Introduction

Q 37: What issues were set for paper hearing with respect to the modeling of capacity zones?

A: The April Order set the following issues for paper hearing (P 18):

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.

In essence, the two fundamental issues are the extent to which modeling of capacity zones should be expanded, and what changes to market power mitigation are necessary to accommodate expanded zonal capacity pricing. I will address some aspects of both issues.

Q 38: What guidance did the Commission provide with regard to the modeling of capacity zones?

A: The Commission stated the belief that it is important to model zones wherever possible and that the ultimate goal should be to always model zones, while recognizing that parties have raised valid issues about expanded zonal capacity pricing. (April Order at PP 134-135). In particular, the Commission noted concerns raised by the IMM and other parties regarding the adequacy of market power mitigation, and the complexities in implementing the descending clock auction with multiple zones which, according to ISO-NE, would require significant further analysis to design.

Q 39: Please summarize your testimony with regard to zonal pricing.

A: I will make the following points.

1. There are several reasons for concern that zonal capacity pricing may decrease rather than increase the efficiency of New England's capacity market; these considerations suggest a cautious rather than aggressive approach to expanding zonal capacity pricing:
    a. Where zonal capacity pricing has been used most extensively (in PJM), the evidence shows that it has not been successful in attracting and retaining capacity in constrained areas. While there have been very large locational price differentials, the markets apparently have not found them to be credible price signals and have not responded to them.
    b. The evidence from PJM also suggests that capacity sellers act consistent with the incentives created by a capacity mechanism. When selling into large, relatively competitive zones where their actions are unlikely to have much impact on price, capacity sellers tend to act more competitively, offering more capacity at more competitive prices. When selling into smaller, concentrated zones where their actions can affect price much more, capacity sellers in aggregate tend to offer relatively less capacity and to more frequently take advantage of available opportunities to withhold capacity or to offer it at higher prices.
    c. New England's zones are rather small, and capacity ownership in them is quite concentrated. As a result, capacity sellers that may act relatively competitively when competing in the larger New England market will face much stronger incentives to withhold when the possibility of zonal pricing is available.
    d. Zonal capacity prices create strong incentives for incumbents to withhold capacity from zones, and these incentives cannot easily be mitigated. Indeed, mitigation approaches generally do not even attempt to mitigate incentives to withhold.

Instead, mitigation approaches attempt to control the ability to withhold existing capacity, and they can only be partially successful in this. While mitigation rules will limit withholding of existing capacity to some extent, they will leave in place incumbents' incentives and ability to withhold incremental capacity and to retire capacity that remains economic to operate.

e. Zonal capacity pricing can also reduce efficiency if Local Sourcing Requirements ("LSR") are determined based on overly conservative assumptions and, as a result, are too high, which will raise zonal capacity prices above efficient levels and lower capacity prices in surrounding zones below efficient levels.

f. Expanding zonal capacity pricing in New England may also lead to unintended, unexpected, and inefficient zonal prices due to particular characteristics of the New England transmission grid and capacity market: the mesh network topography within which the directions of capacity transfers are not known in advance, and the descending clock auction solution approach under which the amount and location of capacity that wishes to de-list at any price is only revealed in the course of the auction.

2. To the extent zonal capacity pricing will be expanded, there is significant risk from the exercise of market power, and the existing mitigation approaches must be revised to prevent inefficient prices that reflect that exercise of market power. Exercise of market power to create capacity zones or to raise prices in them should not be allowed at any price level. If a market share "safe harbor" is set to exempt very small sellers from mitigation, the threshold must be quite low and must be calculated on a zonal, not ISO-wide, basis.

Q 40: Please summarize the objectives of zonal capacity pricing.

A: The primary purpose for implementing zonal pricing is to allow prices in constrained areas to rise higher as needed to clear sufficient local capacity and thereby to maintain reliability. In principle, zonal capacity pricing can lead to more efficient prices. It can also obviate the need for rejecting de-list bids of plants needed for reliability and paying such plants out-of-market. Theory suggests that zonal prices will be higher in areas where capacity is most needed, and that these higher prices should attract and retain relatively more capacity to these areas.

B. Relevant Experience With Zonal Capacity Pricing in PJM

Q 41: Has zonal capacity pricing been effective in achieving its objectives in other regions where it has been applied?

A: No. The RTO that has by far the most experience with locational capacity pricing is PJM. The accumulating evidence suggests that zonal pricing in PJM is not having the desired impact of attracting and retaining relatively more capacity in the zones identified as constrained, where prices are higher and capacity is presumably more needed.

In the most recent auctions for the 2012/2013 and 2013/2014 delivery years, the zonal prices in PJM's constrained zones were several times higher than the "Rest of RTO" price. However, these higher prices did not attract relatively more capacity to the constrained zones. Relatively less new generation, existing plant upgrades, demand response and energy efficiency resources, and net imports from outside PJM have been offered in constrained zones compared to the Rest of RTO region, while relatively more retirements have occurred in the constrained zones.

Apparently, the price signals resulting from the higher zonal prices are largely being ignored by the market, and are being dominated by the increased incentives to withhold capacity when zonal pricing is allowed.

Q 42: How did you evaluate whether higher zonal capacity prices in PJM are attracting and retaining relatively more capacity to the high priced zones?

A: Both PJM and the PJM market monitor produce reports on each RPM auction, and my analysis relies on this data. In order to determine whether zonal pricing has attracted and/or retained relatively more capacity in PJM's constrained zones it is necessary to make comparisons between areas that are of different sizes. Because capacity needs are proportional to peak loads, one appropriate approach is to compare changes in capacity

relative to each region's peak load. If a small constrained region has attracted capacity equal to two percent of its peak, while a larger region has attracted only one percent of its larger peak, the smaller region has attracted relatively more capacity, even if the absolute quantity is less.

Q 43: Please summarize the scope of zonal capacity pricing in PJM.

A: PJM has now run capacity auctions for seven delivery years, of which the auctions for the first three and last two delivery years entailed multiple capacity zones. In the auction for the 2012/2013 delivery year, six zones were modeled in addition to the RTO Region, resulting in five locational prices, and for the 2013/2014 delivery year, seven zones were modeled in addition to the RTO Region, resulting in four locational prices.

Q 44: On which PJM zones did you focus for this analysis?

A: My analysis focuses on the Mid-Atlantic ("MAAC") and Eastern MAAC zones. I focus on these two zones because both had separate prices in the most recent two auctions, and because PJM reports more details for these zones than for the other, smaller zones.

Q 45: On which RPM auctions did you focus for this analysis?

A: I focused on the two most recent Base Residual Auctions, for the 2012/2013 and 2013/2014 delivery years, held in May 2009 and May 2010 respectively. These auctions modeled several zones, while the prior two auctions (for the 2010/2011 and 201/2012 delivery years) had few or no zones. In addition, these auctions were held three years in advance of the delivery year, as was intended in the RPM design. Some of the earliest RPM auctions also involved zonal pricing, but these auctions were not held three years forward of the delivery year and, in addition, there was very little incremental capacity in those auctions.

Q 46: Please summarize the zonal capacity prices that have resulted from the various RPM auctions.

A: Exhibit DPUC-8 shows the prices over the seven auctions for the major zones (a few additional, smaller zones had separate prices in some of the delivery years and are not shown). The exhibit shows that capacity prices have been quite volatile over this period. However, overall, prices have been higher in the zones than in the Rest of RTO region, on average over all seven auctions and especially in the most recent two auctions, as summarized in Exhibit DPUC-9. Thus, it would be reasonable to expect that, consistent with the theory and objectives of zonal capacity pricing, market participants would prefer to invest in new capacity in the zones rather than the Rest of RTO region, and the higher prices would also lead to relatively fewer retirements in the zones than in the Rest of RTO region.

Q 47: Have there been relatively more generation increases in these zones relative to the Rest of RTO Region?

A: No. Exhibit DPUC-10 summarizes the data from PJM's reports on the auctions. As described above, I present the data in MW per 1,000 MW of peak load in each zone, to normalize for the different sizes of the regions. The MAAC region is roughly the same size as the Rest of RTO region before American Transmission Systems, Inc. ("ATSI") joined PJM. (ATSI was included in the 2013/2014 base residual auction, so it is included in Rest of RTO Region for those auction results.) Contrary to the results that might be expected based on much higher zonal prices, Exhibit DPUC-10 shows that there have been relatively more generation increases in the Rest of RTO region than in either MAAC or Eastern MAAC, per 1,000 MW of peak load in the delivery year, for both the 2012/2013 and 2013/2014 delivery years.

Q 48: Have there been relatively more generation uprates or new units in the zones?

A: No. Exhibit DPUC-11 shows this data, which is available only for 2013/2014. Both of these measures show more additions in Rest of RTO than in the zones, despite the large price differences.

Q 49: Has there been relatively more demand response and energy efficiency offered in the zones?

A: No. Exhibit DPUC-12 presents the data. There has been relatively more demand response and energy efficiency offered in the Rest of RTO. However, because of the much lower price in the RTO Region, relatively more demand response and energy efficiency resources were able to clear in the zones.

Q 50: Has there been relatively more net capacity imported from adjacent RTOs into the zones?

A: No. Exhibit DPUC-13 shows the data, which again was only reported for the 2013/2014 delivery year. Imports have exceeded exports for the Rest of RTO, resulting in net imports of capacity, while capacity has only been exported from the zones.

Q 51: Have there been relatively more retirements in the lower-priced Rest of RTO region than in the zones?

A: No, there have been more retirements in the constrained zones. Exhibit DPUC-14 shows that in both the 2012/2013 and 2013/2014 auctions, there were more retirements in the zones than in Rest of RTO. PJM's list of Planned Deactivations (Exhibit DPUC-15) provides another perspective on this question, and this data also suggests that relatively more capacity is being retired in the zones than in Rest of RTO.

Q 52: Have the lower prices in the Rest of RTO resulted in a relatively large amount of older generation failing to clear, thus increasing the risk of future retirements?

A: No. In fact, relatively more older generation has failed to clear in the zones, despite the much higher prices. This is shown in Exhibit DPUC-16, based on a report by PJM's

market monitor. The significant difference shown in Exhibit DPUC-16 is not explained by the fact that there is relatively more older generation located in the zones, because the differences are not that large. Plants over 30 years old represent 52 percent of the capacity in Rest of RTO, compared to 60 percent in MAAC and 53 percent in Eastern MAAC. Plants over 40 years old represent 23 percent of the capacity in Rest of RTO, compared to 29.5 percent in MAAC and 26 percent in Eastern MAAC, according to PJM data from its EIA-411 filings.

Q 53: Looking forward, what do PJM's interconnection queues suggest with regard to likely future capacity additions? Are market participants proposing to add relatively more capacity in the high-priced zones in future years?

A: No. Exhibit DPUC-17 summarizes the planned new generation capacity, by future delivery year, reflected in PJM's interconnection queues as of June 4, 2010. The data show capacity values (so, for instance, wind capacity is reflected at far below nameplate), weighted by the commercial probabilities PJM uses for planning purposes (projects further along in the process are considered more likely to be built). Both for RPM delivery years for which auctions have already been held, and for future delivery years, there is relatively more capacity planned for the Rest of RTO Region than for the zones.

Exhibit DPUC-18 presents the same interconnection queue data, summarized by the date on which each project was added to the queue, thus permitting an examination of the more recently queued projects. The most recent proposals (queued February 2009 to May 2010) still reflect relatively more capacity being proposed in the Rest of RTO than in the zones, suggesting that higher zonal prices are having little or no influence over market participants' decisions regarding where to add new capacity resources.

Q 54: In your summary you stated that capacity sellers may offer capacity at higher prices in zones. What is the available evidence in this regard?

A: Under RPM, capacity suppliers are subject to mitigation in the form of offer caps based on net avoidable cost. However, they are permitted to add to these offer caps amounts reflecting an amortization of major investments in their plants (Accelerated Project Investment Recovery, or "APIR").

Under competitive circumstances, market participants generally would not add APIR to their offer caps, because those investments usually are sunk costs by the time of the capacity auction, and raising offer caps for sunk costs is not economically rational under competitive circumstances. The only reason a market participant would take advantage of the opportunity to add sunk costs to its offer caps would be to attempt to raise the clearing price earned on a portfolio of capacity. (I explained this in detail in my Supplemental Affidavit in Support of Answer of the RPM Buyers filed July 28, 2008 in Docket No. EL08-67 at PP 47-55.)

Exhibit DPUC-19 shows that in fact, APIR has been used – and used to the maximum extent allowed – almost exclusively in the smaller zones, and has hardly been used at all in the Rest of RTO and even in the relatively large MAAC zone.

Q 55: Please summarize what these results from PJM's capacity market show.

A: These results show that PJM's constrained zones, where prices have been much higher, have <u>not</u> attracted or retained relatively more capacity compared to the Rest of RTO zone.

Q 56: Why has zonal capacity pricing in PJM failed to achieve its objectives in terms of attracting new or retaining existing capacity?

A: There are three principal reasons. First, the market is apparently not finding the zonal price signals credible and is ignoring them. Second, while other market participants may largely ignore zonal price signals, capacity sellers with portfolios of capacity in the zones may face strong incentives to offer less rather than more capacity in the zones. Finally, the zones tend to be relatively developed areas where it can be more difficult to build.

Q 57: Why has the market apparently ignored the substantial zonal capacity price differentials that have occurred in PJM?

A: There are a number of likely contributing causes. The zonal prices are set for a single year at a time, and have been highly volatile, due to changes in available transmission, internal generation, demand response capacity, and RPM rules, among other determinants of prices. Market participants know that the RTO plans to build transmission that may relieve constraints and reduce or eliminate zonal price differentials. Market participants also know that the locational price signals overstate the need for new capacity to some extent, due to overly conservative assumptions behind PJM's calculations of the local capacity requirements. Market participants also know that capacity market rules are frequently changed, which can affect whether and which zones are defined and the magnitude of zonal prices. Volatile and highly uncertain zonal capacity prices apparently are not considered credible price signals and do not appreciably influence investment decisions.

Q 58: Please elaborate regarding the impact of zonal pricing on the incentives of sellers with portfolios of capacity in the zones.

A: The evidence from PJM, showing relatively more incremental capacity offered in the large, competitive, but low-priced RTO Region compared to the higher-priced

constrained zones, also suggests that capacity sellers' actions are consistent with the incentives created by a capacity mechanism. When selling into large, relatively competitive unconstrained zones where their actions are likely to have little or no impact on clearing prices, capacity sellers tend to act relatively competitively, offering relatively more capacity and at more competitive prices. When selling into smaller, constrained zones (that also tend to have more concentrated ownership) where their actions affect price much more, capacity sellers in aggregate tend to offer relatively less capacity and to more frequently take advantage of available opportunities to withhold capacity or to offer it at higher prices.

Q 59: Please explain how the fact that the constrained zones tend to be relatively developed areas might have contributed to the failure of zonal capacity pricing.

A: The results in PJM may also reflect the fact that the constrained zones where prices have been highest tend to be relatively developed areas where it can be more difficult to identify suitable sites and obtain all regulatory approvals. (This is also largely true of the NYISO's and New England's zones.) Higher, but volatile short-term zonal prices apparently are not sufficient to overcome the impediments to building new generation in such areas. In addition, the best sites for incremental capacity tend to be the sites of incumbents' existing plants, but, as noted above, incumbents face disincentives to expand capacity because it will tend to depress the zonal capacity price earned by their other resources.

Q 60: Can you quantify the impact of ownership of a portfolio of capacity on a supplier's incentive to offer or withhold incremental capacity from PJM's zonal capacity markets?

A: Yes. The impact on an owner's total revenue from offering or withholding incremental capacity determines its incentive to offer or to withhold the capacity. The impact on

revenue results from the potential impact of the incremental capacity on the auction clearing price. This will depend upon the slopes of the supply and demand curves in the vicinity of the auction clearing point. Exhibit DPUC-20 illustrates the concept. The upper panel ("Model 1") illustrates relatively "flat" supply and demand curves. In this example, withholding of 2 units shifts the supply curve from S1 to S2 and raises the clearing price $0.50. In the lower panel ("Model 2"), the supply and demand curves are steeper (less elastic), and the same 2 unit shift in supply causes the price to rise $2.

The impact incremental capacity would have had on the zonal prices in past auctions can be calculated exactly based on the actual demand and supply curves, which PJM publishes. Assuming market participants were able to reasonably accurately anticipate these conditions, this calculation quantifies the incentives to offer capacity or to withhold that they faced in those auctions, and will face in future auctions to the extent supply and demand conditions are expected to be similar.

Table 1 summarizes the analysis, which was based on the impact of offering an incremental 100 MW into the 2012/2013 auction (the most recent auction for which supply curves are available). The incremental 100 MW would earn the clearing price but would also lower the clearing price somewhat, reducing the earnings of the remainder of an owner's portfolio clearing in the same auction. Table 1 shows that, based on the supply and demand curves for this auction, offering an additional 100 MW would lower the Eastern MAAC price by $4.77/MW-day. The incremental 100 MW would earn $4.9 million annually as a capacity payment, as shown in Table 1. However, for an owner with a portfolio of 2,000 MW clearing in the zone, the lower price would reduce the capacity revenue for this other capacity by $3.5 million. Netting this loss from the

payment for the 100 MW, the owner would realize only 29% of the clearing price for the incremental capacity.

Table 1 shows that an owner with a portfolio of 2,000 MW effectively realizes only 69% of the full payment for the incremental capacity in the MAAC region, or 29% in Eastern MAAC; the incentive to offer this incremental capacity is muted under these assumptions by the lost revenue on the rest of the portfolio. For an owner with a 7,500 MW portfolio, the incentive is totally negated in both MAAC and Eastern MAAC – *i.e.*, the owner actually earns less overall if the incremental capacity is offered, resulting in a strong incentive to withhold, and a strong disincentive to offer incremental capacity.

Table 1: Impact of a Portfolio on Incentive to Offer Incremental Capacity (PJM, 2012/2013)

Zone:	MAAC	EMAAC
Clearing price ($/MW-day)	$133.37	$139.73
Estimated impact on clearing price of additional 100 MW*	- $ 2.02	- $ 4.77
Annual RPM revenue from additional 100 MW (incentive)	$4,794,385	$4,926,158
Impact of lower price on annual RPM revenue of rest of portfolio:		
Portfolio: 2000 MW	$1,472,406	$3,479,743
Portfolio: 3500 MW	$2,576,710	$6,089,551
Portfolio: 7500 MW	$5,521,522	$13,049,038
Incentive to offer the incremental 100 MW, considering impact of lower price, expressed as percent of the full incentive from auction clearing price (if negative, reflects incentive to withhold it):		
Portfolio: 2000 MW	69%	29%
Portfolio: 3500 MW	46%	-24%
Portfolio: 7500 MW	-15%	-165%

Sources: Parameters and results of RPM 2012/2013 base residual auction.
* Impact of incremental 100 MW on price results from slopes of supply and demand curves.
Slope of supply curve estimated based on segment +/- $50/MW-day around clearing point.

Q 61: How much of the capacity in PJM's zones is owned by entities with large enough portfolios to face muted incentives to offer incremental capacity, or even incentives to withhold capacity?

A: The majority of the capacity in the constrained zones is owned by entities with disincentives to offer incremental capacity. I evaluated PJM capacity sellers' portfolios based on the generating capacity data PJM makes available in its annual EIA-411 filing.

In the Mid-Atlantic zone (MAAC), 55 percent of the generating capacity is owned by entities with portfolios of 7,500 MW or larger and who, therefore, have no incentive to offer incremental capacity when this zone is modeled according to my analysis. Another 25% of the capacity in MAAC is owned by entities with portfolios from 5,000 MW to 7,500 MW, with very weak incentive to offer incremental capacity.

In Eastern MAAC, 70% of the capacity is owned by entities with portfolios of 3,600 MW or larger, and no incentive to offer incremental capacity (and an incentive to withhold or retire capacity) when this zone is modeled, according to this analysis.

In Southwest MAAC, two entities each hold about 5,000 MW (about 90% of the total capacity). These entities face strong disincentives to offer incremental capacity, and strong incentives to withhold, from this zone when it is modeled.

C. Suppliers' Incentives and Ability to Withhold From Locational Capacity Markets

Q 62: Please explain why zonal capacity pricing creates stronger incentives for incumbents to withhold capacity from zones.

A: It is well known that capacity markets are particularly susceptible to the exercise of market power. This is because typically there is only enough capacity to meet reliability needs with a small excess, and capacity market mechanisms attempt to procure nearly all of the available capacity. Thus, even participants with relatively small market shares can be pivotal and possess the ability to affect price by withholding.

In relatively large market areas, the ability to raise the price by withholding may be relatively weak due to the large number of other sellers offering capacity. Zonal capacity pricing generally leads to much stronger incentives to withhold, for the following reasons:

1. Zones are typically constrained areas where there is little or no excess capacity. Under such circumstances, relatively small amounts of withholding can affect price, and even relatively small sellers are pivotal.

2. Ownership of capacity is usually more concentrated in zones, with one or a few incumbents controlling a high percentage of the capacity (and I will show later in this testimony that this is the case in New England in particular). Incentives to withhold are proportional to the amount of capacity that would earn the higher price. The larger incumbents will have both the ability and incentive to withhold.

3. As I have mentioned, constrained zones are often developed areas where there may be fewer available sites suitable for new capacity, and the best sites may be the locations of the incumbents' power plants. This further restricts competition and increases the likelihood that withholding can have a significant impact on price.

Q 63: Can the incentives to withhold capacity from zones be mitigated?

A: No, it would be very difficult and likely impractical to mitigate these incentives. Mitigation approaches do not even attempt to mitigate them, instead focusing exclusively on mitigating the ability to (physically or economically) withhold, by imposing must-offer requirements and pricing thresholds or bid caps.

Q 64: Can the ability to withhold existing capacity from zones be mitigated?

A: Only partially. For instance, capacity sellers can always retire or export capacity that remains economic to operate in the zone, and this can be profitable if it raises the zonal capacity price earned by an owner's other capacity. It would be very difficult for a market monitor to distinguish between retirements or exports that are justified by a plant's economics from retirements or exports that are influenced by a desire to raise a zonal price.

Q 65: Can the ability to withhold new, incremental capacity be mitigated?

No. Market participants cannot be required to offer incremental capacity that they may be able to provide economically. Thus, even if the mitigation rules could be effective in limiting withholding of *existing* capacity, they will leave in place incumbents' incentives and ability to withhold *incremental* capacity. For example, incremental capacity provided at the sites of existing power plants, including capacity from minor uprates or major repowering, can be materially less expensive than capacity from new "green field" projects. But incumbents will know that providing such capacity is likely to reduce the capacity clearing price and, hence, their portfolio's capacity revenues. The ability to withhold such incremental capacity cannot be mitigated. The only way to mitigate sellers' ability to raise zonal capacity prices by withholding would be to enlarge the geographic markets.

D. Concentration of Capacity Ownership in New England's Zones

Q 66: You stated that the incentive to attempt to raise zonal prices will depend upon the sizes of the portfolios in which generating capacity in New England's zones is held. What does the data show in this regard?

A: The data show that ownership of capacity in New England's zones is generally quite concentrated. I calculated market shares and concentration statistics for various New

England zones based on the ISO's *2010-2019 Forecast Report* of *Capacity, Energy, Loads, And Transmission* ("CELT Report," revised May 18, 2010). I performed these calculations for fifteen zones: the thirteen Regional System Plan subareas plus two combined zones (all of Connecticut, and Central/Northeastern Massachusetts including Boston). For each zone, I calculated the market share of each Lead Participant, the zone's Herfindahl-Hirschman Index ("HHI"), and also the two- and three-firm concentration ratios (combined market shares). The results are shown in Table 2 and illustrated graphically in Exhibit DPUC-21.

While these data do not reflect capacity available in the form of imports or demand response, and include some participants who are load-serving entities and likely do not have incentives to withhold, it gives a reasonable indication of the concentration of generation ownership in New England's zones.

The U.S. Department of Justice considers a market concentrated if its HHI exceeds 1800. On this basis, fourteen of the fifteen zones I evaluated are concentrated and the remaining one is very close to this level (1691). In all but one zone, two participants control a majority of the capacity; in the remaining zone, two participants control 46% of the capacity. In all zones, three participants control at least 60 percent of the capacity. Table 2 also shows that in the ISO region as a whole, ownership of capacity is less concentrated.

Table 2: Concentration Statistics for New England Zones								
Zone	BHE	BOSTON	CMA/ NEMA	CT	ME	NH	NOR	RI
Total MW	921.3	3,359.5	199.2	4,467.4	935.9	4,115.7	515.8	5,266.1
HHI	3,274	4,036	3,260	3,231	1,959	2,279	7,395	2,381
Largest shares:								
1	53%	59%	51%	47%	30%	30%	85%	38%
2	17%	23%	20%	29%	26%	30%	14%	20%
3	10%	7%	10%	10%	15%	16%	1%	15%
Top 2	70%	82%	71%	76%	56%	60%	99%	58%
Top 3	80%	89%	81%	86%	71%	76%	100%	73%
Source: Summer seasonal claimed capacity by lead participant from 2010 CELT Report, page 2.1.								

Table 2: Concentration Statistics for New England Zones (continued)								
Zone	SEMA	SME	SWCT	VT	WMA	CT-ALL	C/NE-MA-ALL	All ISO
Total MW	3,478.3	1,499.3	2,246.0	966.9	3,724.2	7,229.2	3,558.7	31,695.6
HHI	1,955	4,901	1,691	4,154	1,808	1,845	3,610	615
Largest shares:								
1	32%	61%	24%	62%	35%	29%	55%	15%
2	20%	34%	23%	9%	16%	26%	22%	11%
3	19%	4%	21%	8%	12%	14%	6%	8%
Top 2	52%	95%	46%	72%	50%	55%	77%	26%
Top 3	71%	99%	67%	79%	62%	69%	84%	35%
Source: Summer seasonal claimed capacity by lead participant from 2010 CELT Report, page 2.1.								

Q 67: What is the connection between concentrated ownership of capacity and incentives to withhold capacity from New England's capacity market, when zones are modeled?

A: An incumbent's incentive to withhold from a zone is proportional to the size of the incumbent's portfolio in the zone, so market shares are a good indication of the strength of the incentive to withhold (the ability to raise price is a different question, and a pivotal supplier test may be a better indicator of the ability to raise price).

Capacity sellers know that in future FCAs if zones are modeled, de-listing capacity located in a zone could cause the auction to set a zonal clearing price that might be much higher than if zonal price formation were not available. For the participants with other capacity offered in the zone, the increase in price will be earned by the entire portfolio. This gives participants with large portfolios strong incentives to offer less rather than more capacity in the auction, and to de-list capacity sooner rather than later as the price falls from round to round.

Q 68: Can you quantify the impact of ownership of a portfolio of capacity on the incentive to offer or withhold incremental capacity from New England's zonal capacity markets, as you did for PJM's zones?

A: Yes. The magnitude of the incentive to withhold will reflect expectations as to the impact on the auction clearing price if additional capacity is removed from the auction. This impact will depend upon the steepness of the supply curve in the vicinity of the clearing price; if the supply curve is very steep, removing even a small amount of capacity will have a substantial impact on price.

To prepare the estimates, I used the supply curve from the most recent FCA (FCA #3), for the 2012/2013 delivery year. From this auction, we have the amount of supply remaining in the auction at the end of each round, which indicates how much supply exits the auction as the price falls. This is the best data available for estimating the impact on price of withholding. I estimated the potential impact on price of offering incremental capacity based on the change in price from the first to last round of FCA #3, compared to the amount of capacity that exited the auction from the first to last round of FCA #3. This approach may understate the expected slope of the supply curve, and, therefore, the

estimated incentives to withhold, because the supply curve was much steeper than this in most rounds, including the final rounds.

Because zonal data is not available, I performed the analysis for two "generic" zones, for which the LSRs were assumed to be 20% and 10% of the ISO Installed Capacity Requirement ("ICR"), respectively. To estimate the supply curve for a zone, I simply used a supply curve with proportionately less capacity at every price level. I also had to assume future clearing prices for this analysis; I used the current value of the FCM CONE parameter, $4.918/KW-mo, for zones, and 0.6 times CONE for the ISO region.

Table 3 summarizes the analysis, which was based on the impact of offering an incremental 10 MW into the auction. This capacity would earn the clearing price but would also lower the clearing price somewhat, reducing the earnings of the remainder of an owner's portfolio clearing in the same auction.

Table 3 shows that under the assumed price and supply elasticity (supply curve slope), offering an incremental 10 MW in Generic Zone #1 (with the LSR assumed to be 20% of the ISO's ICR) would lower the clearing price by $.168/kW-month, and earn the owner $569,982 per year as a capacity payment for the 10 MW at the lowered price. However, if the owner had an additional 200 MW offered in the auction, the lower price would reduce its capacity payment for this other capacity by $404,367. Netting this loss from the payment for the 10 MW, the owner would realize only 29% of the clearing price for the incremental capacity, resulting in a muted incentive to provide it. In the smaller Generic Zone 2, the owner with 200 MW would realize a net loss from offering the 10 MW of incremental capacity, and face a disincentive to offer it. With a 400 MW portfolio, there is a disincentive to offer incremental capacity in both Generic Zone #1

and Generic Zone #2. Table 3 also shows that the incentives to offer incremental capacity are greater if selling into the All ISO region instead of into one of the zones because in the larger area, the impact of incremental capacity on the clearing price is lower.

Table 3: Impact of a Portfolio on Incentive to Offer Incremental Capacity (New England, 2012/2013)

Zone:	All ISO	Generic Zones:	
		# 1 (20% of ISO)	# 2 (10% of ISO)
Size of zone (ICR/LSR)	31,965	6,393	3,197
Assumed clearing price ($/kW-month)	$2.95	$4.92	$4.92
Estimated impact on clearing price of additional 10 MW*	- $ 0.034	- $ 0.168	- $ 0.337
Annual FCM revenue from additional 10 MW (incentive)	$350,076	$569,982	$549,763
Impact of lower price on annual FCM revenue of rest of portfolio:			
Portfolio: 200 MW	$80,873	$404,367	$808,735
Portfolio: 400 MW	$161,747	$808,735	$1,617,469
Portfolio: 1,000 MW	$404,367	$2,021,836	$4,043,673
Incentive to offer the incremental 10 MW, considering impact of lower price, expressed as percent of the full incentive from auction clearing price (if negative, reflects incentive to withhold it):			
Portfolio: 200 MW	77%	29%	-47%
Portfolio: 400 MW	54%	-42%	-194%
Portfolio: 1,000 MW	-16%	-255%	-636%

Sources: Parameters and results of FCA #3 for 2012/2013.
* Impact of incremental 10 MW on price based on price and quantity change from first to last round.

Q 69: How much of the capacity in New England's zones is owned by entities with large enough portfolios to face muted incentives to offer incremental capacity, or even incentives to withhold capacity, according to this analysis?

A: All of Connecticut is roughly the size of Generic Zone #1. Over 80% of the capacity in Connecticut is owned by entities with over 500 MW in the zone, who would face disincentives to offer incremental capacity according to this analysis. Three participants representing almost 70% of the capacity in this zone each have over 900 MW, and would face very strong disincentives to offer incremental capacity, based on these assumptions.

For the Boston zone, which is similar in size to Generic Zone #2, over 80% of the capacity is owned by two participants each with over 700 MW, who would have strong incentives to withhold. Most of New England's potential zones are even smaller than Generic Zone #2.

This analysis suggests that capacity sellers that may act relatively competitively when competing in the relatively large New England market will likely have much stronger incentives to withhold when the possibility of zonal pricing is available.

E. Market Power Mitigation Provisions to Support Expanded Zonal Capacity Pricing

Q 70: If zonal capacity pricing will be expanded in New England, are changes needed to the existing market power mitigation provisions?

A: Yes. My analysis shows that zonal capacity pricing will increase the ability and incentive to withhold and thereby to raise prices in New England's zones, which typically are small and quite concentrated. As I described earlier, even comprehensive mitigation would have no impact on the *incentives* to withhold, no impact on the *ability* to withhold incremental capacity, and would only partially mitigate the ability to withhold existing capacity. To prevent exercise of market power to cause and raise zonal prices in New England, reducing the efficiency of capacity pricing, mitigation should be stringent and comprehensive.

Q 71: Should there be a "safe harbor" market share so that very small suppliers are not mitigated?

A: There could be a safe harbor market share, although for capacity markets, a pivotal supplier test may be more appropriate for such screening. If there were a safe harbor market share below which suppliers would not be mitigated, this market share should be

quite low, however. Suppliers with very small shares will be pivotal even if a zone has a small margin of capacity over the amount required to meet reliability requirements.

Market shares must be calculated on a zonal, not ISO-wide, basis for this purpose, because zones become the relevant markets. For example, one Lead Participant whose market share is only 1.5% of the New England Control Area is over 50% of one zone, based on the same data used in Table 2 earlier. Another Lead Participant owns less than 3% of the capacity in the entire Control Area but over 50% of a different zone. A third Lead Participant is 6% of the Control Area but over 80% of one zone. If a "safe harbor" market share is established, resources should be mitigated unless they represent less than the safe harbor market share in all modeled zones in which they are located.

F. Other Reasons for Concern About the Efficiency of Zonal Capacity Pricing in New England

Q 72: In your summary you mentioned a few other reasons for concern about the efficiency of zonal capacity pricing in New England. What other concerns have you not yet described in detail?

A: There are two. First, if zonal capacity requirements are not calculated accurately this can reduce efficiency. Second, there are complexities peculiar to the New England transmission grid topology and capacity auction solution approach that could reduce efficiency.

Q 73: Please elaborate on how the calculation of zonal capacity requirements could potentially reduce efficiency.

A: To implement zonal capacity pricing, ISO-NE must determine the amount of capacity to be purchased in each zone (the LSR). If LSRs are determined based on overly conservative or simplified assumptions and, therefore, are higher than necessary to satisfy reliability standards, it will raise zonal capacity prices above efficient levels and lower

capacity prices in surrounding zones below efficient levels. It will also increase the likelihood that market power will be able to raise the zonal prices.

The Joint Filing eliminated some conservative assumptions underlying these calculations, and ISO-NE has committed to a further process to review the components of these calculations. That process could potentially reduce the impact of overly conservative LSRs on zonal capacity pricing in New England.

Q 74: Please elaborate on the concern about the New England transmission grid topology and auction solution approach.

A: New England faces some unique challenges in implementing widespread zonal pricing that lead to heightened risk of unintended, unexpected, and inefficient outcomes. According to ISO-NE, there are multiple instances where capacity could flow in either direction between New England's zones, and the directions of flow will depend upon market participants' real-time choices of whether to remain in or exit the descending clock auction. This contrasts with both NYISO and PJM, where there is a clear "hierarchy" of zones, and no uncertainty about the direction in which capacity would be imported from one zone to another. In those markets, capacity flows from unconstrained and lower priced western areas to higher priced and more constrained eastern areas. This allows the auction administrator to solve the auction and determine prices in a straightforward manner. The solution approach will have to be significantly more complex in New England.

In addition, the FCM uses a descending clock auction which allows market participants to make real-time decisions to remain in or exit the auction in each round. This makes simultaneously solving the interconnected zones more difficult and raises the risk of a

suboptimal solution – *i.e.*, incorrect and inefficient prices and capacity supply obligation awards. By contrast, in both NYISO and PJM, capacity offers are submitted in advance and cannot be changed during the auction. This allows the capacity market to be solved with a computer algorithm, even if many combinations must be considered.

Finally, the FCM purchases, for each zone, its LSR. Because there generally tend to be few supply offers at prices close to clearing levels in the FCM auctions, small changes in capacity offers can potentially cause zones to separate, and can potentially have a large impact on prices. In both NYISO and PJM, sloped capacity demand curves are used, which can have a dampening impact on clearing prices.

While ISO New England may be able to devise an auction solution approach that it expects will effectively deal with these unique challenges, it will be a substantial change from the current approach and entail elements that have not been applied or tested elsewhere.

Q 75: Does this complete your testimony?

A: Yes it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England, Inc. and New England Power Pool Participants Committee	)	Docket No. ER10-787-000
New England Power Generators Association 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

DIRECT TESTIMONY OF JAMES F. WILSON
IN SUPPORT OF FIRST BRIEF OF
THE JOINT FILING SUPPORTERS

James F. Wilson, being first duly sworn, states he is the same James F. Wilson whose Direct Testimony in Support of First Brief of the Joint Filing Supporters accompanies this affidavit; and that the facts set forth therein are true and correct to the best of his knowledge, information, and belief.

James F. Wilson

Subscribed and sworn before me, a Notary Public in and for the State of Maryland

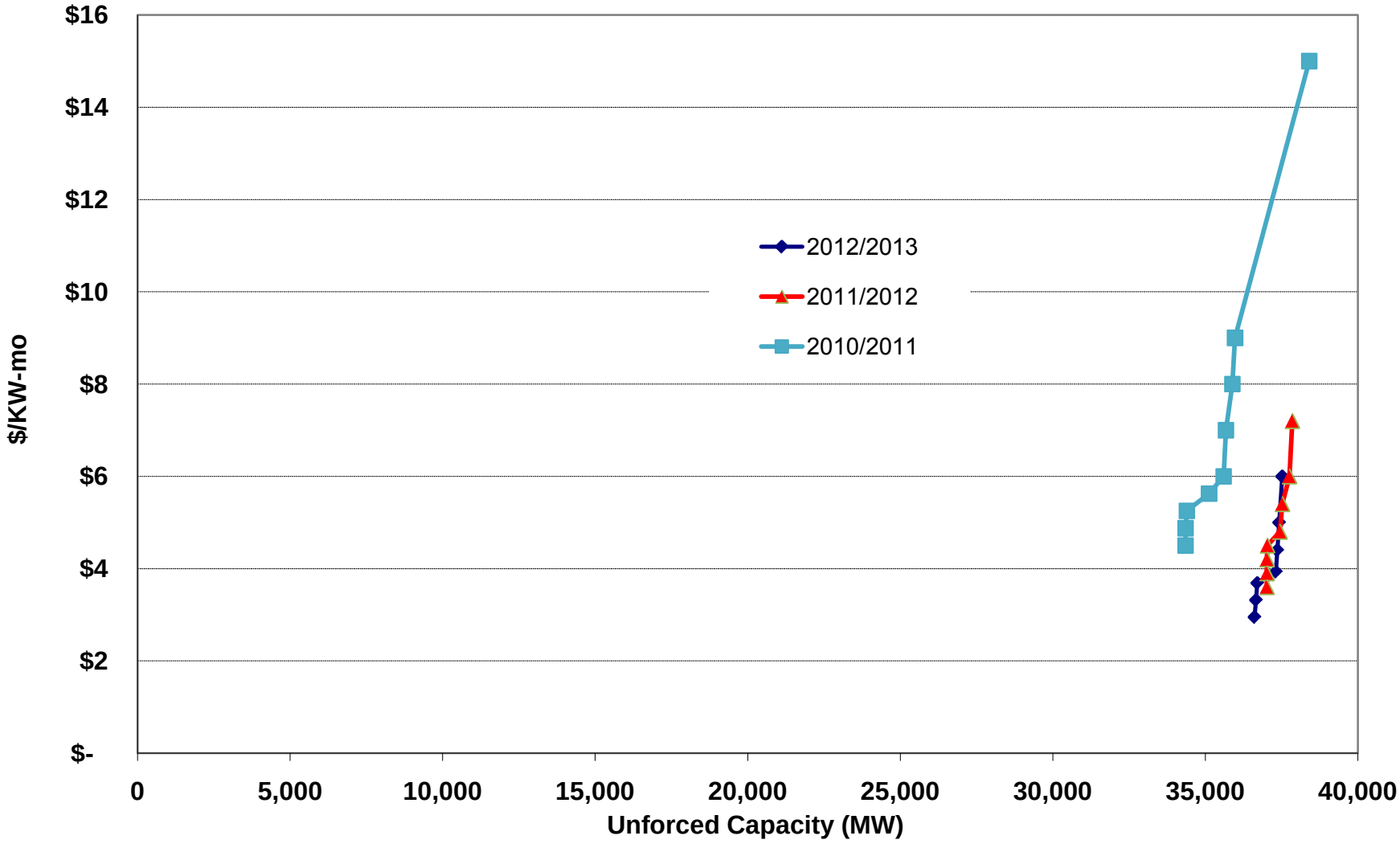
this 1 day of July, 2010.

Notary Public
My Commission expires:

DIANA C. MANZANAREZ
Notary Public, State of Maryland
My Commission Expires May 21, 2013

Exhibit DPUC-4

Price and Total Supply By Round In FCM Auctions

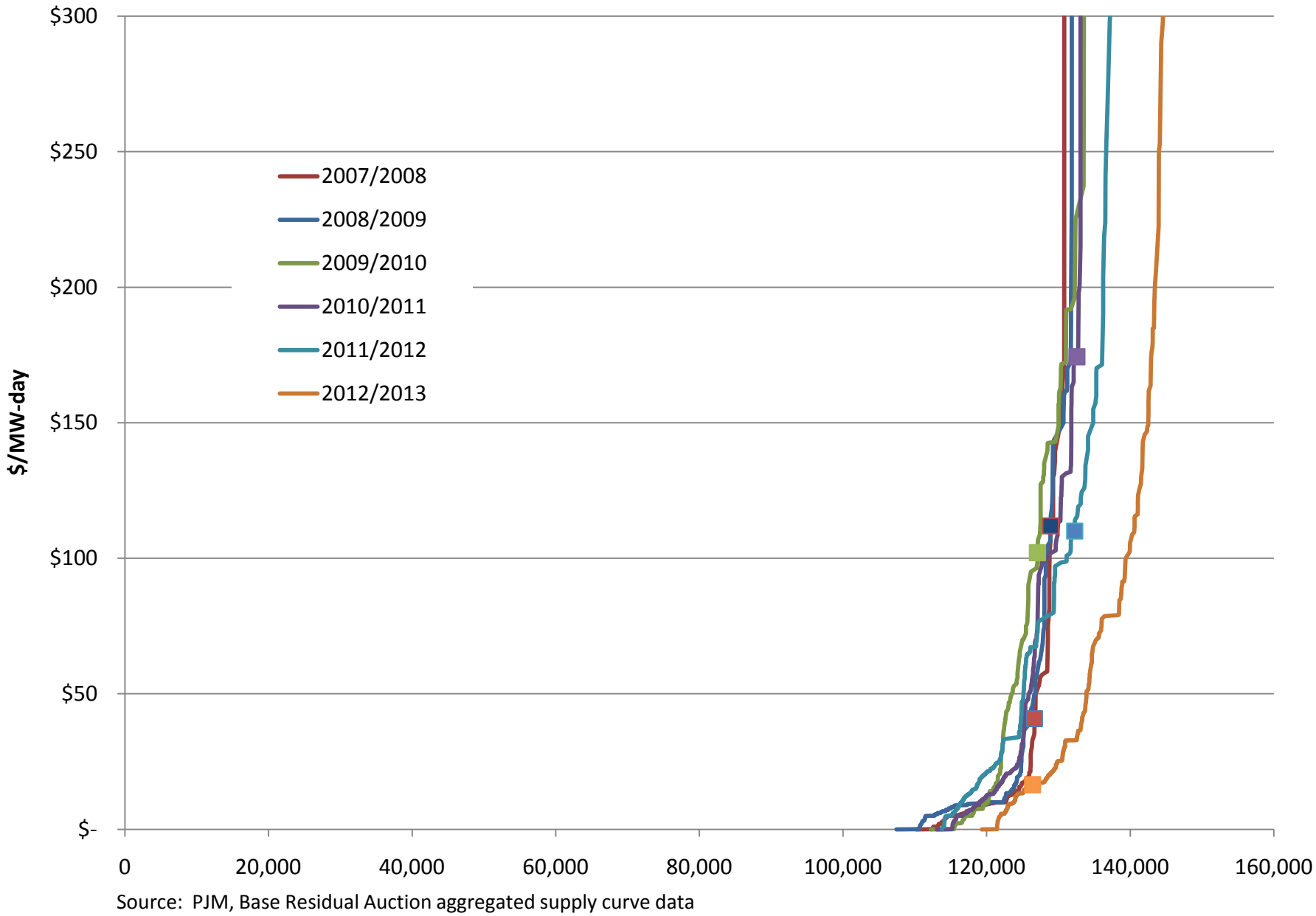


Source: ISO-NE reports of results of Forward Capacity Auctions

Exhibit DPUC-5

Exhibit DPUC-5

RPM Supply Curves - RTO Region

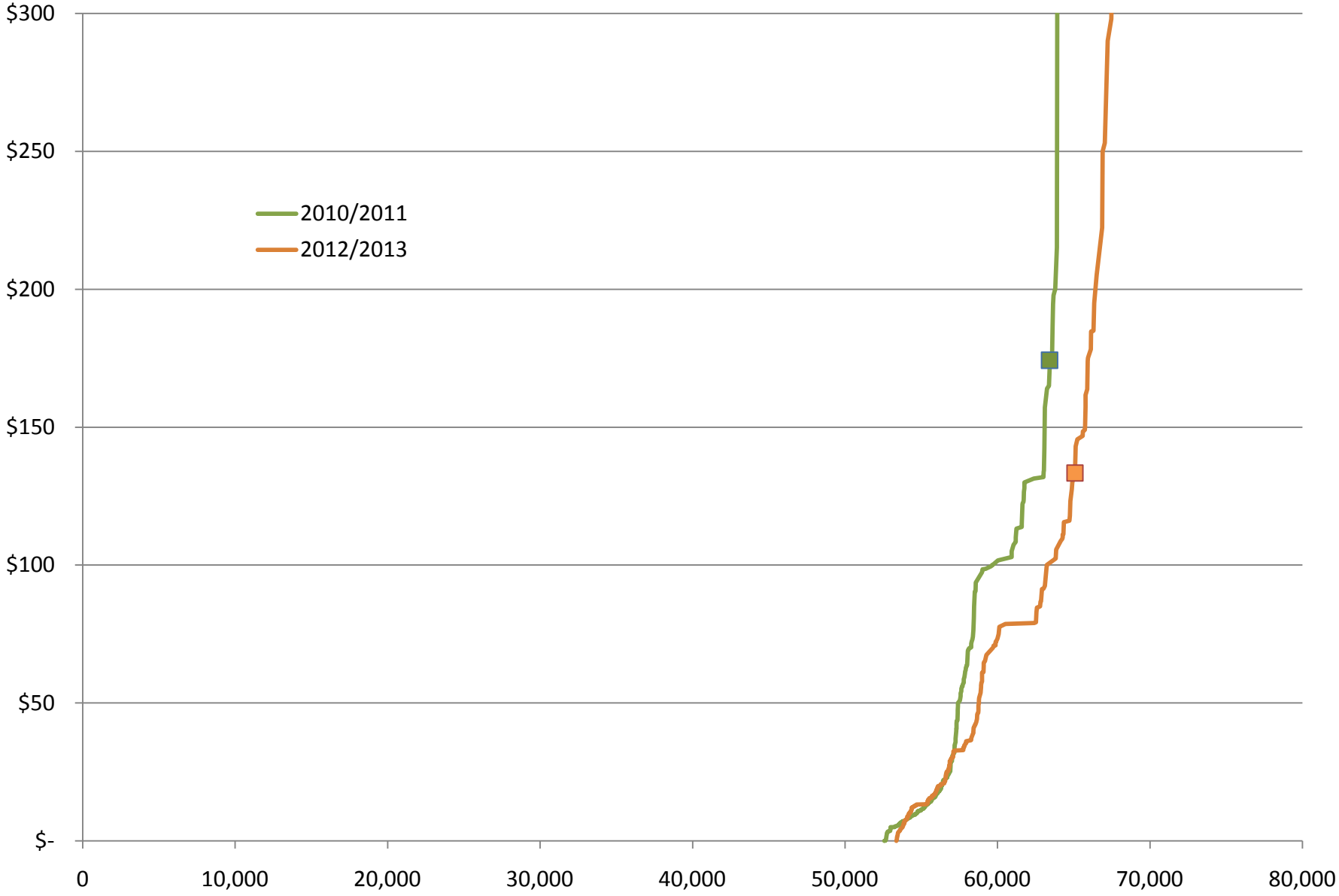


Source: PJM, Base Residual Auction aggregated supply curve data

Exhibit DPUC-6

Exhibit DPUC-6

RPM Supply Curves - Mid Atlantic Region

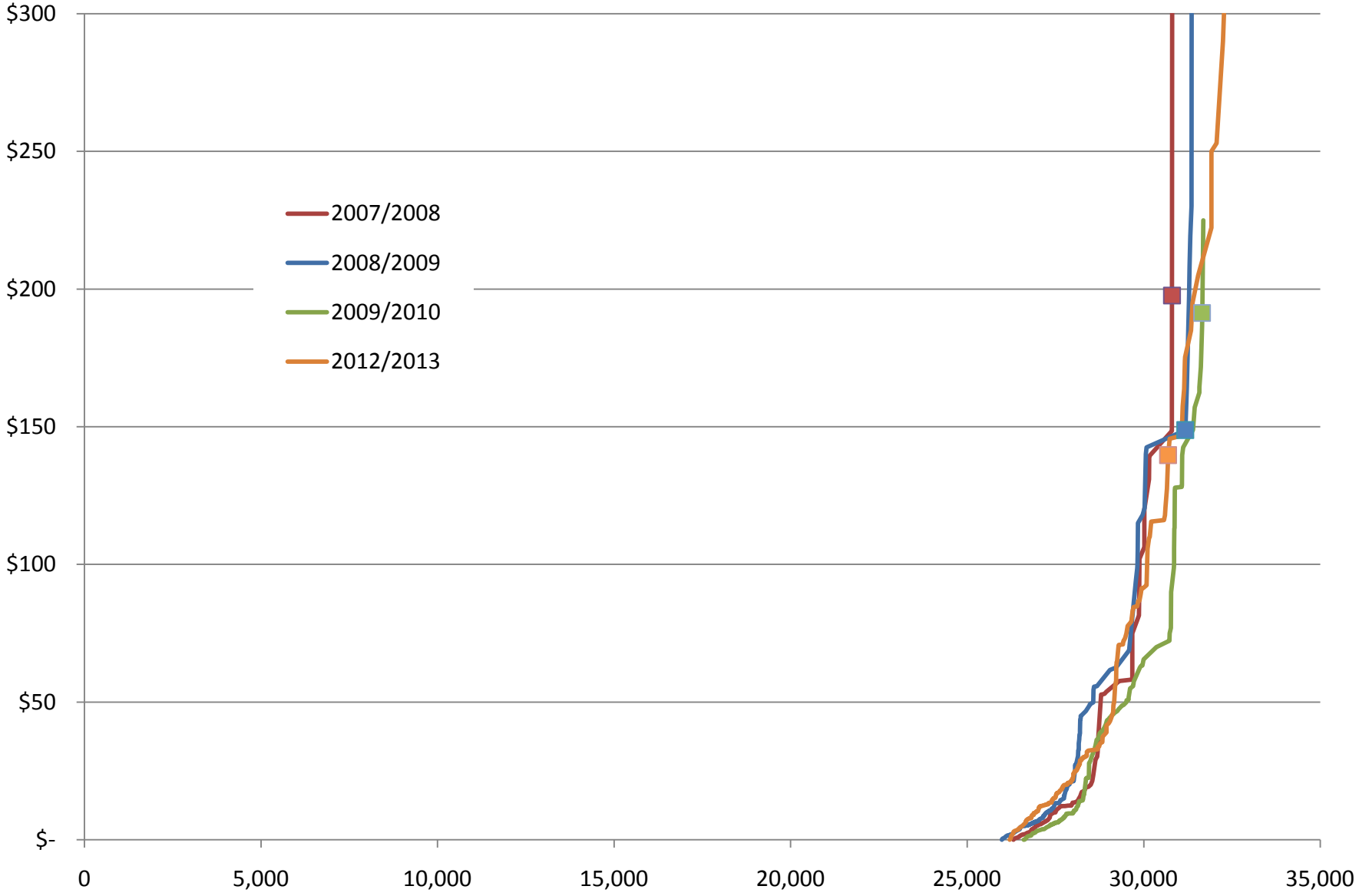


Source: PJM, Base Residual Auction aggregated supply curve data

Exhibit DPUC-7

Exhibit DPUC-7

RPM Supply Curves - Eastern MAAC Region

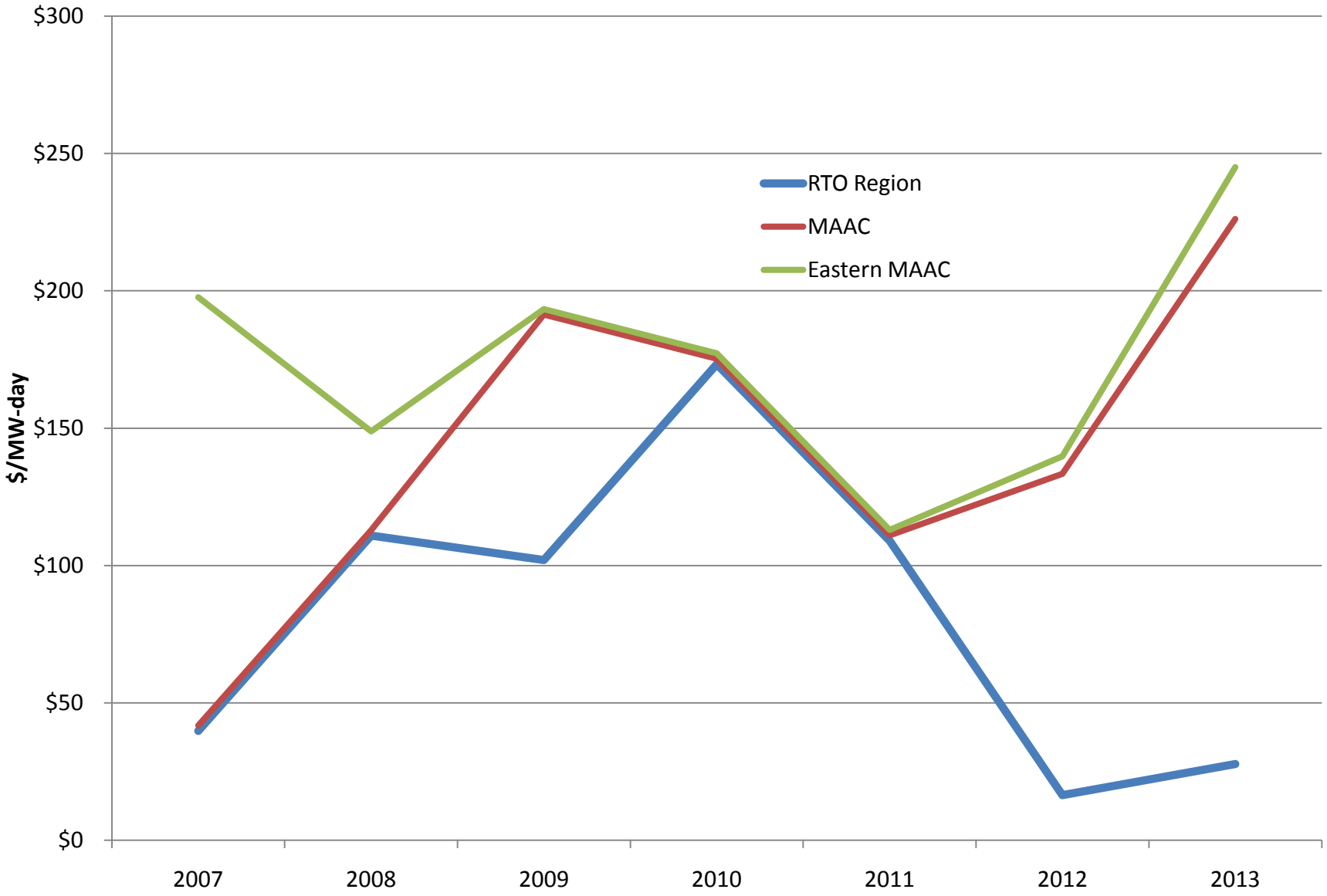


Source: PJM, Base Residual Auction aggregated supply curve data

Exhibit DPUC-8

Exhibit DPUC-8

RPM Clearing Prices 2007/2008 to 2013/2014 Base Residual Auctions

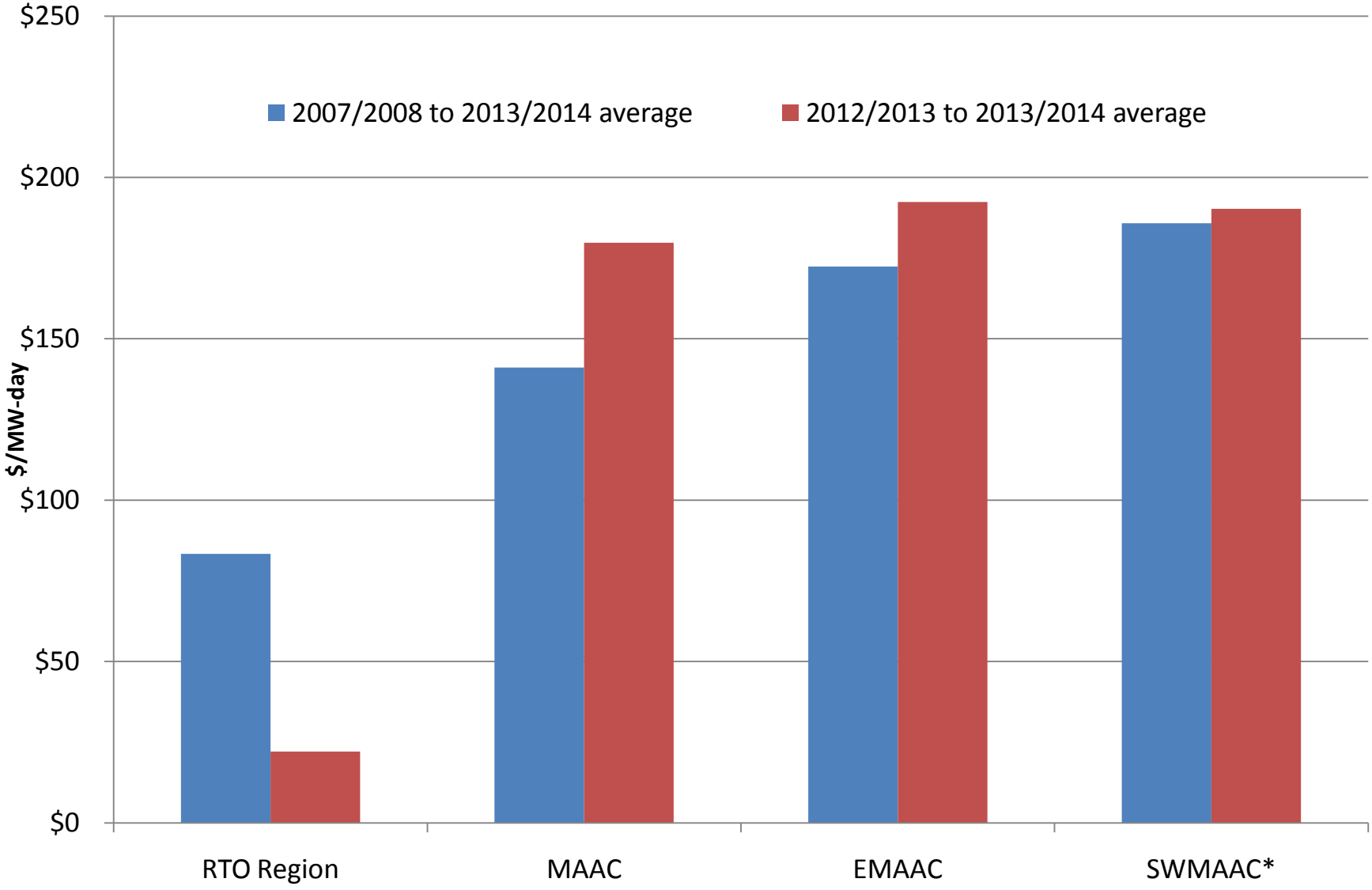


Source: RPM Base Residual Auction Results reports for various years

Exhibit DPUC-9

Exhibit DPUC-9

Average RPM Prices By Zone



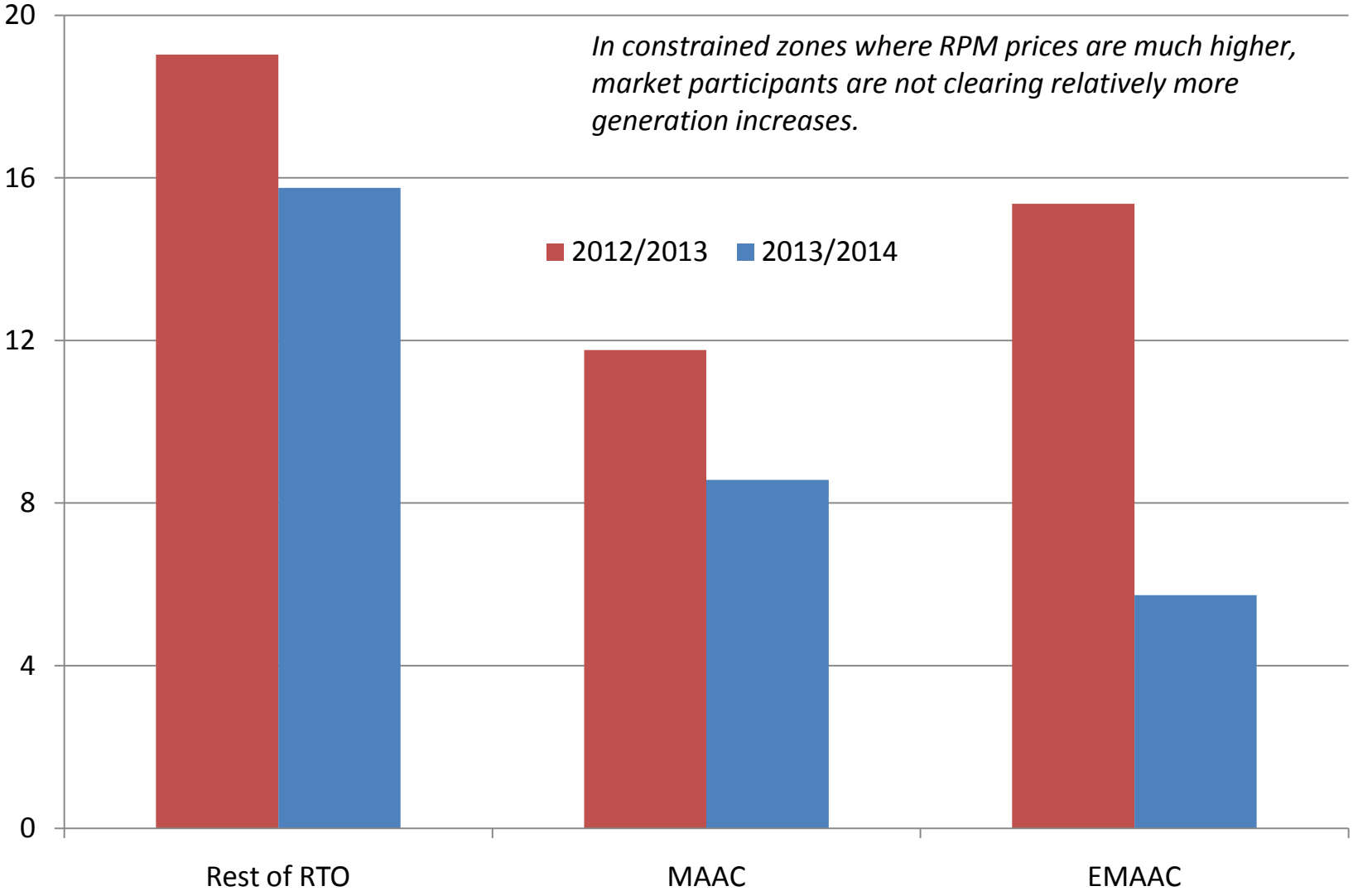
Source: RPM Base Residual Auction Results reports for various years. The averages are for "rest of" and do not reflect higher prices in nested LDAs. * For SWMAAC, the PEPCO price is used for 2013/2014.

Exhibit DPUC-10

Exhibit DPUC-10

Generation Increases In RPM

(MW, per 1,000 MW of zonal peak load)



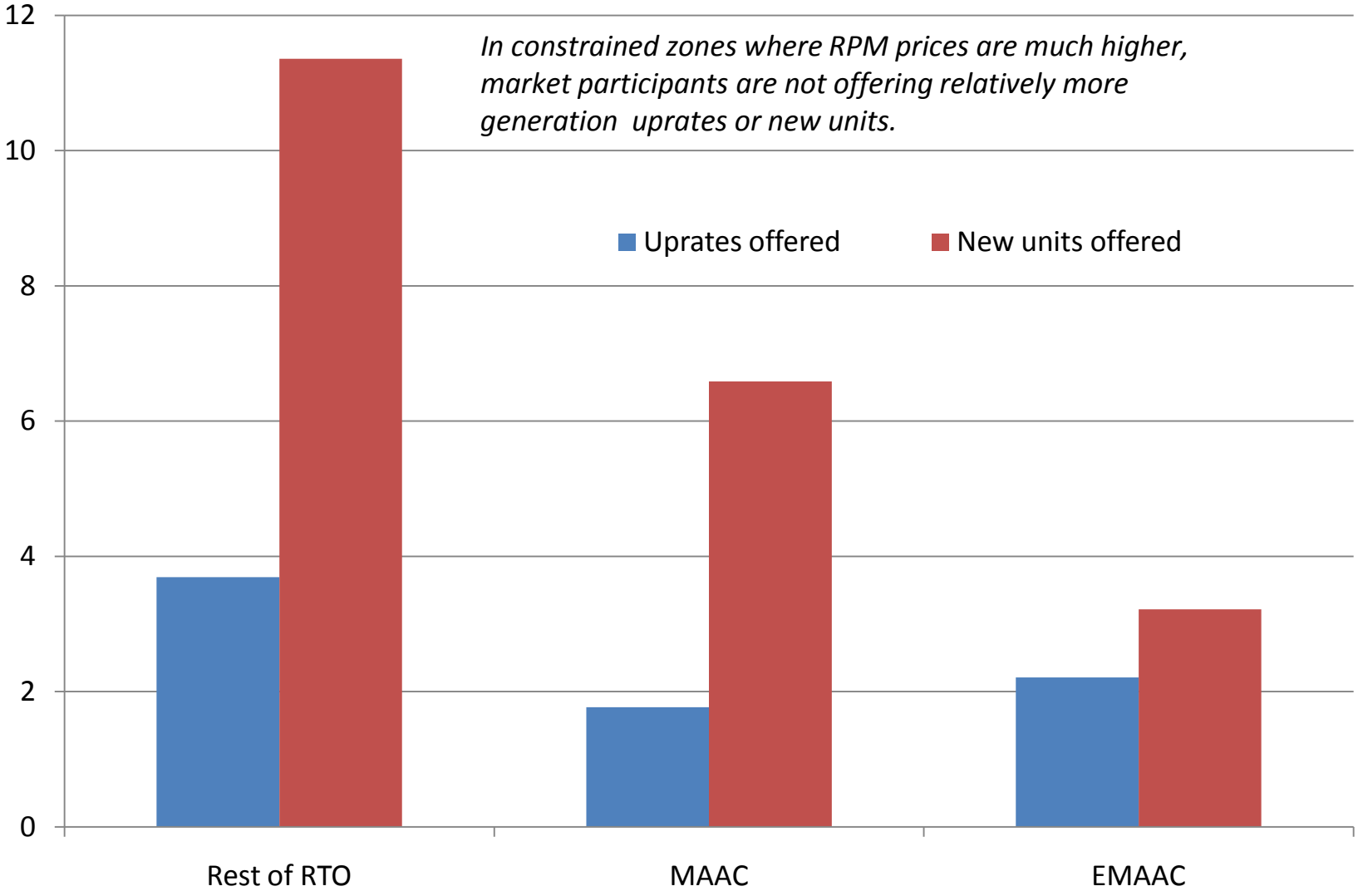
Source: 2013/2014 RPM Base Residual Auction Results, Table 6A, 2012/2013 RPM Base Residual Auction Results, Table 4A.

Exhibit DPUC-11

Exhibit DPUC-11

Generation Uprates and New Units In RPM

(MW, per 1,000 MW of zonal peak load)



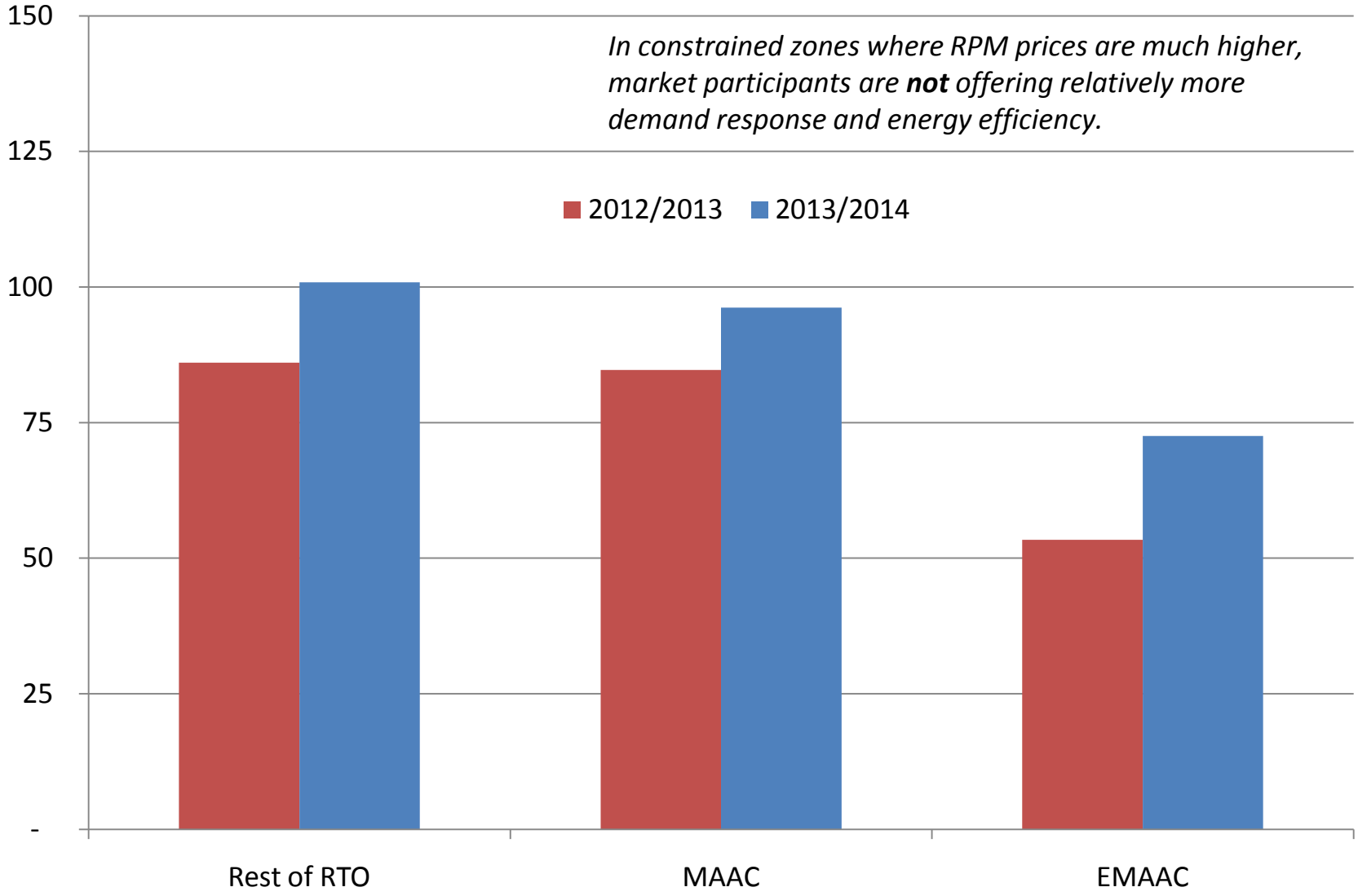
Source: 2013/2014 RPM Base Residual Auction Results, Table 6B.

Exhibit DPUC-12

Exhibit DPUC-12

Demand Response and Energy Efficiency Offered Into RPM

(MW, per 1,000 MW of zonal peak load)



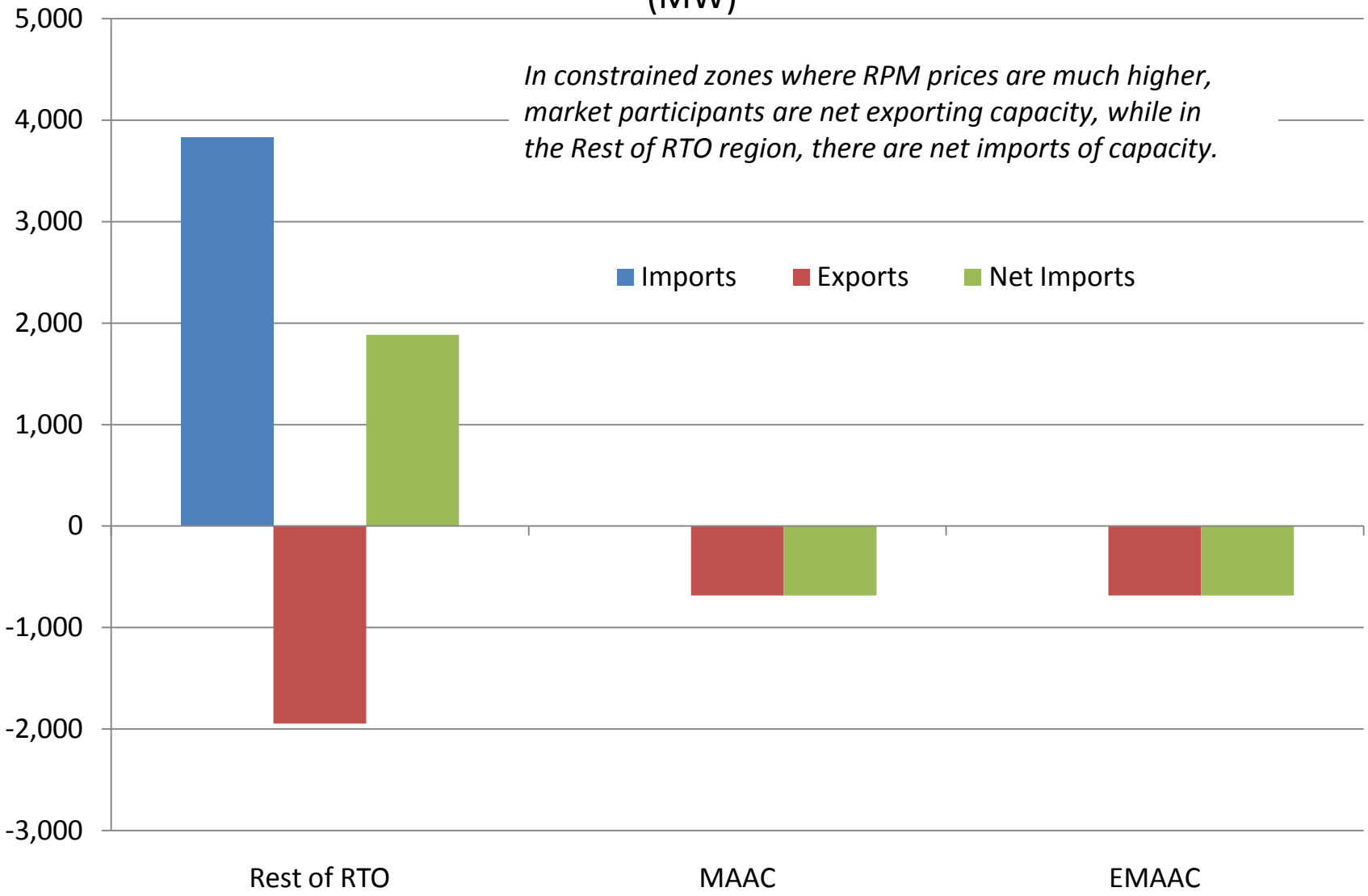
Source: 2013/2014 RPM Base Residual Auction Results, Table 2B, 2012/2013 RPM Base Residual Auction Results, Table 3A.

Exhibit DPUC-13

Exhibit DPUC-13

Capacity Imports and Exports In RPM, 2012/2013

(MW)



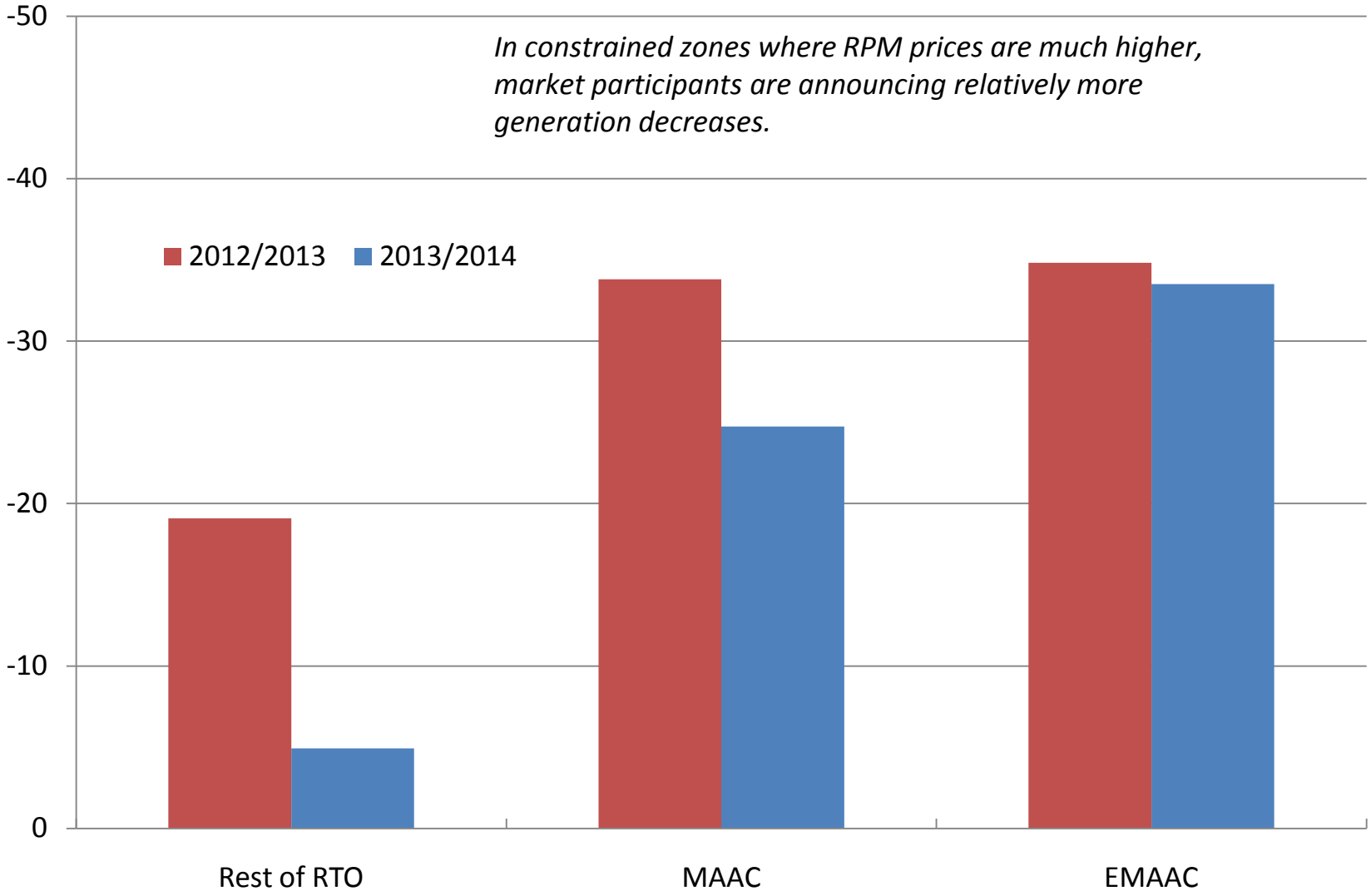
Source: Monitoring Analytics, Analysis of the 2012/2013 RPM Base Residual Auction, Tables 6, 12, 13.

Exhibit DPUC-14

Exhibit DPUC-14

Generation Decreases In RPM

(MW, per 1,000 MW of zonal peak load)



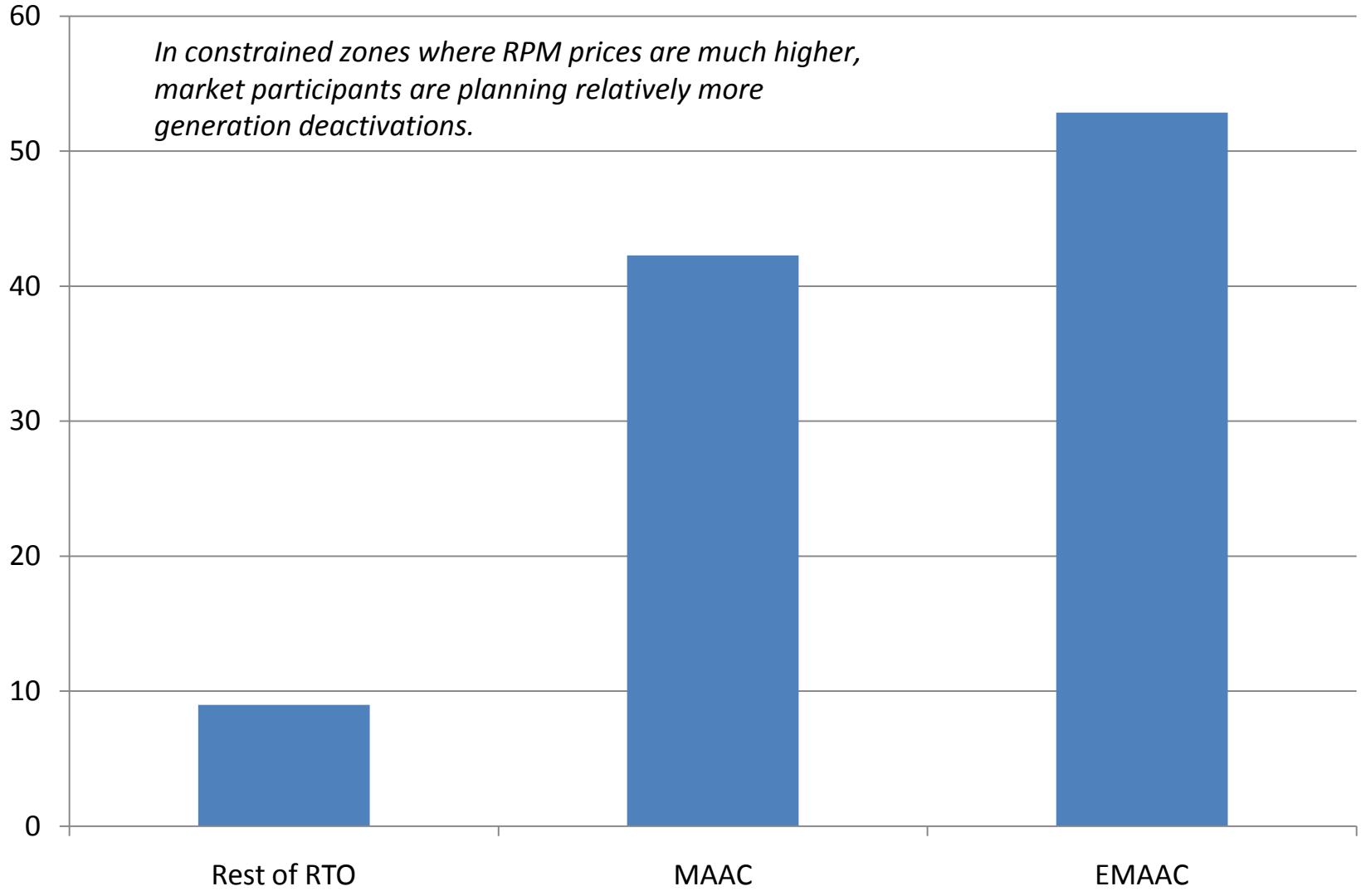
Source: 2013/2014 RPM Base Residual Auction Results, Table 6A, 2012/2013 RPM Base Residual Auction Results, Table 4A.

Exhibit DPUC-15

Exhibit DPUC-15

Planned Deactivations

(MW, per 1,000 MW of zonal peak load)



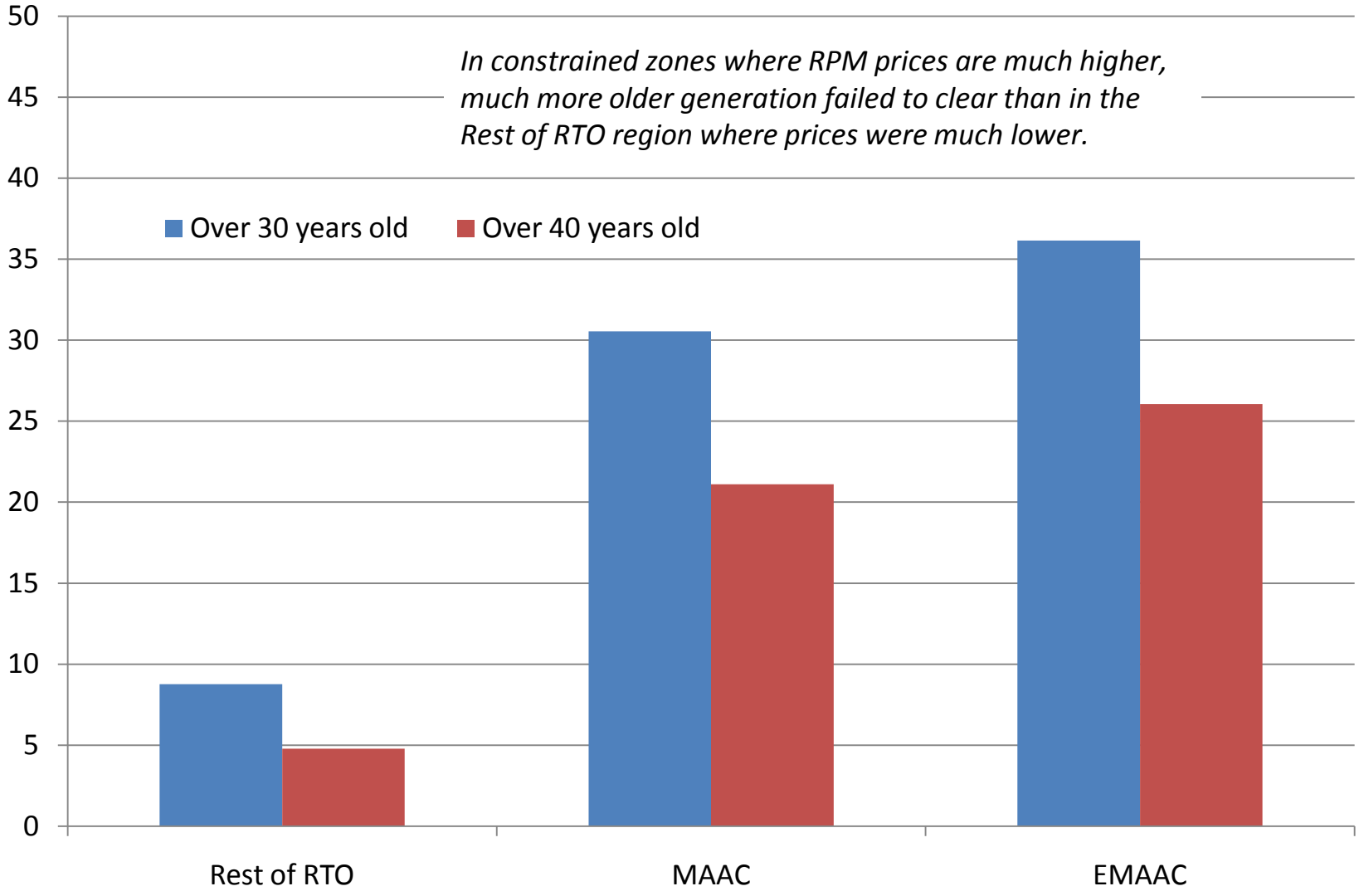
Source: PJM list of Future Deactivations as of June 1, 2010.

Exhibit DPUC-16

Exhibit DPUC-16

Uncleared Older Generation, 2012/2013

(MW, per 1,000 MW of zonal peak load)



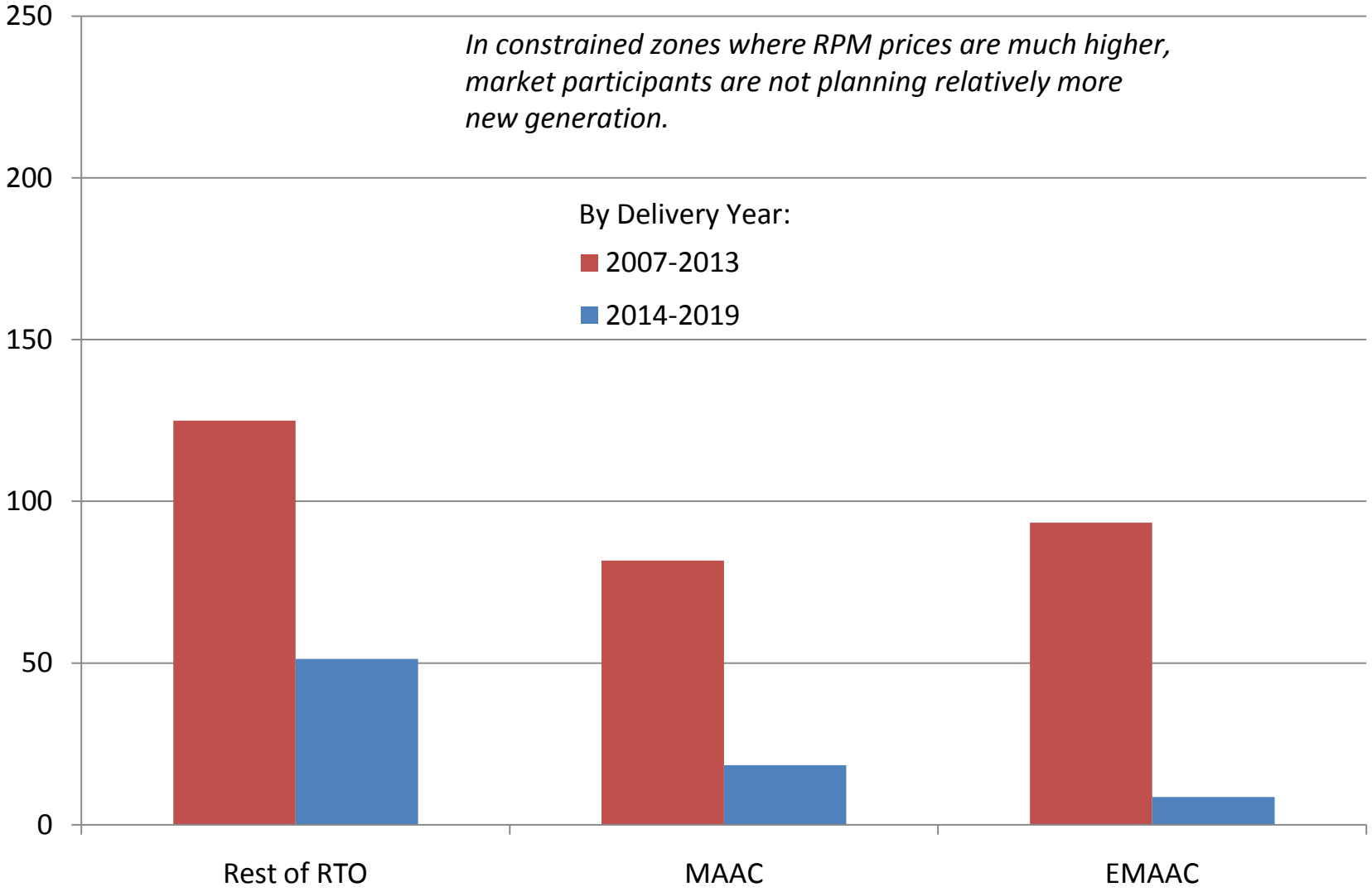
Source: Monitoring Analytics, Analysis of the 2012/2013 RPM Base Residual Auction, Table 9.

Exhibit DPUC-17

Exhibit DPUC-17

Planned New Generating Capacity (weighted by commercial probability)

(MW, per 1,000 MW of zonal peak load)



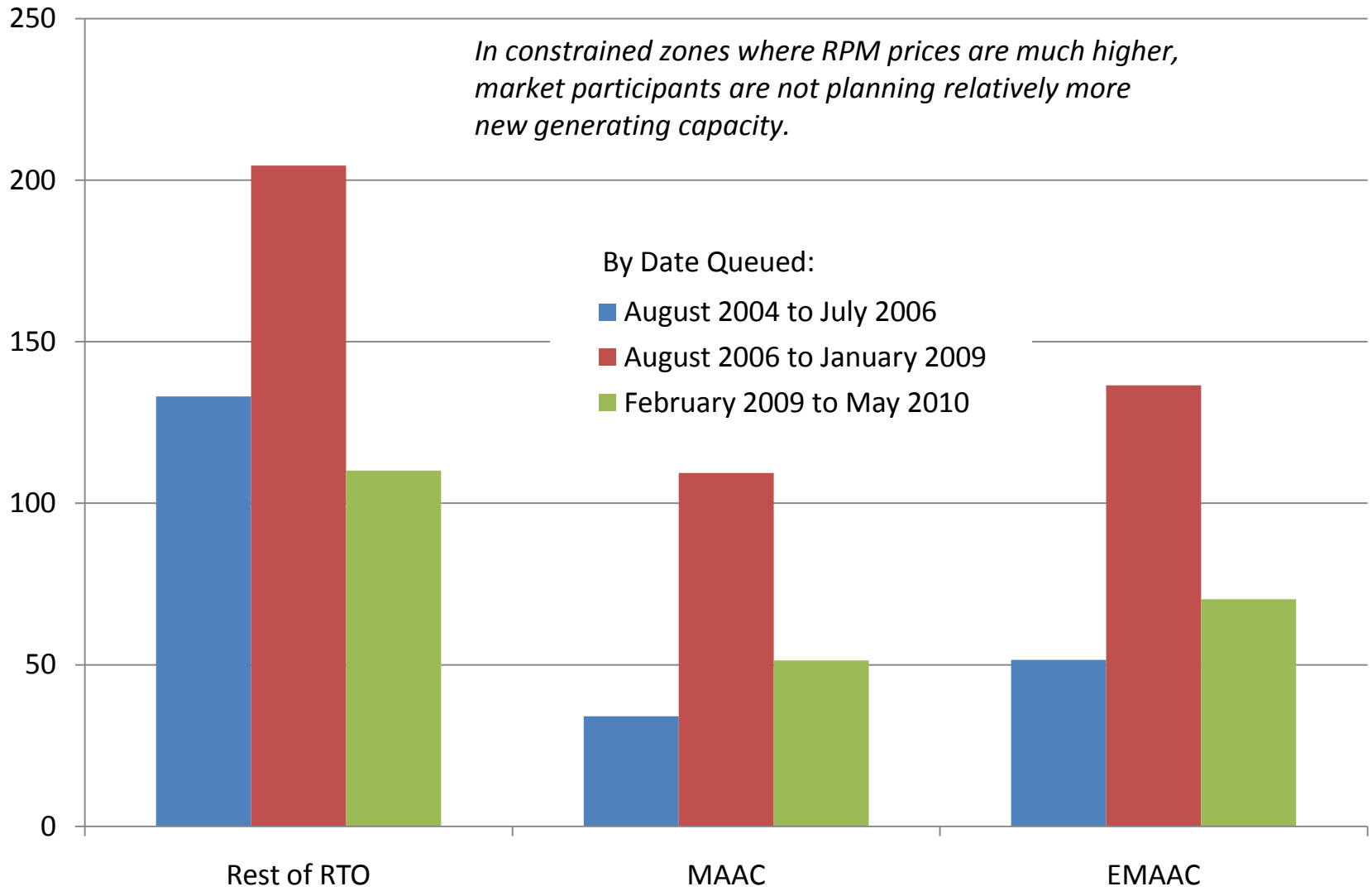
Source: PJM interconnection queue data accessed June 4, 2010, MWC weighted by commercial probability.

Exhibit DPUC-18

Exhibit DPUC-18

Planned New Generating Capacity (weighted by commercial probability)

(MW, per 1,000 MW of zonal peak load)



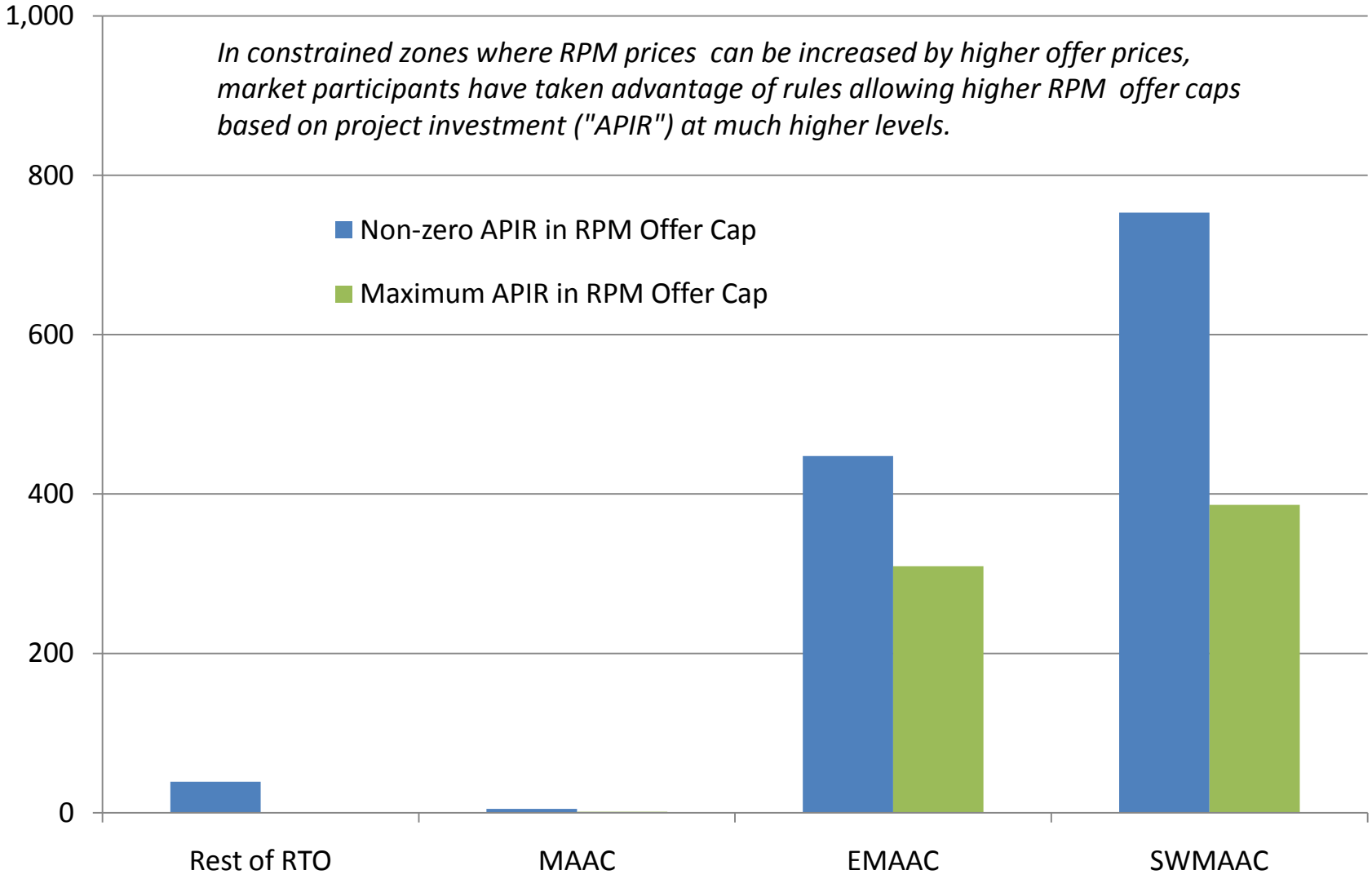
Source: PJM interconnection queue data accessed June 4, 2010, MWC weighted by commercial probability.

Exhibit DPUC-19

Exhibit DPUC-19

Use of "APIR" at Maximum Allowed Level

(MW, per 1,000 MW of zonal peak load)



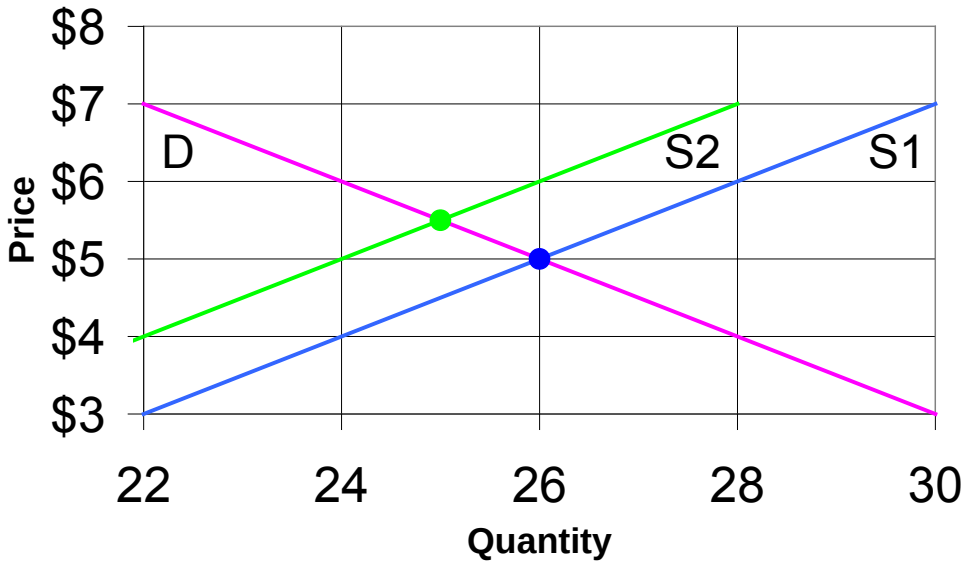
Source: Monitoring Analytics: Analysis of APIR Investment and MW Added Under RPM 2007 - 2011 RPM Auctions (Sept. 2008) Table 4.

Exhibit DPUC-20

Exhibit DPUC-20

Impact of Withholding on Clearing Price Depends Upon Slopes of Supply and Demand Curves

Model 1, "flatter" supply and demand:
If supply shifts 2 units to S2, price rises to $5.50



Model 2, "steeper" Supply and demand:
If supply shifts 2 units to S2, price must rise to $7

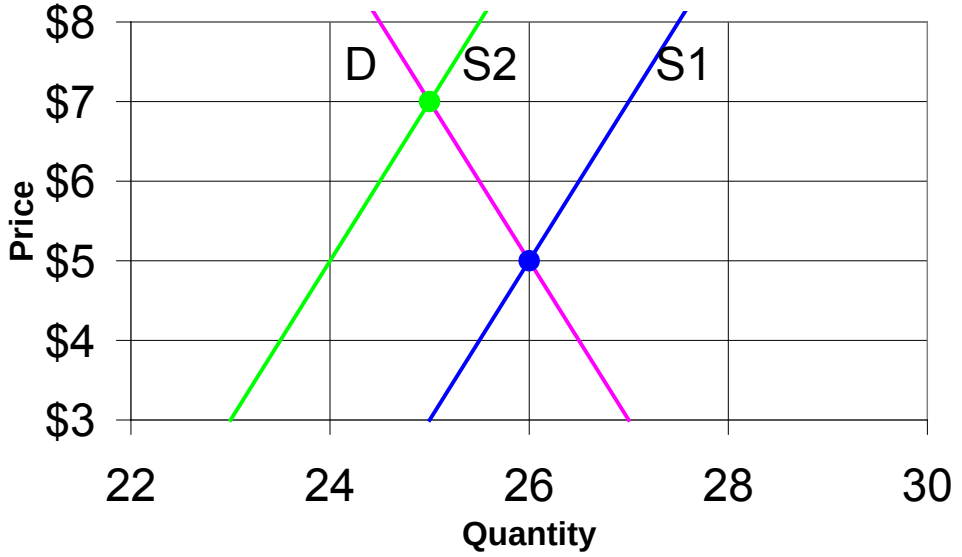
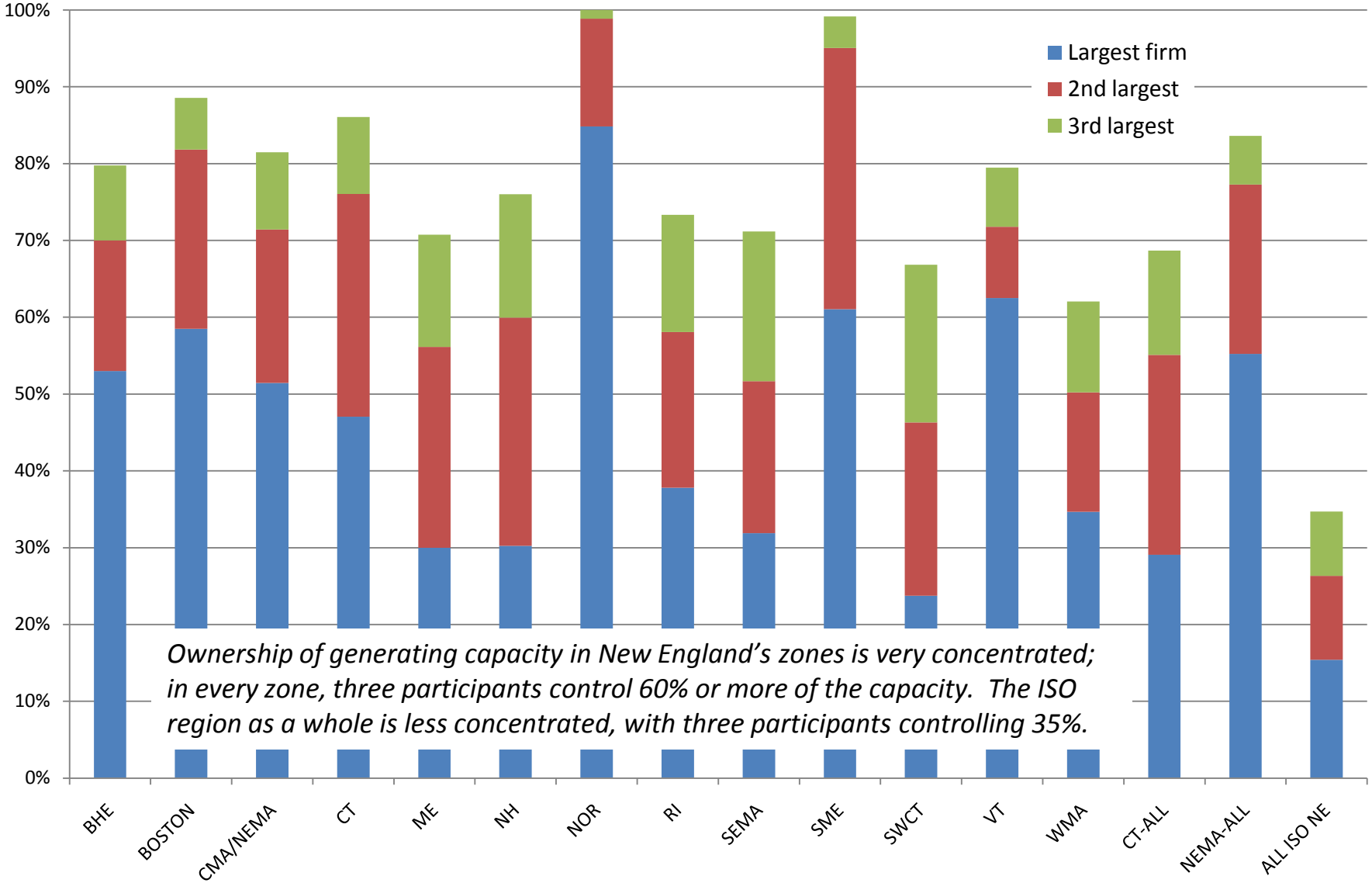


Exhibit DPUC-21

Exhibit DPUC-21

Largest Three Market Shares by ISO-NE Zone



Source: ISO-NE, 2010-2019 Forecast Report of Capacity, Energy, Loads, And Transmission, revised May 18 2010.