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July 2, 2010

BY HAND DELIVERY

Kristi Izzo, Secretary
New Jersey Board of Public Utilities
Two Gateway Center
Newark NJ 07102

Re: In the Matter of the New Jersey Board of Public Utilities Review of the State's Electric Power and Capacity Needs
BPU Docket No. EO09110920

Dear Secretary Izzo:

Enclosed for filing please find an original and ten copies of the Division of Rate Counsel's comments regarding New Jersey's electric generation and capacity needs. These comments are being submitted pursuant to the Board Secretary's letter dated June 14, 2010 initiating a technical conference and soliciting public comment. These comments will also be submitted electronically as directed in the Secretary's letter.

We have also enclosed one additional copy of the materials transmitted. Please stamp and date the copy as "filed" and return it to our courier.

Thank you for your consideration and attention to this matter.

Respectfully submitted,

STEFANIE A. BRAND
DIRECTOR, DIVISION OF RATE COUNSEL

By: Stefanie A. Brand

c: President Lee A. Solomon
Commissioner Jeanne M. Fox
Commissioner Joseph L. Fiordaliso
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New Jersey Capacity Issues- Technical Conference
I/M/O The Provision Of
The New Jersey Board of Public Utilities Review of the State's Electric Power and Capacity Needs
BPU Docket No. EO09110920

Comments of the Division of Rate Counsel

July 2, 2010

Introduction

By Secretary's Letter dated June 14, 2010, the Board of Public Utilities (the "Board") announced that a technical conference would be held on June 24, 2010 in the Board's Hearing Room in Newark, New Jersey. The purpose of the conference was to "seek information on the challenges raised during the 2010 BGS proceeding regarding the additional electric generation and capacity needs of New Jersey." The agenda attached to the Secretary's letter listed three panels: the Capacity Issues Panel; the Potential Obstacles Panel and the Possible Solutions Panel. The Secretary's Letter asked for public comments to be filed with the Board no later than July 2, 2010.

The Division of Rate Counsel ("Rate Counsel") was pleased to participate in the June 24 technical conference and is hereby submitting the following comments based on issues discussed at the conference. Rate Counsel's comments will initially focus on problems with the status quo and the possible solutions that should be considered by the Board in addressing the enormous capacity problem facing New Jersey electric consumers. In section 3 of these comments Rate Counsel will address specific statements made by panelists at the technical conference.

I. Problems with Status Quo.

RPM Capacity Market Prices in New Jersey are High

The table below summarizes capacity prices applicable to the New Jersey zones in PJM. The "equivalent" $/MWh price is representative of what BGS suppliers would have to pay to purchase through the PJM RPM market to secure capacity to meet their supplier obligations – prior to any markup those suppliers may impose.

New Jersey Capacity Prices - PJM RPM Auction Results

Auction Date	Planning Period	New Jersey - All		NJ - PSEG North	
		$/MW-Day	$/MWh	$/MW-Day	$/MWh
May-07	2007/2008	197.67	16.47	Same	
Jul-07	2008/2009	148.80	12.40	Same	
Oct-07	2009/2010	191.32	15.94	Same	
Jan-08	2010/2011	174.29	14.52	Same	
May-08	2011/2012	110.00	9.17	Same	
May-09	2012/2013	139.73	11.64	185.00	15.42
May-10	2013/2014	245.00	20.42	Same	

Note: $/MWh equivalent prices derived from clearing price using 50% load factor.

The BGS-CIEP price is a transparent capacity-based price. The capacity component of BGS-FP pricing is unknown. With a total peak load of roughly 17,000 MW, New Jersey's implied capacity costs (in 2010/2011) are on the order of $1 billion per year. For 2013/2014, the price rises to roughly $1.5 billion per year.

RPM does not result in sufficient levels of economic capacity in NJ.

Even though New Jersey pays over $1 billion per year for capacity, there is minimal construction of major new generation facilities in New Jersey, for New Jersey's load benefit. There have been increases in generation capacity seen under RPM, but those instances are generally limited to either nuclear facility incremental upgrades, capacity slated for export to New York, smaller generating facilities, or incremental increases at existing plants. With the exception of the Linden cogeneration plant (whose output is committed to New York), the major increases in generation in New Jersey occurred earlier in the decade (2000 to 2003) during a time when financing availability was much different than it is today.

Over 2,400 MW of potential new capacity is present in PJM's generation interconnection queue, primarily at existing generation sites in northern New Jersey. However, as Mr. Herling from PJM stated on June 24, 2010, there is a very high drop out rate from the interconnection queue, over 85% in the last 10 years. Transcript page 10-11. Therefore, it remains uncertain if such generation construction will proceed absent contracting methods other than RPM. As Mr. Kormos of PJM aptly stated:

> I would offer that RPM was never meant to be end-all and be-all for the capacity markets. We always envisioned [it] to be a piece of it. We envisioned that there would be longer term contracts. There are ways to self supply. There are ways to literally pull yourself out of RPM. Those options were always, always built in there.

In sum, PJM's table of capacity resources in New Jersey includes mostly resources that were built prior to RPM (which commenced in 2007) and includes resources whose capacity commitment is to New York (including the Linden cogeneration plant, 1,186 MW of the 1,188 MW entry for 2006). It does not represent a level of economically optimal generation for New Jersey.

II. Possible Solutions

There are multiple ways to secure reasonably low-cost reliable capacity resources for New Jersey ratepayers. Among those mechanisms are i) energy efficiency and demand response resources provided through existing and proposed utility and PJM programs, ii) long-term contracting for renewable resource capacity, iii) other long-term contracting processes, and iv) capacity procurement through the existing BGS auction process. There is no technical, economic, institutional or legal reason why capacity resources cannot be obtained using a combination of these approaches. Rate Counsel supports such a combined approach.

Demand Side Resources

Demand side resources generally represent the most cost-effective capacity (and energy) resource. New Jersey currently procures demand-side energy (energy efficiency) and capacity (peak load savings) resources through a number of utility and Office of Clean Energy mechanisms, and – in stark contrast to the BGS energy and capacity procurement process - there is continual examination and refinement of these procurement mechanisms. The total cost for procurement of such demand-side resources is on the order of *hundreds of millions* of dollars per year. In contrast, the total cost to procure BGS-FP energy and capacity alone is on the order of *six billion* dollars per year.[1] It is reasonable to assume that the same level of review and scrutiny should be given to BGS-FP energy and capacity as is given to demand side resources, which only account for a fraction of the dollars spent on BGS-FP.

Long Term Contracts – Renewable Resources

The amended New Jersey law N.J.S.A.48: 3 - 87(d) effectively calls for over 3,000 MW of solar PV by 2026. Currently, long term contracting structures are being used to secure these installations. This includes the solar loan and SREC Securitization Programs approved by the Board. Offshore wind development will undoubtedly involve some form of long-term contracting arrangements.

Other Longer Term Contracting

Longer-term contracting for more conventional supply on behalf of New Jersey load should be considered for the economic benefits it would confer. Longer term contracting for incremental supply in New Jersey would have the ability to ensure new capacity commitments for New Jersey load and all else equal, will place downward price pressures on the clearing price in the New Jersey zones in the PJM RPM auction. Capacity commitments from New Jersey generation built for New York load, does not result in downward price pressure in the New Jersey zones.

Lower clearing prices in the RPM auction will reduce capacity prices for all New Jersey load. Long term contracting may be opposed by those who

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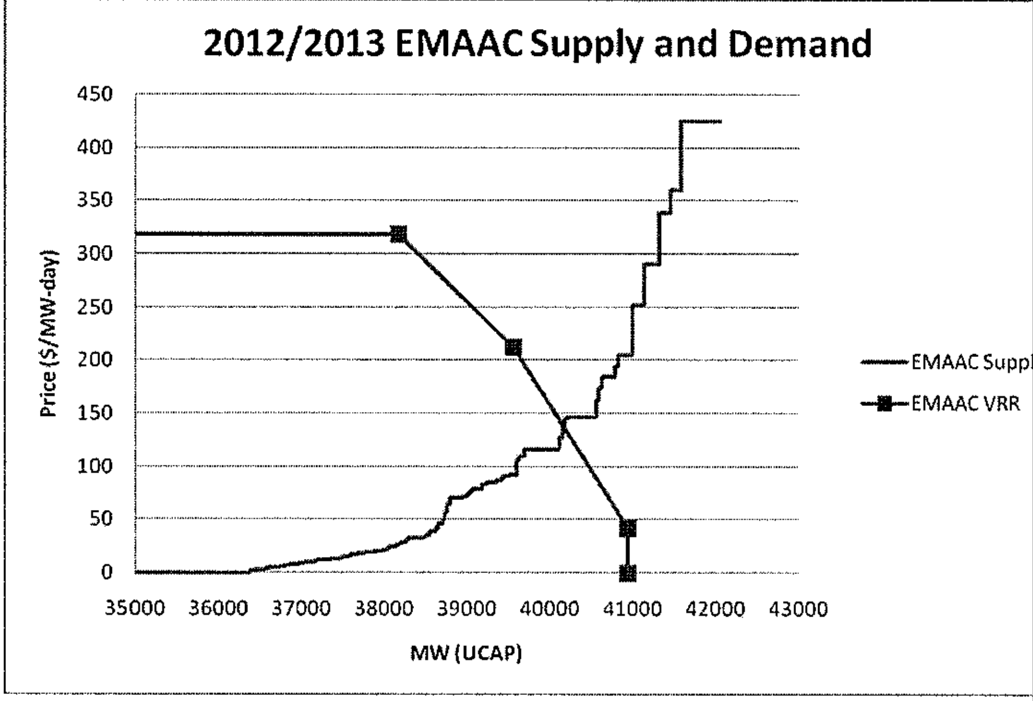
[1] Roughly, 60 million MWh per year of BGS-FP load, at $100/MWh (10 cents/kWh).

currently sell capacity resources in New Jersey through either BGS-CIEP or BGS-FP because a competing capacity procurement vehicle's competitive pressure – and resulting new supply - can reduce capacity-based revenues for sellers of *existing* generation capacity, given the RPM construct in place. However, the benefit to New Jersey ratepayers should outweigh such parochial interests.

PJM has indicated that it will provide by August 2010 more information on how additional generation could affect New Jersey zone (i.e., "LDAs" or local deliverability area) prices. Transcript, page 38. There is no need to wait until August, however, to see how the fundamentals of the auction mechanism itself illustrate the broad effect that new capacity can have on the prices for all *existing* capacity based on publicly available parameters from PJM on how the RPM auction works. The graph below, taken from the PJM RTO base residual auction report for 2012/2013, shows how RPM clearing prices decrease when overall capacity increases – i.e., it illustrates the fundamental mechanics of supply and demand, and how the clearing price is lower when more supply is available.

Figure 7 - Graphical Illustration of EMAAC Clearing Results for 2012/13 Base Residual



Source: PJM RPM Base Residual Auction Report, 2012/2103, http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx, page 28.

In that auction, for the 2012/13 time frame, the slope of the demand curve (i.e., the "EMAAC VRR[2]" line) at the clearing price was roughly $61 per MW-day for every 500 MW of supply. In other words, if EMAAC supply were increased by 500 MW, the clearing price for capacity would decline by $61/MW-day.[3] (Note that in the 2012/13 planning year, "EMAAC" prices apply for the New Jersey zones of JCPL, ACE, RECO and part of PSE&G. In the PSE&G "north" zone for that auction, the slope was even steeper and the price-reducing impact of new supply would be even greater.)

In the most recent auction, for the 2013/2014 time frame, the slope of the demand curve was such that the price in EMAAC would decline by roughly

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[2] "VRR" means Variable Resource Requirements.

[3] See PJM RPM auction planning period parameters available at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-2013-rpm-planning-parameters.ashx.

$75/MW-day if there was an additional 500 MW of supply. A price reduction of $75 per MW-day in the RPM auction translates to a potential savings for New Jersey's peak load at (roughly 17,000 MW) of $465 million per year.[4] The annual carrying costs for a 500 MW peaker in New Jersey might be on the order of $75 million per year, based on standard assumptions.[5] Clearly, the customer savings seen in the RPM clearing market for all New Jersey load would be much greater than the annual carrying costs of a new peaker.

This example illustrates the economic benefits of new capacity. What we have seen with RPM is that it appears to send short-term market price signals that result in increases in capacity to at least nominally address reliability concerns (it is named the "Reliability" Pricing Model for a reason). However, it does not, and was not intended, to incentivize the construction of all economically desirable capacity.

Long-term contracting of supply using competitive market forces is not "out of market" procurement, or "intervention" into the market. It is simply another approach that utilizes market forces. It is an approach that would allow New Jersey to procure increases in capacity that are economically beneficial to ratepayers.

The means to ensure a competitive process to procure new capacity resources are varied. It can be done through an auction, RFP, or negotiation. Such procurement should not resemble the process that resulted in the New Jersey NUG contracts, which were undertaken in a different era when electric power markets did not exist. As Mr. Hoatson representing LS Power Development, LLC correctly pointed out at the June 24th conference, NUG prices were not

[4] 17,000 MW x $75/MW-day x 365 days.
[5] This estimate reflects a cost of $1,000 per kW, a 500 MW plant, and a fixed charge rate of 15%.

competitively set but were administratively determined based on utility avoided cost. Transcript pp 177-178. Capacity procurement in today's world also does not automatically imply energy procurement – the existence of a liquid wholesale spot energy market allows for the energy output of any capacity resource to be directly valued at market rates. However, fair and reasonable processes for procuring energy, or at least accounting for how profits from energy production might reduce contract capacity prices – should also be considered when structuring such procurement.

New Jersey currently uses long-term contracting approaches only for solar PV resources. It is considering such approaches for other renewable energy resources, notably offshore wind. Both of these resources include capacity components, i.e., their capacity counts under the PJM RTO obligations borne by New Jersey load. For some of the same reasons that long-term contracting is used or considered for renewable resources, it can also be used to procure non-renewable based resource capacity.

Existing BGS Procurement Process and RMP

The existing BGS procurement process for all-requirements load obligation includes a capacity component. The costs of capacity procured through the BGS process are *unknown* for the BGS-FP load, since all costs are folded into an all-in per MWh value. However, the costs of capacity for BGS-CIEP load is the clearing price in the BGS auction and can be studied as shown in the chart below. Over the past two years, the cost for this capacity has been roughly the same as the PJM RPM capacity price for the associated year. In the two years prior, BGS CIEP capacity prices were lower than the associated PJM RPM price for New Jersey.

Comparison of Capacity Prices – BGS CIEP and PJM RPM / NJ Zones

		BGS CIEP Auction Result - $/MW-day		
Applicable Year	PJM RTO NJ $/MW-day	PSE&G	JCPL	ACE
2010/2011	174	171	178	171
2009/2010	191	203	204	215
2008/2009	149	103	116	109
2007/2008	198	129	122	136

Therefore, changes to the PJM RPM to produce sufficient levels of economic capacity should have a positive lowering effect on BGS prices paid by New Jersey ratepayers. A discussion of possible solutions to improve on PJM RPM is attached hereto as Attachment A.

III. Critique of Statements by Parties at Technical Conference

At the technical conference on June 24, 2010, a number of parties critiqued the idea of long-term contracting for capacity resources. The complaints about the effect of long-term contracting can be summarized as follows:

1. Long term contracts are "out of market" (PS Power, page 86).
2. Long term contracts lead to stranded costs for captive ratepayers.
3. Merchant developers manage risks and consumers don't pay for them. Customers don't bear long term risk of generation from the RPM paradigm (Meehan, page 26).
4. Connecticut's purchase of peaking capacity was an out-of-market intervention.
5. There is no need to intervene for reliability purposes, since RPM is working. RPM produces "sufficient" capacity (Meehan, p26).
6. Supplier under a long-term purchase is "given" a contract (Meehan, p29).

All of these criticisms are either unfounded, factually incorrect, or lack credibility as they come from those who stand to lose market share if generation is procured through alternative competitive vehicles. The Board should focus on the very real challenges of determining the form, timing and quantities of a competitive market-based, long-term capacity procurement process; and give little weight to these notions. We address each in turn.

1. **Competitive procurement of capacity through long-term contract vehicles is not equivalent to "out of market" procurement.** The phrase "out of market' implies that the resources were not procured using a market-based process, and/or implies that the prices are greater than current prices for the same product. It could also imply that prices are greater than current prices for a different market, such as comparing long-term prices or costs with short-term (spot) prices or costs. A competitive process used to secure the rights to capacity over a long time frame is an established, market-based means to procure capacity. Since there is no data in New Jersey on such alternatives, and thus no basis on which to even compare capacity pricing alternatives, there is no evidence whatsoever of even the potential for "out of market" pricing. It is pure supposition to suggest otherwise.

2. **Long-term contracts will not lead to stranded costs for ratepayers if the supply is competitively procured with proper attention to contract form, timing and quantity.** The New Jersey NUG contracts, which are often used as the benchmark for what represents both "out of market" and a source of stranded costs, are not representative of the type of long-term contract Rate Counsel would consider as economically beneficial for ratepayers. New Jersey currently imports a considerable portion of its capacity, and has considerable levels of older generation that is reasonably

expected to either retire or be replaced with repowered capacity – thus, there is a long-term need to supplant significant amounts of New Jersey's current capacity base. For example, Mr. O'Sullivan's presentation (page 7) indicated that approximately 4,630 MW of generation is currently used as "high electric demand day" (i.e., peaker) generation and is subject to the effect of potential emission requirements. The amount of generation considered for long-term capacity procurement certainly should not be excessive. But it is false to claim that new capacity contracted long-term would become a 'stranded cost" liability in New Jersey when such significant levels of older, dirtier generation can be expected to retire – or be replaced with generation contracted under a long-term approach.

3. **Consumers currently pay for generation development risk.**

Merchant developers "manage" risks by charging consumers for that risk. Mr. Meehan's comments (transcript page 26) imply that consumers do not bear the costs of generation development risks. That is untrue. Consumers currently do pay for the risks associated with new generation development – they pay either directly, such as the BGS-CIEP customer obligation that is tied to RPM capacity prices, or they pay indirectly as part of the all-requirements per MWh rate that flows through for BGS-FP customers. Under RPM, developers risk includes price uncertainty for the "out years" of a new generation development and contract term uncertainty, since RPM is only for one year.

4. **Connecticut**[6]

To address future capacity needs, the state could take a more proactive and less passive stance toward future resource adequacy. This approach has the added benefit that the state can exert more influence over the types of capacity brought to the state.

Actions by the State of Connecticut and its regulatory authority, the Connecticut Department of Public Utility Control (DPUC), provide an example of proactive efforts to achieve resource adequacy and other state resource goals. In response to concerns expressed by ISO New England about resource adequacy in Connecticut, the State of Connecticut responded with programs to provide long-term contracts for new investment in generation and peaking resources. Connecticut's programs reflected clear legislative policy directives to facilitate development of emerging alternative energy supplies such as renewable generation and to promote energy efficiency and demand-side response. Pursuant to legislative directives, the DPUC assessed the state's needs for capacity and conducted proceedings to consider bilateral contracts for needed new capacity resources. A competitive bidding process was held, and bids were evaluated based on multiple attributes, including contribution to local resource adequacy, reduction in major pollutant emissions, use of existing sites and electric generation infrastructure, diversity of ownership, fuel diversity and fuel switching capability.

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[6] This is based on and supported by 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, filed March 30, 2010 in FERC Docket No. ER10-787, and also references 131 FERC ¶ 61,065, Order On Forward Capacity Market Revisions And Related Complaints, issued April 23, 2010.

In 2008, the Connecticut Department of Public Utilities approved the cost-based procurement of 678 MW of gas-fired peaking capacity. This capacity is being procured from three separate plants, developed by three separate generation vendors (including PSEG Power), for commercial operation in the 2012 timeframe, under long-term contracts tied to the cost of service. Connecticut's peak load is roughly 8,000 MW, and has in-state capacity resources of roughly 7,000 MW. Thus, the procurement represents less than 10% of the existing in-state capacity market. Additional capacity resources are imported from out-of-state.

Many of the comments made at the June 24 technical conference referred to Connecticut's long-term purchase of capacity as "out of market," implying negative economic effects of the purchase. However, since there is no long-term market for capacity in Connecticut, there is no basis on which to assess the extent to which such purchases might be "out of market". What the purchase does achieve is certainty of supply at a certain price, tied to the actual costs of building the peaking plants.

These processes were ultimately successful in acquiring capacity with the required attributes. The resulting capacity was offered into ISO New England's Forward Capacity Market ("FCM"; the equivalent of RPM) and contributed to meeting reliability needs and capacity obligations. It is not surprising that no additional near-term capacity is now needed in Connecticut, given the success of the procurement of peaking capacity with long-term arrangements, and given other factors in play: notably, Connecticut has completed a build-out of new transmission import capacity, has secured additional demand response and energy efficiency resources, and also has seen its load forecasts drop due to the recession.

5. **New capacity resulting from RPM price signals may be sufficient for reliability reasons, but there are economic reasons to contract for additional capacity**. Any suggestion of competitive procurements made outside the PJM RPM reliability construct is seen as an "intervention" in the RPM market. However, the RPM construct was never intended to be the only means by which new generation capacity comes to market. State-level procurement processes that lead to new construction of capacity are not an "intervention" in the markets, but are a complement to the reliability-based process that is the basis for RPM. As seen in the example above, it benefits New Jersey's ratepayers to use the forces of supply and demand to lower costs of capacity from existing resources.

6. **Alternative contracting vehicles do not lead to contracts that are "given" away**. Mr. Meehan states (transcript, page 29) that alternative purchase arrangements amount to contracts that are "given" away. This is not the form of competitive procurement vehicle that Rate Counsel would see as benefiting consumers. The process must leverage competitive forces to the utmost benefit to ratepayers. As noted above, the Board would need to give careful attention to the details of the form, timing and quantity of procurement.

Conclusion

Contrary to the assertions made by several participants in the technical conference held on June 24 , 2010, New Jersey is facing a pressing need to build generation in New Jersey that will ultimately serve the State's load requirement. New Jersey needs a cost-effective solution to the development and retention of supply resources. Relying on RPM alone is no longer a viable option. A balanced portfolio of existing BGS auction, long term contracts as well as other resources such as demand response and energy efficiency measures should all be considered by the Board as part of the solution.

<u>**ATTACHMENT A**</u>

I. RPM Is Not Working As Intended: High RPM Prices in New Jersey Are Not Attracting New Capacity

(This section is based on and supported by the Direct Testimony of James F. Wilson In Support of First Brief of the Joint Filing Supporters, filed July 1, 2010 in FERC Docket No. ER10-787)

There is now substantial experience with locational (or zonal) capacity pricing in PJM, and the accumulating evidence is clear: locational capacity pricing in PJM is not having the desired impact of attracting and retaining more capacity to the zones where prices are higher and capacity is presumably more needed.

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. Eastern MAAC has had a separate price in five of the seven delivery years. The Eastern MAAC price averaged more than double the "Rest of RTO" price over the first three delivery years, and over *eight times* the Rest of RTO price for the two most recent delivery years (2012/2013 and 2013/2014). So the "price signal" that is supposed to tell market participants to bring new capacity to Eastern MACC, in preference to the rest of the RTO region, has been loud and long. However, it has not achieved the desired result.

PJM and its market monitor publish various details about the results of the RPM auctions. Capacity needs are proportional to peak loads, so for comparison purposes, it is appropriate to consider changes in capacity as a percent of 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.)

The RPM auction results show that in the two most recent auctions, and even taking into account that Eastern MAAC is smaller, the market has not heeded the price signal at all. In particular, market participants:

- Offered and cleared fewer generation uprates in Eastern MAAC than in the Rest of RTO region
- Offered and cleared less new generation in Eastern MAAC than in the Rest of RTO region
- Offered relatively less demand response and energy efficiency resources in Eastern MAAC than in the Rest of RTO region (the cleared quantity was higher in Eastern MAAC)
- Exported capacity from Eastern MAAC, while net importing capacity into the Rest of RTO region
- Deactivated far more generation in Eastern MAAC than in the Rest of RTO region
- Offered far more existing capacity at prices that failed to clear in Eastern MAAC than in the Rest of RTO region
- Have taken advantage of the opportunity to increase the RPM offer prices for existing capacity based on "Accelerated Project Investment Recovery" (APIR) at far higher rates than in the Rest of RTO region
- Are proposing less new generation for 2014-2019 in Eastern MAAC than for the Rest of RTO region
- Since February 2009, have queued less new generation for Eastern MAAC than for the Rest of RTO region

There are three principal reasons why zonal capacity pricing in PJM failed to achieve its objectives in terms of attracting new or retaining existing capacity.

First, the market is apparently not finding the zonal price signals credible and is ignoring them. There are a number of reasons for this. 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 will relieve constraints and reduce or eliminate the zonal price differential. 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 (peak load, CETO, CETL, and Reliability Requirements; more on this later). 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.

Second, while other market participants may largely ignore the RPM 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. 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, suggests that capacity sellers' actions are consistent with the incentives created by a capacity mechanism. When selling into the large, relatively competitive Rest of RTO region where incremental sales will 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 zones such as Eastern MAAC (that also tend to have more concentrated capacity 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, for instance with APIR.

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 can easily be estimated, based on the supply and demand curves from the RPM auctions, which PJM publishes. Based on recent auctions, it has been estimated that 70 percent of the existing capacity in Eastern MAAC is owned by entities that have no incentive to offer incremental capacity into the RPM auctions (offering incremental capacity would reduce the RPM price somewhat, and they would actually lose more money as a result than they would gain by clearing additional capacity). This helps explain why relatively few plant uprates are offered in Eastern MAAC compared to the Rest of RTO region, despite the price being eight times higher.

Third, Eastern MAAC is a relatively developed area where it can be more difficult, more difficult to identify suitable sites, and more difficult to obtain all regulatory approvals. 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.

II. RPM Is Not Working As Intended: What To Do About the High Cost of RPM for New Jersey

That RPM is not working for New Jersey is no surprise to many consumer advocates, who were concerned that RPM could be ineffective and expensive. RPM was supposed to produce stable price signals that would influence investment, and that has not occurred. RPM has not performed as expected due to flaws in the theory behind it and changing industry conditions, and it was never likely to significantly influence new capacity decisions.[1]

Therefore, rather than try to further tweak RPM and spend additional years spending and hoping, one focus going forward should be to reduce the cost of RPM while other approaches to ensuring future capacity needs are pursued. Following are several ideas for reducing the cost of RPM to New Jersey.

1. Eliminate zonal capacity procurement.

Stakeholders should consider eliminating zonal capacity procurement entirely, as it is ineffective. As discussed earlier, part of the market ignores the zonal price signals, while incumbents in the zone have incentives to withhold incremental capacity when there is a zonal price. When there are no zones and all participants are forced to compete on the larger and more competitive RTO region playing field, the incentives to withhold are much weaker. In theory, zonal capacity procurement should increase efficiency, however, there is now substantial evidence that in fact it reduces efficiency.

2. Purchase only the capacity needed through RPM.

[1] See, Wilson, James F., Forward Capacity Market CONEfusion, June 2010, forthcoming in Electricity Journal.

If zonal capacity procurement is retained, the cost of RPM can be reduced by setting more realistic targets for capacity procurement. One of the main reasons RPM has been excessively costly for New Jersey consumers is that PJM acquires an amount of capacity through RPM for Eastern MAAC that is more than is really needed for reliability. Specifically, the "Reliability Requirement" (the amount of capacity considered needed that is acquired through RPM) is too high due to flaws and overly conservative assumptions in its calculation. In addition, the Reliability Requirement reflects peak load forecasts that are too high. The amount of capacity procured through RPM is also excessive due to overly conservative estimates of the amount of transmission available into Eastern MAAC (its "CETL", which reduces the amount of capacity that must be purchased in Eastern MAAC). The result is that RPM must buy more capacity in Eastern MAAC than is needed. Purchasing an excessive quantity can sharply raise the RPM clearing price that applies to all of the capacity acquired in the zone, resulting a large increase in the cost of capacity for New Jersey consumers.

3. Set more realistic peak load forecasts.

One major reason the Reliability Requirements are too high is that PJM's peak load forecasts are too high. Since about 2002, peak load growth in PJM and the Eastern MAAC region has been slowing, and the economy only partly explains this trend. Higher electricity prices and increasing efficiency of electricity use are contributing to this trend, which PJM's peak load forecasts do not capture. PJM's forecasts anticipate substantial growth in future peak loads based on very optimistic economic forecasts, including, for example, the assumption that several new casinos will be built and in operation in Atlantic City by 2013. Because RPM auctions are held three years in advance, load forecast errors are extremely costly for consumers. PJM has substantially lowered its forecasts for 2009, 2010 and 2011 recently, but the damage is done because the RPM auctions for these delivery years were held in 2007 and 2008. In response to stakeholder urging, PJM has agreed to hire an independent consultant to review its peak load forecasting approach.

4. Correct errors and overly conservative assumptions in PJM's Reliability Requirements calculations

Stakeholders have been raising questions about PJM's methodology for calculating the Reliability Requirements based on the load forecast for over two years. In their Motion for Technical Conference (March 19, 2008, p. 14) the RPM Buyers "respectfully request[ed] that the Commission institute a Technical Conference to address the following issues: ... 6. Whether PJM's administrative mechanisms for setting Reliability Requirements within LDAs have appropriately reflected the need for new capacity in LDAs, and what changes should be made to reflect needed capacity more accurately." The Brattle Group's 2008 report on RPM also questioned aspects of PJM's calculation of reliability requirements. In its order on the motion for technical conference, FERC stated (P 48), "We also expect that PJM and its stakeholders will review, in accordance with the Brattle Report's recommendations and RPM Buyers' concerns, the methodology for determining the Locational Delivery Areas and the specific reliability requirements, i.e., (1) loss of load expectation criteria ..." The issue was also raised in PJM Capacity Market Evolution Committee meetings in 2008 and 2009 and in the PJM Long Term Capacity Issues Symposium held last winter. However, to date nothing has been done.

More recently, PJM's methodology for calculating its "Capacity Emergency Transfer Objective" or "CETO", which is the key input to the Reliability Requirements that RPM must purchase, was criticized in testimony by James F. Wilson in the PATH transmission line application proceeding in Virginia. Mr. Wilson found several reasons why PJM's CETO values and Reliability Requirements are too high. In particular, in addition to excessive peak load forecasts, he found errors in the CETO analysis and overly conservative assumptions, such as the "one day in 25 years" reliability criterion, which no other RTO uses.

5. Use more realistic estimates of the transmission available to Eastern MAAC ("CETL")

PJM's approach for determining the amount of transmission available to zones (the "CETL" values), which directly reduce the amount of capacity that must be purchased in the zone, was also criticized in the Virginia proceeding on the PATH transmission line, by Eddie S. Dehdashti, Ph.D. who found that PJM's approach did not conform to industry standards and included overly conservative assumptions. PJM never responded to these criticisms because the application was withdrawn.

More realistic estimates of the capacity that actually needs to be acquired within New Jersey would result from more realistic peak load forecasts and improved methodologies for calculating Reliability Requirements and available transmission, and this would lower RPM costs for New Jersey by billions of dollars.

6. Reconsider three-year-forward mandatory capacity obligations[2]

Holding the RPM base residual auctions three years in advance was supposed to allow multiple proposals for new capacity to compete in the auctions, and to result in stable, "long-term" price signals that would encourage new investment. PJM also values knowing, three years in advance, that there will be enough capacity, and the specific resources committed to provide the capacity.

However, it is not clear the three-year-forward capacity market has accomplished anything that a one year forward capacity market would not have, other than the advance identification (subject to later adjustment) of future capacity resources. At the same time, there have been significant disadvantages to the three-year-forward approach. Forecasts of capacity requirements for 2009 and 2010 were too high, resulting in the acquisition of excessive amounts of capacity at excessive prices for these delivery years through the RPM auctions held years in advance. As a result, the cost of capacity for these delivery years was billions of dollars higher than necessary for reliability.

The three-year-forward approach may have led to higher capacity prices and costs for additional reasons. Many of the new resources that ultimately will be available for an upcoming delivery year have not been identified or are not prepared to offer into the RPM auction three years in advance (most notably, demand resources). Some existing resources (such as older plants near retirement) may find it too risky to enter into a commitment three years in advance. As a result, the RPM auctions try to satisfy nearly all of the Reliability Requirement at a time when not all of the capacity that ultimately will be

[2] This section is based on and supported by Wilson, James F., Forward Capacity Market CONEfusion, June 2010, section 7.

available for the delivery year is in a position to participate in the auction, resulting in a mismatch between the auction's supply and demand that raises the clearing price and capacity cost. In later, incremental auctions, where additional supply becomes available but generally not additional demand, prices are typically much lower.

The risk that three-year-forward forecasts of capacity requirements will be significantly wrong is substantial at this time. Future peak load growth is highly uncertain, due to the uncertain pace of economic growth, the potential impact of energy prices, increasing efficiency in energy use, and developing price-responsive demand. Other significant uncertainties – such as climate policy and its impact on coal and other generation, and the rate at which the smart grid will develop – make years-forward procurement riskier for both buyers and sellers and place a higher value on maintaining flexibility. At the same time, there is now more flexibility to adjust capacity obligations closer to the delivery year than was anticipated when the three-year-forward approach was selected through settlement in 2006. Many of the incremental resources that have been offered into RPM have short lead times, including demand response, incremental upgrades to existing plants, energy efficiency, plant reactivations or delayed retirements, and imports from neighboring regions. This flexibility means that even if peak loads increase unexpectedly (contrary to state policies encouraging efficiency and peak load reductions), it will likely be possible to acquire additional needed resources with short lead time.

Under these circumstances of high uncertainty and substantial flexibility, the need for and potential value of three-year-forward mandatory procurement is lower and the associated risk is higher. Under present circumstances the costs and risks of the mandatory three-year-forward approach may outweigh the potential benefits. While processes that reveal market supply, demand, and apparent adequacy years in advance are valuable, this also may be accomplished to some extent through voluntary processes.

7. Provide capacity buyers additional flexibility in the timing of capacity procurement

If the three-year-forward procurement is retained, its cost and risk can be reduced by providing additional flexibility for capacity buyers to shift procurement closer to the delivery year. Capacity sellers already have the flexibility to offer new, incremental capacity into an incremental or reconfiguration auction if they expect higher prices there than those found in the three-year-forward base residual auction. But capacity buyers have no such flexibility, as PJM attempts to procure on their behalf almost all of the Reliability Requirement in the three-year-forward auction. To date, incremental auctions have generally cleared at much lower prices than the base residual auctions. A greater ability to arbitrage between the three-year-forward auction and the additional auctions closer to the delivery year (such as the ability to offer "virtual capacity" that is allowed under some capacity mechanisms) would increase market efficiency and lower the risk that the three-year-forward procurement will result in excessive capacity cost.