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Monitoring Analytics

In the Matter of the Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results.

Administrative Docket PC22

Responses to Questions from the Maryland PSC

The Independent Market Monitor for PJM

October 4, 2010

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Question No. 1

What value or benefit will customers in the MAAC zones receive in exchange for the higher capacity prices they will pay in 2013-14? Is it true that because the MAAC and DPL South zones cleared below Net CONE, RPM is not incenting new developments in those zones? If the Commissioners were asked by the public to explain the purpose of the capacity market and the benefit customers receive from capacity payments, what should they say?

Response

The purpose of the capacity market is to ensure that the PJM system is reliable and that the total cost of reliable energy is minimized. A capacity market is not the only way to provide this result, but it is an effective way to provide this result. A wholesale energy market will not consistently result in adequate revenues in the absence of an administrative mechanism designed to address the issue of revenue adequacy. The administrative mechanism can be a capacity market, or administrative scarcity pricing or a combination. Regardless of the choice, the revenue adequacy issue requires an administrative solution.

Wholesale electric power markets are affected in significant ways by externally imposed reliability requirements. A regulatory authority administratively determines the acceptable level of reliability, which is enforced through a requirement to maintain a target level of installed or unforced capacity. This exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess, on average, of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This in turn reduces net revenue to generation owners which reduces the incentive to invest.

Actual net revenues in PJM were below the level required to cover the full costs of new generation investment on average for all unit types for the entire eight year PJM market period preceding the implementation of the RPM capacity market design.

Wholesale power markets, in order to be viable, must be competitive and must provide adequate revenues to ensure an incentive to invest in new capacity. Neither competition nor adequate revenues result automatically from the operation of wholesale power markets. Market power mitigation rules are required in order to ensure competition because the structural conditions for competition do not exist, especially in cases of local market power in the energy market. Administrative rules are required in order to ensure an expectation of adequate revenues because enforcement of a reliability requirement results in lower prices and revenues.

A wholesale energy market will not consistently result in adequate revenues in the absence of an administrative mechanism designed to address the issue of revenue adequacy. The administrative mechanism can be a capacity market, or administrative scarcity pricing or a combination. Regardless of the choice, the revenue adequacy issue requires an administrative solution.

For example, Table 1, shows that in 2009, 9.1 percent of total net revenues for CTs in PJM came from the energy market. For the period from 1999 through 2009, 41.6 percent of total net revenues for CTs in PJM came from the energy market. These results vary by location. For example in the BGE Zone, in 2009 15.0 percent of total net revenues for CTs came from the energy market. For the period from 1999 through 2009, 48.5 percent of total net revenues for CTs in the BGE Zone came from the energy market.

Table 1 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2009

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$55,612	$16,677	$0	$0	$2,248	$74,537
2000	$8,498	$20,200	$0	$0	$2,248	$30,946
2001	$30,254	$30,960	$0	$0	$2,248	$63,462
2002	$14,496	$11,516	$0	$0	$2,248	$28,260
2003	$2,763	$5,554	$0	$0	$2,248	$10,566
2004	$919	$5,376	$0	$0	$2,248	$8,543
2005	$6,141	$2,048	$0	$0	$2,248	$10,437
2006	$10,996	$1,758	$0	$0	$2,194	$14,948
2007	$17,933	$28,442	$0	$0	$2,154	$48,529
2008	$12,442	$35,691	$0	$0	$2,398	$50,532
2009	$5,113	$48,441	$0	$0	$2,384	$55,939

The choice is not between the energy market as it is and the energy market plus a capacity market. The choice is not between retaining or eliminating the capacity market. The choice is between adding an administrative scarcity pricing mechanism or a capacity market to address the revenue adequacy issue. Regardless of the choice, the expected value of the increased revenues must be the same if the incentives to invest in generation are to be adequate to result in a reliable system.

While it is clear how to incorporate the target level of capacity in a capacity market, the same is not true for an administrative scarcity pricing mechanism. It is as difficult or more difficult to manage energy prices so as to produce the target level of capacity in a market where demand remains extremely price inelastic and the physical ability does not yet exist for individual customers to signal or to receive their desired level of reliability. The right level of reliability will not emerge automatically from a market design without a capacity market any more than it will from a design that includes a capacity market. The actual level of installed capacity results from investor decisions which are a function of investor expectations about the level and volatility of net revenues that will result from the market design. In an administrative scarcity pricing mechanism market designed to meet a target level of reliability, net revenues result from the management of scarcity pricing. Administrative scarcity pricing levels must be set so as to produce the required level of net revenues from the energy market while adjusting for variations in demand and supply in real time, addressing locational issues and preventing the exercise of market power. Given that maintaining a target level of capacity will tend to reduce energy price levels and volatility, the required scarcity prices in such a market are likely to be extremely high, to be relatively infrequent and to occur for unpredictable periods. To the extent that scarcity pricing levels require ongoing intervention and modification to achieve target reliability levels, regulatory risk is also introduced. Investor expectations are likely to incorporate the resultant volatility and regulatory risk in the form of a risk premium over that incorporated in a capacity market design.

The effectiveness of RPM prices as an investment incentive depends on the price level, on the costs of investments in new and existing resources, and on investor expectations about future prices. Investors must have a reasonable expectation that prices over the life of the project will make the investment profitable. That expectation depends in part on expectations that the key features of the capacity market design will persist and that prices will reflect supply and demand conditions.

The benefit of the RPM capacity market is not solely related to reliability. The definition of a capacity resource links capacity to the energy market in critical ways. These links are part of the benefit of the capacity market.

The current definition of capacity includes several components: the obligation to offer the energy of the unit into the Day-Ahead Market; the obligation to permit PJM to recall the energy from the unit under emergency procedures; the obligation to provide outage data to PJM; the obligation to provide energy during the defined high demand hours each year; and the obligation that the energy output from the resource be deliverable to load in PJM.

The most critical of these components of the definition of capacity is the obligation to offer the energy of the unit into the Day-Ahead Market. If buyers are to pay the high prices associated with RPM, it must be clear what they are buying and what the obligations of the sellers are. The fundamental energy market design should assure all market participants that the outcomes are competitive. This works to the ultimate advantage of all market participants including existing and prospective load and existing and prospective generation. The market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.

Capacity resources are required to ensure the reliability of the system. Reliability is not defined as the operation of the system only during an emergency but the reliable operation of the system in every hour of the year. If the system reserve margin were comprised of demand resources that would only interrupt for 10 days or generation resources that would only perform during an emergency or generation that will only perform when the price is $999 per MWh, the probability of needing those resources would increase significantly and the number of hours during which those resources are needed would increase significantly. As a general matter, the probability of needing such resources increases with the level of such resources that are defined to be capacity and thus needed for reliability.

Higher clearing prices in a constrained Locational Deliverability Area (LDA) relative to other LDAs or the unconstrained RTO region reflect local supply and demand conditions and provide incentives to invest in upgrades to existing units rather than retire such units; to build new generation resources; to provide new demand side resources; and to upgrade existing transmission lines or build new transmission lines.

Table 1 shows the RPM clearing prices for all RPM auctions to date, and Table 2 and Table 3 show the MAAC, SWMAAC, Pepco, EMAAC, and DPL South RPM clearing prices compared to net Cost of New Entry (CONE).

Table 2 Capacity prices: 2007/2008 through 2013/2014 RPM Auctions

	RPM Clearing Price ($ per MW-day)							
	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG North	Pepco
2007/2008 BRA	$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$188.54
2008/2009 BRA	$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$210.11
2008/2009 Third IA	$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$223.85
2009/2010 BRA	$102.04	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$237.33
2009/2010 Third IA	$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00
2010/2011 BRA	$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29
2010/2011 Third IA	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
2011/2012 BRA	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00
2011/2012 First IA	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00
2011/2012 ATSI FRR Integration Auction	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2012/2013 BRA	$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$185.00	$133.37
2012/2013 ATSI FRR Integration Auction	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First IA	$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$16.46
2013/2014 BRA	$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$247.14

Table 3 MAAC capacity prices and net Cost of New Entry (CONE): 2007/2008 through 2013/2014 RPM Auctions

	MAAC		SWMAAC		Pepco	
	Clearing Price ($ per MW-day)	Net CONE ($ per MW-day)	Clearing Price ($ per MW-day)	Net CONE ($ per MW-day)	Clearing Price ($ per MW-day)	Net CONE ($ per MW-day)
2007/2008 BRA	$40.80	$148.47	$188.54	$158.68	$188.54	$158.68
2008/2009 BRA	$111.92	$148.80	$210.11	$159.02	$210.11	$159.02
2008/2009 Third IA	$10.00	$148.80	$223.85	$159.02	$223.85	$159.02
2009/2010 BRA	$191.32	$148.81	$237.33	$159.04	$237.33	$159.04
2009/2010 Third IA	$86.00	$148.81	$86.00	$159.04	$86.00	$159.04
2010/2011 BRA	$174.29	$131.87	$174.29	$112.77	$174.29	$112.77
2010/2011 Third IA	$50.00	$131.87	$50.00	$112.77	$50.00	$112.77
2011/2012 BRA	$110.00	$125.94	$110.00	$105.87	$110.00	$105.87
2011/2012 First IA	$55.00	$125.94	$55.00	$105.87	$55.00	$105.87
2011/2012 ATSI FRR Integration Auction	$108.89	$125.94	$108.89	$105.87	$108.89	$105.87
2012/2013 BRA	$133.37	$176.44	$133.37	$176.44	$133.37	$176.44
2012/2013 ATSI FRR Integration Auction	$20.46	$176.44	$20.46	$176.44	$20.46	$176.44
2012/2013 First IA	$16.46	$176.14	$16.46	$176.14	$16.46	$176.14
2013/2014 BRA	$226.15	$227.20	$226.15	$227.20	$247.14	$227.20

Table 4 EMAAC capacity prices and net Cost of New Entry (CONE): 2007/2008 through 2013/2014 RPM Auctions

	EMAAC		DPL South	
	Clearing Price ($ per MW-day)	Net CONE ($ per MW-day)	Clearing Price ($ per MW-day)	Net CONE ($ per MW-day)
2007/2008 BRA	$197.67	$148.47	$197.67	$148.47
2008/2009 BRA	$148.80	$148.80	$148.80	$148.80
2008/2009 Third IA	$10.00	$148.80	$10.00	$148.80
2009/2010 BRA	$191.32	$148.81	$191.32	$148.81
2009/2010 Third IA	$86.00	$148.81	$86.00	$148.81
2010/2011 BRA	$174.29	$131.87	$186.12	$131.87
2010/2011 Third IA	$50.00	$131.87	$50.00	$131.87
2011/2012 BRA	$110.00	$125.94	$110.00	$125.94
2011/2012 First IA	$55.00	$125.94	$55.00	$125.94
2011/2012 ATSI FRR Integration Auction	$108.89	$125.94	$108.89	$125.94
2012/2013 BRA	$139.73	$212.13	$222.30	$212.13
2012/2013 ATSI FRR Integration Auction	$20.46	$212.13	$20.46	$212.13
2012/2013 First IA	$153.67	$212.13	$153.67	$212.13
2013/2014 BRA	$245.00	$261.06	$245.00	$261.06

Table 5 shows the capacity changes for generation resources, Demand Resources, and Energy Efficiency Resources in SWMAAC for the 2008/2009 through 2013/2014 delivery years. Net capacity changes in SWMAAC were 1,491.1 MW. Table 5 shows that there has been a net decrease in new generation capacity in SWMAAC since the inception of RPM, which has been more than offset by the increase in demand side resources.

Table 5 SWMAAC capacity changes: 2008/2009 through 2013/2014 delivery years

	ICAP (MW)						
	New Generation	Reactivated Generation	Retired Generation	Net Capacity Modifications	Net DR Modifications	Net EE Modifications	Total
2008/2009	0.0	21.8	0.0	21.0	253.8	0.0	296.6
2009/2010	0.0	0.0	0.0	34.2	(28.9)	0.0	5.3
2010/2011	0.0	0.0	0.0	(61.1)	156.0	0.0	94.9
2011/2012	0.0	0.0	0.0	7.0	316.0	0.0	323.0
2012/2013	0.0	0.0	(788.0)	0.0	1,235.9	154.7	602.6
2013/2014	242.0	0.0	0.0	24.2	(121.8)	(47.7)	96.7
Total	242.0	21.8	(788.0)	25.3	1,811.0	107.0	1,419.1

Resource owners can include an Avoidable Project Investment Recovery Rate (APIR) component in their unit-specific Avoidable Cost Rate (ACR) calculations.[1] The ACR less PJM energy and ancillary service markets net revenues determine the market seller offer caps. Project investment is the capital reasonably required to enable a capacity resource to continue operating or improve availability during peak-hour periods during the delivery year. Table 6 and Table 7 show offered and cleared MW by APIR range for the 2007/2008 through 2013/2014 Base Residual Auctions. From the 2009/2010 BRA through the 2013/2014 BRA, more than 50 percent of all offered MW from generation capacity resources in SWMAAC included an APIR component. The inclusion of an APIR component means that new investments in existing resources had been planned.

Table 6 SWMAAC offered and cleared generation capacity by APIR range: 2007/2008 through 2009/2010 RPM Base Residual Auctions

	2007/2008 BRA		2008/2009 BRA		2009/2010 BRA	
	Offered UCAP (MW)	Cleared UCAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)
No APIR	7,215.7	7,215.7	7,322.7	7,322.7	4,578.4	4,578.4
$0 per MW-day to $50 per MW-day	2,488.9	2,488.9	2,540.7	2,540.7	1,063.0	1,063.0
$50 per MW-day to $100 per MW-day	448.6	448.6	0.0	0.0	268.1	268.1
$100 per MW-day to $150 per MW-day	28.3	28.3	315.3	315.3	200.8	200.8
$150 per MW-day to $200 per MW-day	0.0	0.0	133.3	133.3	0.0	0.0
$200 per MW-day to $250 per MW-day	0.0	0.0	0.0	0.0	0.0	0.0
> $250 per MW-day	0.0	0.0	0.0	0.0	3,845.1	3,448.0
Total	10,181.5	10,181.5	10,312.0	10,312.0	9,955.4	9,558.3

1 See PJM OATT § 6.8(a) (Attachment DD: Reliability Pricing Model," Third Revised Sheet No. 614 (Effective June 29, 2009)).

Table 7 SWMAAC offered and cleared generation capacity by APIR range: 2010/2011 through 2013/2014 RPM Base Residual Auctions

	2010/2011 BRA		2011/2012 BRA		2012/2013 BRA		2013/2014 BRA	
	Offered UCAP (MW)	Cleared UCAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)	Offered UCAP (MW)	Cleared UCAP (MW)
No APIR	5,071.9	5,071.9	5,347.7	5,126.9	4,800.3	4,560.3	4,725.9	4,725.9
$0 per MW-day to $50 per MW-day	519.4	519.4	355.7	231.0	1,147.9	1,021.9	1,023.4	1,023.4
$50 per MW-day to $100 per MW-day	664.0	664.0	795.2	610.0	72.1	59.0	961.3	961.3
$100 per MW-day to $150 per MW-day	37.5	37.5	183.5	131.5	38.2	0.0	110.4	110.4
$150 per MW-day to $200 per MW-day	35.8	0.0	54.8	19.0	0.0	0.0	0.0	0.0
$200 per MW-day to $250 per MW-day	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
> $250 per MW-day	4,080.6	4,061.6	4,135.0	3,920.9	4,319.3	4,020.0	3,186.8	2,660.7
Total	10,409.2	10,354.4	10,871.9	10,039.3	10,377.8	9,661.2	10,007.8	9,481.7

The results of the markets, shown in the tables and figures, indicate that the capacity market has had a significant impact on the reliability of the PJM market, and on the reliability of the eastern LDAs, which include Maryland. The capacity market design, especially the ability to recover the costs of incremental investments in existing resources using APIR, has resulted in substantial investment in existing capacity resources, which are critical to maintaining the reliability of SWMAAC. Figure 1 shows the role of existing capacity that has made significant investments under the APIR rule.

Figure 1 SWMAAC offered capacity by type: 2007/2008 through 2013/2014 RPM Base Residual Auctions

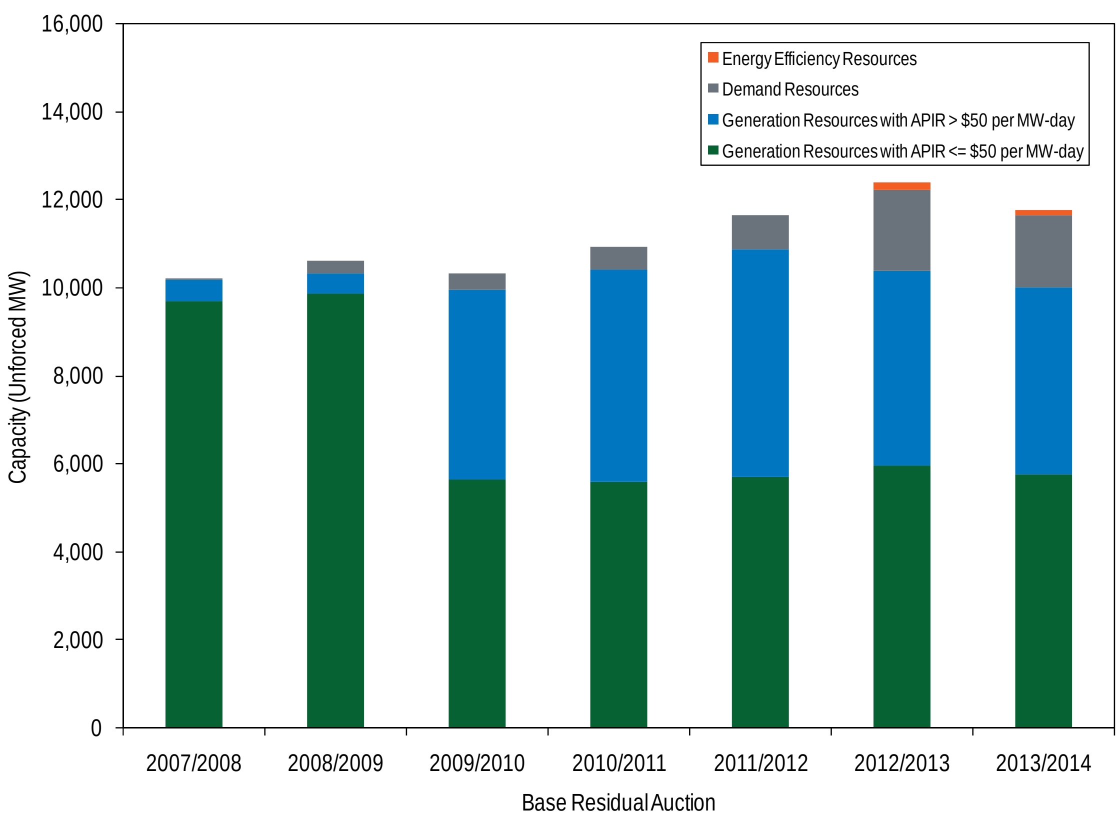
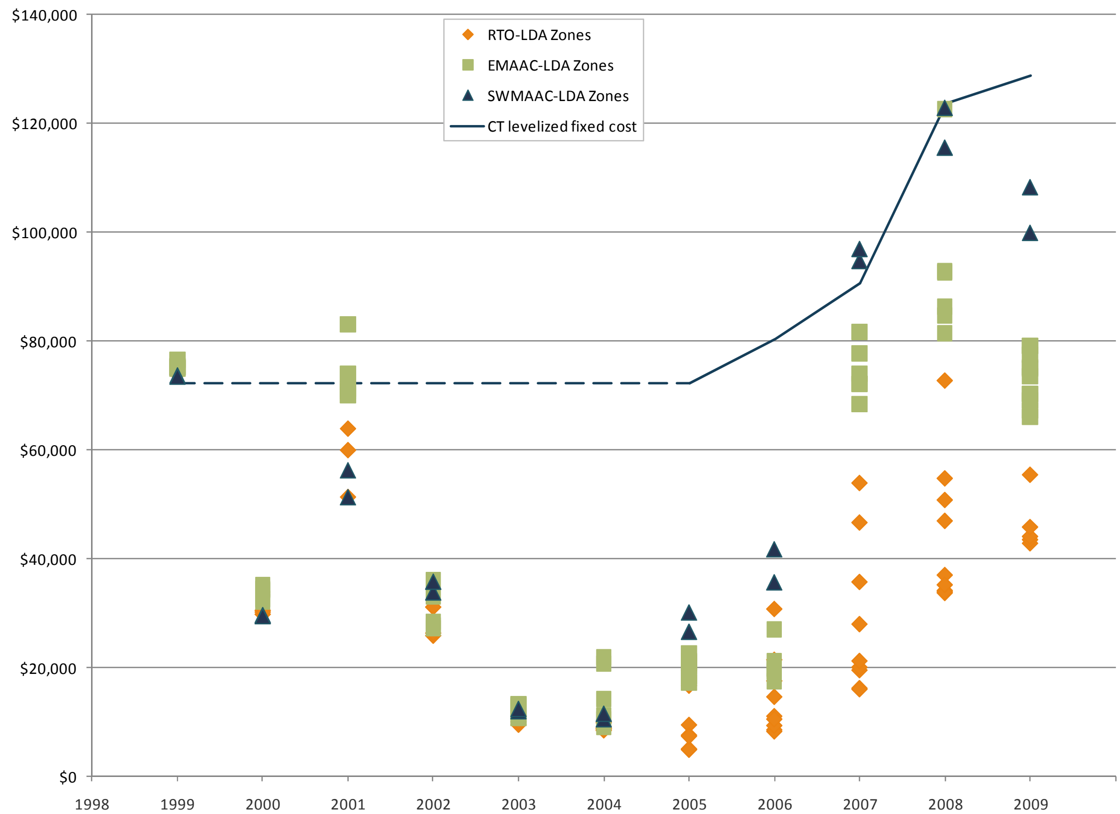


Figure 1 shows capacity offered in SWMAAC by type, defined as either Demand Resource, Energy Efficiency Resource, generation resource with an APIR component greater than $50 per MW-day UCAP, or generation resource with an APIR component less than or equal to $50 per MW-day UCAP. The amount of Demand Response offered and the Demand Response share of offered MW in SWMAAC increased through the 2012/2013 BRA. From the 2009/2010 BRA through the 2013/2014 BRA, 40 to 50 percent of all offered MW from generation capacity resources in SWMAAC included an APIR component greater than $50 per MW-day.

Net CONE is a good indicator of the expected net revenue that must be obtained from the capacity market, in addition to net revenues from the energy and ancillary services markets, in order to incent new investment. Nonetheless, net CONE is not a perfect indicator. Net CONE includes gross CONE offset by an historical three year average of net revenues from the energy and ancillary services markets, which is an imperfect estimate of expected revenues for the RPM delivery year.

Net revenues for a new entrant CT are shown in Figure 2. The data show that net revenues, including capacity market revenues, in the SWMAAC LDAs since the implementation of RPM in mid 2007 have been quite close to the level required to incent new investment in a CT. The reduced levels of net revenues in 2009 reflect the low energy market net revenues in 2009 and are not expected to persist. In fact, the low energy market net revenues will tend to increase net CONE values for the next three auction years because the energy market revenue offset will be reduced.

Figure 2 New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2009 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2009



Question No. 2

Identify and explain, with specificity, the mechanisms in the tariff, operating agreement, and manuals, that explain the resource clearing price for the MAAC and Pepco LDAs in the BRA for the 2013/2014 Delivery Year being higher than the RTO clearing price.

Response

The RPM rules, set out in the tariff, result in higher prices in local markets, defined by Location Deliverability Areas or LDAs, when enough cheaper capacity cannot be imported to meet the reliability requirements in the LDA and more expensive internal capacity must be purchased to clear the market. This occurred in both MAAC and Pepco in the BRA for the 2013/2014 Delivery Year.

A PJM region must first be defined as a modeled LDA prior to the Base Residual Auction (BRA) in order for it to be modeled in the auction as a potentially constrained region. Section 5.10(a)(ii) of Attachment DD of the PJM OATT and Section 2.3 of PJM Manual 18 include the rules applied to determine the modeled LDAs for a delivery year.

PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 delivery year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a Locational Price Adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a Locational Price Adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 delivery year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of the above three tests. In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."

CETO measures the requirement to import capacity in order to meet the reliability needs of an LDA. CETL measures the ability to import capacity to meet the reliability needs of an LDA. When CETL is greater than CETO, the chances of the LDA being constrained in a capacity auction are reduced. As CETL approaches CETO, the chances of the LDA being constrained increase.

Whether a modeled LDA has a binding constraint and therefore higher prices is dependent upon supply and demand conditions. The Variable Resource Requirement (VRR) curve (the demand curve) is established for the RTO and each modeled LDA per Section 5.10(a)(i) of Attachment DD of the PJM OATT. PJM must post the parameters of the VRR curve by February 1 prior to the conduct of the BRA for the first delivery year in which the new values will be applied per Section 5.10(a)(vii) of Attachment DD of the PJM OATT. Section 5.11(a) of Attachment DD of the PJM OATT includes the list of all the relevant information and parameters that PJM must post prior to the BRA. Inputs to the Variable Resource Requirement (VRR) curve include the Reliability Requirement, the Installed Reserve Margin, the Short-Term Resource Procurement Target, the Cost of New Entry (CONE), the Net E&AS Revenue (E&AS) Offset, and the Pool-Wide Average EFORd. Section 2 of PJM Manual 18 provides an overview of the PJM planning parameters, and Section 3 of PJM Manual 18 explains the VRR curve. Sections 5.10(a)(iv) and 5.10(a)(v) of Attachment DD of the PJM OATT provide rules for establishing the net CONE and E&AS parameters.

Section 6 of Attachment DD of the PJM OATT establishes rules affecting the shape of the supply curve including the RPM must offer requirement, Equivalent Demand Forced Outage Rates (EFORds), market structure tests, market seller offer caps, and market power mitigation rules. Capacity resource requirements are defined in Section 5.5 of Attachment DD of the PJM OATT in conjunction with Schedules 9 and 10 of the PJM Reliability Assurance Agreement and PJM Manual 21 for generation capacity resources and Schedule 6 of the PJM Reliability Assurance Agreement, Attachment DD-1 of the PJM OATT, and PJM Manual 18B for Demand Resources and Energy Efficiency

Resources. Section 5.6.6 of Attachment DD provides the rules for establishing the level of available capacity for sale along with rules for delisting a PJM capacity resource. Section 5.6.1 of Attachment DD of the PJM OATT defines RPM sell offer rules.

The auction clearing mechanism for BRAs is defined in Sections 5.12(a) and 5.12(d) of Attachment DD of the PJM OATT. In addition, Section 5.14(a) of Attachment DD of the PJM OATT defines the rules for establishing Locational Price Adders. The optimization algorithm calculates the overall clearing solution to minimize the cost of satisfying the reliability requirements across the PJM region while considering the sell offers, the RTO and LDA VRR curves, and locational constraints. The CETL value defined prior to the BRA is used to model the import limitation into the constrained region.

Question No. 3

Why was the capacity clearing price for the 2013-14 planning year so much higher in MAAC than the clearing price for the 2012-13 planning year? What changed? What new price signals or economic incentives does the higher 2013-14 clearing price send?

Response

The MMU found that the most significant factor contributing to the higher MAAC clearing price in the 2013/2014 BRA was the decrease in the MAAC CETL used to model capacity imports into the MAAC region. The decrease in the CETL meant a reduced ability to import cheaper capacity, which meant relying on more expensive internal capacity to clear the market.

MAAC internal supply increased 62.0 MW UCAP (0.1 percent) from 69,016.9 MW in the 2012/2013 Base Residual Auction (BRA) to 69,078.9 MW in the 2013/2014 BRA.[2] RPM market rule changes between the 2012/2013 BRA and the 2013/2014 BRA that affected the supply curve in MAAC include the elimination of the market rule that subjected existing Demand Response and EE to an offer cap of $0/MW-day and the increase in the default Avoidable Cost Rates (ACRs).

Changes affecting the MAAC demand curve include the adjustment to the Cost of New Entry (CONE) values in accordance with changes in the Handy-Whitman Index and the decrease in the 2013/2014 Energy & Ancillary Services (E&AS) offset from the 2012/2013 values. The net CONE, gross CONE less the E&AS offset, in UCAP terms is the basis for

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2 See "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated" (September 20, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf>.

the price coordinates in the Variable Resource Requirement (VRR) curves. The net CONE value in UCAP terms for MAAC increased $50.76 per MW-day (28.8 percent) from $176.44 per MW-day in the 2012/2013 BRA. The MAAC reliability requirement increased by 1,017.0 MW (1.4 percent) from 72,125.0 MW UCAP in the 2012/2013 BRA.

The results of the PJM Capacity Emergency Transfer Limit (CETL) and Capacity Emergency Transfer Objective (CETO) tests prior to the BRA also affected the outcome of the MAAC market. The outcomes of these tests include the determination of which Locational Deliverability Areas (LDAs) will be modeled as potentially constrained regions and the CETL values used in modeling transmission limitations into constrained regions. [3] The CETL value for MAAC decreased 1,917.0 MW (30.1 percent) from 5,600 MW in the 2012/2013 BRA. In addition, the CETL/CETO ratio for Pepco in the 2013/2014 BRA was less than 1.15, and therefore it was modeled as a constrained LDA. Pepco was not a modeled LDA in the 2012/2013 BRA.

The MMU found that the most significant factor contributing to the higher MAAC clearing price in the 2013/2014 BRA was the decrease in the MAAC CETL used to model capacity imports into the MAAC region. The increase in the MAAC net CONE value was the next most significant factor. The DR and EE market power mitigation rule change and the adjusted default ACR values did not have a significant impact on the MAAC market clearing. The effect of modeling Pepco as a constrained LDA and Pepco having a Locational Price Adder was a decrease in the price in the rest of MAAC.[4] All else equal, the clearing price in the RTO or a parent LDA market would be expected to be lower if an additional nested LDA were modeled and had a binding constraint, because it would result in less demand clearing in the parent LDA market.

Another factor affecting the MAAC auction results was the 2.5 percent reduction in demand, the Short-Term Resource Procurement Target. Under the current RPM rules, PJM removes the Short-Term Resource Procurement Target, or 2.5 percent of the Reliability Requirement, from the demand curve. The MMU included an analysis of the impact on the market results of this demand reduction in its “Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated” report and concluded that the

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3 See PJM “2013/2014 RPM Base Residual Auction Planning Period Parameters,” (March 12, 2010) <http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/planning-period-parameters-report.ashx> (169.51 KB).

4 See “Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated” (September 20, 2010) < http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf>.

removal of the 2.5 percent demand significantly reduced the clearing prices for Pepco, EMAAC, MAAC and the RTO. A similar analysis was included in the MMU's "Analysis of the 2012/2013 RPM Base Residual Auction" report.[5] A summary of the results of the analyses are shown in Table 8.

Table 8 Impact of not reducing demand by Short-Term Resource Procurement Target: 2012/2013 and 2013/2014 RPM Base Residual Auctions

	2012/2013 Base Residual Auction				2013/2014 Base Residual Auction			
	Actual Auction Results		Without Short-Term Resource Procurement Target Reduction		Actual Auction Results		Without Short-Term Resource Procurement Target Reduction	
LDA	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)
PSEG North	$185.00	3,521.9	$185.00	3,558.2	$245.00	4,159.4	$324.01	4,173.4
PSEG	$139.73	7,194.0	$185.00	7,244.3	$245.00	8,019.1	$324.01	8,033.1
DPL South	$222.30	1,241.5	$222.30	1,305.5	$245.00	1,612.4	$324.01	1,612.4
EMAAC	$139.73	31,080.2	$185.00	31,635.0	$245.00	32,835.4	$324.01	32,977.5
Pepco	$133.37	5,357.2	$175.00	5,370.1	$247.14	4,791.7	$272.34	5,288.9
SWMAAC	$133.37	11,594.6	$175.00	11,866.7	$226.16	11,242.1	$272.34	11,768.2
MAAC	$133.37	65,452.4	$175.00	66,394.0	$226.15	67,639.9	$272.34	68,308.1
RTO	$16.46	136,143.5	$23.92	139,486.8	$27.73	152,743.3	$42.00	156,493.0

The higher clearing price in MAAC recognizes the locational value of capacity in MAAC and provides incentives to either not retire existing units, to build new resources in MAAC, or to upgrade existing transmission lines or build new transmission capability into MAAC.

Question No. 4

What changes have been considered to RPM or within the PJM stakeholder process that could potentially facilitate more levelized capacity prices throughout the RTO?

Response

The current pattern of RPM prices in PJM reflects the very different locational supply and demand conditions in the capacity market. Within the RPM market design, the only way to facilitate more equal prices across PJM areas is to build more transmission capability to reduce the transmission constraints that limit the ability of capacity anywhere in the system to meet reliability needs anywhere in the system. The transmission planning process currently attempts to account for the costs and benefits of increased investment in transmission.

The RPM design explicitly incorporates locational pricing in order to improve the efficiency of the capacity market and to ensure that supply and demand conditions in

[5] See "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf>.

local markets are reflected in local prices. This is especially important in an RTO as large and diverse as PJM. With locational capacity prices, if capacity were needed in an area, the prices would signal the need for an investment in that area. In the absence of a locational price signal, the need for capacity would not be reflected in prices if the entire RTO had adequate capacity. If an individual zone or subzone area needed capacity under a levelized capacity market price, an out of market solution would be required.

When locational price differences are removed, prices in constrained areas decrease and prices in unconstrained areas increase. Depending on the relative amounts of load served in constrained and unconstrained areas, total payments for capacity could increase as a result of removing locational capacity market price differences.

Question No. 5

What changes could be made to RPM that would stimulate increased generation and demand response investment in Maryland? Should RPM be kept as is, amended or abandoned?

Response

The changes that could be made to RPM to stimulate increased generation and demand response include better price signals: elimination of the 2.5 percent demand offset; and clarification and strengthening of the new entry price adjustment rule. The changes that could be made to RPM to stimulate increased generation and demand response also include addressing barriers to entry: clarification and improvement of market rules defining local markets; and elimination of any local barriers to entry including access to sites for new plants and state regulatory barriers.

The MMU recommends that the use of the 2.5 percent demand reduction be eliminated immediately. The logic of reducing demand in a market design that looks three years forward, to permit other resources to clear in incremental auctions, is not supportable. There are tradeoffs in using a one year forward or a three year forward design, but the design should be implemented on a consistent basis. If the demand for the capacity that is required to provide reliability is correctly defined and the demand curve reflects that requirement, reducing demand results in a price that is less than the market clearing price. Removing a portion of demand affects prices at the margin, which is where the critical signal to the market is determined. Ironically, the lower prices that result from the 2.5 percent demand reduction reduce revenues for Demand Resources as well as generation resources.

This rule has had a significant impact on prices throughout PJM. In the 2013/2014 BRA, the result was to reduce prices in the eastern part of PJM and to reduce the quantity of capacity purchased in the eastern part of PJM. The result was also to significantly reduce the clearing price for the RTO market, affecting substantial MW of capacity and reducing total payments to capacity by a significant amount. In SWMAAC, the 2.5 percent reduction in demand resulted in a decrease in the clearing price from $272.34 to $226.16 per MW-day and a decrease in the amount of capacity purchased from 11,768.2 MW to 11,242.1 MW for the 2013/3014 BRA. The impacts are shown in Table 4.

The new entry price adjustment (NEPA) rule was designed to provide increased assurance to new entrants that the capacity market price would not fall as a result of new investment in generation capacity in a constrained LDA, reducing or eliminating the incentive to respond to the RPM price signal. The current NEPA rule should be strengthened to provide a guarantee that new generation, if cleared in a BRA for a constrained LDA, would continue to receive that clearing price for five years.

LDAs are, with a few exceptions, simply the original transmission zones from the utility members of PJM. While that was a reasonable starting place, there is no necessary alignment of the boundaries of such zones and constraints on the PJM transmission grid. This is particularly true for transmission zones that include non contiguous portions, like the APS zone. The definition of LDAs should be refined to more closely reflect the actual constraints on the transmission grid. The goal is to ensure that if the construction of new capacity in a location meets the need for capacity in an area and will correspondingly improve reliability in an area, the new capacity receives a price that reflects that need. Similarly the CETO/CETL analysis that is used to determine the required balance between capacity in an LDA and capacity outside that LDA needs to be improved and made more sophisticated and transparent. For example, if a unit does not clear in an RPM auction and makes an economic decision to retire but is then informed by PJM that it is needed for reliability, this is likely to be evidence that the market is not working because the local market is not properly defined. Such PJM determinations that a unit is needed for reliability are based on a more detailed analysis than the CETO/CETL analysis. PJM should perform such a more detailed reliability analysis of all at risk units, including all units that do not clear in RPM auctions and units that face significant investment requirements due, for example, to environmental requirements. If such units are needed for reliability, this could result in the definition of additional LDAs to reflect the actual reliability requirements of the system. Accurate locational pricing also requires that generation owners make offers that reflect their legitimate investment requirements. For example, units that will be forced to retire by environmental regulators unless they make defined investments in new technology should reflect the costs of that investment in their capacity market offer. That is essential to the functioning of the forward looking capacity market.

Ownership of potential sites for new generation should be evaluated. If ownership of existing sites in a state serves as a barrier to entry to new generation, state regulatory authorities should consider appropriate remedies. Similarly, if state regulatory rules including environmental rules serve as a barrier to new generation, state regulatory authorities should consider appropriate remedies.

Question No. 6

Should the Commission monitor or regulate the participation of regulated electric companies with regard to their capacity offers of Demand Response and Energy Efficiency? If so, how? If not, why not?

Response

The Commission should ensure that there is open, effective and transparent competition among CSPs to sign up customers, and take such other action is it deems appropriate that would remove barriers to participation, including explicit incentives to invest in any necessary infrastructure.

Question No. 7

What mechanism exists in PJM's market rules and procedures that allows PJM to inform and share data with state commissions of the specific measures that could be undertaken by the state commissions to reduce energy and capacity costs for customers, and how do such procedures operate?

Response

The Commission has direct access to PJM's transmission planning process, and to information developed in that process. Schedule 6 of the PJM Operating Agreement (§ 1.3) provides that state regulatory commissions, among others, may participate in the Planning Committee, the Transmission Expansion Advisory Commission (TEAC), and Subregional RTEP Committees. PJM, through an "open and collaborative process" including the TEAC and Subregional RTEP Committees, develops and submits to the PJM Board the annual 15-year-out Regional Transmission Expansion Plan (RTEP) (§ 1.5.6). At the commencement of each annual RTEP process, PJM is required to convene at least one initial assumptions meeting, which must, among other things, "incorporate regulatory initiatives as appropriate, including state regulatory agency initiated programs" (§ 1.5.4(d)). The PJM Board approves the final RTEP.

Section 1.5.5 of Schedule 6 obligates PJM to coordinate the development of the RTEP with neighboring transmission systems, and to "incorporate input from parties that may be impacted by the coordination efforts," including state commissions.

Section 1.5.4(c) of Schedule 6 of the Operating Agreement requires PJM to solicit "information required by, or anticipated to be useful" from the state commissions, among others, as it develops the RTEP. Section 1.5.4(f) provides PJM "shall supply any information and data reasonably" required by PJM state commissions, among others, subject to confidentiality.

Detailed knowledge about the constraints that may cause persistent congestion is essential to formulating positions on optimal transmission system investments, designing incentives to Demand Resources and designing incentives for new generation capacity resources.

Such mechanisms should be further developed so that states have all the information they need to make fully informed decisions and to affect the decisions made by utility companies, transmission owners, generation investors, Demand Resource investors, PJM and the FERC. The MMU has prepared analyses to assist the Commission pursuant to Section VI.B of Attachment M of the PJM OATT, and is available to provide further analyses.

Questions No. 8

What duty does PJM have, or should it have, to facilitate levelized capacity prices across the RTO?

Response

Capacity prices should reflect local supply and demand conditions. If capacity cannot be delivered into an area as a result of transmission constraints, a local market exists and capacity market prices should reflect the local market conditions.

Locational capacity market prices serve to increase the efficiency of the capacity market. Equal capacity market prices across the RTO would not be efficient if they did not reflect actual supply and demand conditions. If there is a relative shortage of capacity in the east but not in the west, it would not be efficient to have the same price in both locations. The price would be too low in the east to incent the required generation investment and the price would be too high in the west.

It can be expected that, in long run equilibrium, capacity market prices actually will be equal across the RTO. These prices would reflect similar supply and demand conditions across the RTO. The similar supply and demand conditions would have resulted from increased investment in generation resources, in demand side resources and in transmission resources in response to price signals and reliability needs.

PJM should not attempt to create equal capacity market prices across the RTO in any way other than attempting to ensure that the capacity market works efficiently and effectively and that the transmission planning process also works efficiently and effectively.

Question No. 9

What can or should the Commission do to address these issues at PJM, FERC or elsewhere?

Response

The MMU hopes that all stakeholders in PJM markets will actively support the improvement of capacity markets to help ensure that capacity markets accurately reflect supply and demand conditions, that barriers to entry to new resources are eliminated and that the planning and construction of new transmission facilities are undertaken in a manner consistent with the design of capacity markets and based on the reliability needs of the system. The Commission has a critical role to play in each of these areas by participating in the PJM processes, by participating in or initiating FERC proceedings and by taking actions within the state if necessary to address related issues.

Question A

Are PJM's proposals to place limitations on Demand Response within the Reliability Pricing Model reasonable?

Response

PJM rules currently place limitations on the requirement of Demand Response resources to perform when needed. In addition, PJM is proposing to limit the total amount of such Demand Response resources that may be purchased in capacity auctions.

PJM should not limit Demand Response resources either by capping the total MW purchased from Demand Response or by limiting the requirement of Demand Response resources to respond when needed.

The proposal to limit the total amount of Demand Response resources purchased in capacity auctions is a substitute for addressing the underlying issue. If Demand Response in fact represents the willingness of customers to not use capacity when the customers who do pay for capacity need it, then there is no need for a limit on the total amount of Demand Response purchased. The underlying issue is that the current RPM rules limit the number of times that Demand Response providers must respond and the duration of each response. Such limits make Demand Response resources less valuable and attenuate their contribution to system reliability.

Question B

What are the implications to Maryland's Demand Response programs if such limitations are adopted?

Response

Demand Response resources should have an unlimited ability to participate in PJM capacity markets provided that Demand Response resources have a similarly unlimited requirement to respond when called.

Limiting the total level of Demand Response that can participate in the capacity markets will reduce competition and potentially limit the least cost solution to the reliability needs of the system. Limiting the requirement of Demand Response to respond whenever called and for whatever duration is called will overstate the reliability of the system, result in a less reliable system and suppress capacity market prices compared to an efficient market outcome.

The standard should not be that Demand Response resources are the same as generation resources. Demand Response resources should be evaluated for the role they plays in markets and held to a standard that ensures that Demand Response resources can in fact provide the reliability benefits they promise.

Accurate measurement and verification is essential if the system is to rely on Demand Response resources for reliability. Current measurement and verification methods are entirely inadequate and must be strengthened. If PJM loads pay for Demand Response curtailment, they should receive that curtailment.

Demand Response resources are not generation resources (unless the Demand Response is behind the meter generation) and it should not be treated like generation. Demand Response in the capacity markets means that load, which agrees to not pay the cost of capacity, must also agree to get off the system whenever the capacity it is using is needed by those customers who have paid for it and for as long as those customers need it. As Demand Response load has not paid for such capacity, there should be no limit on the number of times that Demand Response load can be required to get off the system or the number of hours that Demand Response load has to remain off the system. The simple fact is that if Demand Response load wants to avoid paying for capacity, it must be willing to not use that capacity when it is needed by those who do agree to pay for capacity. That bargain means that there can be no limit on requirements for Demand Response load to get off the system. The probability of needing the capacity used by Demand Response load increases with the total amount of Demand Response load on the system. The market must be allowed to work. While it is inappropriate to limit the total amount of Demand Response, it is also inappropriate to protect Demand Response load from the terms of its agreement to not buy and therefore not use capacity when it is needed by those who have paid for it.