Synapse
Energy Economics, Inc.

Incenting the Old, Preventing the New

Flaws in Capacity Market Design, and Recommendations for Improvement

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1. Introduction

Capacity markets have been promoted as a means to address a number of perceived gaps in restructured electricity markets. In a restructured market environment, some suppliers may be unable to recover most or all of their fixed costs through sales of energy and ancillary services alone. Further, in order to meet reliability needs, electricity markets require generating capacity above and beyond the requirements to simply meet demand. Thus some peaking power generators may only operate for a few hours a year, if at all. In markets where wholesale electricity prices are capped, capacity markets are also meant to signal the need for new capacity when supply becomes relatively tight. Capacity markets that allow for location-specific prices should also signal to developers where capacity is needed most. In both of these roles, capacity markets are intended to replace targeted subsidies such as "reliability must-run" contracts or uplift payments to support needed but otherwise uneconomic generation. Capacity markets can also serve as an incentive for investment in alternatives to generation, such as demand response or transmission.

While capacity markets were devised, ultimately, to benefit ratepayers, in practice they have turned out to be a bad deal for electricity consumers; the limited benefits resulting from capacity markets have come at extraordinary costs, and many of the desired benefits have not materialized. High capacity prices in local markets have increased the profitability of incumbent generation at ratepayer expense, but have not led to significant investment in new power plants. Capacity markets have effectively encouraged participation in demand response programs, but there has not been a surge in investment in generation or transmission alternatives to address locational capacity needs.

In fact, there is reason to believe that capacity markets actually *discourage* investment in new generation. Forward capacity markets, which provide an inflexible one-year contract period as the standard capacity product, do provide a sustaining stream of revenue to existing generation that might otherwise be uneconomic. At the same time, they provide insufficient revenue certainty to developers to support financing of new projects. Capacity markets may also provide a perverse incentive to incumbent generation owners, who could lose more revenue by responding to "price signals" than by preserving the status quo, or even by trying to prevent new entry. Thus these markets may actually prevent the construction of newer, more efficient, and cleaner generating stock to replace aging and higher-emissions resources. The result is a double penalty: more pollution from existing plants and higher prices for consumers.

In this report we discuss the impact of capacity markets on generator revenues and on costs for consumers in the PJM Interconnection region (PJM) and, to a lesser extent, in the New York Independent System Operator region (NYISO). We do not focus on the details of the New England ISO, where capacity revenues are a much smaller part of a generator's overall revenue stream. One benefit of focusing on the PJM capacity market is that it provides the closest context for the potential impact of a transition to a capacity market currently under development in the Midwest Independent Transmission System

Operator (MISO). NYISO does not have a forward capacity market, and so while it does offer a different perspective on how capacity markets can be structured, it is probably not the sort of market that may be implemented in other parts of the country.

For PJM we find that approximately 95% of the capacity market revenues have gone to existing generation. Moreover, 61% of all revenues have gone to existing coal and natural gas plants. For the period covering 2007 to 2014, natural gas and coal plants have earned or will earn \$13.7 billion and \$12.3 billion in capacity payments, respectively.

In addition, much of the so-called "new" generation that has bid into capacity auctions has actually been increases in the capacities of existing generation, or old generation being brought out of retirement. The PJM capacity market has been successful in bringing new demand response generation into the market, especially in recent years as the rules have evolved to facilitate the participation of this resource. However, the complete picture shows that the real winners from the capacity market have been the incumbent generators, and the losers are consumers.

Ensuring resource adequacy in deregulated markets

As capacity markets are a relatively recent construct, it is worth briefly examining where they come from. In a traditional, cost-of-service electricity market, generation-owning utilities are effectively compensated based on average cost, including variable costs, fixed costs, and a "reasonable" return on equity. There is no need for a formal "capacity market" because the utilities are able to pass through to ratepayers the cost of building and maintaining adequate reserves. In many cases, capacity-sharing arrangements have been negotiated among utilities as a way to reduce the overall capacity burden when the utilities have non-coincident load peaks.

In restructured markets the concept of average cost has been replaced by a focus on marginal cost as a means of obtaining the least-cost dispatch of resources. As part of this paradigm shift, each generating resource is treated conceptually as an independent player in the market, and there is no regulator to ensure that generation-owning companies are neither undercompensated nor overcompensated for their costs and investments. The basic underlying theory is that in a single-clearing-price electricity market, each generator will bid into the market at its marginal cost, receiving rents in excess of marginal cost (and thus recovering fixed costs) whenever a more-expensive generator sets the clearing price. High-capital cost resources such as hydro and nuclear will almost always recover some fixed costs because their operating costs are low, while lower-capital resources with high running costs will more rarely recover fixed costs. The most expensive resources to run, sometimes called "peaking" plants, have very low capital costs. They will recover their costs during those few ultra-high-priced hours when even they are inframarginal, and some extraordinarily high-priced resource such as dispatchable demand is on the margin. It's an elegant construct, but it relies on idealized market conditions and a supply curve that has reached equilibrium.

In practice, one outcome of allowing a marginal-cost electricity market to run its course is volatile and unpredictable price spikes. During years in which there are relatively more price spikes, all generators over-recover their fixed costs at the expense of Load Serving Entities (LSEs) and/or their customers. This wealth transfer can be extraordinarily large, as was seen in the California electricity crisis of 2000. It can also be extraordinarily profitable for generators.

Moreover, even in an environment with uncapped prices, there is no guarantee that generators will maintain enough capacity in reserve to meet load spikes significantly beyond normal system operations. Generator owners earn no revenues on plants that do not operate, but they do earn windfall profits from the price impact of shortages. In a market with instantaneous supply and demand balancing and high costs of entry, this is a recipe for massive market failure.

To ensure that enough generation is kept in reserve in order to meet unexpected spikes in demand requires some form of administrative intervention. A market administrator can enforce a certain reserve margin by requiring LSEs to purchase capacity above and beyond what they need to serve load. The Southwest Power Pool ("SPP") maintains its reserve margin requirements in this manner, though members do coordinate to meet their reserve needs through the reserve sharing pool.[1] An alternative out-of-market mechanism is the reliability-must-run (RMR) agreement, which requires specific generators to stay on line to meet reliability needs, funding their costs through some sort of out-of-market payments. While these contracts could theoretically go to new, efficient generators, in practice they have been used to sustain existing units that are not otherwise able to compete economically. This is at least in part because generation owners and developers are unregulated entities, so there is no mechanism for states or commissions to order them to build needed generation.

As an alternative, LSEs could enter into long-term contracts to support the development of new resources. Some states, faced with high but ineffective capacity prices, have taken it upon themselves to ensure resource adequacy. New Jersey recently passed legislation that provides financial support to new generation that is either located within or deliverable to a point within the state where capacity is needed; Maryland recently issued a draft Request for Proposals (RFP) for a similar purpose. These state-level actions have proven to be controversial, especially among competing generators, who argue that this is in essence an anti-competitive state subsidy that will, in turn, artificially depress capacity prices. While this narrow argument for "market orthodoxy" serves the interests of generation owners that benefit from continued high capacity prices, it contrasts sharply with the facts recognized by the states: capacity markets have failed to incentivize generation where it is needed most, despite high prices in these regions. The states have chosen to implement a mechanism beyond price signals to more reliably ensure resource adequacy and protect ratepayers.

[1] "Southwest Power Pool Criteria", January 25, 2011, http://www.spp.org/publications/CRITERIA%20and%20Appendices%2001-25-2011Current.pdf

2. Analysis of existing markets

A. PJM: Keeping the Coal Fire Burning in the 21st Century

The PJM capacity market, called the Reliability Pricing Model (RPM), is a forward market in which generators make a one-year supply commitment, three years in advance of each delivery year. Forward capacity markets are meant to give developers a guaranteed future capacity revenue stream to partially offset the risk of relying on uncertain future energy revenues. If forward capacity markets work as intended, developers and owners should receive and respond to price signals to invest in new generation, or to retire uneconomic existing generation.

Prior to the introduction of RPM, capacity was primarily transacted bilaterally in PJM, with RTO Daily and Monthly Capacity Credit Market (CCM) run for residual capacity requirements.[2] However, following an explosion of investment in new gas-fired generation in the late 1990s and consistent with the capacity surplus in the region, CCM clearing prices were quite low through most of the early 2000s. Generators that had built during the boom years but were unhedged through bilateral contracts were unable to cover their fixed costs at these prices. This led to creation of RPM which, through the use of an administratively constructed "variable resource requirement" curve, would keep capacity prices relatively high even under conditions of surplus.

How well this construct has worked in PJM is a matter of dispute. The 2010 market monitor's report claims that it has been successful, claiming credit for a large quantity of generation additions.[3] A closer examination reveals that the bulk of new generation is either increases in capacity at existing generators, or old generators coming out of retirement. Since RPM was approved, nearly 278 MW of installed capacity (ICAP) have been reactivated, 1,917 MW of retirements have been postponed or canceled, and 2,030 MW of deactivation requests have been withdrawn, or 4,225 MW of ICAP in total (Table 1).[4] Installed capacity refers to the nameplate capacity of the resources offered into the auction. In terms of unforced capacity (UCAP), or capacity adjusted to take into account actual availability, a cumulative total of 3,250 MW have actually cleared in the market since the start of RPM. For comparison, the total amount of UCAP that cleared in the 2014/15 auction was 149,975 MW.

[2] For more information and archived CCM market data, see http://www.pjm.com/markets-and-operations/rpm/cap-credit-archive.aspx.

[3] PJM 2010 State of the Market Report, Table 5-3 http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010.shtml

[4] 2014/2015 RPM Base Residual Auction Results, Table 8 http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx

	Capacity Offered (MW)*
Withdrawn Deactivation Requests [a]	2,030
Postponed/Canceled Retirements [a]	1,917
Reactivated [a]	278
Uprates to Existing Units[a]	5,149
New Generation Construction [a]	7,477
Generation Derating [a]	(8,895)
Total "New" Generation [a]	**7,956**
Total Cleared Capacity in 2014/15 [b]	**149,975***

Table 1. Cumulative changes to generation retirement decisions since the start of RPM.

a. Value is given in Installed Capacity terms.

b. Value is given in Unforced Capacity terms.

Of the so-called "new" capacity, 5,149 MW have actually been increases in capacity to existing units, and 7,477 MW is actual new construction of generation.[5] The amounts do not account for the 8,895 MW in deratings that reduced generation capacity in PJM. Nearly one-third of "new" capacity that has cleared in the capacity market since 2010 has actually been coal plant capacity increases. Renewable generation makes up only 11% of new capacity, almost all of which has been wind. Among this array of "additions", a large fraction is comprised of energy resources that would have made the same decision in the absence of RPM. Almost none of these new resources have been in capacity-constrained areas. Thus it is hard to support the assertion that RPM has been effective overall at bringing on new capacity, and it is clearly not the case that locational price signals have been effective at relieving locational shortfalls.

PJM's capacity market has been successful in attracting new demand resources, at least in the most recent years: 14,118 MW of demand response cleared in the 2014/15 Base Residual Auction (BRA), compared to only 963 MW in the 2010/11 auction.[6] Energy efficiency and transmission upgrades are also allowed to participate, but most of the non-generating resources have been demand response.

Prices and Revenues

When capacity markets were established, the expectation was that capacity resources would bid at or near their net Cost of New Entry (net CONE). Net CONE is the cost that a new resource would need to recover its fixed costs, plus a reasonable return on equity, after taking into account energy and ancillary services market revenues. This is an administratively determined parameter, set each year by PJM, based on the market

[5] 2014/2015 RPM Base Residual Auction Results, Table 9.

[6] PJM 2010 State of the Market Report, Table 5-8

operator's estimate of the costs and expected energy revenues for a "proxy" new resource. Stable prices near or above net CONE should in theory attract new investment.[7]

Interestingly, RPM prices for the non-constrained RTO region have been below PJM's estimate for net-CONE in five out of the past six auctions (Figure 1). The large changes in net CONE are due mainly to changes in forecasted energy and ancillary services revenues.

Figure 1. RPM auction RTO area clearing prices and PJM RTO net CONE

The fact that new resources have consistently been added to the unconstrained region of the market despite these "low" prices belies the validity of PJM's proxy resource as an indicator of the required capacity price. On the other hand, prices in constrained regions of the market have been much higher—yet new supply resources in these capacity-short regions have not been forthcoming. Clearly and unsurprisingly, one-year price guarantees are not sufficient to drive 9- or 10- figure investments in generating resources with operating lives of decades.

Capacity market prices are a small but growing portion of the overall wholesale electricity price. According to the 2010 PJM Market Monitor, capacity costs accounted for about 5.6% of the total wholesale price of electricity on an annual basis in 2007, but 18.1% of the total wholesale price in 2010.[8] (Prior to the introduction of RPM these costs made up less than 1% of the wholesale price of electricity, including a low of 0.04% in 2005.) Capacity payments remain a relatively small revenue source for base load resources when compared to their energy and ancillary services revenues; however, these payments can represent most of the net revenues for a typical combustion turbine.

[7] James F. Wilson, "Forward Capacity Market CONEfusion", June 2010, http://www.wilsonenec.com/CRRIpaper_CONEFusion.php

[8] PJM 2010 State of the Market Report, Volume 2 ("Detailed Analysis"), Table 1-9, page 22.

Combustion turbines are peaking units, and as capacity resources they do not expect to recover much of their fixed costs from energy sales. During the first four years of RPM (2007-2010) a typical new entrant combustion turbine peaker would have earned between 60% and 90% of its revenues from the capacity market.[9] Capacity revenues for a typical new peaker have grown dramatically since the introduction of RPM in 2007, averaging $11,761/MW-year from 1999 to 2006 compared to $41,971/MW-year from 2007 through 2010 (Table 2).

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
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
2010	$36,925	$55,309	$0	$0	$2,384	$94,619
Average	**$18,103**	**$41,971**	**$0**	**$0**	**$2,330**	**$62,405**

Table 2. Real-time PJM-wide net revenue for a hypothetical combustion turbine under peak-hour, economic dispatch by market (Dollars per installed MW-year)

According to the PJM market monitor, a hypothetical new entrant combined cycle unit would have earned an average of $38,743/MW-year in the capacity market during the RPM years of 2007-2010, compared to $62,128/MW-year in the energy market. In the pre-RPM years 1999-2006, it would have earned an average of only $11,345 in the capacity market, compared to $41,627 in the energy market (Table 3).[10]

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2007	$66,616	$31,098	$0	$0	$3,094	$100,809
2008	$62,039	$38,691	$0	$0	$3,198	$103,928
2009	$31,581	$46,596	$0	$0	$3,198	$81,376
2010	$88,275	$38,588	$0	$0	$3,198	$130,061
Average	**$62,128**	**$38,743**	**$0**	**$0**	**$3,172**	**$104,044**

Table 3. Real-time PJM-wide net revenue for a hypothetical combined cycle under peak-hour, economic dispatch by market (Dollars per installed MW-year)

Base load resources do not require as much or any support from the capacity market, as they earn most of their fixed cost recovery in energy revenues. However, because RPM

[9] PJM 2010 State of the Market Report, Volume 2, Table 3-8, page 167.

[10] PJM 2010 State of the Market Report, Volume 2, Table 3-10, page 169.

does not distinguish among resource types and pays all resources on a per-MW basis, these resources actually capture most of the revenues from RPM. A typical coal plant, which operates as baseload generation, would have also earned the largest net energy revenues. During the RPM years 2007-2010 a typical new entrant coal plant (assuming there was one) would have earned an average of $150,472/MW-year in the energy market and $36,375/MW-year in the capacity market (Table 4).[11]

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2007	$244,419	$29,343	$0	$1,172	$2,350	$277,284
2008	$179,457	$36,107	$0	$796	$1,783	$218,144
2009	$49,022	$43,931	$0	$231	$1,783	$94,968
2010	$128,990	$36,117	$0	$174	$1,783	$167,064
Average	**$150,472**	**$36,375**	**$0**	**$593**	**$1,925**	**$189,365**

Table 4. Real-time PJM-wide net revenue for a hypothetical coal plant under peak-hour, economic dispatch by market (Dollars per installed MW-year)

The overall revenue benefit from RPM for capacity resources has been substantial, and most of this revenue has gone to incumbent generators. Since the 2007/08 auction (but excluding the most recent 2014/15 auction, for which we do not have revenue data) coal plants have earned or stand to earn $12.3 billion in capacity revenues, or 29% of total capacity market revenues.[12] Natural gas plants have earned $13.7 billion, or 33%, and nuclear plants have earned $8.8 billion, or 21% of the total. (As shown above, coal plant energy revenues are higher per unit than for natural gas.) Demand response and energy efficiency have earned $1.0 billion, or 2% of the total, though $831 million of that revenue was from the last two auctions alone. Solar and wind have earned only $61 million (less than 1% of the total revenues earned by capacity resources).

[11] PJM 2010 State of the Market Report, Volume 2, Table 3-12, page 170.

[12] The fact that the PJM capacity market is a forward market means that generators will earn some of these revenues in the future. Actual load obligations for the 2011/12, 2012/13, and 2013/14 periods are not finalized.

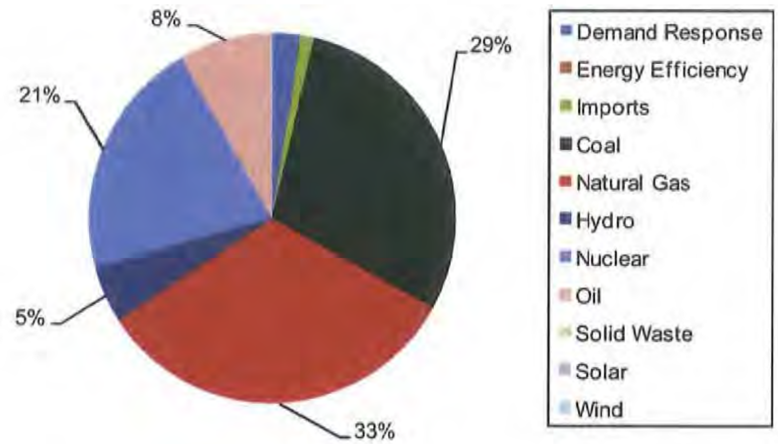

Figure 2. RPM revenues by generator type as portion of total.

Existing resources have received 95% of all revenues since the 2007/08 auction, excluding the most recent 2014/15 auction, or $40.1 billion in total. Of revenues going to new resources ($575 million), 77% has been for new gas fired generation, 9% has been for new coal generation (most likely capacity increases to existing generation), and 4% has been for new oil generation. Total revenues declined in the 2011/12 and 2012/13 RPM auctions, but have increased again in the 2013/14 auction.

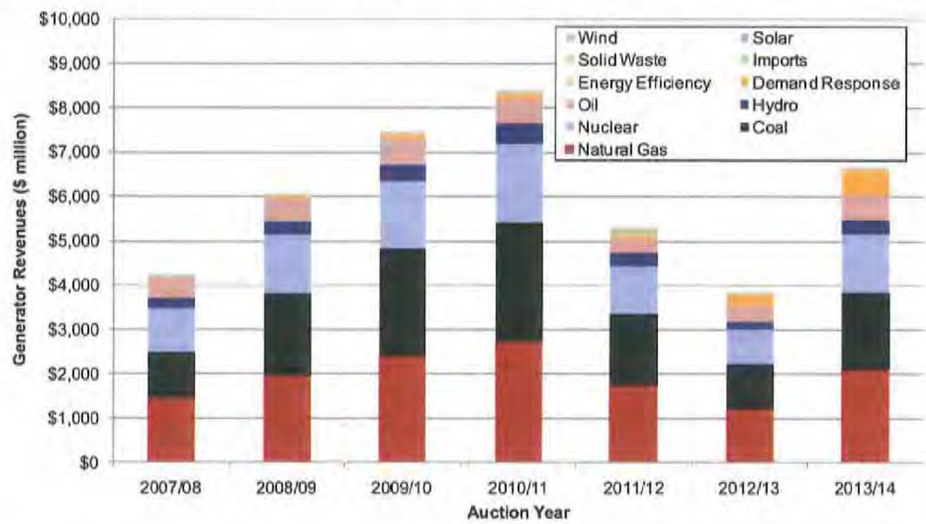

Figure 3. RPM revenues by generator type.

Another important question is the degree to which the incumbent generation supported by these revenues would have otherwise retired. In the six years prior to introduction of

RPM, retirements averaged 1,000 MW a year. From its introduction through 2010, retirements have averaged only 384 MW per year.[13]

There is evidence to suggest that a significant fraction of the coal generation in PJM would not be economic in the long term without the support of capacity payments. A 2009 assessment by the Brattle Group put the amount of generation at-risk for retirement without capacity payments at 30,000 MW.[14] In 2010, 6,769 MW of coal plants were unable to cover their avoidable costs, or costs which generators must meet in order to keep a unit active, even with capacity payments.[15] Going forward, new EPA regulations are widely expected to make even more coal plants uneconomic in throughout the United States.[16] To what extent will capacity market revenues offset this increase in cost? At some point, will PJM states and their ratepayers opt for the far lower cost of direct investment in new, cleaner and more efficient power plants and energy efficiency instead of continuing to rely on PJM's highly flawed capacity market?

B. New York: Weak Incentives for New Generation

The New York capacity market is quite different from PJM's RPM construct. New York's market is a short-term, voluntary market that allows load-serving entities to meet their capacity obligations bilaterally if they choose to do so. PJM's approach, by contrast, is a mandatory forward market. Nevertheless, the New York capacity market offers an instructive alternative to PJM's forward market structure. In particular, it is another piece of evidence that capacity markets that offer only short-term revenues provide poor and ineffective incentives for new generation.

Unlike PJM, coal is a very small part of New York's generation mix, making up only 6% of its summer capacity.[17] No new coal plant has been built in New York State since 1991. Since 2007, there have been 2,207 MW of retirements, 30% of which (on a MW basis) have been coal plants, the rest being natural gas fired.

The New York capacity market seems to have had little impact on levels of investment in new generation. Since the capacity market's formation in 2000, New York has added 6,412 MW of new capacity. However, in the decade prior to 2000, New York added 5,860 MW of capacity. If the capacity market has had an impact, it is indistinguishable from random variation over time.

Because New York has no forward capacity market, price signals for new and existing generation come from spot electricity, ancillary, and capacity prices; that is, prices that

[13] Excludes retirements in 2011, which is only a partial year. As of May 2011 101 MW of capacity have retired.

[14] Johannes Pfeifenberger, Kathleen Spees, and Adam Schumacher, "A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs," Brattle Group, September 2009

[15] PJM 2010 State of the Market Report, page 45.

[16] See for example the World Resources Institute's Fact Sheet, ""Response to EEI's Timeline of Environmental Regulations", November 2010. Also NERC, Brattle Group and ICF studies.

[17] 2011 Gold Book, New York ISO

are for immediate delivery, and which therefore offer no information as to expectations for the future.

New York has a regional capacity market covering all of New York State (referred to as the New York Control Area) and two locational markets: one for New York City and one for Long Island. New York requires that a certain percentage of the capacity obligations for New York City and Long Island be met by local capacity. Capacity prices are quite volatile, especially in New York City. Similar to PJM, clearing prices are well below New York's estimated CONE for each region (Figure 4).

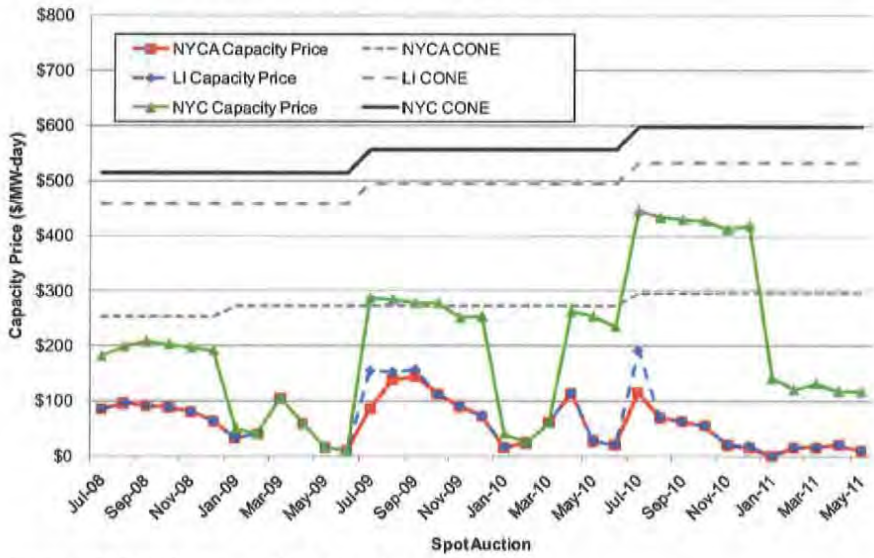

Figure 4. NYISO capacity prices by region.

The capacity market makes up a relatively small portion of the average all-in price for electricity.[18] This is illustrated in the New York market monitor's estimated composition of regional all-in prices, reproduced in Figure 5.[19]

[18] The all-in price includes the price of capacity, energy, ancillary services, uplift, and NYISO cost of operations. Specific figures are not provided in the 2010 State of the Market Report, so proportions given are estimates based on charts.

[19] New York ISO 2009 State of the Market Report, Figure 4

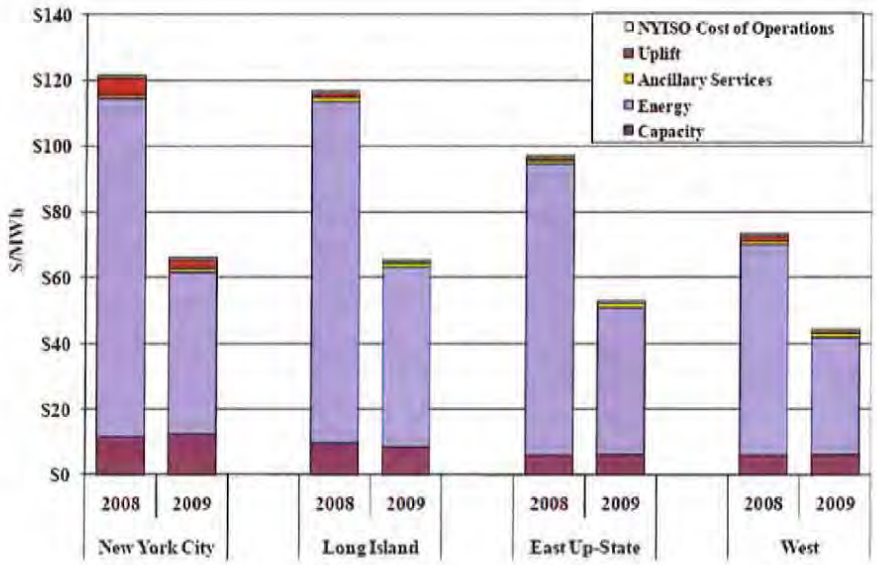

Figure 5. New York all-in electricity prices by region. Reproduced from the New York ISO 2009 State of the Market Report, Figure 4

In western New York, the all-in price in 2009 was approximately $45/MWh, of which the capacity price was approximately $5/MWh or 11%. In east up-state New York the all-in price was a bit more than $50/MWh, while the capacity price was around $5/MWh. In New York City the all-in price was approximately $65/MWh, with the capacity price around $10/MWh. In Long Island the all-in price was slightly more than $60/MWh, with the capacity price around $5/MWh.

While capacity price accounts for a relatively small portion of the all-in price of electricity, capacity payments do make up a significant portion of the net revenues for a typical combined cycle or combustion turbine plant in many parts of New York. In 2009, a combined cycle unit in Western New York would have earned more than two-thirds of its net revenues from the capacity market, while a combustion turbine would have earned around 80% of its revenues from the capacity market. In New York City, a combined cycle plant would have earned more than half of its net revenues from the capacity market, and a peaker would have earned around 60% (Figure 6 and Figure 7).

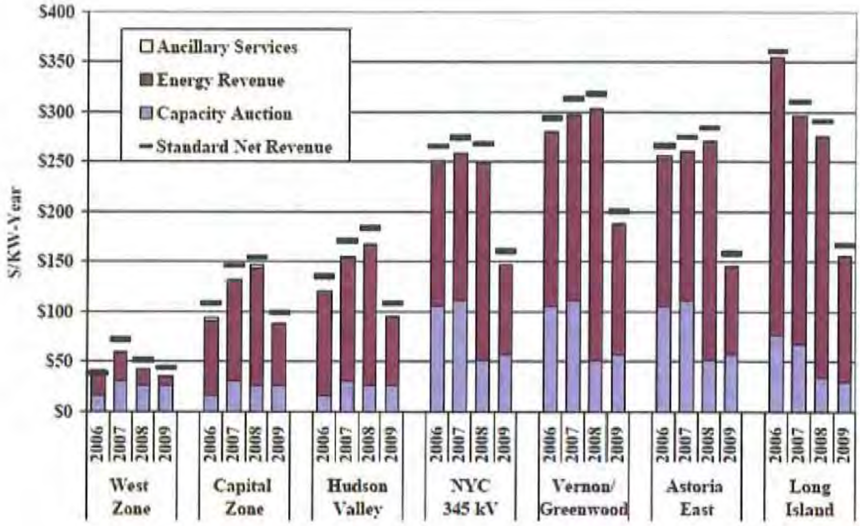

Figure 6. Estimated net revenues for a combined cycle unit.

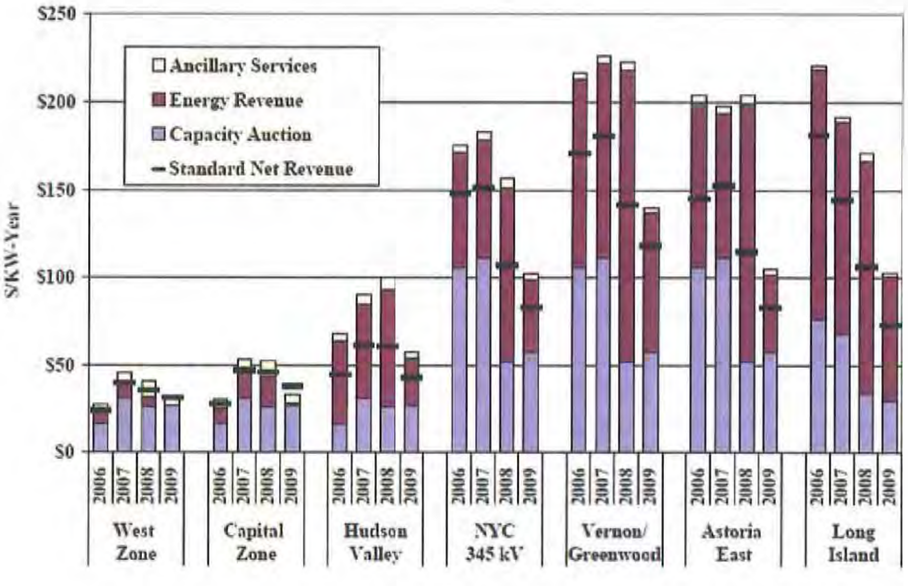

Figure 7. Estimated net revenues for a combustion turbine (peaker) unit.

It is interesting to note in these figures that while New York City is the constrained market, western New York has significant levels of capacity. It seems clear that rather than incentivizing the development of new generation in New York City, where it is needed most, the capacity market seems instead to be supporting natural gas plants in western New York, where they otherwise might not be profitable because of existing capacity surplus.

C. Midwest ISO: Heading in the Wrong Direction?

In June of 2009, MISO introduced a voluntary capacity market. This market accounts for only a small fraction of how capacity obligations are met, ranging from 0.1 to 1.2 percent of total designated capacity in 2009.[20] MISO has seen a number of utility control areas moving away from MISO regional dispatch to join PJM, and there are indications that this trend could continue.[21] One likely reason is that utilities with unregulated generation affiliates see better economic opportunities in RTOs/ISO that have capacity markets.[22] MISO's Supply Adequacy Working Group is in the process of developing a proposal for a three-year forward locational capacity market modeled on PJM's capacity market.

Coal makes up about half (52%) of MISO's capacity and approximately three-quarters (74%) of generation. Natural gas accounts for 28% of capacity, and nuclear accounts for 8%. Wind's share is growing, but currently makes up only 5.1% of capacity. In 2009, coal units were marginal 96% of the time,[23] significantly more than even PJM, where they are marginal 68% of the time.[24]

As the PJM example shows, the vast majority of the financial benefits of a mandatory, single clearing-price capacity market will accrue to existing generators. In the case of MISO, implementing an RPM-style capacity market would produce a vast annual windfall for owners of existing coal-fired power plants, even if capacity remains in surplus, and regardless of these plants' overall economic merit. MISO already has relatively low levels of retirements, with only 756 MW of generation having retired in 2010. A capacity market would work to bulk up revenues for existing generating units, likely driving economic retirements down even further, again without providing an adequate incentive for new, lower emission generation—and at a very high cost to ratepayers.

3. Improving capacity markets

As MISO moves forward with its plans for a forward capacity market, it is worth considering whether there are alternatives that would meet reliability needs and promote the development of cleaner, more efficient resources without producing windfalls for existing coal plants or other generation that, for environmental or economic reasons, should otherwise be retired.[25]

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[20] 2009 State of the Market Report for the Midwest ISO, pg 24, http://www.potomaceconomics.com/uploads/midwest_documents/2009_State_of_the_Market_Report.pdf

[21] First Energy became part of PJM in June 2011 (http://www.reuters.com/article/2011/06/01/utilities-pjm-firstenergy-idUSN0118668220110601). Duke Energy announced that it is leaving MISO and will join PJM in January 2012 (http://www.troutmansandersenergyreport.com/2010/10/ferc-approves-duke%E2%80%99s-initial-application-to-move-from-midwest-to-pjm/)

[22] "MISO explains real reason it believes IOUs are moving to PJM", Restructuring Today, July 28, 2010 http://www.restructuringtoday.com/public/11085print.cfm

[23] 2009 State of the Market Report for the Midwest ISO, pg 6.

[24] PJM 2010 State of the Market Report, pg 47

[25] The views discussed in this section are Synapse's, and do not necessarily reflect the views or recommendations of APPA.

Regulatory structure matters. Energy markets with reserve margin requirements (and no capacity markets) work better in vertically integrated environments. In a restructured market, where most utility LSEs do not own generation, some kind of forward-looking market may be more appropriate—so long as it is designed in a way that will procure needed capacity at reasonable cost to consumers.

PJM's forward capacity market has failed to attract significant levels of new generation in part because it does not offer developers a stable enough revenue stream over the long term. By guaranteeing capacity payments for only one year, RPM offers a new generator an extremely limited timeframe in which it will receive a stable revenue stream. Short-term contracts means higher long-term revenue risks, which in turn means generators will require higher payments. But there is no reason why a forward capacity market could not incorporate longer contract lengths.

The key to incentivizing development is to offer stable prices over an extended period of time. Perhaps the idea of a mandatory market for capacity is simply the wrong approach. The American Public Power Association (APPA), in its Competitive Market Plan, has recommended that RTOs "use a combination of resource adequacy requirements, a comprehensive transmission planning process, and long-term power supply and demand response arrangements" in order to meet reliability needs.[26] For new generators, long-term bilateral contracts (10 to 15 years) may be most appropriate, though APPA rightly notes that there is no need to mandate a specific contract length administratively.[27]

LSEs could meet their reliability needs through an RFP process, with generators and developers indicating what contract terms they would require to remain economically viable. Doing so would allow both LSEs and generation owners to take a portfolio approach to meeting capacity requirements—a flexible, stable, and economically efficient way of meeting reliability goals.

4. Conclusion

Capacity markets exist, ostensibly, to fill a gap that energy markets do not otherwise fill. In addition to ensuring that adequate resources are available to meet peak demand, capacity markets should provide signals to the market when and where new resources are needed or, conversely, when there is excess supply. They should provide a long-term revenue stream with sufficient certainty that supports the capital requirements for new, cleaner generation and demand resources.

In PJM, with its RPM capacity market, developers have increased the nameplate rating of existing generation and brought retired generation back onto the market, as well as developed some new generation and, in recent years, significant levels of demand response participation. RPM and other capacity markets have failed, however, to

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[26] "APPA's Competitive Market Plan, 2011 Update," June 2011, pg 42, www.publicpower.org/emri.cfm

[27] "APPA's Competitive Market Plan, 2011 Update," pg 21

provide an adequate incentive for the development of new, cleaner generation that meets the needs of consumers, especially in tightly constrained areas. These markets, and particularly RPM, have also operated at an extraordinarily high cost to consumers.

Existing PJM generators have received 95% of all RPM revenues, a third of which has gone to existing coal plants. When new generation has been developed, it has generally been in regions that already have a capacity surplus. Regions with tight reserve margins, like New Jersey, generally have high energy and capacity prices, but these "price signals" are clearly not enough to support new generation. Developers either cannot or will not respond to these short-term signals, instead accepting lower capacity payments in regions where the development costs are low.

Resource developers know that high capacity prices in places like New Jersey exist precisely because of the lack of supply. Developers, chiefly the incumbent generators that build generation in these regions run the risk of cutting the revenue stream out from under themselves, by driving local capacity (and energy) prices down. When states like New Jersey try to take direct action to build needed generation, this is exactly the dynamic they are addressing: it is against the self-interest of incumbent *and* new generation developers relying on (or profiting from) high capacity prices to add capacity to constrained, high-priced areas. The state is motivated by the interest of ratepayers to secure resource adequacy at reasonable cost by offering long-term capacity guarantees not available from the RTO-administered market.

Capacity markets need to do more than merely fill a revenue gap for incumbent generators. They need to provide true market signals and long-term support for the development of generation and demand resources in regions where demand is highest, at a reasonable cost to consumers. To do otherwise is to limit, significantly and unnecessarily, the economic and environmental benefit that ratepayers can and should receive in return for their investment. Consumers ultimately pay the price for ensuring resource adequacy, and they should not be held hostage to market designs that put incumbent generator interests before their own.