STATE OF NEW JERSEY
BEFORE THE
BOARD OF PUBLIC UTILITIES

In the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning	))	Docket No. EO11050309

JOINT COMMENTS OF THE PUBLIC POWER ASSOCIATION OF NEW JERSEY AND THE AMERICAN PUBLIC POWER ASSOCIATION

The Public Power Association of New Jersey ("PPANJ") and the American Public Power Association ("APPA") submit these joint comments in response to the questions posed by the New Jersey Board of Public Utilities ("BPU") in the Notice of a Public Meeting issued on May 27, 2011, in the above-noted docket.

Introduction

PPANJ and APPA commend the state of New Jersey and the BPU for implementation of the Long-Term Capacity Agreement Pilot Program ("LCAPP") and for initiating this investigation. We greatly appreciate the opportunity to provide these comments.

PPANJ. The PPANJ is a non-profit association of locally-owned and controlled electric systems comprised of the municipal electric utilities of the Boroughs of Butler, Lavallette, Madison, Milltown, Park Ridge, Pemberton, Seaside Heights, South River, the Vineland Municipal Electric Utility ("VMEU"), and Sussex Rural Electric Cooperative, Inc. Each of these utilities is transmission dependent. With a combined peak demand in excess of 300 megawatts, the members of the PPANJ take transmission services from investor-owned utilities that are members of PJM Interconnection, L.L.C. ("PJM") under the terms of the PJM Open Access Transmission Tariff ("OATT"). The PPANJ members were among the first to take advantage of open access to acquire wholesale power and energy at market-based rates upon enactment of the Energy Policy Act of 1992. The PPANJ municipal members conduct periodic competitive procurements consistent with New Jersey municipal procurement rules to acquire electric wholesale energy supply for their customers. Each of the municipal PPANJ members purchases electric capacity from the PJM capacity market at PJM established prices, including even Vineland which is the only PPANJ member that owns some generating facilities. Each of these entities operates independent from BPU oversight, with the exception of Butler, the only member that serves customers outside of its municipal boundaries. To enhance their ability to operate more effectively in the PJM markets, the PPANJ members have pending before the New Jersey

Assembly a bill to allow them to work together to purchase electricity and build generation to satisfy the needs of their customers. (Municipal Shared Services Energy Company Law, S. No. 2630, 214th Leg. (N.J. 2011).) If enacted, the pending legislation will create what 37 states already have, which is the right for municipal utilities and cooperatives in New Jersey to work together for purposes of electric procurement and generation construction.

APPA. APPA is the national service organization representing the interests of the approximately 2,000 not-for-profit, publicly-owned electric utilities throughout the United States that collectively serve more than 45 million consumers. Public power systems provide over 15 percent of all kilowatt-hour (kWh) sales to ultimate customers, and provide service in every state except Hawaii. APPA member utilities are owned by the communities they serve, operate on a not-for-profit basis, and have retained the legal obligation to provide retail electric service to their customers. Since they are owned by the customers they serve and have no outside shareholders, all costs are passed through directly to the customer. Public power systems own approximately 10 percent of the nation's electric generating capacity, but purchase nearly 70 percent of the power used to serve their ultimate consumers from the wholesale market. APPA's members therefore have an abiding interest in well-functioning wholesale power-supply markets and in the adequacy of supply to meet future load.

In response to growing problems that public power utilities were experiencing obtaining power supplies in RTO regions with centralized, RTO-run power supply markets, APPA launched its Electric Market Reform Initiative ("EMRI") in March 2006 to investigate restructured wholesale electricity markets and develop needed reforms to those markets.

Under this initiative, APPA commissioned a series of studies investigating the restructured RTO-run wholesale markets under federal jurisdiction.[1] Based on the results of these studies, APPA concluded that RTO-run centralized wholesale markets had substantial problems, and were not yielding "just and reasonable rates," as the Federal Power Act (FPA)[2] requires. APPA therefore embarked on the development of potential reforms to these markets, an effort which culminated in the release of APPA's Competitive Market Plan (CMP or the Plan). The CMP was initially released in February 2009, and an updated version was just issued this week.[3]

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1 The results of these studies are available on the EMRI section of APPA's Web site at: www.APPAnet.org/emri.cfm

2 FPA Sections 205 and 206, 16 U.S.C. §§ 824d, 824e.

3 APPA's Competitive Market Plan: A Roadmap for Reforming Wholesale Electricity Markets, 2011 Update, http://www.publicpower.org/files/PDFs/2011CompetitiveMarketPlanUpdate.pdf

The steps taken by New Jersey in the LCAPP are similar to recommendations that APPA makes in its Competitive Market Plan, discussed below. APPA and PPANJ endorse the efforts of New Jersey to establish reforms such as LCAPP which are designed to increase reliability while decreasing consumer costs and to do so in an environmentally responsible manner.

The goal of the reforms presented in the Plan is to achieve just and reasonable rates for consumers, reduce opportunities for the exercise of market power, and meet future load in a reliable manner. A central goal of the CMP is for longer-term bilateral agreements and resource ownership to become the primary methods of obtaining generation and demand-side resources, along with an eventual phase-out of mandatory centralized capacity markets. PPANJ and APPA support a combination of resource adequacy requirements, a comprehensive transmission planning process, and long-term power supply and demand response arrangements as a far superior alternative to the mandatory capacity market. If desired by the stakeholders in a particular RTO region, a voluntary residual capacity market could also be included in the array of options for those LSEs finding themselves short of capacity in the nearer term.

A key component of accomplishing the transition to bilateral contracting-centered market is the Plan's recommendation that "state public service commissions establish competitive resource procurement processes to develop diversified resource portfolios for incumbent IOU LSEs that no longer have the obligation to serve customers, with a significant portion of their power supplies being obtained under longer-term contracts or owned-generation arrangements. These measures could provide much needed price discipline in RTO-run centralized markets, as well as a steady revenue stream to support construction of new generation resources and investment in demand response technologies." Plan at 16. The steps that New Jersey has taken through the LCAPP program mirror these recommendations made by APPA in the original plan and reiterated in the updated version. We therefore commend both the state legislature and BPU for taking these steps.

The remainder of these comments will focus on the issues raised in the BPU's May 27 Notice. PPANJ and APPA are not in these comments responding to the questions pertaining to specific state-level resource needs. Instead, these comments provide a broader perspective and cover our assessment of the efficacy of the PJM Interconnection LLC's (PJM) mandatory locational capacity market, the Reliability Pricing Model (RPM), barriers to new capacity within the current market structure, major challenges for reliability, and recommendations for market reforms. The comments reflect both PPANJ's own experience with PJM and its RPM, and APPA's knowledge gained in the EMRI studies, feedback from members, and development of the CMP.

Failure of the Reliability Pricing Model (RPM)

Basic data on the RPM auctions to date demonstrate the ineffectiveness of this market in achieving the goal of developing new resources where they are most needed. According to PJM data,[4] total additions to generation capacity through the first eight auctions are 13,165 MW, of which 540 MW were reactivations and 5,149 were uprates to existing units. In addition, there has been a decrease in 8,735 MW resulting from deratings. The net result is an increase of only 4,430 MW of new generation. The total spent on all eight auctions has been $49 billion, for a total procurement of just over a million MW of generation, or an average of 133,000 MW per year. The net new generation therefore represents less than one percent of the eight year sum and just 3 percent of the annual average.[5] The $49 billion spent is equal to an average of $11 million per MW of net new generation (note that this also includes payments for demand response and existing generation, significantly lower cost resources). In the NJ LCAPP program, the estimated gross present value cost is roughly $1.5 billion for just under 2,000 MW of new capacity, or about $770,000 per MW.[6] This is close to Energy Information Administration capital cost estimates for new natural gas generating plants, which range from $665,000 to $1 million per MW.[7]

A new study by Synapse Energy Economics (attached as Appendix A) (Synapse Study) found that almost none of these few new resources have been in capacity-constrained areas, leading Synapse to conclude that "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." Synapse Study at 4. A similar lack of success of locational energy pricing as incentive for the development of new resources was found in a 2007 Synapse study of locational marginal pricing.[8] The continued reliance on locational pricing in the

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4 Data is from PJM 2014/15 Base Residual Auction Report, Tables 5, 6, and 8, http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx

5 This is equal to the 4,430 MW as a percentage of the 1.058 million MW of total generation procured in all eight auctions (0.4 percent) and 4,430 MW as a percentage of the average of 133,000 MW (3 percent.)

6 LCAPP Agent's Report, Prepared for the New Jersey Board of Public Utilities, Levitan and Associates, Inc., March 21, 2011, Figure 13, p.69, http://www.nj-lcapp.com/Documents/LCAPP_Agent_Report.pdf

7 Updated Capital Cost Estimates for Electricity Generation Plants, Table 1, Energy Information Administration, U.S. Department of Energy, November, 2010, http://www.eia.gov/oiaf/beck_plantcosts/index.html

8 *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers* by Ezra Hausman, Robert Fagan, David White, Kenji Takahashi, and Alice Napoleon, Synapse Energy Economics, February 2007, http://appanet.cms-plus.com/files/PDFs/SynapseLMPElectricityMarkets013107.pdf In this study, Synapse found that the areas where LMP prices are the highest, and thus transmission facilities are the most congested,

design of RPM represents a continued misunderstanding of the "on the ground" dynamics of the market and the practical decision-making of incumbent generation owners and new generation developers. Simply put, incumbent owners of existing generation face a financial disincentive to build substantial new generation in constrained areas, as this would reduce their profits. RPM has also become an increasingly important source of profits for the incumbent owners of unregulated generation, who often earn returns on equity exceeding 20 percent.[9] New generation developers, on the other hand, would like to enter the market, but cannot do so without obtaining the needed financing, as discussed further below.

The most recent evidence of the failure of the PJM capacity market to incent new generation in the constrained PSE&G Zone is the request by PJM that PSE&G keep Hudson Unit 1 operational for reliability reasons, together with PSE&G's request for $59 million in "Reliability Must Run" ("RMR") payments to keep the unit operational. [10] Obviously, if the PJM capacity market was working, such an out-of-market "fix" would not be necessary to maintain system reliability. These RMR payments are borne by the customers that would otherwise suffer reliability problems, which means that customers such as the PPANJ Members and New Jersey citizens will be expected to pay for ***both*** RMR payments ***and*** RPM capacity payments to keep Hudson Unit 1 running.

The ineffectiveness of the capacity market in PJM to incent needed new generation is paradoxically imposing rising burdens on consumers. Although capacity costs accounted for about 5.6% of the total wholesale price of electricity on an annual basis in 2007, these costs represented 18.1% of the total wholesale price in 2010.[11] The rising costs stem in part from PJM's over-procurement of capacity as a result of being unwilling and/or unable to adjust the load forecast to reflect the effects of the recession in advance of the auction. We are pleased to report that a PPANJ-lead stakeholder effort prompted PJM to review its Load Forecast Methodology and improvements are expected to be adopted this summer. We are hopeful that the improvements will result in a more accurate forecast going forward. The huge increase in the PJM "Zonal RPM Scaling Factor", which rose from the range of 4% to 5% in 2007/08 to the range of 9% to 13% in 2013/14, is due to the need to spread the acquisition of capacity over

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do not correspond with the areas where the greatest investments in new generation and transmission have been made.

9 See *Financial Performance of Owners of Unregulated Generation in PJM: 2010 Update*, http://www.publicpower.org/files/PDFs/FinancialPerformance2010UpdateMay2011.pdf

10 *PSEG Energy Resources & Trade LLC; PSEG Fossil LLC,* FERC Docket Nos. ER05-644 and ER11-2668, filing dated June 3, 2011

11 PJM 2010 State of the Market Report, Volume 2 ("Detailed Analysis"), Table 1-9, page 22, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010/2010-som-pjm-volume2-sec1.pdf

fewer MW. So, even as RPM customers are suffering with high priced capacity and they are forced to buy more of it.

Barriers to New Capacity

The shorter-term and volatile capacity market prices produced by RPM through the annual auctions benefit primarily older, largely-depreciated generation units, which follows logically from the premise (ignored by RPM) that long-term contracts are a fundamental prerequisite for financing new generation. In comments submitted by Competitive Power Ventures (CPV) to the Maryland Public Service Commission, CPV attached several letters from financial institutions asserting that long-term contracts are critical for obtaining financing for new generation projects. For example, the Bank of Tokyo-Mitsubishi wrote that it "favor[s] the projects which operate in markets with transparent and stable regulatory regimes and projects which benefit from long-term fixed-price power purchase agreements with investment grade counterparties." [12] Similarly, UnionBank stated that "the prevailing market dynamic in PJM alone, without the ability to secure long-term off-take contracts, is not supportive of project-based financing…Moreover, given our extensive history as a market leader in the project finance sector within North America, we are confident that other lenders share our view on this matter."[13]

Not only do the failures of RPM create barriers to a reliable and cleaner power supply, but the nature of RPM and the recent Minimum Offer Price Rule (MOPR) revisions also impede competition in the market. Because long-term contracts, such as those provided for in the NJ LCAPP, are a means for new generation to enter the market, and such entry is a fundamental requirement of successful competition, the absence of such contracts is a barrier to competition in the RTO markets. The heavy influence that the existing generation owners have on the governance process within PJM and in turn, their influence on market rules, further exacerbates the non-competitive nature of these markets. Indeed, when PPANJ members requested specific exemption from the Minimum Offer Price Rule due to their small size and relatively low market impact, FERC adopted the argument put forward by the P3 companies who asserted that even a 3% change in capacity offer prices may have a significant impact upon capacity market prices. At 300 MW, not only does PPANJ not even come close to 3% of the PJM market, but is not even

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12 Comments of CPV Maryland, LLC, *In the Matter of the Reliability Pricing Model And the 2013/2014 Delivery Base Year Residual Auction Results*, Maryland Public Service Commission, Administrative Docket PC22, October 1, 2010, Attachment B, http://webapp.psc.state.md.us/Intranet/AdminDocket/NewIndex3_VOpenFile.cfm?ServerFilePath=C%3A%5CAdminDocket%5CPublicConferences%5CPC22%5C35%2Epdf

13 Comments of CPV Maryland, LLC, Attachment D

3% of the New Jersey market. And yet, the P3 companies seek to thwart PPANJ Members from self supplying load with owned generation.[14]

Another barrier to the development of new capacity is that current RTO transmission planning processes lack a clear linkage between LSEs' long-term resource commitments and long-term transmission availability. To foster the development of long-term contracts, APPA proposes that long-term transmission rights (LTTRs) should be allocated to LSEs to support bilateral power supply contracts or owned generation resources, with a priority for power supply arrangements of 10 years or longer. APPA believes that if properly done, regional transmission planning could support allocations of LTTRs to support LSE resource plans. Such resource plans would inevitably reflect applicable state resource procurement policies (such as renewable portfolio standards). Therefore, transmission facilities that are in fact needed to support LSE-selected generation resources will be necessarily included in RTO's regional transmission plans, presuming those plans are based upon the resource plans of LSEs in the region. Reductions in reliance on transmission facilities due to increased use of local generation, demand response, energy efficiency and distributed generation would likewise be taken into account.

Challenges for Future Reliability

The Environmental Protection Agency ("EPA") is currently conducting a series of rulemakings to regulate emissions of greenhouse gases from large stationary sources, including power plants. In addition, the EPA is in the middle of a substantial number of other rulemakings, dealing with coal ash, mercury, and other hazardous air pollutants, criteria pollutants (smog), water use in once-through cooling systems, and a number of other items.

As these various rules go into effect, their cumulative effect will likely make it uneconomic for generators to continue to operate a substantial number of existing coal-fired power plants. Estimates of coal plant closures nationwide range from 30 to 70 gigawatts (GW) of coal generation within the next ten years, with most estimates trending towards the higher end of this range.[15] A substantial portion of that retiring capacity will have to be replaced, mostly with

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[14] "We reject Public Power-NJ's argument that municipal utilities and cooperatives should be granted a targeted exemption for self-supply, given the limited scope of their operations. We also reject Public Power-NJ's alternative argument, basing an exemption for municipal utilities and cooperatives with sales less than 4 million MW/h per year. Both arguments ignore the fact that the sloped demand curve used in PJM's base residual auctions is very steep, and as a result, even small amount of additional supply can result in large price reductions. As P3 observes, a three percent increase in supply will decrease capacity prices by 60 percent.[99]" Footnote 99 reads "*See* P3's March 18, 2011 Answer at 15." *PJM Interconnection LLC; PJM Power Providers Group v. PJM Interconnection LLC*,134 FERC ¶61,022 (April 12, 2011) at Par. 196.

[15] Studies of projected coal plant closures have been undertaken by: The North American Electric Reliability Corporation (10 - 35 GW of coal and 40 - 70 GW of all capacity by 2018), *2010 Special Reliability Scenario*

natural-gas-fired units. And coal-fired power plants constitute a substantial portion of the generation fleet in PJM, comprising 41 percent of capacity and 49 percent of energy output as of the end of 2010.[16] Estimates of coal plant closures in PJM range from 12 to 25 GW, equal to about 20 to 30 percent of the coal capacity in PJM.[17] Moreover, Exelon announced that the Oyster Creek nuclear power plant will be retired in 2019, equal to 645 MW of capacity, partly due to the expected capital costs of compliance with cooling water regulations.[18] Synapse found that the current RTO locational capacity markets "may actually prevent the construction of newer, more efficient, and cleaner generating stock to replace aging and higher emission resources." Synapse at 1.

Unlike generation owned by a vertically- integrated, rate-regulated utility, the future earnings of merchant generation owners would be higher for their remaining existing plants if a portion of generation is shut down and the supply of power becomes constrained.[19] Several financial analysts point to greatly increased earnings for merchant generators from the closure of coal plants.[20] PPL Corporation actually lists pending coal plant closures as one of the "catalysts for growth" in its earnings in a February 2011 presentation to financial analysts.[21]

Assessment, October, 2010, Table IV-6, http://www.nerc.com/files/EPA_Scenario_Final.pdf; Credit Suisse Equity Research (60 GW of coal capacity between 2013 and 2017), *Growth From Subtraction: Impact of EPA Rules on Power Markets*, September 23, 2010, http://op.bna.com/env.nsf/id/jstn-8actja/$File/suisse.pdf; The Brattle Group (50 – 66 GW of coal capacity by 2020), *Potential Coal Plant Retirements Under Emerging Environmental Regulations*, December 8, 2010, http://www.brattle.com/_documents/UploadLibrary/Upload898.pdf, and FBR Capital (30 – 70 GW in the next few years), *EPA regs may shut 70,000 MW of U.S. coal plants: FBR,* Reuters, December 13, 2010 http://www.reuters.com/article/2010/12/13/us-utilities-epa-coal-idUSTRE6BC3JN20101213; BernsteinResearch (54 GW resulting just from the MACT rule), *Surviving the Train Wreck: The Impact of EPA's Mercury & Air Toxics Standards*, May 17, 2011, http://www.eei.org/meetings/Meeting%20Documents/2011May17EPARegulationWynne.pdf

16 2010 Year End Review, Monitoring Analytics LLC, May 17, 2011, p. 17, http://www.monitoringanalytics.com/reports/Presentations/2011/IMM_AM_2010_Year_in_Review_20110517.pdf

17 Credit Suisse (25 GW in PJM out of a total 60 GW nationwide), Brattle Group (12 to 19 GW in PJM, all of which is merchant, out of a total 50 to 66 GW), and BernsteinResearch (13 GW, out of a total of 54 GW).

18 Exelon to Retire Oyster Creek Generating Station in 2019, December 8, 2010, http://www.exeloncorp.com/newsroom/pr_20101208_Nuclear_OysterCreekRetirement.aspx

19 For a detailed discussion of the greater adverse impact on reliability and prices in RTO regions resulting from EPA regulations, see Issue Brief: Why New CO2 Regulations Could Produce Windfall Profits and Unproductive Costs for Consumers, American Public Power Association, March 2011, http://www.publicpower.org/files/PDFs/IssueBriefWindfallProfitsandEPARegsMarch2011.pdf

20 Credit Suisse projects that the market value of Allegheny, Exelon, and FirstEnergy would all increase between 20 and 25 percent, and their earnings would increase by almost 40 percent by 2015 under a 60 gigawatt (GW) coal plant retirement scenario. Credit Suisse, Exhibit 106, p. 53 and Exhibit 111, 55. An analyst from Sanford C. Bernstein stated that earnings could increase by 15 to 30 percent in the RTO markets as a result of the coal

One likely scenario is for merchant generators to strategically close the plants that are the most costly to retrofit while allowing their remaining plants, especially nuclear and lower emission coal plants, to benefit from the resulting higher prices.[22] Several recent analyses have found that the closure of coal plants is in fact likely to be greater for merchant units. The Brattle Group found that most of the coal plants likely to retire will be merchant units, accounting for 64 to 76 percent of merchant coal capacity, compared to 1 to 4 percent of regulated coal, whose regulated owners would be much more likely to retrofit the plants.[23]

Given these financial incentives for owners of existing merchant generation to constrain the capacity supply, there will be a strong interest in maintaining a capacity market that supports the *status quo* by foreclosing new entrants, as evidenced by the PJM generators' recent successful efforts to revise the MOPR tariff.

Recommendations

The RTO states, especially those with restructured retail markets and without vertically integrated utilities, are likely to be the main laboratory for the development of market reforms. APPA realized this potential in the CMP where it recommended that state regulatory agencies become the primary means to spur the development of a bilateral contracting market. The CMP also recommends that the RTOs establish resource adequacy standards applicable to all LSEs, and multi-state regional processes to develop needed RTO-wide resource adequacy requirements under agreed-upon policy goals. States would then implement procurement processes to ensure that state-regulated IOU LSEs obtain a diversified portfolio of power supply and demand-side resources of varying lengths and terms that will assist in meeting the RTO-wide resource

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plant closures, and that the greatest beneficiaries of these increased earnings would be Constellation, Exelon, PSEG, PPL, Calpine, Dynegy, GenON, and FirstEnergy. Bernstein Research, May 17, 2011, p. 33.

21 PPL Corporation, Credit Suisse Global Energy Summit, February 8-11, 2011, Slide 12, http://files.shareholder.com/downloads/PPL/1184323975x0x439853/e3b801ef-3a55-42c8-9c6f-52bce977d833/PPL_IP_2.8.11.pdf

22 For example, Credit Suisse notes that "the retrofit / closure decision will not occur in a vacuum such that plants 'on the bubble' for investment could be attractively economic as other plants are pulled from the market." Credit Suisse Equity Research, p. 36. Similarly, Fitch Ratings concluded that: "Merchant generation that does not rely on coal (or coal-fired generation that is already highly controlled) could increase its profitability if a significant portion of coal-fired generation in the same region is retired and heat rates rise in the region due to stringent enforcement of new EPA rules." Time to Retire? US Coal Plants in Environmental Crosshairs, FitchRatings, February 2011, p. 2 http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=604365

23 The Brattle Group, p. 6

adequacy requirements.[24] States and LSEs could also agree to pool their LSEs' respective resource needs for procurement purposes, rather than having each individual state or LSE act on its own. Sufficient safeguards would also need to be included in the selection process to ensure that third-party generation and demand-side suppliers get fair and equitable consideration of their offers and proposed projects.[25]

PPANJ's and APPA's recommendation to the BPU is that it continue on its current course in the pursuit of longer-term contracting and greater state control of resources. Along with these state-level regulatory efforts, PPANJ and APPA recommend that the BPU maintain its active voice in current and future FERC and court proceedings to actively challenge FERC's apparent assumption that PJM markets are working. If you are not already doing so, we urge you to collaborate with other similarly situated public service commissions in Maryland and Delaware, for example, to present a coordinated chorus of concerned regulators to FERC demanding change. We strongly suggest that you begin attending PJM stakeholder meetings for the purpose of making your views known before the votes are cast. Finally, as this is an issue of national as well as regional concern, we suggest the state communicate its continuing concerns with the adverse impact of PJM's markets on the citizens of New Jersey directly to state and federal policy makers and legislators.

Based on our experience with these issues since APPA initiated its EMRI five years ago, it will take such a concerted effort to effect positive changes regarding RTO market issues.

Respectfully submitted,

PUBLIC POWER ASSOCIATION OF NEW JERSEY
By /s/ James Jablonski __________

James Jablonski, Executive Director
Public Power Association of New Jersey

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24 Public power and cooperative utilities in RTO regions, because they have retained their obligation to serve retail customers, already develop and implement such resource adequacy plans, under the supervision of their local governing bodies. They conduct periodic generation procurements, assessing "buy v. build" generation options, as well as the use of demand response and energy efficiency measures to reduce demand, in lieu of securing additional generation. Because they are not-for-profit and do not earn a return on owned generation assets as investor-owned utilities do, they approach these decisions from a consumer-benefit perspective. For these reasons, public power utilities should continue to procure their resources under their own plans, unless they choose to opt into a larger state procurement process.

25 State competitive procurement "best practices" are discussed at length in a 2008 paper prepared for the Collaborative on Competitive Procurements between FERC and the National Association of Regulatory Utility Commissioners (NARUC). Susan Tierney and Todd Schatzki, Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices, July 2008, http://www.naruc.org/Publications/NARUC%20Competitive%20Procurement%20Final.pdf

PO Box 206, 420 Boardwalk
Seaside Heights, NJ 08751
(732) 793-4060
Fax: (732) 793-4062
Email: ppanj@tellurian.com

AMERICAN PUBLIC POWER ASSOCIATION
By /s/ Elise Caplan __________

Elise Caplan , EMRI Coordinator
American Public Power Association
1875 Connecticut Avenue, N.W., Suite 1200
Washington, D.C. 20009-5715
(202) 467-2974
Fax: (202) 467-2918
Email: ecaplan@publicpower.org

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APPENDIX A

Incenting the Old, Preventing the New: Flaws in Capacity Market Design, and Recommendations for Improvement

By Synapse Energy Economics

Incenting the Old, Preventing the New

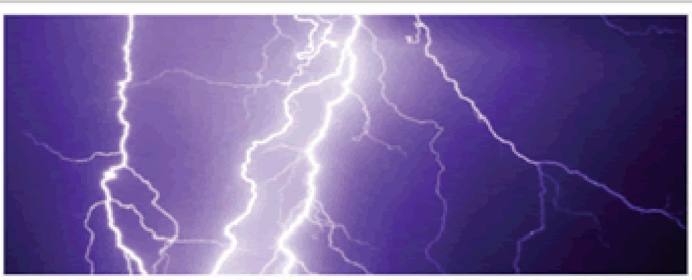
Flows in Capacity Market Design, and Recommendations for Improvement

June 14, 2011

AUTHORS

Matthew Wittenstein

Ezra Hausman



485 Massachusetts Ave.
Suite 2
Cambridge, MA 02139

617.661.3248
www.synapse-energy.com

Table of Contents

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.[26] 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.

[26] "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 21 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.[27] 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.[28] 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).[29] 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.

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

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

[29] 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.[30] 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.[31] 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

[30] 2014/2015 RPM Base Residual Auction Results, Table 9.

[31] 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.[32]

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.

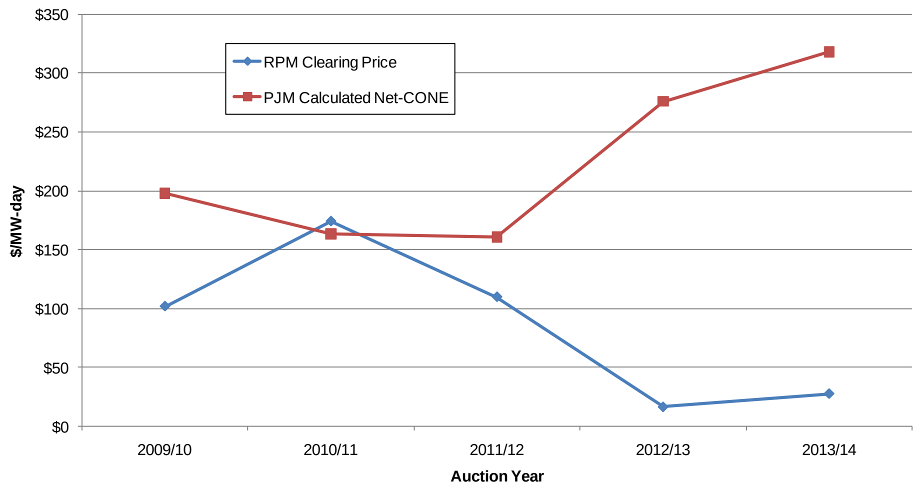


Figure 1. RPM auction RTO area clearing prices and PJM RTO net CONE

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.[33] (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;

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

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

however, these payments can represent most of the net revenues for a typical combustion turbine.

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.[34] 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).[35]

	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**

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

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

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 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).[36]

	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.[37] 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).

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

[37] 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.

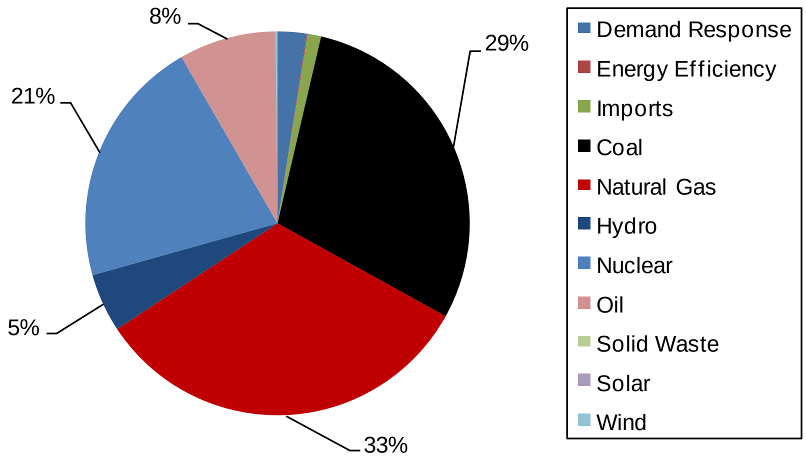

Figure 2. RPM revenues by generator type as portion of total.

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.

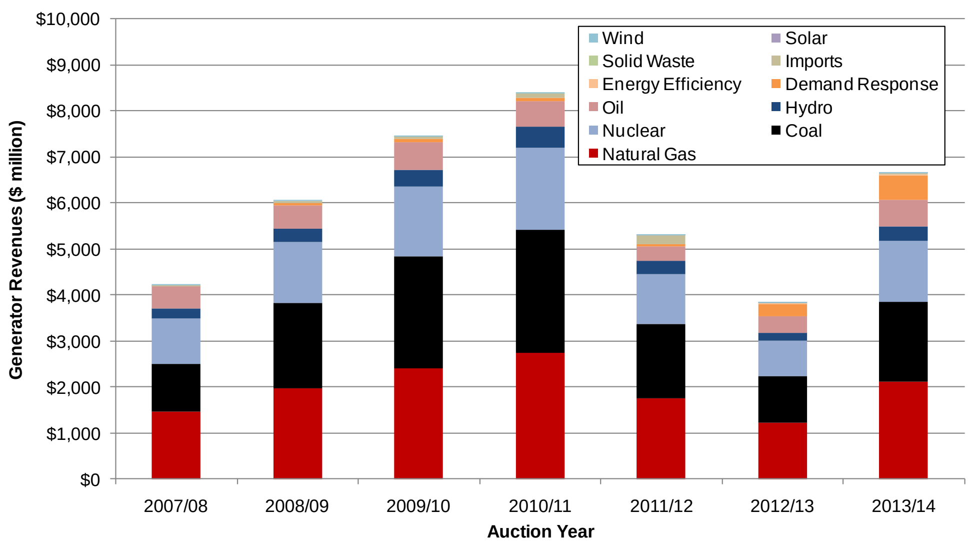

Figure 3. RPM revenues by generator type.

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.[38]

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.[39] 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.[40] Going forward, new EPA regulations are widely expected to make even more coal plants uneconomic in throughout the United States.[41] 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.[42] 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

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

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

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

[41] 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.

[42] 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).

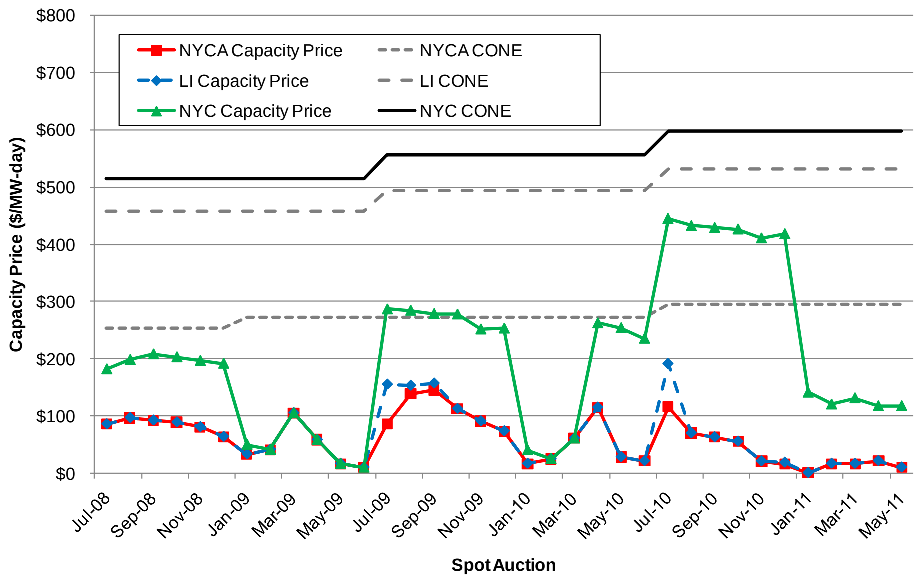

Figure 4. NYISO capacity prices by region.

The capacity market makes up a relatively small portion of the average all-in price for electricity.[43] This is illustrated in the New York market monitor's estimated composition of regional all-in prices, reproduced in Figure 5.[44]

[43] 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.

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

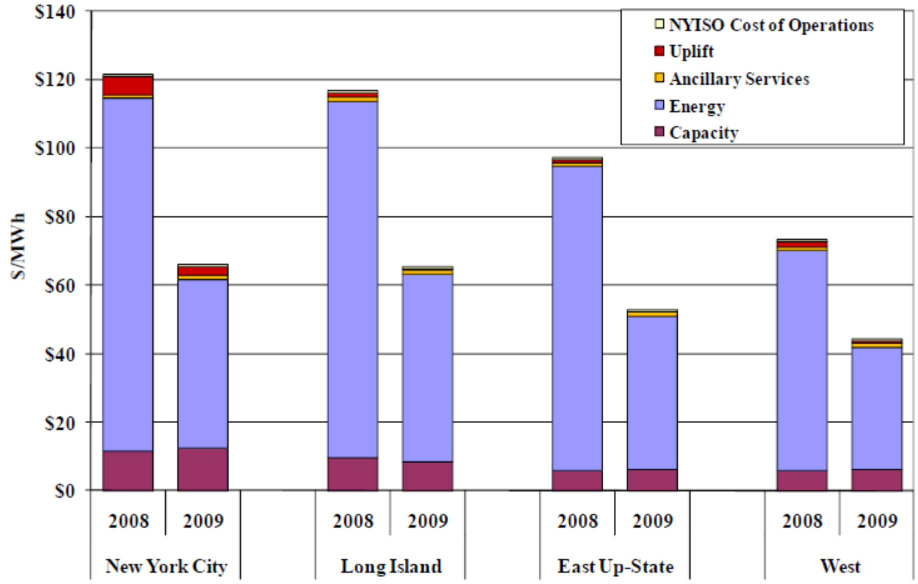

Figure 5. New York all-in electricity prices by region. Reproduced from the New York ISO 2009 State of the Market Report, Figure 4

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).

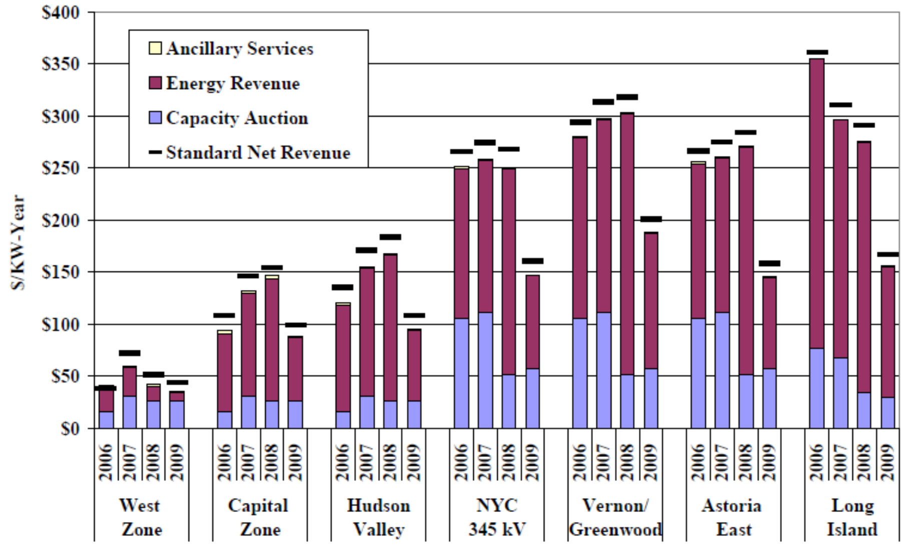

Figure 6. Estimated net revenues for a combined cycle unit.

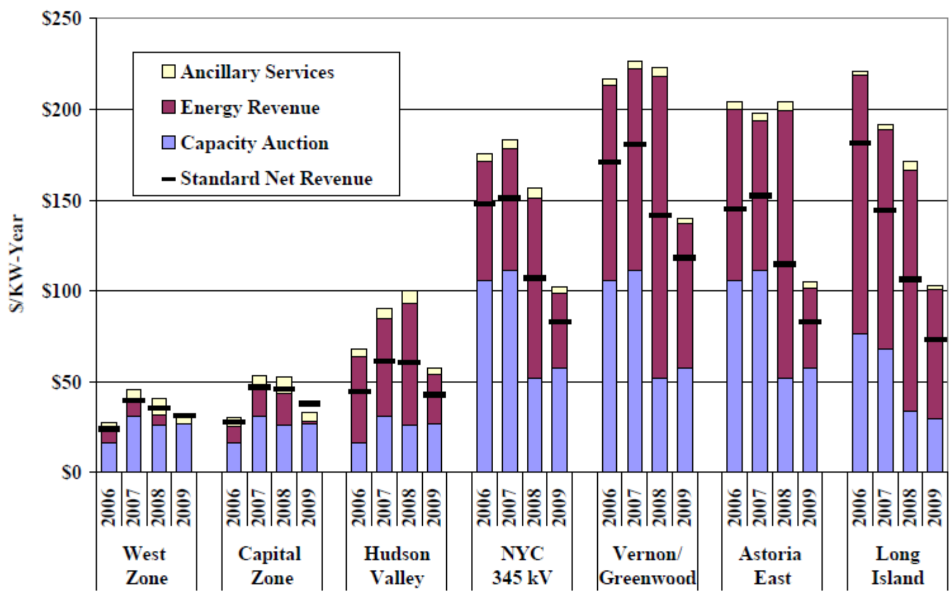

Figure 7. Estimated net revenues for a combustion turbine (peaker) unit.

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.[45] 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.[46] One likely reason is that utilities with unregulated generation affiliates see better economic opportunities in RTOs/ISO that have capacity markets.[47] 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,[48] significantly more than even PJM, where they are marginal 68% of the time.[49]

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.[50]

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[45] 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

[46] 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/)

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

[48] 2009 State of the Market Report for the Midwest ISO, pg 6.

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

[50] 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.[51] 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.[52]

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

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

[52] 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.