



Capacity Markets in PJM

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ABSTRACT

The PJM capacity market evolved from a mechanism to support fair and efficient retail competition, to a core market design component implemented to provide adequate revenue to attract sufficient supply and demand side resources to meet PJM's administrative reliability criteria. The lessons learned in the evolution of the PJM capacity market illustrate issues that are shared across all wholesale power markets. An exogenously imposed administrative reliability requirement has generally been interpreted to require the ownership of, or contracts for, capacity in excess of expected peak loads by a reserve margin. In PJM, the reserve margin requirement resulted in a level of capacity greater than would have been the result of the operation of an "energy only" market without such a requirement. The result was lower energy prices for all units and a shortfall of net revenues compared to the annualized costs of building a new generating unit. The early wholesale power market designs, including PJM, replicated the efficient dispatch of a tight power pool, but did not address the sources of revenues to cover the costs of investment in new and existing generating capacity and thus did not address the endogenous sustainability of the market design consistent with administrative reliability criteria. The introduction and redesign of a capacity market has largely solved this "resource adequacy" problem. But the PJM capacity market design continues to be imperfect and the resolution of the remaining design issues is critical to the continued success of the PJM market as demand increases and generating units retire.

Keywords: Capacity Market, PJM Interconnection, RPM, Minimum Offer Price Rule

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✎ 1. INTRODUCTION OF A CAPACITY MARKET ✎

The original PJM market design, which became effective April 1, 1999, did not include a formal capacity market. But the PJM operating agreement among PJM members did define capacity, did impose a capacity requirement on PJM load serving entities and did permit the bilateral sale and purchase of capacity. These bilateral sales were of capacity as a derivative product, based on the ownership of physical units, which did not confer any physical rights over those units, but which did satisfy the requirement to own capacity. Thus the capacity obligation and ultimately the capacity market can be traced back to the provisions of the PJM operating agreement before restructuring. Even in its earliest days the PJM market was never an energy only market.¹

1. The term energy only market is used to refer to a wholesale market design which does not include a capacity market but which may include a day-ahead energy market and a real-time energy market, and ancillary services markets including synchronized reserves and regulation and administratively procured ancillary services like reactive and black start. These are all potential sources of net revenues although the energy market is the source of most of the net revenue, which can vary by unit type. Although PJM has never been an energy only market, the PJM market was equivalent to an energy only market when the capacity credit market revenues were close to zero.

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PJM had operated as a power pool since 1927 in order to take advantage of the efficiencies associated with economic dispatch in real time across multiple generation owners based on short run marginal cost. The PJM operating agreement, in order to prevent any member from free riding on the capacity of other members and not bearing the cost of owning capacity, required that each member have capacity, through ownership or contract, equal to its forecasted peak load plus a reserve margin. The reserve margin was defined to meet administrative reliability criteria whose exact origins are murky. The members were at that time all vertically integrated utilities, subject to state public utility commission cost of service regulation. Thus, each member was a load serving entity subject to the requirement to have sufficient capacity to meet its peak demand plus a reserve margin. The operating agreement included a requirement to pay a financial penalty in the event a member was short capacity in a year, equal to the annualized fixed cost per MW of building a new CT, net of expected net revenues from selling energy, the penalty rate. When there was net excess capacity in the pool, this provision resulted in the creation of a gray market in capacity in which long members competed to sell capacity to members who were temporarily short capacity. This provision for covering shortfalls of capacity helped members address the lumpiness of investments in very large capacity resources. This provision also helped General Public Utilities (GPU) fulfill its capacity obligation after the loss of one of the Three Mile Island (TMI) nuclear power plants in March 1979. GPU also purchased capacity from external sellers, which was imported into PJM using firm transmission service and accepted as a capacity resource.

At the time of restructuring, PJM included all or parts of seven states plus the District of Columbia.² Some PJM states opened their retail markets to competition at around the same time that the modern PJM market was implemented in 1999. The states found that the PJM capacity requirement created a barrier to entry for retail competitors. New retail entrants, which were not PJM members, competing to serve portions of the retail loads of existing utilities, became load serving entities in PJM and therefore needed to have capacity through ownership or contract equal to their peak loads plus a reserve margin. New retailers wanted to compete to serve load but did not want to become utilities or to build power plants in order to meet the capacity obligation. Retailers needed to be able to purchase and sell capacity in small increments with a short lag as they gained or lost load. The existing capacity construct did not facilitate such transactions, as it was annual. In addition, the retailers had to buy capacity from the utilities that owned power plants and with whom they were competing to serve load.

After a series of FERC filings by the Pennsylvania Public Utility Commission making the arguments about competition and barriers to entry, the result was the creation of the PJM capacity market, also known as the capacity credit market, effective January 1, 1999.³ The capacity credit market was a daily market with a daily requirement to purchase capacity equal to each load serving entity's (LSE) capacity obligation, subject to a penalty payment. The daily capacity market met the need of retail competitors to buy and sell capacity as needed. The daily capacity market had a number of issues including the lack of any market power mitigation rules, despite the fact that the ownership of capacity was highly concentrated and the market was frequently characterized by one or more pivotal suppliers. Market power was exercised at times.⁴

2. See 2004 *State of the Market Report for PJM*, Appendix E, p. 313.

3. 117 FERC ¶ 61, 331 (2006).

4. See 2002 PAPUC investigation into PJM Installed Capacity Credit Market, Case No. I-00010090.

In the absence of market power, the marginal cost of daily capacity was effectively zero, daily sell offers were generally zero or close to zero and, beginning in 2005, clearing prices were close to zero.⁵

During this period, PJM had adequate reserve margins and reliability was maintained. But after a few years of operation, it became increasingly clear that the PJM market was not sustainable in its then current form. With a competitive energy market, the energy offers of units were generally at short run marginal cost and unless demand was quite high, net revenues for generation, including capacity credit market revenues, were well below replacement cost.⁶ In addition, PJM began to recognize that, given transmission constraints between west and east, potential reliability issues were emerging in the more constrained eastern portions of the system but not in the western part of the system and that a single capacity market price could not reflect local supply and demand conditions.⁷

✎ 2. CAPACITY MARKET BASICS ✎

The lessons learned in the evolution of the PJM capacity market illustrate issues that are shared across all wholesale power markets.^{8,9} An exogenously imposed administrative reliability requirement has generally been interpreted to require the purchase of capacity in excess of expected loads by a reserve margin. The reserve margin, generally between 15 and 20 percent of expected peak load, is designed to ensure reliability under worst case conditions including high demand, forced generation outages and transmission outages. The reliability goal has generally been characterized as no more than one loss of load event in ten years.¹⁰

The reserve margin means that there are units capable of producing energy in excess of demand under most supply and demand conditions. This excess supply means that competition in the energy market results in prices that are set by offers at short run marginal cost based on the cost of fuel, emissions permits and short run variable operation and maintenance expense. The result of these supply and demand conditions is that peaking units, some of which run in a year and some of which do not run, will earn small or zero margins in the energy market.

In PJM, the reserve margin requirement resulted in a level of capacity greater than would likely have been the result of the operation of an energy market without such a requirement. The result was lower energy prices for all units and lower net revenues for all units, although the relative net revenue shortfall was greatest for the peaking units that were needed to run

5. See the *2012 State of the Market Report for PJM*, Volume II, Section 4: Capacity Market. Figure 4-3 History of capacity prices: Calendar year 1999 through 2015.

6. See the *2007 State of the Market Report for PJM*, Volume II, Section 5: Net Revenue.

7. See “*Settlement Agreement and Explanatory Statement of the Settling Parties Resolving all Issues*,” PJM Interconnection, L.L.C., Docket Nos. ER05-1410-000, -001 and EL05-148-000, -001 re RPM Effective June 1, 2007 (September 29, 2006).

8. These papers provide theoretical approaches to market design issues and capacity markets: Cramton/Stoft (2006): “The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO’s Resource Adequacy Problem”, available at <http://stoft.com/>; Cramton/Stoft (2005): “A Capacity Market that Makes Sense.” *Electricity Journal*, 18: 43-54; Joskow/Tirole (2007): “Reliability and Competitive Electricity Markets,” *Rand Journal of Economics*, 38(1): 60-84; Hogan (2005): “On an ‘Energy-Only’ Electricity Market Design for Resource Adequacy”; Joskow (2008): “Capacity Payments in Imperfect Electricity Markets: Need and Design.” *Utilities Policy*, 16(3): 159-170.

9. This paper draws on related work of the author and on the work of Monitoring Analytics, LLC. In particular, this chapter draws on analysis by Alexandra Salaneck, the principal capacity market analyst at Monitoring Analytics. All Monitoring Analytics reports may be found at www.monitoringanalytics.com.

10. PJM Manual 20: PJM Resource Adequacy Analysis Rev. 4 (June 1, 2011).

for fewer hours per year. When peaking units ran, they set price at their short run marginal cost which, even accounting for variations in efficiency, meant low net revenues. The reliability requirement thus resulted in a shortfall of net revenues compared to the annualized costs of building a new generating unit.¹¹ Absent a market design change, markets faced a reduction in reserve margins below the target level, locational reliability issues and pressures to address those shortfalls in some way since the market was not generating sufficient revenues to make it attractive to invest in new generating capacity.

The early wholesale power market designs, including PJM's, replicated the efficient dispatch of the tight power pool, compensated generators based on locational marginal prices and charged loads based on zonally aggregated locational marginal prices. But these early market designs did not address the source of revenues to cover investment costs and thus did not address the endogenous sustainability of the market design.

This is exactly the situation that faced the PJM market beginning a few years after the market was established and operating. Early excesses in market reserve margins that resulted from new investments based on expectations about the operation of the new market were reduced as a result of unit retirements and load growth. Several years of actual data on market prices and total net revenue led to more realistic expectations for investors and a reduction in new investment in generating units.¹²

This is also the situation that faces other wholesale power markets, all of which face the same dynamic. Examples in the U.S. are the Electric Reliability Council of Texas (ERCOT), California Independent System Operator (CAISO) and Midcontinent Independent System Operator (MISO) markets.

✎ 3. THE INTRODUCTION OF THE RPM CAPACITY MARKET ✎

In response to this dynamic, PJM developed and implemented a new capacity market design in 2007, the Reliability Pricing Model (RPM). The design of the RPM market was intended to address the fundamental issue of whether the market was sustainable, whether the market signals would result in adequate incentives to build new capacity when and where it was needed without regulatory intervention. Each of the elements of the RPM market design was intended to address part of that issue.¹³

The basic elements of the RPM capacity market design included the definition of capacity as an annual product, a must offer requirement for all capacity resources, a must buy requirement for all load, the recognition that capacity is a physical product, performance incentives and a net revenue offset as the link between energy and capacity markets. The RPM design included a sloped demand curve with defined inflection points, a three year forward procurement, a locational market definition, and market power mitigation rules.

11. See the "2007 State of the Market Report for PJM," Volume II, Section 3, Energy Markey, Part 2, Net Revenue.

12. See 2008 State of the Market Report for PJM, Volume II, Section 5: Capacity Market.

13. There are other market design approaches to addressing these issues, including various forms of administrative scarcity pricing. See, for example: *Protest and Compliance Proposal of the Independent Market Monitor for PJM*, Docket No. ER09-1063-004 (July 19, 2010), *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM*, Docket No. ER09-1063-004 (August 26, 2010), *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM*, Docket No. ER09-1063-004, (September 7, 2010).

Definition of capacity

The RPM capacity market design in PJM was created and defined as a result of revenue sufficiency issues in the energy market. The design of the capacity market reflected this tight integration between energy and capacity markets. The sale of capacity in the capacity market meant that the capacity had to be physical, that the energy from the capacity had to be deliverable to all loads in PJM, that the energy from the capacity had to be offered into the day-ahead energy market every day, that the energy from the capacity was recallable in an emergency, that capacity resources had to meet minimum performance requirements and that owners of capacity resources had to report outage data.

Physical capacity is needed in order to provide the reliable delivery of energy under all system conditions. In practice that means, for example, that a firm liquidated damages contract is not physical and cannot be capacity. Payment of liquidated damages is not considered an acceptable substitute for the delivery of energy during a period when load approaches the capability of the generating capacity.

Deliverability means that the transmission system must be capable of delivering the energy output from the resource under peak conditions to load anywhere in PJM. Deliverability is enforced by requiring the builder of new capacity to pay for any transmission upgrades necessary to ensure that the energy is deliverable, according to transmission system analysis done by PJM and the transmission owners. This provides a strong incentive to locate where the transmission system is robust and also provides a market signal about the full cost of new capacity when transmission system upgrades are required.

In recognition of the tight integration between PJM energy and capacity markets to ensure reliability and revenue sufficiency, capacity resources are required to offer energy output equal to their full installed capacity value into the day-ahead energy market every day. This requirement reflects the fact that the purpose of the capacity market is to help ensure revenue sufficiency for units operating in PJM's energy markets rather than creating a standalone capacity product.

Energy from all capacity resources that clear in a capacity auction is recallable by PJM in an emergency. This ensures that even when such energy is being exported, PJM customers who paid for the capacity to ensure reliability, have a call on that energy at the PJM market clearing price if the energy is needed to meet load in PJM.

Must buy and must offer

The only way in which a capacity market can result in a price that reflects the actual supply and demand conditions without the exercise of market power through withholding is if all capacity offers to sell capacity and all load bids to buy capacity equal to forecasted peak load plus a reserve margin. In the RPM design, all capacity resources are required to offer capacity into the capacity auctions and all load is required to purchase capacity in the market.¹⁴

Demand curve

All LSEs are required to purchase capacity equal to their forecast load plus a reserve margin. That requirement is enforced through the demand curve, the variable resource requirement (VRR) curve, in the RPM capacity market design. The demand curve for system

14. The Fixed Resource Requirement (FRR) option is an exception discussed below.

capacity in the RPM capacity market design is downward sloping, replacing the vertical daily demand curve in the capacity credit market design. The shape and inflection points of the RPM demand curve are based on the reliability requirement and the net cost of new entry for a peaking unit, and have a significant impact on prices in the capacity market. The net cost of new entry includes the gross costs net of the net energy and ancillary services revenues offset. This offset reflects the total revenue sufficiency purpose of the capacity market and the integration of the capacity and energy markets. Figure 1 is the demand curve for the 2016/2017 RPM Base Residual Auction for the entire RTO.¹⁵

The highest price part of the demand curve is flat from the y or price axis at a price equal to 1.5 times the net cost of new entry, or the gross cost of new entry if that is higher.¹⁶ The flat portion extends to point A, where the quantity equals the reliability requirement less approximately three percent.¹⁷ The curve slopes downward to point B, where the price is the net cost of new entry. The quantity at point B is the reliability requirement plus approximately one percent. The curve slopes downward to point C where the price is 20 percent of the net cost of new entry. The quantity at point C is the reliability requirement plus approximately five percent. The demand curve drops to the x axis from point C. The quantity at each point is reduced by the 2.5 percent Short-Term Resource Procurement Target (STRPT). The demand curve shown in Figure 1 is for the entire RTO without accounting for locational differences. There are separate supply and demand curves for each LDA with a potentially binding transmission constraint.¹⁸

The demand curve design incorporates a form of scarcity pricing. The price goes to the maximum level if the supply, at offer prices less than the maximum price, is less than approximately 97 percent of the reliability requirement. For example, if the reliability requirement were 100,000 MW, the price would be set to the maximum whenever the supply, at an offer price less than the maximum, is less than approximately 97,000 MW. The scarcity price also serves as a price cap.

The demand curve design conservatively sets the quantity associated with the expected equilibrium price at a level slightly higher than the reliability requirement. This means that the market clearing price will equal the net cost of new entry at a quantity approximately one percent greater than the reliability requirement (Point B). As a result, the demand curve sets the price for the reliability requirement at greater than the net cost of entry.

The downward slope requires the purchase of capacity greater than the reliability requirement if consistent with offer prices and requires the purchase of capacity less than the reliability requirement if consistent with offer prices. The downward sloping demand curve is also intended to add some elasticity compared to the vertical demand curve used in the capacity credit market that was replaced by the RPM.

Multiple auctions

The RPM design provides for the primary Base Residual Auctions (BRA) and subsequent Incremental Auctions (IA) to permit market participants to true up positions as necessary.

15. This demand curve ignores the minimum annual and minimum extended summer requirements.

16. The prices are all adjusted to be on an unforced capacity basis. Unforced capacity is installed capacity or gross capacity adjusted for the relevant forced outage rate. See PJM Interconnection, L.L.C., "Manual 18: PJM Capacity Markets," Revision 15 (June 28, 2012), p. 98.

17. The exact equations can be found in Manual 18.

18. For the detailed rules, see the *2012 State of the Market Report for PJM*, Volume II, Section 4- Capacity Market, p. 143.

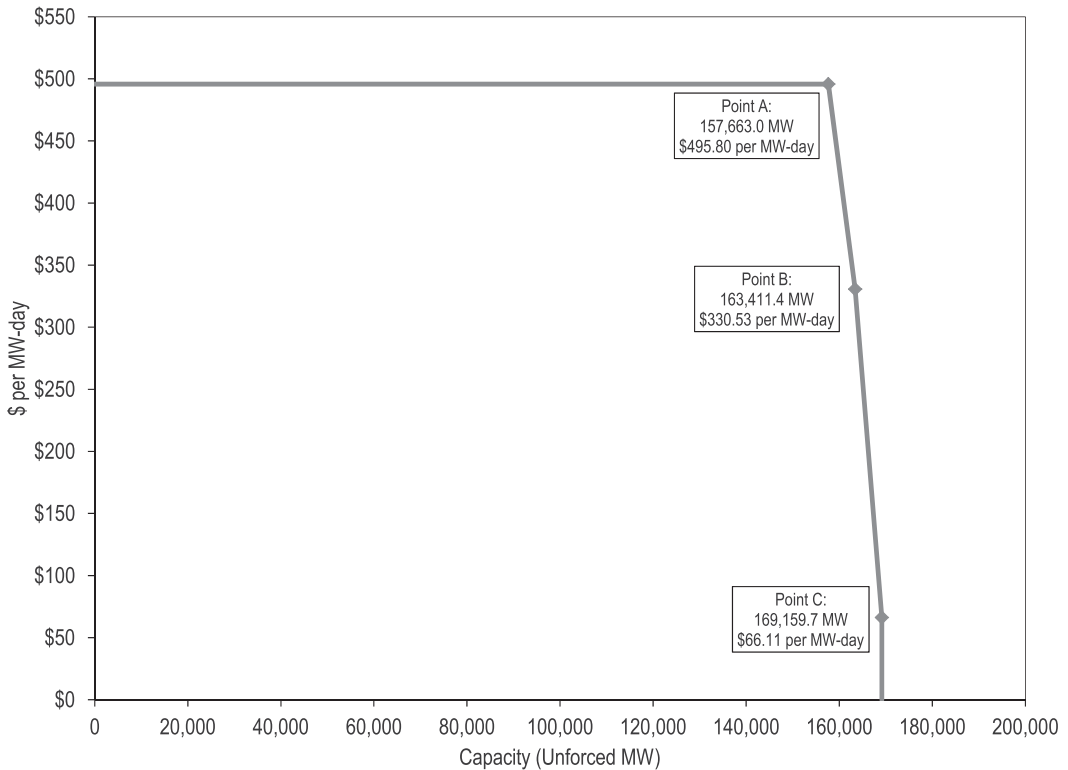


FIGURE 1

Demand curve for 2016/2017 RPM Base Residual Auction

Under RPM, capacity obligations are annual. BRAs are held for delivery years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions are held for each delivery year.¹⁹

Forward procurement

The RPM design reflects supply and demand three years in the future; RPM is a forward market. The goal of the three year forward requirement is to provide for competition from new entry, to provide an opportunity to market test decisions to invest in existing units, to provide for advance decisions about unit retirements and to provide for a window to resolve reliability issues revealed in market outcomes before they occur. In each case, the three year forward requirement provides for more competition in a market for long lived assets that require years to build or modify. The three year forward procurement allows the market to

19. See 126 FERC ¶ 61,275 (2009) at p. 86. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year. See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010). Effective for the 2012/2013 Delivery Year, the purpose of IAs also includes release or additional procurement of capacity by PJM due to reliability requirement adjustments and the deferment of the STRPT. Also effective for the 2012/2013 Delivery Year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year. See 126 FERC ¶ 61,275 (2009) at p. 88.

react to external factors like changes in environmental regulations and provides an incentive to make retirement decisions prior to the capacity auction.

Locational markets

The RPM design includes the potential for locational price separation to reflect locational differences in supply and demand conditions. The demand curves in individual Locational Deliverability Areas (LDA) are defined in exactly the same way as the system demand curve except that the locational reliability requirements are used in place of the system reliability requirements and locational net cost of new entry values are used for the price points.

There is locational price separation when the demand for capacity in an LDA cannot be met by the supply taken in merit order over the entire system including capacity within the LDA and capacity imported into the LDA, but must be met by higher cost supply located in the LDA. This is analogous to locational marginal pricing in the energy market.

The PJM capacity market has cleared with significant locational price differences in all but one Base Residual Auction since 2007, with prices in the transmission constrained eastern parts of PJM generally exceeding prices in the western part of PJM.²⁰

✎ 4. PERFORMANCE INCENTIVES ✎

The goal of the capacity market performance incentives should be to match the incentives that would result from a competitive energy only market. The performance incentives in the PJM capacity market fall well short of that objective. The most basic market incentive is that sellers are not paid when they do not provide a product. That is only partly true in the PJM capacity market. There are two areas where the performance incentives are inadequate, overpayment for underperformance and incorrect outage rate definition.²¹

In RPM, a capacity resource will be paid 50 percent of its full capacity market revenues even in the case of complete nonperformance in the first year of such nonperformance. For example, a resource that sold 500 MW of unforced capacity at \$150 per MW-day would be paid \$75 per MW-day even if the resource did not produce energy when called during any of the PJM-defined approximately 500 RPM critical hours. That decreases to 25 percent in year two of sub 50 percent performance and to zero in year three, but returns to 50 percent after three years of better performance. Under some extreme circumstances, total nonperformance would result in total nonpayment as a result of penalties.

Not all unit types are subject to RPM performance incentives. Wind, solar and hydro generation capacity resources are exempt from key performance incentives. Wind and solar generation capacity resources are not subject to peak hour availability incentives, to summer or winter capability testing or to peak season maintenance compliance rules. Hydro generation and intermittent generation capacity resources are not subject to peak season maintenance compliance rules.²² Given that all generation is counted on for comparable contributions to

20. See *2012 State of the Market Report for PJM*, Volume II, Section 4: Capacity Market, Table 4-21 Capacity prices: 2007/2008 through 2015/2016 RPM Auctions. Prices in the ATSI LDA, in the western part of PJM, exceeded prices in all other LDAs in the 2015/2016 BRA.

21. See Monitoring Analytics, LLC and PJM Interconnection, LLC, "*Capacity in the PJM Market*" (August 20, 2012.)

22. PJM Interconnection, L.L.C., "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012) p. 119. The rationale for this treatment of hydro, wind and solar capacity is unclear.

system reliability, it would be efficient for all generation types to face the same performance incentives.²³

In the PJM capacity market, the forced outage rate is a performance incentive. Resource owners sell unforced capacity in the capacity market, which is installed capacity times one minus the forced outage rate for the resource. The higher the forced outage rate, the less capacity can be sold from a generating unit in the capacity market and the lower are the capacity market revenues for that unit. The capacity market creates an incentive to have low forced outage rates in this direct way. The forced outage rate also affects the level of payment actually received for the level of capacity sold in the RPM Auctions. The issue in the PJM capacity market is that the forced outage rates used to provide these incentives do not correctly measure actual forced outage performance because they exclude some forced outages.²⁴ There is no reason not to reflect all outages in the economic fundamentals of the capacity market and the capacity market outcomes, exactly as they are reflected in PJM system planning. The current incentive design is not consistent with an efficient outcome.

Vertically integrated utilities

When RPM was introduced in 2007, most incumbent utilities' generation assets in PJM had been deregulated or divested. As a result, the owners of capacity, including merchant generators, rely on PJM markets for the revenue to cover the full costs of their generating capacity. That is why the design and implementation of the capacity market is critical to the success of the PJM markets. However, there are large vertically integrated utilities in PJM whose revenues remain subject to cost of service regulation. The RPM construct includes the Fixed Resource Requirement (FRR) option which permits but does not require such utilities to effectively remain outside RPM while maintaining PJM reliability requirements, with a limited ability to buy from or sell to the capacity market. The FRR option permits utilities with cost of service revenue recovery for generation assets to participate in PJM energy markets on a competitive basis while not distorting the capacity market based on the fact that such companies fully recover their capacity costs outside the market.

Market power and market power mitigation

Capacity markets are generally tight; the supply of capacity is approximately equal to the demand for capacity. The PJM capacity market is tight at an aggregate level, with a number of very large generation owners who are individually pivotal. A generation owner is individually pivotal if the market cannot clear without the capacity of that owner.²⁵ When the market structure is characterized by one, two or three pivotal suppliers, it is considered to exhibit structural market power. The locational markets also exhibit structural market power. Struc-

23. The installed capacity of wind and solar resources is derated when offered in RPM because, even if not on outage, such resources may not be available at times of peak demand. PJM derates wind resources to 13 percent of installed capacity. PJM derates solar resources to 38 percent of installed capacity.

24. For a more complete discussion of this issue, see the IMM's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "*Capacity in the PJM Market*" (August 20, 2012).

25. The residual supplier index (RSI) is a measure of whether one or more asset owners are pivotal. The RSI equals (total market supply less the supply of the owner or owners in question) divided by (total market demand). Thus an owner is pivotal if the RSI for that owner is less than or equal to 1.0. The three pivotal supplier test includes the supply of the top three owners in the RSI equation.

tural market power is endemic to the PJM capacity markets. As a result, functional market power mitigation rules are required to ensure that capacity market outcomes are competitive.

The RPM design includes explicit and detailed market power mitigation rules which require competitive behavior when there is structural market power. The market power mitigation rules require that any capacity owner that fails the three pivotal supplier test must offer existing capacity at a price equal to the marginal cost of capacity if their offer absent mitigation would increase the clearing price. Planned generation is generally presumed to be competitive but is subject to maximum offers linked to the cost of new entry if pivotal. The marginal cost of capacity is defined to be the costs that an owner could avoid by not operating for a year (avoidable costs), net of the net revenues earned from other PJM markets. The offset of net energy and ancillary services market revenues recognizes the total revenue sufficiency purpose of the capacity market and its tight integration with the energy market.

Unit owners have the option of using a pre-calculated default avoidable cost rate based on technology type and delivery year, or calculating unit specific avoidable costs. In both cases, the avoidable costs are offset with actual unit specific net revenues. If actual avoidable costs are to be used they must be documented and verified. While this is a data intensive exercise, it is doable and experience makes it easier to do as it is possible to compare costs across units and over time.²⁶

The marginal cost of capacity, as defined in the RPM market power mitigation rules, also includes the full costs of any incremental investments required to maintain the ability of an existing generating unit to be a capacity resource.²⁷ For example, the annualized fixed costs of an investment in new environmental technology can be added to the offer cap or the costs of a turbine overhaul can be added to the offer cap. The ability to include in the mitigated offer price the annualized fixed costs associated with the capital expenditures needed to maintain a unit as a capacity resource is an essential part of the market power mitigation process. The ability to add the fixed costs associated with necessary capital additions to offer prices permits a market test of the need for the investment. If the investment cost is added and the unit clears, the resulting higher market price signals the appropriate cost of incremental capacity. If the investment is added and the unit does not clear, the market signal is that the unit is no longer needed with the required investment.

The rules on adding annualized fixed costs permit such costs to be added for a duration linked to the expected remaining life of the asset. Thus, a new investment can result in a substantially higher cost based offer that persists for up to 30 years.²⁸

✎ 5. ISSUES IN THE PJM CAPACITY MARKET DESIGN ✎

Although the basic elements are sound, there are features of the RPM market design that distort market prices and result in market prices that do not reflect market fundamentals. These flawed features need to be addressed directly before the capacity market can work as intended in tight integration with the energy market. An additional problem with such market

26. The independent Market Monitoring Unit for PJM does this review for every RPM auction.

27. Full costs include a return on and of capital.

28. Such an offer is not actually the marginal cost of the unit. A competitive offer from the unit after the first year would exclude the annualized fixed costs. Any price received in excess of the actual marginal cost would contribute to covering fixed costs and would mean that it is economically rational to continue operation.

design features is that they result in unintended market outcomes which result in pressure to make ad hoc modifications to market rules with their own unintended consequences.

Net revenue offset

Implementation of a capacity market was based on a documented shortfall in net revenue from the operation of an energy market without a comprehensive scarcity pricing regime. The energy market did not produce enough revenue to make investments in new capacity profitable even when this capacity was needed to meet reliability criteria. As a result, net revenues are the key link between the capacity and energy markets. Net revenues are incorporated in key parameters of the capacity market demand curve and net revenues are incorporated in offer caps in the capacity market.

The net cost of new entry is a parameter of the capacity market demand curve. The net cost of new entry is defined to be the annualized gross cost of new entry net of the net revenues such a unit would be expected to earn during the delivery year.²⁹ The unit type selected for the cost of new entry parameter is the least expensive peaking unit that could be used to meet peak loads in PJM. To date, this has been a combustion turbine (CT). The gross cost of new entry is the annualized cost of purchasing and installing such a unit including site related costs, the cost of interconnecting to the electric grid and the cost of interconnecting to a source of gas.³⁰

Net revenue is the equilibrating mechanism between the energy market and the capacity market. The capacity market is designed to provide the level of net revenue required to cover the annualized fixed cost of a new peaking unit after accounting for the net revenue from the energy market.

The net cost of new entry in the delivery year equals levelized gross cost less first year net revenue. Net revenue is the difference between gross revenue from selling power at the relevant nodal LMP and marginal costs, which include the cost of fuel, short run marginal operating and maintenance costs and emissions costs. Thus net revenue is the contribution to fixed costs from operating the plant. In PJM, net revenue for the net cost of new entry calculation is based on the average net revenue from the last three years.³¹

The net revenue estimate can have a significant impact on the shape and location of the demand curve, including the level of the maximum price and the clearing price. The use of the net revenue estimate based on the average of three years of history, as is the current practice, can distort capacity market prices either above the competitive level or below the competitive level depending on the relationship between historical revenues and actual revenues during the delivery year. If net revenues were high in some or all of the historical period and are low in the actual delivery year, the capacity clearing price will be biased downward. If net revenues

29. A delivery year is the year in which the capacity must perform. Delivery years run from June 1 to May 31 to be consistent with transmission planning periods.

30. The annualized gross cost is calculated using a financial model and also depends on the cost of capital, the life of the asset and the levelization method chosen. Levelization means calculating the required revenue to meet the target return on an investment such that the annual required revenue is the same every year, termed nominal levelization, or increases by the same percentage every year, termed real levelization. In PJM, the gross cost of new entry calculation is based on a twenty year financial life and nominal levelization. The direct installed equipment cost component of the gross cost of entry is relatively noncontroversial because the market cost of the technology is known, but the cost of and requirement for ancillary investments and approaches to the calculation of the cost of capital can result in differences about the level of gross cost.

31. The net revenue used in capacity market calculations includes net revenue from energy and ancillary services markets.

were low in some or all of the historical period and are high in the actual delivery year, the capacity clearing price will be biased upward. These differences can be significant.³²

Use of the same historical approach also distorts offer caps in the capacity auctions. The market power mitigation rules include net revenue as an offset to the avoidable cost rates. While a net revenue offset is logical and reflects the appropriate relationship between energy and ancillary market revenues, the use of historical net revenues distorts the offset and has potentially significant impacts on market outcomes.

Net revenue offset and scarcity pricing

A new scarcity pricing regime became effective in PJM on October 1, 2012.³³ Under scarcity pricing, energy prices will be able to rise as high as \$2,700 per MWh when PJM experiences a shortfall in reserves.³⁴ Scarcity prices are determined primarily by an administratively defined demand curve which is triggered when reserves fall below identified levels. Prior to scarcity pricing, the highest energy price in PJM was \$1,000 per MWh.

Scarcity pricing will result in substantial increases in energy market revenues when the defined conditions occur, which could happen as infrequently as once every five years if history is a guide. These substantial but episodic and unpredictable increases in energy market revenues make the impact of the net revenue calculation on the capacity market even more significant.

Under the RPM market rules, all energy market net revenues, including those that result from scarcity pricing, are included in the three year historical average net revenue offset.

This approach to the treatment of energy market scarcity revenues is flawed. The inclusion of scarcity revenues in the historical average net revenue offset will worsen the mismatch between historical revenues and expected revenues and add to the distortion of RPM prices for subsequent auctions. RPM prices for a three year forward delivery year, set in the auction run during the year after the scarcity event, will be lower due to the higher net revenues, despite the fact that the scarcity event signaled that not enough capacity was available and despite the fact that the probability of a similar scarcity event occurring in the delivery year is unknown.

The approach to energy market based scarcity should reflect the fact that revenues in the capacity market are by design a substitute for scarcity revenues. Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM design reflects the recognition that the energy markets, by themselves, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues. The revenues in the capacity market are themselves scarcity revenues. Accordingly, with the PJM RPM design, there is no need for a scarcity pricing mechanism in the energy market to ensure revenue adequacy.

Nonetheless, it is preferable to include a scarcity pricing mechanism in the energy market as a complement to a capacity construct because it provides direct, hourly, market-based incentives to load and generation at the margin. If RPM appropriately compensates capacity

32. The net revenue offset is the average net revenues for the three years prior to an auction. The auction for the 2016/2017 Delivery Year was run in May of 2013. The net revenues are calculated based on the net revenues for the years 2010, 2011 and 2012. The net revenues from 2010 will affect the price of the capacity resource in the first five months of 2017, a lag of seven years. Any relationship between historical net revenues and actual or expected net revenues in 2016 or 2017 is accidental.

33. 139 FERC ¶ 61,057 (2012).

34. This maximum price will be phased in over four years.

resources and provides for reliability as it was designed to do, no additional compensation from scarcity pricing is required. Any such payment would represent double recovery of scarcity revenues. The purpose of the net revenue offset mechanism is to prevent double recovery of scarcity revenues.

Given that RPM appropriately compensates capacity resources and provides for reliability and that no additional compensation from scarcity pricing is required, the most straightforward way to ensure that such over collection does not occur, and that the forward markets for capacity provide meaningful investment signals, is to ensure that capacity resources do not receive scarcity revenues from the energy market unless such scarcity revenues, for a delivery year, exceed capacity revenues for that delivery year. The appropriate scarcity revenue payment to a capacity resource would be total scarcity revenues less capacity revenues for the delivery year. This approach ensures that, if the capacity market did not procure adequate resources or if the capacity market price was suppressed, that capacity resources receive the appropriate incentives in a year when there is significant scarcity while preventing double recovery.

Demand side resources

The basic concept of a demand side resource is that it provides a market option to customers that do not want to pay for capacity. But if a customer does not pay for capacity it must also agree to interrupt its load when there is not enough capacity to meet total load, and when those customers who do pay for capacity need that capacity.

The treatment of demand side resources in RPM has been inconsistent with market fundamentals from the inception of RPM and subsequent modifications to the market design have made matters worse. Prior to RPM, demand side actions reduced the demand for capacity either as a result of customers responding to price signals or as a result of utility rate reduction options in the regulated environment. Under the RPM design, demand side resources are offered as supply, included in the market supply curve and compete directly with offers from generating units as if they were equivalent.

Both before and after the introduction of PJM markets, some large customers interrupted their own load on high load days in order to reduce their payments for capacity. Capacity payments were assigned to customers based on their share of load on the five coincident peak load days so a reduction in load on peak days meant a reduction in payments for capacity as well as distribution costs linked to peak demand.

Both before and after the introduction of PJM markets, some PJM member utility companies had programs under which large customers agreed to curtail load during emergencies in return for lower rates. These programs reduced the demand for which the utility companies had to own or acquire capacity. In the initial PJM capacity credit market, PJM created the Active Load Management (ALM) program under which such curtailable resources received a MW credit which offset their capacity obligation.

In the RPM capacity market design, the PJM ALM program was replaced by the PJM Load Management (LM) program under which qualifying demand side resources could be offered directly into the capacity auction as capacity resources in the same way as generation supply resources. The LM program initially included two new products and a third was added later. The Demand Resource (DR) product was offered in RPM auctions as capacity and received the clearing price. The Interruptible Load for Reliability (ILR) product was not offered in RPM auctions, but was committed just prior to the delivery year and received the capacity clearing price previously determined in the BRA for the delivery year. As part of the

ILR design, PJM subtracted the ILR forecast from the reliability requirement, reducing demand for capacity in the BRAs by shifting the demand curve to the left. The ILR product was eliminated effective with the 2012/2013 delivery year. The Energy Efficiency (EE) product was introduced for RPM Auctions beginning with the 2012/2013 Delivery Year and Incremental Auctions for the 2011/2012 Delivery Year. An EE Resource is a project that improves the efficiency of equipment, processes or systems, designed to achieve a continuous (during peak periods) reduction in power usage.

The RPM design introduced demand side resources as supply, but without most of the critical attributes of supply. Demand Resources were only required to interrupt ten times per year for a maximum of six hours per interruption and only during peak hours in the summer. Demand Resources were not required to offer in the day ahead energy market. Demand resources were not required to show evidence of an actual, physical project prior to offering in RPM Auctions. The ILR product was a free option to sell an unlimited quantity of DR at the market clearing price which was known three years in advance of deciding whether to sell, just prior to the delivery year and with only a limited obligation to perform. The ILR product was also packaged with a reduction in demand in Base Residual Auctions, which suppressed the clearing price for all resources.

At the same time that ILR was eliminated, PJM began to reduce demand in every BRA by 2.5 percent. The ILR adjustment was equivalent to removing 1.2 percent of the reliability requirement in the 2011/2012 BRA, the last auction in which the product existed. The stated rationale for this 2.5 percent administrative reduction in demand in the BRA was to permit procurement of DR, asserted to be a short lead time resource, in later IAs for the same delivery year. (For that reason, this reduction is referred to as the Short-Term Resource Procurement Target or STRPT.)

Although never stated explicitly, it appears that the well intentioned market design goal for the inclusion of DR in RPM was to encourage DR by making DR easier to monetize for third party providers (curtailment service providers or CSPs). Actual demand reductions by participants had, up to that point, been monetized as a bill reduction to an individual participant or as a reduction in capacity obligations for a load serving entity (LSE). When DR could participate as supply in RPM, the CSPs offering DR received direct payments which could be retained in part and shared with customers in part. This well intentioned goal has had significant, negative unintended consequences for the PJM capacity market.

The market design logic associated with DR has been confused. DR is a demand side resource which has been treated as both supply and demand. DR is treated as a supply resource while total market demand has simultaneously been administratively reduced to permit and/or account for the participation of DR in the market. The logic of reducing demand in a market design that looks three years forward, to permit demand resources to clear in IAs, is flawed. 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. Removing a portion of demand affects market clearing prices in the BRAs at the margin, which is where the critical signal to the market is determined.

The result of the shift in the demand curve is to suppress the price and the quantity of capacity purchased. The price suppression occurs directly as a result of the reduction in demand and indirectly as the result of permitting an inferior product, the 60 hour demand side product, to displace capacity resources which are obligated to be available for 8,760 hours per year.

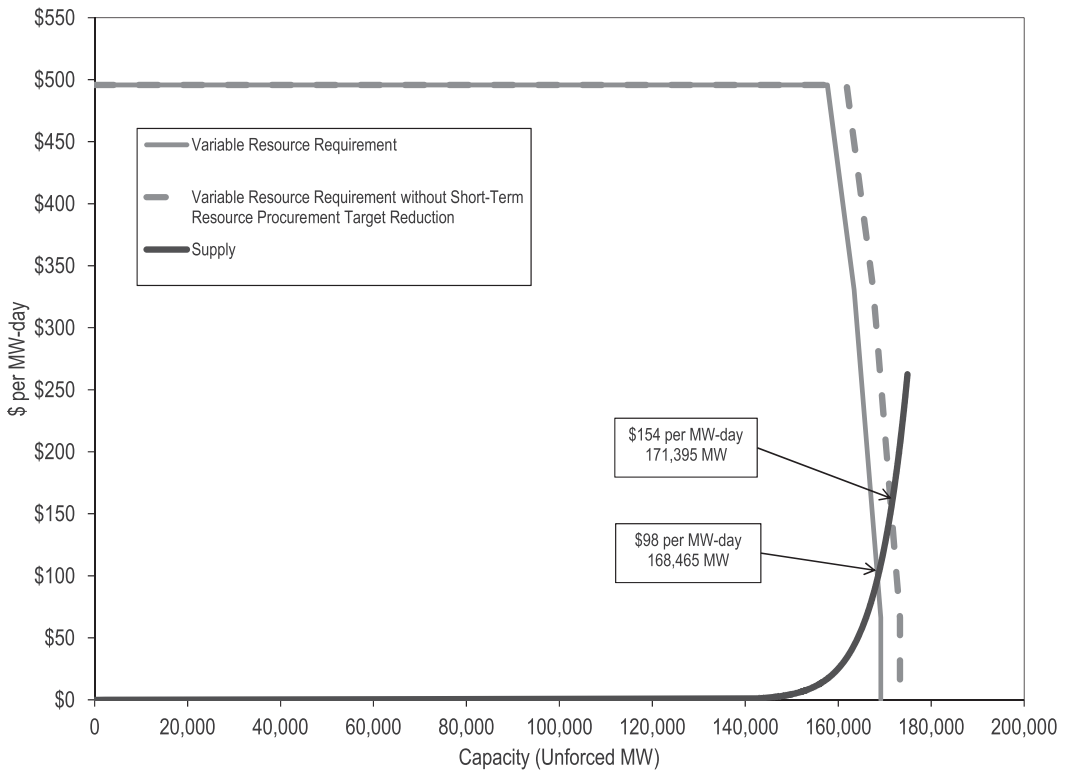


FIGURE 2
Illustration of 2.5 percent shift of demand curve

The impacts are extremely large. For example, the use of the 2.5 percent demand reduction resulted in a 21 percent reduction in RPM revenues for the 2015/2016 Base Residual Auction (a difference of \$2.7 billion in market revenues) compared to the revenues that would have resulted without the reduction.

The shift in the demand curve is implemented by reducing the quantity associated with each of the inflection points in the demand curve definition by an amount equal to 2.5 percent of the reliability requirement.³⁵ (See Figure 2)

More recently, PJM has suggested that the 2.5 percent demand reduction is a correction for forecast error.³⁶ Apart from the implausibility of forecast error being the same 2.5 percent every year and always in the same direction, it would make more sense to fix the forecast method directly if that were really the issue. But forecast accuracy does not appear to be the real issue. The PJM manuals do not indicate that the Short-Term Resource Procurement Target is related to forecast accuracy. The same forecast, which is adjusted down in the capacity market, is used without adjustment for PJM's reliability analysis to determine whether PJM needs to mandate the construction of transmission facilities to ensure reliability. It does not make sense to use different forecasts for reliability purposes depending on the nature of the reliability fix which could result.

35. See PJM Interconnection, L.L.C., "Manual 18: PJM Capacity Market," p.18.

36. See the "PJM Response to the 2012 State of the Market Report," PJM Interconnection, L.L.C., (May 10, 2013).

If the transmission related forecast is always higher than the capacity related forecast, then transmission fixes for reliability issues will be identified when no reliability issue is identified in the capacity market. This creates a bias towards relying on transmission rather than generation to resolve reliability issues. This creates additional risk for potential investors in generation who could see the value of their investment undercut by a subsequent investment in transmission facilities. Given the difference in load forecasts, the need for a transmission upgrade could still be identified even when the full amount of capacity required to resolve the reliability problem as measured in the capacity market has been procured.

Effective with the 2014/2015 Delivery Year, the RPM market design added Annual and Extended Summer DR product types, in addition to the previously established Limited DR product type.³⁷ Each DR product type is subject to a defined period of availability, a maximum number of interruptions, and a maximum duration of interruptions. The RPM rule changes related to DR product types also include the establishment of a maximum level of Limited DR and a maximum level of Extended Summer DR cleared in the auction.

The Minimum Resource Requirements are targets established by PJM to ensure that a sufficient amount of Annual Resources are procured in order to address reliability concerns with the Extended Summer and Limited DR products, and to ensure that a sufficient amount of Annual Resources and Extended Summer Resources are procured in order to address the stronger reliability concerns with the Limited DR product alone. The reliability risk associated with relying on either the Extended Summer or Limited DR products results from the fact that reliability must be maintained in all 8,760 hours per year while these resources are required to respond for only a limited number of hours when needed for reliability. There is a maximum level of Limited DR and a maximum level of Extended Summer DR that PJM will purchase to meet reliability requirements, because additional purchases of these products is not consistent with reliability based on a PJM analysis of the probability of needing Limited DR resources when they are not available.³⁸

MOPR

The RPM design includes market power mitigation rules to limit the extent to which capacity sellers can raise market prices above the competitive level. The market power mitigation rules were included because structural market power gave sellers the ability to increase market prices above the competitive level. The RPM design also includes market power mitigation rules to limit the extent to which capacity buyers can suppress the price below the competitive level. The rule designed to address buyer side market power is called the Minimum Offer Price Rule (MOPR). The MOPR was introduced in the original RPM rules in 2007 as the result of the perceived ability and desire of capacity buyers to intervene to suppress the price in capacity markets in order to reduce payments by load for capacity. One mechanism for the exercise of buyer side market power could be intervention by an individual state which would sign a long term bilateral contract for capacity with payments guaranteed by state ratepayers, typically at an above market price, and require that the capacity be offered into the RPM market at a zero price. Another mechanism could be the construction of capacity by a utility subject to cost of service ratemaking. Ratepayers would guarantee recovery of

37. 134 FERC ¶ 61,066 (2011).

38. 143 FERC ¶ 61,076 (2013).

investment costs while the capacity was offered into the market at zero. The result in both cases would be to suppress capacity market prices below the competitive level.

In PJM, two states took such actions in 2011.³⁹ The immediate origins of the state actions were in large part the result of the two states being informed, after RPM auctions had cleared, that their states nonetheless faced reliability issues. It appeared to the states that RPM was not providing reliability and that state action was therefore required. Nonetheless, both states took actions to sign contracts with developers of proposed new units located in the states, which did not include the use of competitive, nondiscriminatory auctions, and persisted in their actions even after PJM showed that there were no reliability issues.

The original MOPR (MOPR1) proved not adequate to the task of addressing explicit state actions with the direct effect of suppressing RPM prices. MOPR1 was explicitly targeted at LSEs and used a net short definition as a trigger. Although the states' customers were net short as a group and the intent of MOPR1 was met, the MOPR1 language needed clarification. Under MOPR1, both New Jersey's LCAPP program and Maryland's RFP for capacity could have resulted in the purchase of capacity at above market prices, the imposition of a non-bypassable charge on state ratepayers and offers into the PJM capacity market at zero.⁴⁰

The MOPR rule was rewritten (MOPR2) to focus specifically on offer prices, but was limited to constrained LDAs and did not cover units in the rest of the RTO.⁴¹ Under MOPR 2 there was an offer threshold equal to 90 percent of the net cost of new entry as defined for the RPM demand curve.⁴² If a new unit wished to offer at a lower price it was subject to a unit specific review process to determine if the desired offer price was consistent with actual project costs. The only units permitted to offer into capacity auctions at less than 90 percent of net CONE were those units with offers at levels greater than or equal to the demonstrated actual net annual levelized cost of their project.⁴³ The offers were subject to review by the independent Market Monitoring Unit. There were objections to the outcome of MOPR2 in the BRA for the 2015/2016 delivery year by capacity sellers who believed that the MOPR offers were too low and by public power capacity sellers who did not believe they should be subject to the unit specific review process.

The next iteration of the MOPR rule (MOPR3) continued the focus on unit offer prices, but created exemptions from the unit specific offer review for demonstrably competitive projects, for projects procured through a competitive, non-discriminatory state auction process and for projects built by public power entities and vertically integrated utilities, subject to a net short and net long test. MOPR3 set the threshold at 100 percent of the applicable net CONE, extended the rule to the full RTO, limited the application of the rule to CTs and CCs, exempted units less than 20 MW and retained the unit specific cost review to be applied

39. Testimony of Joseph Bowring before the New Jersey Board of Public Utilities regarding the Board's Investigation of Capacity Procurement and Transmission Planning, Docket No. EO 11050309, June 17, 2011, October 14, 2011 and November 1, 2011. Testimony of Joseph Bowring before the Maryland Public Utility Commission regarding New Generating Facilities Needed to Meet Long-Term Demand, Case No. 9214, January 28, 2011.

40. See the "*PJM- MMU Letter to NJ BPU*," re LCAPP.

41. 135 FERC ¶ 61,022 (2011).

42. The energy and ancillary services offset for CONE areas for the MOPR CT screen price uses the net energy revenue offset for the zone with the highest net energy values in the CONE Area, while the net CONE calculation for the VRR curve uses the zone in which the reference resource was assumed. In addition, there is a MOPR screen price established for a CC.

43. MOPR2 did not apply to offers for nuclear, coal, Integrated Gasification Combined Cycle, hydroelectric, wind, or solar. In addition, under MOPR 2, resources not a CT or a CC and not an exempted technology could offer at 70 percent of the applicable net CONE.

as necessary.⁴⁴ The primary difference between MOPR3 and MOPR2 is that MOPR3 created specific exemptions from the rule for broad classes of market sellers with the result that MOPR3 applies primarily to state subsidized projects that are not procured through a competitive, non-discriminatory auction process.

The MOPR issue, if left unaddressed, would have undermined key elements of the capacity market design. Those receiving subsidized contracts argue that capacity cannot be built in the absence of a long term guaranteed contract. The argument is that a one year clearing price, three years forward, is not an adequate basis on which to build a new capacity resource. This position ignores the fact that long term market based contracts are available, including the sale of energy market price hedges and tolling agreements, which reflect market participants' views of future market conditions.

However, once subsidized long term contracts are introduced into the market, with out of market payments and offers in the market at a price of zero, the market price would be significantly distorted. This would affect confidence in the price going forward and would reduce the likelihood that any participants would make competitive offers in the market without subsidies.

Subsidies can come from states and subsidies can come from the cost based ratemaking process. Vertically integrated utilities that receive cost of service rates are effectively receiving an out of market guaranteed long term contract for the sale of capacity. The offers from such utilities into the capacity market have the potential to distort market outcomes and should not be exempted from the MOPR.

✎ 6. CONCLUSION ✎

Capacity markets can be an effective part of wholesale electricity market design, as demonstrated by the PJM capacity market. But it is important to get capacity market design right to permit capacity market prices to reflect the actual underlying locational supply of and demand for capacity. The PJM capacity market includes some elements that distort market outcomes and lead to ad hoc efforts to address those distorted outcomes which threaten to further distort the market. The goal should be to remove those distortions and let the market work.

44. 143 FERC ¶ 61,090 (2013).