RPM 2006: Windfall Profits for Existing Base Load Units in PJM

An Update of Two Case Studies

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I. Executive summary

In 2005, Synapse Energy Economics produced two reports[1] on the anticipated impact of a proposal by PJM Interconnection, L.L.C. (PJM)[2] to introduce a structure referred to as the Reliability Pricing Model (RPM) for compensating resources for their capacity product. For the first report, we reviewed expected capacity revenues for four base load generating units in Pennsylvania; the second calculated these revenues for six base load nuclear facilities owned by Exelon in Illinois. In both cases, we documented how the RPM approach to securing new capacity investments would in fact produce considerable transfers of wealth from consumers to owners of existing, amortized, profitable, base load generation. We went on to question what consumers were likely to get in return for these generous payments.

This report is an updated look at the RPM proposal based on PJM's August recent filing with FERC.[3] PJM's filing included a revised Variable Resource Requirement (VRR) curve, detailed calculations of the cost of new entry (CONE), and expected Energy and Ancillary Service (E&AS) revenues. PJM also provided updated simulation results projecting RPM capacity prices throughout the system through 2010[4], and we investigate what these projections imply for generator capacity revenues during this period.

We find that the revisions to the VRR curve, CONE, and E&AS estimates do not affect our conclusions from the earlier studies: RPM represents a major windfall for owners of base load generation at the expense of consumers. The revisions have only a minor impact on the target long-term average and maximum capacity prices under RPM, so they have only a minor impact on expected generator capacity revenues at equilibrium or under conditions of shortfall. Compared to recent capacity prices in PJM, RPM as filed would mean an additional $590 million annually in payments to the owners of the base load generating plants we have studied in Illinois and Pennsylvania (a total of approximately 17,000 megawatts). On a system-wide basis, the additional payments would amount to over $5.5 billion annually based on peak

[1] The two reports are: "Capacity Revenues for Existing, Base Load Generation in the PJM Interconnection" (June, 2005) and "RPM Case Study: Higher Costs for Consumers, Windfall Profits for Exelon" (October, 2005). Both reports are available on Synapse's website, www.synapse-energy.com.

[2] PJM is the Regional Transmission Organization (RTO) that runs the transmission grid serving 45 million people across parts of 13 states stretching from the east coast to Chicago. In addition to being responsible for regional reliability and the determination of which power plants run at any given time, PJM operates the wholesale electricity markets. PJM is governed by a board of directors operating with the advice of its staff and 350 stakeholder PJM members (including Pennsylvania Office of Consumer Advocate and the Citizens Utility Board)

[3] Docket Nos. ER05-1410-000 and EL05-148-000.

[4] Reliability Pricing Model Updated Prototype Simulation, January 6, 2006, at http://www.pjm.com/committees/working-groups/pjmramwg/downloads/updated-rpm-prototype-simulations.pdf

load projections for 2012. It is not clear what consumers would get in return for these additional payments.

PJM's revised simulation results do show some significant differences from the earlier values in terms of near-term RPM payments. It is not clear to us where these differences come from or how meaningful they are. This is because the RPM mechanism is designed to achieve a target capacity price as a long-term average, and this target has not changed significantly with PJM's revised curve.

We further investigate the model underlying the CONE and E&AS estimates, taking advantage of the additional detail that PJM has provided with their filing. We find the justification for these numbers deficient in that PJM has not provided testimony that explores the range of values for their calculations of these fundamental, but clearly uncertain, numbers. We show that small, but reasonable, variations in the underlying parameters would translate into significant amounts per year in costs or savings to consumers. Given this profound impact of various administrative modeling decisions, we question the wisdom of proposing an RPM price-setting mechanism that rests on such an arbitrary and uncertain foundation.

Finally, we point out that at least two assumptions underlying the CONE calculation, which significantly increase costs to consumers, are inconsistent with market realities. PJM's testimony in the RPM docket on the capital costs for peaking units presumes that such units would incorporate both SCR emissions control technology and dual-fuel capability, neither of which has been implemented in any recent peaking plants in PJM. Because of the low capacity factor of these resources, these costs are clearly not justified. The inclusion of these technologies on the hypothetical units would cost consumers hundreds of millions of dollars per year, including $100 million in extra payments to Exelon for its Illinois nuclear units, and $75 million for the owners of the base load plants we have studied in Pennsylvania.

As in our earlier reports, we find that RPM is an inefficient and arbitrary price-setting scheme that will lead to windfall profits for generators, much higher costs for consumers, and no guarantee of increased reliability.

II. Introduction

In 2005, Synapse Energy Economics produced two reports on the anticipated impact of a proposal by PJM Interconnection, L.L.C. (PJM) to introduce a structure referred to as the Reliability Pricing Model (RPM) for compensating resources for their capacity product. RPM is a non-market, locational construct that is proposed to replace the current bid-based, pool-wide capacity market. The justification is that current capacity prices are neither location specific, nor sufficiently high, to induce new entrants to build capacity where it is needed in PJM. Many PJM stakeholders have maintained that while the new construct would indeed compensate generators at a higher rate (at substantial cost to ratepayers) it is not clear that this would induce greater investment. We have found that existing generators would be by far the greatest beneficiaries under RPM, and that they would have both the incentive and the means to ensure that capacity shortages and high capacity prices were the norm.

The first of our earlier reports was prepared for the Pennsylvania Office of Consumer Advocate and published in June 2005. The second was prepared for the Citizens Utility Board in Illinois and published in October 2005. Both of those reports showed that PJM's RPM proposal would provide hundreds of millions of dollars annually in additional capacity compensation for base load generation, despite the facts that these existing resources have already been largely depreciated at consumers' expense, that they are profitable in the energy market, and that the goal of RPM is supposed to be adequately compensation for *new* resources. We found that there is neither requirement nor incentive for any sort of performance for existing units to earn these revenues.

This report updates the prior reports to reflect changes to the RPM proposal that the earlier reports had relied upon, and that are reflected in PJM's FERC filing of August 31, 2005.[5] We have also updated our analysis to reflect PJM's market simulation analysis of January, 2006.[6] We use this updated information to recalculate near term capacity revenues that might be expected for the base load units in Illinois and Pennsylvania examined in our earlier reports.

In addition, we explore the implications of uncertainty in the calculations of the cost of new entry (CONE) and Energy and Ancillary Service revenues (E&AS) that are so central to the setting of the capacity price under RPM. Finally, we explore some of the specific assumptions underlying the calculation of CONE, and show that they are at best arbitrary and at worst a miscalculation of actual new entry costs. Because the capacity price under RPM is set based on this administrative calculation, it is important to recognize the uncertainties and unexplained judgments built into this formula.

PJM's staff developed the RPM proposal due to concerns that the current prices in its wholesale markets are insufficient to promote the construction of new generation capacity in specific areas, and the belief that a threat to reliability may be looming behind the current surplus in capacity in the region as a whole. Thus the goal of RPM is to apply an administrative process to produce a price for capacity which is more stable, locational, and much higher than the price which the current market would produce. This price would then be paid—on a per-MW capacity basis—to all generating resources in the affected area. Because most resources in all parts of PJM are already in place and already profitable, most of these administrative payments would be made to generators which have no need for these revenues to satisfy their capital requirement.

PJM asserts that putting these payments in place would provide sufficient incentive for new generation investments in areas where they are needed, and support some

[5] Docket Nos. ER05-1410-000 and EL05-148-000.

[6] http://www.pjm.com/committees/working-groups/pjmramwg/downloads/updated-rpm-prototype-simulations.pdf

existing needed generation that is not profitable today. Whether or not RPM can achieve these goals, RPM would unquestionably produce higher electricity prices for consumers, windfall profits to existing generation owners, and a strong, perverse incentive for these owners to make sure that capacity remains in short supply.

III. Background

The Pennsylvania OCA Report evaluated four base load generation facilities in two local areas: the PSEG service territory near Philadelphia and the PPL service territory to the south and west of Philadelphia. Table 1 identifies the four facilities, their capacities in megawatts, and their overall capacity factors for the period 2002 through 2004.

Table 1: Operating characteristics of the four generating facilities in Pennsylvania.

Summary Facility Characteristics					
Station	Units	Summer Capacity	Type	Fuel	2002-04 CapFac
Eddystone	1&2	581	ST	Coal	50.0%
Eddystone	3&4	760	ST	RFO	9.3%
Eddystone	30&40	60	GT	DFO	0.1%
Eddystone overall:		1,401			26%
Limerick	1&2	2,268	NUC	NUC	97.4%
Montour	1&2	1,540	ST	Coal	73.4%
Susquehanna	1&2	2,216	NUC	NUC	90.8%

The Illinois CUB Report evaluated six nuclear facilities owned by Exelon that operate in Com Ed's service territory in northern Illinois. Table 3 summarizes the six Exelon nuclear facilities in Illinois.

Table 2: Exelon's nuclear generating fleet in Illinois

Unit	Exelon Share	Reactors	Total Capacity	2003 Capacity Factor
Braidwood Generating Station	100%	2	2,362	97%
Byron Generating Station	100%	2	2,356	97%
Clinton Power Station	100%	1	1,017	97%
Dresden Generating Station	100%	2	1,700	92%
LaSalle County Generating Station	100%	2	2,260	93%
Quad Cities Generating Station	75%	2	1,710	92%
Zion Generating Station	*Out of Service*		-	
			10,978	95%

Source: *http://www.eia.doe.gov/cneaf/nuclear/page/at_a_glance/reactors/nuke1.html*

PJM's new Variable Resource Requirement (VRR) curve filed with FERC (Figure 1) is very similar to the curve discussed in the 2004-2005 Stakeholder Working Group meetings and considered in Synapse' earlier reports. The most significant change is that the new curve now ends at approximately five percent above the installed reserve margin (IRM) whereas the previous curve extended to approximately twelve percent above IRM. This has the effect of creating a "zero" price for capacity at quantities that exceed 105% of IRM. The faint line in Figure 1 approximates the earlier version.

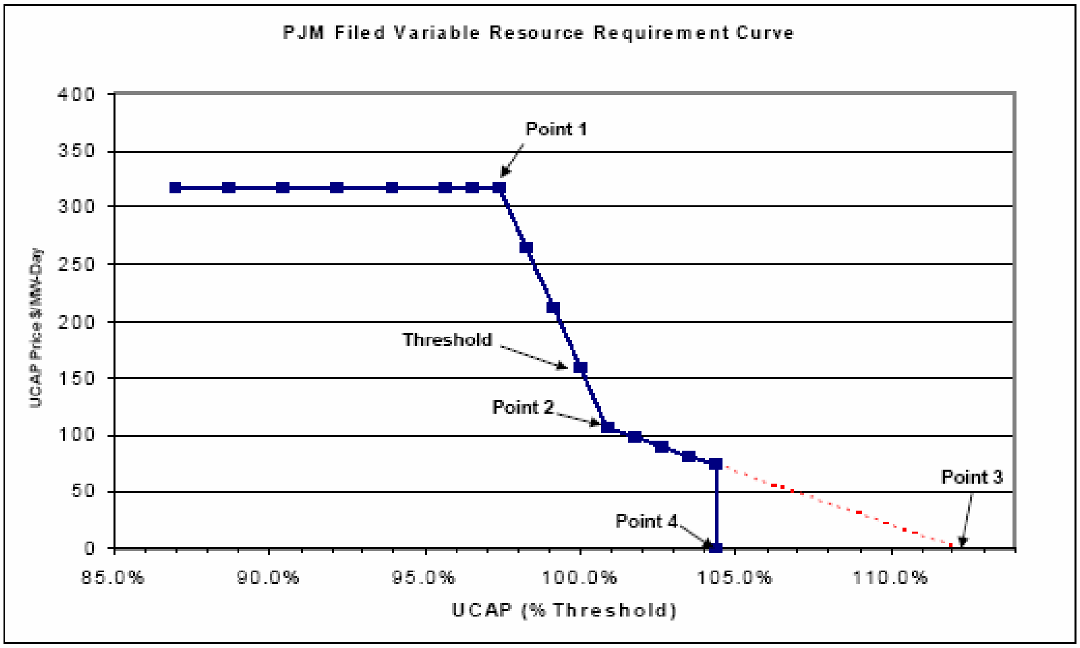

Figure 1: PJM VRR curve as filed on August 31, 2005

"Point 2" indicates the target UCAP level[7], at 100.9% of IRM. IRM is indicated as "Threshold". "Point 2" is the maximum RPM price, which is reached if UCAP falls to 97.4% of IRM or below. "Point 3" is the point from the previous version of the curve at which the RPM price fell to zero, at 112.2% of IRM. This point still serves to set the slope of the VRR curve for UCAP levels between 101% and 105% of IRM. Point 4 is the UCAP level at which the RPM price falls to zero.

Some characteristics of this curve seem arbitrary. Only "Point 2" has a hint of a theoretical basis behind it, as it is supposed to represent the break-even capacity subsidy required for new peak load generation investments. However, even this point requires several more or less arbitrary assumptions from PJM, as we discuss later in this paper, and would be better set by the market. Despite this arbitrariness, the financial and market impact of each of these parameters can hardly be overstated.

In addition to changing the structure of the VRR curve, PJM developed three updated estimates of the cost of new entry (CONE). Both the UCAP level and the CONE prices underlying the VRR curve, as well as E&AS revenue forecasts, are to be defined on a locational basis. This reflects regional differences in market conditions across the PJM footprint. The three CONE values given by PJM are for New Jersey, Maryland, and Illinois. Table 3 shows the data inputs for these three CONE estimates.

[7] UCAP stand for "unforced capacity" and represents the actual expected capacity that a resource can provide after reductions for forced (unexpected) outages.

Table 3. Inputs to Expert Pasteris' revenue requirements model by State.

CONE CT REVENUE REQUIREMENTS
PJM REGIONAL FRAME CT PLANT

SUMMARY			
PJM REGION	New Jersey	Maryland	Illinois
Capital Cost ($Million)	$156.636	$158.527	$159.749
Capital Cost ($/kW)	$466.04	$471.67	$475.30
2004 ($/MW-Year)	$58,752	$60,305	$60,102
2004 ($/MW-Day)	$160.96	$165.22	$164.66
2006 ($/MW-Year)	$61,726	$63,359	$63,144
2006 ($/MW-Day)	$169.11	$173.59	$173.00
Total Levelized ($/MW-Year)	$72,207	$74,117	$73,866
Total Levelized ($/MW-Day)	$197.83	$203.06	$202.37
FINANCIAL CRITERIA			
Project Evaluation (Years)	20		
Percent Equity	50%		
Percent Debt	50%		
Internal Rate of Return (%)	12.0%		
Loan Term (Years)	20		
Loan Interest Rate (%)	7.00%		
MACRS Depreciation Schedule (Yrs)	15		
GENERAL ASSUMPTIONS			
CT Model	GE Frame 7FA		
Number of CTs	2		
Ambient Temperature (F)	92.0		
Ambient Wet Blub Temperature (F)	78.0		
Net Capacity (MW)	336.1		
Heat Rate (BTU/kWh) (HHV)	10,826		

Source: PJM FERC filing, August 31, 2005, affidavit of Ray Pasteris.

IV. Updated RPM capacity revenue calculations

In Synapse's Illinois report we estimated the long-term impacts of RPM based on PJM's stated target price for RPM, equal to CONE, the levelized cost of a new peak load unit, less the annual revenues such a unit would be likely to earn in the energy and ancillary service markets. That Report focused only on long term impacts, comparing four capacity price scenarios: (1) the recent capacity prices in Illinois region; (2) the six-year average of PJM capacity prices; (3) the target capacity price under RPM; and (4) the maximum capacity price under RPM.

For the Pennsylvania Report, we estimated impacts of RPM in the near-term based on simulations provided by PJM[8] in January 2005. These simulations covered the present through 2009/2010, during which time period system capacity was expected to be in surplus and the target price under RPM would not have been reached. We compared these outcomes to low, medium and high priced scenarios based on historical capacity market prices.

[8] "Reliability Pricing Model, Prototype Simulation" presentation by PJM at the RAM working group meeting 1/26/05.

In this updated report we pay closest attention to the RPM average prices that would be produced over the long term with the three new VRR curves from PJM.[9] It is this target price that the VRR curves are designed to achieve as a long-term average, although the simulations carried out by PJM expert witness Benjamin Hobbs shows considerable year-to-year variation in this outcome.[10] The target prices are derived in Table 4, below. As in our earlier reports, we compare this price to the current construct, which uses competitive, market-based bidding to establish the monthly price of capacity rather than a pre-determined administrative target as under RPM.

Table 4. Calculation of the RPM target and maximum prices under PJM filing of August, 2005.

State	Levelized cost ($/MW-day)	E&AS Revenues ($/MW-day)	RPM Target Price ($/MW-day)	RPM Maximum Price ($/MW-day)
New Jersey	$197.83	$98.62	$99.21	$297.04
Maryland	$203.06	$81.38	$121.68	$324.74
Illinois	$202.37	$79.75	$122.62	$324.99

These updated capacity prices are compared with PJM's original proposal (used in our earlier study) and with prices from the current, bid-based capacity market in Table 5. Projected capacity market revenues for the Exelon nuclear plants under each of these scenarios is shown in Table 6; these revenues for the Pennsylvania plants are shown in Table 7. Because PJM has not produced CONE and E&AS revenue projections for Pennsylvania, we have used the average of the values from Maryland and New Jersey.

[9] Although the three VRR curves are different, the variations between them amount to less than 5% and are the result of very small differences in the CONE values for each region.

[10] PJM FERC filing, August 31, 2005, affidavit of Benjamin Hobbs.

Table 5. Comparison of current market capacity prices with two PJM proposals. "Recent" price is for one-year capacity contract from June 2005 through May 2006. "Six-year average" reflects average capacity prices in PJM from 1999 through 2004. The original PJM proposal was presented to the PJM stakeholders in January 2005. PJM filed an updated proposal on August 31, 2005 (Dockets ER05-1410-000 and ER05-148-000.) RPM equilibrium price is calculated as projected CONE (per PJM expert Pasteris) net of average simulated E&AS revenues from the past six years (per PJM expert Bowring); this is point 2 in Figure 1. RPM maximum is twice CONE, minus E&AS revenues; this is point 1 in Figure 1.

Capacity Price Scenarios for Illinois and Pennsylvania		
	Case	**Price ($/MW-day)**
Existing capacity market	*Recent (May 2005)*	$ 5.25
	Average last six years	$ 46.23
Original PJM Proposal	*RPM Equilibrium*	$ 124.97
	RPM Shortfall	$ 327.35
PJM filing with FERC	*RPM Equilibrium*	$ 122.62
	RPM Shortfall	$ 324.99

Table 6. Projected annual capacity revenues ($million) for Exelon nuclear plants under each of the price scenarios shown in Table 5.

	Scenario	**Clinton**	**Dresden**	**LaSalle**	**Byron**	**Quad Cities**	**Braid-wood**	**Total**
Existing capacity market	*Recent (May 2005)*	1.9	3.3	4.3	4.5	2.5	4.5	21.0
	Average last six years	10.1	16.8	22.4	23.3	12.7	23.4	108.7
Original PJM Proposal	*RPM Equilibrium*	46.4	77.5	103.1	107.5	58.5	107.7	500.7
	RPM Shortfall	121.5	203.1	270.0	281.5	153.2	282.2	1,311.6
PJM filing with FERC	*RPM Equilibrium*	45.5	76.1	101.1	105.4	57.4	105.7	491.3
	RPM Shortfall	120.6	201.7	268.1	279.5	152.1	280.2	1,302.2

Table 7. Projected annual capacity revenues ($million) for selected base load generating plants in Pennsylvania under each of the price scenarios shown in Table 5.

	Scenario	**Eddystone 1 & 2**	**Eddystone 3 & 4**	**Eddystone 30 & 40**	**Limerick**	**Montour**	**Susque-hanna**	**Total**
Existing capacity market	*Current (May 2005)*	1.4	1.5	0.1	4.3	3.1	4.2	14.6
	Average last six years	11.9	13.2	0.7	38.3	27.4	37.4	128.9
Original PJM Proposal	*RPM Equilibrium*	32.3	35.7	1.9	103.5	74.1	101.1	348.5
	RPM Shortfall	84.5	93.4	5.1	271.0	194.1	264.8	912.9
PJM filing with FERC	*RPM Equilibrium*	31.7	35.0	1.9	101.5	72.7	99.2	341.9
	RPM Shortfall	83.9	92.8	5.0	269.0	192.7	262.9	906.3

For comparative purposes, we have also considered PJM's updated estimates of the cost of capacity under RPM during the first three years of implementation. These PJM estimates were provided in an updated Simulation Analysis in January 2006. PJM's updated simulation analysis uses similar inputs to its January 2005 Simulation

Analysis. Table 8 below shows recent market prices,[11] as well as PJM's estimates of the annual prices in each region for the first three years of RPM implementation for both the 2005 and 2006 simulations. The revenues associated with all of these prices are shown in Figure 2.

Table 8. Historic PJM capacity prices compared to PJM simulation of RPM prices from 2005 and 2006 simulations. In 2006 simulation, "Eastern MAAC" price is used for PECO in 2007-08, and "Market" price is used for PPL in 2007-08 and 2008-09. "Market" price is used for ComEd in all simulation years.

		2004	2005	2005-06	2007-08	2008-09	2009-10
Existing Market	*PECO*	$ 17.74	$ 18.00	$ 5.25			
	PPL	$ 17.74	$ 18.00	$ 5.25			
	ComEd	$ 27.98	$ 18.00	$ 5.25			
January 2005 Simulation	*PECO*				$114.43	$ 113.81	$ 115.05
	PPL				$ 25.00	$ 55.67	$ 94.00
	ComEd				$ 25.00	$ 55.67	$ 68.24
January 2006 Simulation	*PECO*				$106.06	$ 100.24	$ 100.62
	PPL				$ 16.14	$ 11.38	$ 35.19
	ComEd				$ 16.14	$ 11.38	$ 8.12

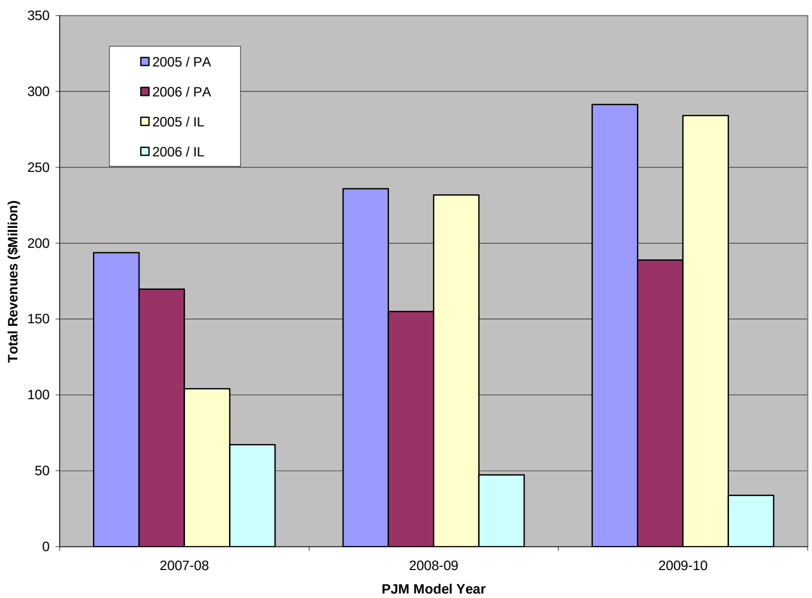

Figure 2. Total forecasted capacity revenues earned by Pennsylvania and Illinois generators (listed in Tables 1 and 2, respectively) according to PJM's RPM simulations. Two sets of simulations are shown, one released by PJM in January, 2005, and the other in January, 2006.

PJM presented these simulations to address the question of the transition period between the current market and maturity of the RPM approach, when they project that capacity will approach the target level of 1% above IRM. They should *not* be

[11] "Market" price refers to the RPM curve price for all non-constrained sub-regions in the PJM simulations. For constrained sub-regions, the sub-regional price is based on the RPM curve for that sub-region.

taken as an indication of long-term price expectations under RPM. Given the current surplus of capacity in many sub-regions of the PJM footprint, during this near-term period RPM is likely to produce prices significantly below the long term, average price target. RPM is designed to achieve both a specific long-term capacity margin and a specific long term price, and this price is *uniformly higher* than the price PJM projects during the first three years of RPM implementation.

Discussion

In our earlier Illinois report we estimated windfall profits for Exelon under RPM based on an RPM target price of $124.97, and a maximum price of $327.35, per MW-day. This represented PJM's then-estimate of the cost of new entry net of projected energy and ancillary service revenues. This translated into annual capacity revenues of $501 million at the long term average price and $1.31 billion for Exelon for any years that the maximum RPM prices occurred.

Based on the PJM filing, we find that Exelon annual revenues under RPM would be $491 million and $1.30 billion at the target and maximum price, respectively. In other words, the small adjustments in the estimates for both CONE and E&AS revenues appear to have decreased payments to Exelon by $10 million per year. While this is some good news for consumers, it does beg the question of what changed between the two filings to account for a $10 million dollar shift. More important, it leaves the impression that this non-market approach to calculating capacity prices, with all of its implications for electricity prices for consumers, is arbitrary and capricious.

Similarly, we find very little difference between the revenues paid to the Pennsylvania base load units under the original RPM proposal and the more recent PJM filing. In both cases, we find that at the long term average RPM price these units would be paid close to $340 million, combined; in the case of capacity shortfall, they would be paid over $900 million annually until the shortfall was remedied.

Taken together, this makes a total capacity payment for these 17,000 MW of base load generation of over $830 million annually. This may be compared with about $240 million base on the average market capacity price over the last six years. Thus RPM, as filed by PJM, would mean an additional $590 million in capacity payments to these existing, largely amortized, base load generating plants in Illinois and Pennsylvania, at consumer expense. These payments, and hundreds of millions more to other base load generators, would do nothing to enhance reliability in PJM.[12]

In the near term results presented by PJM, there are large differences between the 2005 simulations and the 2006 simulations for both Illinois and Pennsylvania. The 2005 simulations suggested that the Exelon nuclear in Illinois plants would earn

[12] Based on PJM's 2006 simulations, which show a UCAP requirement of over 158,000 MWs by the 2009/2010 power year, the additional system wide cost for RPM at the long term average price would be almost $5.5 billion dollars.

between $250 and $300 million in the 2009/2010 capacity year. In the updated 2006 simulations based on a new demand curve, these plants only earn about $30 million during this year.

In Pennsylvania, PJM's 2005 simulations for the near term suggested revenues for the plants we examined of approximately $280 million in the 2009/2010 capacity year. The new 2006 projections show a value of about $170 million that year.

What's going on?

These results reinforce concerns that the price-setting process under RPM is arbitrary in nature, and that small changes to any of the numerous administrative assumptions (see the discussion of CONE in the next section) can produce quite large variations to the revenues that resource providers will earn. These revenues come ultimately from consumers in their electric bills. There is at least as much art as science, for example, in defining the various locations in PJM and deciding when new pricing regions should be created; this seems to be one major factor underlying the differences between the 2005 and 2006 simulations. To date, PJM has done very little to identify, explain, and justify how the uncertainty in these aspects of its RPM model will be resolved. How much confidence can we have in mechanism that produces an unexplained, near ten-fold reduction (or increase) in the estimate of annual revenues (costs) for a single year as seen in the estimated prices for the ComEd region? Neither the physical transmission infrastructure nor the market changed between the two simulation runs; it was PJM's administrative curve and other model parameters that changed.

Consumers are better served when market participants evaluate the cost of new entry for themselves, and bid that price into a competitive capacity market. Prices determined by competitive bids can adjust quickly, up or down, in response to current and projected market conditions. In contrast, the RPM approach would rely upon periodic administrative updates to CONE values, historic six-year average energy and ancillary service revenues, adjustments to the shape of the VRR curve, and assumptions about transmission upgrades several years into the future in an effort to "predict" future capacity prices. Unfortunately, once such a prediction is made, this sets the price that consumers will pay in stone. Such a mechanism is relatively unresponsive to market conditions when compared to the current capacity mechanism, and it may introduce new incentives and opportunities for gaming that are not present in today's capacity pricing mechanism. It would certainly create additional disputes in the stakeholder process whenever a change is proposed for any one of the myriad administrative determinations underlying this process.

V. Objections to CONE and E&AS calculation

Extreme sensitivity to CONE parameters

As shown in Table 4, the RPM price calculation is heavily dependent on estimates of both the levelized annual cost of new entry (CONE) and projected energy and ancillary service (E&AS) revenues for a hypothetical new peak load serving plant. The difference between these parameters is taken to be the long term break-even capacity market revenues required to induce investment in such a resource. Not just the target and maximum prices, but the entire VRR curve is defined by these values. A small change in either number could mean tens of millions of dollars in annual costs or savings for consumers, and in additional or diminished annual profits for generation owners. For this reason PJM's expert witnesses[13] have a responsibility to detail their calculations of these fundamental elements of the RPM proposal.

Conspicuously absent in both affidavits, however, is any evaluation in the uncertainty inherent in their estimates. Of course, an acknowledgement of uncertainty would disturb the very foundation of RPM because of the non-market based nature of the construct, and because of the redistribution of wealth implicit in any values chosen. Nonetheless, it is important for all market participants, including consumers, to understand just how well-determined or arbitrary the setting of these values is, and how much of their money rides on each determination.

Capacity markets are like other markets in having a range of possible price outcomes, and in the implications of the outcome for the ultimate cost to consumers. However, in competitive markets a price can emerge that reflects the dynamics of supply and demand, as opposed to the judgment of experts. It is generally acknowledged that to have any market operator step in and dictate a price is arbitrary, inefficient, and damaging to the credibility of the marketplace. Unfortunately, that is precisely how the RPM proposal, as currently designed would resolve this uncertainty in the capacity market.

To take a simple example, Pasteris selects an internal rate of return (IRR) for his financial model of 12%. This is a perfectly reasonable estimate and may well reflect the planning parameters of some market participants. It is no more reasonable, however, than 11%, or 13%, which may reflect the preferences of other entities. This variability translates linearly into the annualized cost of a new unit. Had Mr. Pasteris chosen 11%, the annualized cost in Illinois would have been $185.51 instead of $202.37, and the target price under RPM (Point 2 in Figure 1) would have been $105.77 instead of $122.62. Indeed, had Mr. Pasteris made this slightly different and equally reasonable assumption in his parameters, it would have reduced payments to Exelon by $58 million per year compared to the proposal PJM filed (to the benefit of consumers).

On the revenue side, PJM has elected to use an estimate of E&AS revenues based on modeling the performance of such a plant over the previous six years of market operations. In addition to the obvious uncertainties inherent in any modeling analysis of an electricity market, even a retroactive one, there are several aspects of this choice that raise questions. Is the range of outcomes over the last six years just normal variation, in which case averaging may make sense, or does it represent real changes in market conditions? Should more recent years be weighed more heavily than earlier years? Economic and market theory give us no answers to these

[13] *See*, PJM FERC filing, August 31, 2005, affidavits of Ray Pasteris and Joseph Bowring.

questions; they are just judgment calls. But as with the other aspects of this analysis, they are judgment calls with enormous implications for generator profits and consumer costs.

Questionable assumptions underlying CONE

Another reason for allowing market signals to dictate prices instead of experts, in general, is that experts are required to make choices in their modeling that may or may not reflect market realities. In the case of Pasteris' calculation of the CONE, on which the entire VRR curve rests, at least two of these assumptions seem significantly out of step with reasonable expectations for new peaking capacity in PJM.

These assumptions are the inclusion of capital costs for SCR emissions control technology, adding $40 per kW, and dual fuel capability, adding $11 per kW, in the cost of a peaking plant. Together these design decisions add over 12% to the cost of the prototype new entry, but are they realistic? Pasteris reviews nine recent projects for comparison with his projected capital costs, and finds that not one of them had either of these characteristics. Thus he "explains away" much of the difference in capital costs between the prototype plant and the real recent additions, without addressing the question of why the prototype should be based on the less realistic option.

In fact, it is more reasonable to expect that new peaking units would *not* be built with these capabilities. Because these plants are designed to run with low capacity factors, a developer would be more likely to forgo the pollution control technology, for example, and simply pay the going allowance price for each unit of NOx emissions. This would also affect the net energy and ancillary service revenues; plants without pollution control technology are more energy efficient, but also face higher emissions costs.

The decision to equip the prototype plant with theoretical SCR and fuel-switching capability increases the RPM target price by $25 per MW-day. This translates (at the target price) into $100 million in additional revenues for the Illinois nuclear plants and $75 million for the Pennsylvania plants, every year, at consumer expense. In case of shortfall, these numbers could be as high as $200 million and $150 million in excess annual payments, purely because the prototype plant was designated to include these technologies. System-wide, the annual cost to consumers would stretch into the hundreds of millions or billions. Needless to say, all of this money would not result in any decrease in pollution!

In this section we have focused specifically on the unrealistic inclusion of SCR technology and dual fuel capability in the prototype plant, but this is only the beginning. A real market solution might uncover much more cost-effective options, such as demand-side resources or alternate fuel peaking units, which would further save consumers money while ensuring adequate reliability. By imposing an administratively derived price based on an arbitrary standard, the RPM proposal would effectively shut off opportunities for the market to do what the market does best: set prices based on bids that reflect individual determinations of cost and risks. It is not reasonable to base a capacity price on an arbitrary and unrealistic, even gold-plated prototype plant, and then pay this price to all generation owners based on their capacity rating.

VI. Conclusions

We have demonstrated in a series of analyses that RPM will produce substantial new revenues for owners of base load resources within the PJM footprint. The new VVR curves proposed in PJM's August filing of RPM will reduce the impact of those higher revenues in the first few years of implementation. Nonetheless, the basic intent of the VVR approach has not changed, which is to provide substantial, long term increases to capacity revenues. When the RPM long term average price in the new VRR curves is compared to the average capacity price in PJM for the last six years,[14] the RPM price provides an additional $590 million dollars annually to the owners of the approximately 17,000 MWs of base load capacity we have reviewed in this study. If we assume a PJM system capacity requirement of 160,000 MWs (which PJM will likely reach by 2012) the annual impact of RPM would be an additional $5.5 billion dollars per year.

Because this administrative price is intended to simulate a "clearing price," it would be paid to all generating units, including those which had been generously funded by ratepayers through cost-of-service ratemaking and transition charges, and which remain profitable today in the energy and ancillary service markets. Exelon's Illinois nuclear fleet falls into this category of existing, ratepayer-funded, profitable plants, as do the four units (nuclear and coal) analyzed in Pennsylvania. We conclude that the owners of existing, base load generation in PJM would have a compelling financial incentive to ensure that capacity prices remain at equilibrium or below. Given these generation owners' dominance in critical areas of the regional market, this concern must be closely examined before RPM can be given serious consideration as the RTO's capacity adequacy model.

PJM's RPM proposal will provide for a considerable transfer of wealth from ratepayers to owners of existing generation, such as Exelon, without any specific requirement for the provision of new services. This poses serious questions about how an RPM-type compensation mechanism can be considered an efficient means of pursuing a public policy goal and whether it can produce wholesale power rates that meet the "just and reasonable" standard of the Federal Power Act.

We suggest that any capacity construct, the current PJM construct, RPM, or an alternative, must be evaluated within the context of the overall bulk power delivery system and not in isolation or as a stand-alone element. Long range planning, transmission upgrades, resource additions and retirements, and the interaction of

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[14] We note again that the six-year period is 1999 thru 2004. It dos not include 2005, which saw capacity payments at low historical levels. Including 2005 data would only <u>lower</u> the annual average and <u>increase</u> the estimated "extra" payments to base load resources.

market systems and rules all need to be considered. We suggest that these and other critical and interdependent questions must be resolved as part of any proposed enhancements to the interconnected system that PJM manages.