Capacity Revenues for Existing, Base Load Generation in the PJM Interconnection

A Pennsylvania Case Study

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I. Introduction and Summary

The efforts to develop a new mechanism for ensuring long-term resource adequacy have preoccupied the three Northeast ISOs for the last several years.[1] Most recently, all three ISOs have proposed modifications to their capacity pricing systems that use a "demand curve" to establish a clearing price for all resources within specific zones. While there are significant differences between the three ISO proposals,[2] much attention has been focused on the impact that demand curves will have on capacity prices. It is expected that capacity prices, and therefore capacity revenues, will rise significantly through implementation of the ISO proposals. These capacity revenues are intended to incent investment in new generation resources. It has also been suggested that the new capacity revenues will provide additional revenues to current "at risk" generation and thereby delay or defer their retirements. However, there has been little focus with respect to existing generation owners, who may already be receiving adequate compensation through existing energy, capacity, and, if applicable, ancillary services revenues.

This paper provides an analysis of the revenues that existing, large base load generation are receiving today from the current capacity market structure and what they would likely receive in the future under both the current capacity structure and under the PJM Reliability Pricing Model (RPM) proposal. Our analysis looks at four large generation stations (two nuclear and two coal) in the PECO and PPL service territories in Pennsylvania. We deliberately chose two different service territories to capture some of the locational variation that the RPM demand curves produce.

For estimates of today's (2004) revenues and for future revenues, we used energy and capacity prices from the PJM State of the Markets Report. For our three future scenarios, we used a constant energy revenue estimate and varied the capacity revenues based on the historical data to create Low, Mid, and High cases. For the RPM scenarios, we used the data provided by PJM for the Resource Adequacy Mechanism (RAM) Stakeholder Working Group process.

We found that the use of an RPM demand curve for setting capacity prices will substantially increase annual capacity revenues for these four, existing plants by the 2009 power year (see table below). When compared to 2004 annual capacity revenues, the annual increase is over $200 million (a six-fold increase). When compared to the average annual capacity revenues over the last six years (the Mid Case), the annual increase is over $130 million (more than double the 2004 revenues). It is difficult to understand the justification for giving existing generation resources such large increases in capacity revenues.

[1] NY, NE and PJM; although NE and PJM are RTOs, they all perform very similar regional functions.

[2] See *Kinky Curves, Synapse December 2004* for an overview of the three ISO proposals.

Table 1: Comparison of Capacity Revenues for Four Different Generating Units Given Various Capacity Revenue Policies: 2004 actual vs. Business as Usual for a typical year during the 2006-2010 period vs. RPM for the 2009-10 operational year.

Capacity Revenue Comparison (Million $)

Facility	2004 Actual	BAU Mid Case	RPM '09-10
Eddystone - 1&2	$4	$10	$24
Limerick - 1&2	$15	$38	$95
Montour - 1&2	$10	$26	$53
Susquehanna - 1&2	$14	$37	$76
Total Revenue	$43	$111	$249

II. The Four Stations

We selected four generation stations to include in the case study. They are all base load generation units that were divested or made affiliates by their original parent companies as part of Pennsylvania's restructuring proceedings in the late 1990s. As such, they were eligible for recovery of stranded costs based on then current estimates of future operating characteristics and likely market revenues. Because Pennsylvania's restructuring proceedings produced a settlement, the specific future revenues attributed to each of these units is unknown; the stranded cost portion of the settlement was a lump sum for each parent utility for all its divested generation assets.[3] Nonetheless, the two largest assets for each utility were the Limerick (PECO) and Susquehanna (PPL) nuclear units.

Eddystone Station

The Eddystone Generating Station is located near Philadelphia in the PECO service territory and consists of six generation units. The Station is currently owned and operated by Exelon Generating Company LLC. Units 1 and 2 are coal fired units with a combined summer capacity of 581 megawatts[4]. Units 3 and 4 are residual fuel oil fired units with a combined capacity of 760 megawatts. Units 30 and 40 are diesel oil fired units with a combined capacity of 60 megawatts. Units 1 and 2 (coal) have a three year average capacity factor of 50%. By comparison, Units 3 and 4 (residual oil) have an average capacity factor of 9.3% and Units 30 and 40 (gas) appear to be peaking units with an average capacity factor of just 0.1%. For the purposes of this analysis, we focus on Units 1 and 2.

Limerick Station

The Limerick Nuclear Generation Station is located northwest of Philadelphia in the PECO Service territory and consists of two units. The Limerick Station is currently owned and operated by Exelon Generating Company LLC. The combined summer capacity of the two units is 2,268 megawatts. The three year average capacity factor for the two units is 94.1%.

Montour Station

The PPL Montour LLC is located in central Pennsylvania in the PPL service territory and consists of two coal units. Montour is currently owned and operated by PPL Generating

[3] Pennsylvania Commission Docket R-00973953 (PECO) Order of 5/14/98 for $5.26 billion of stranded costs and Docket R-00973954 (PPL) Order of 8/27/98 for $2.97 billion of stranded costs.

[4] The reported summer capacity in the EIA-920 data of 581 MW is significantly below the nameplate rating of 707 MW. So as not to overstate capacity revenues we have used summer capacity throughout this report.

LLC. The combined summer capacity of the two units is 1,540 megawatts. The three year average capacity factor for the two units is 73.4%.

Susquehanna Station

The PPL Susquehanna LLC is a nuclear station located north of Harrisburg in the PPL service territory and consists of two units. Susquehanna is currently owned and operated by PPL Generating LLC. The combined summer capacity of the two units is 2,216 megawatts. The three year average capacity factor is 90.5%.

Table 2: Operating Statistics of the Four Generating Facilities Under Review in this Paper

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%
		1,401			
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%

III. Revenues

Business as Usual Case - Current Market Revenues

We calculated current revenues by using information in PJM's 2004 State of the Markets Report and hourly real time price data.[5] For energy revenues, we calculated appropriate mixes of peak and off-peak energy prices depending on the facility's current year capacity factor (e.g. nuclear plants received the all-hours energy price, intermediate load coal plants earned a higher price). The table and chart below show estimated energy and capacity revenues based on market prices for the four facilities from 1999 through 2004. Actual revenues may be different for a variety of reasons including contractual obligations. Ancillary revenues for services such as spinning reserves and automatic generation control are not included in these totals.

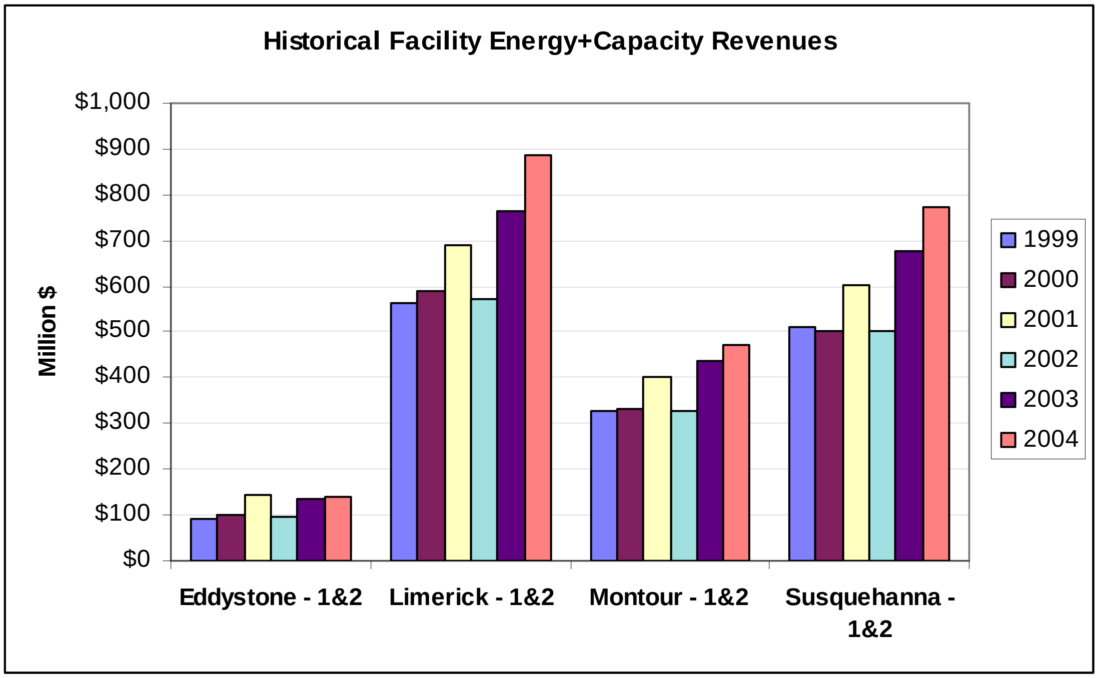

Figure 1: Total Revenues (Energy and Capacity) for the Generating Facilities (1999-2004)

Most of the increase in total revenues in recent years is a result of higher energy prices, which have increased approximately 50% from 1999 to 2004. Capacity factors and generation have also increased moderately. More details are available in Appendix A.

[5] PJM State of the Markets Reports are available at http://www.pjm.com/markets/market-monitor/som.html
PJM energy price data is available at http://www.pjm.com/markets/energy-market/real-time.html

Table 3: Estimated Capacity Revenues of the Four Facilities

Estimated Revenues for Selected Facilities Based on Market Prices ($1000)

Station	Units	Category	1999	2000	2001	2002	2003	2004
Eddystone	**1&2**	Energy	$79,929	$86,561	$125,124	$88,607	$131,382	$134,597
		Capacity	$11,210	$12,841	$20,218	$7,083	$3,713	$3,762
		Total	$91,139	$99,401	$145,342	$95,689	$135,095	$138,359
Limerick	**1&2**	Energy	$519,526	$539,387	$611,753	$544,485	$751,710	$870,302
		Capacity	$43,759	$50,125	$78,924	$27,649	$14,495	$14,686
		Total	$563,285	$589,512	$690,677	$572,134	$766,205	$884,988
Montour	**1&2**	Energy	$297,814	$298,930	$348,360	$309,355	$427,482	$461,766
		Capacity	$29,713	$34,035	$53,591	$18,774	$9,842	$9,972
		Total	$327,526	$332,966	$401,950	$328,129	$437,324	$471,738
Susquehanna	**1&2**	Energy	$467,719	$453,656	$524,244	$477,260	$661,246	$760,273
		Capacity	$42,755	$48,975	$77,115	$27,015	$14,163	$14,349
		Total	$510,475	$502,631	$601,359	$504,275	$675,409	$774,621
All Stations		Energy	$1,364,988	$1,378,534	$1,609,481	$1,419,706	$1,971,820	$2,226,938
		Capacity	$127,436	$145,975	$229,848	$80,522	$42,214	$42,768
		Total	$1,492,424	$1,524,509	$1,839,329	$1,500,227	$2,014,033	$2,269,706

Note that although capacity revenues have declined significantly in the last three years, the increases in energy revenues (associated with the higher cost of natural gas for most of the marginal units in the PJM energy market) have more than compensated for capacity revenue declines. A comparison of average annual energy revenues for 2003-2004 compared to the1999-2002 period shows an increase of 45%. While coal prices have also increased during this time period, the much larger percentage increase in gas price has provided additional, annual inframarginal revenues to the coal as well as the nuclear units in 2003 and 2004.

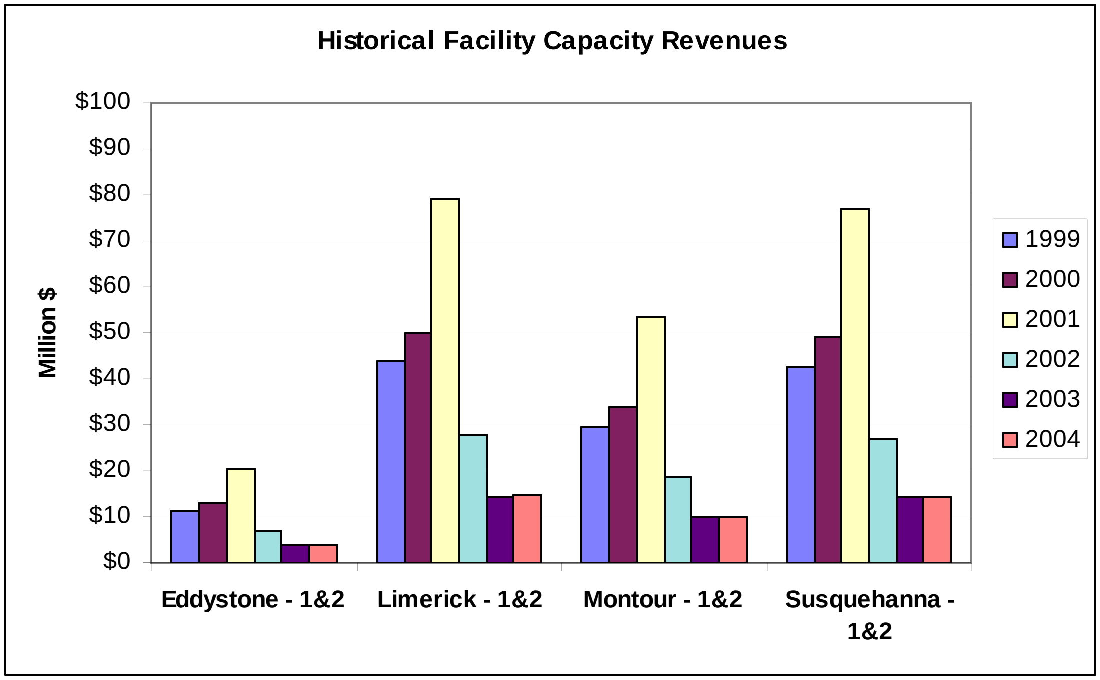

Figure 2: Capacity Revenues for the Generating Facilities (1999-2004)

Energy market prices[6] have risen substantially over the last several years reflecting, primarily, the increase in natural gas prices. None of these units use natural gas for a fuel; their production costs are not directly affected by higher gas prices.

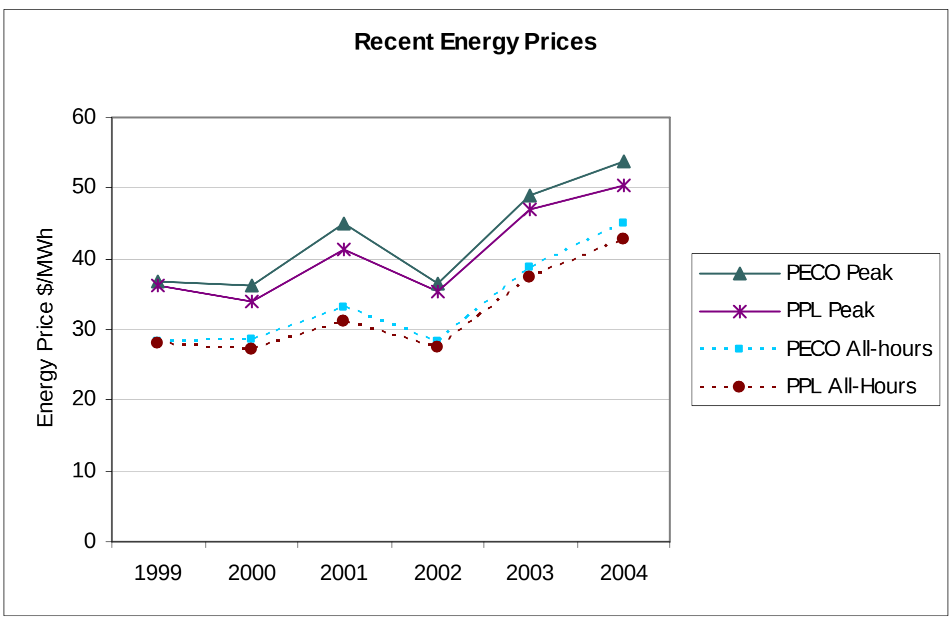

Figure 3: Energy Prices in PECO and PPL (1999-2004)

[6] These average prices were calculated from the hourly locational real-time price data on PJM's website.

Capacity prices have declined significantly in recent years from initial levels. The 2001 spike in capacity prices[7] was partly caused by three months of unusual bids from a single market participant. Although the quantities of capacity affected by the unusual bids were relatively small, the impact on the average price for 2001 was significant. It is generally agreed that the high 2001 prices did not reflect a situation of inadequate capacity resources.[8] The low capacity prices of recent years are generally taken to be a reflection of the current overall PJM surplus of capacity.

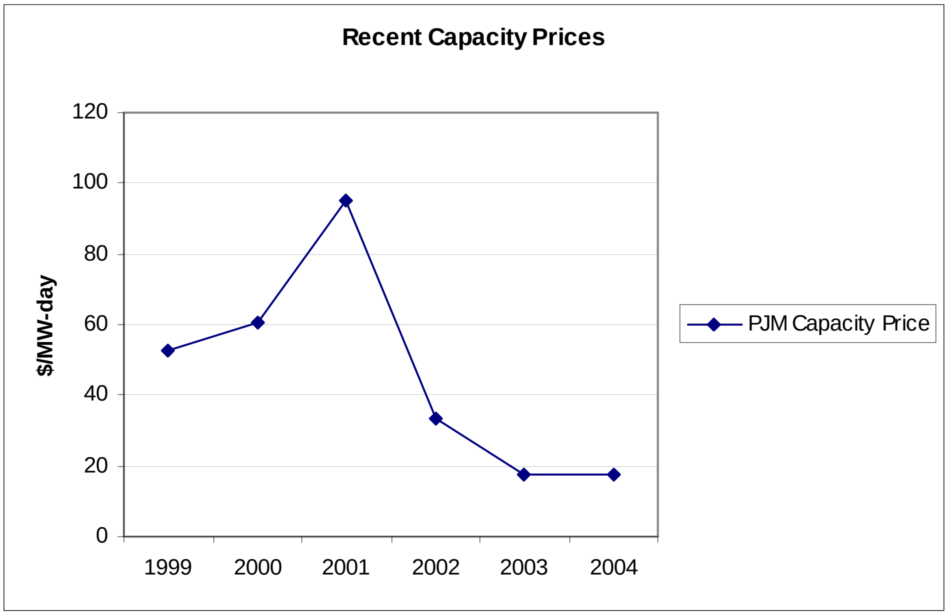

Figure 4: Capacity Prices in PJM (1999-2004)

[7] Capacity prices are from the PJM State of the Market (SOM) Reports.

[8] For a discussion of the 2001 capacity market prices, see PJM's 2001 State of the Market Report at p. 81.

Business as Usual Case: Future Market Revenues

We calculated future market revenues for the four power stations using the same quantities of energy and capacity as for the most recent three years. We then applied estimates of future market prices for both energy and capacity under three scenarios based on historical prices. We used the same estimate of future energy prices for all three scenarios[9] and chose selected historical capacity prices for the three scenarios: (1) Low: 2003 & 2004 capacity prices[10]; (2) Mid: 1999-2004 capacity prices[11]; and (3) High: 2000 & 2001 capacity prices[12]. Our expectation is that PJM market energy prices are likely to remain at fairly high levels, since they depend strongly on the cost of the marginal fuel, natural gas, which is unlikely to fall significantly. In addition, capacity prices with the current market structure may rise as reserve margins decline.

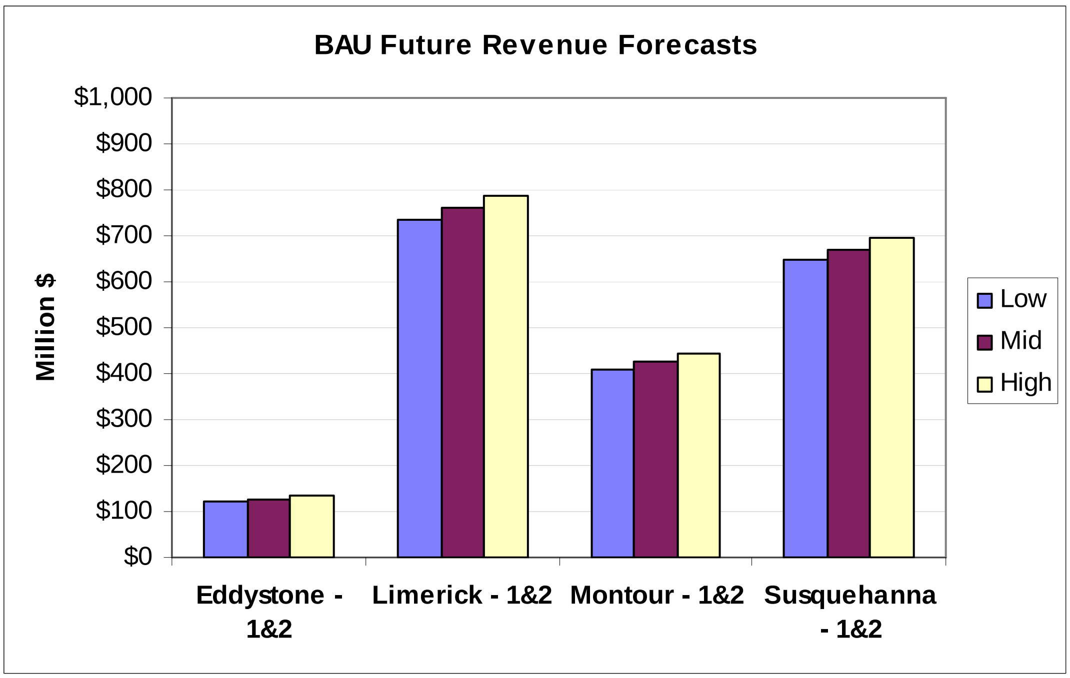

Figure 5: Future Revenue Forecasts in the Business as Usual Cases (low-mid-high capacity prices)

[9] PJM market energy prices are up for a number of fundamental reasons and are very unlikely to return to pre-2002 levels so we selected an average of 2002-2004 energy prices for the three cases.

[10] Capacity prices have been lowest in the last two years 2003 & 2004 and may stay that way for a while.

[11] For the mid case we used the average of the capacity prices for the last six years.

[12] For the high case we use the average of the highest two years for the capacity prices (2000 & 2001).

Table 4: Forecasted Future Revenues in the Business As Usual Case

BAU Forecast Revenues for Selected Facilities Based on Historical Prices ($1000)

Station	Units	Category	Low	Mid	High
Eddystone	**1&2**	Energy	$117,738	$117,738	$117,738
		Capacity	$3,738	$9,804	$16,529
		Total	$121,475	$127,542	$134,267
Limerick	**1&2**	Energy	$721,980	$721,980	$721,980
		Capacity	$14,590	$38,273	$64,524
		Total	$736,570	$760,253	$786,505
Montour	**1&2**	Energy	$399,022	$399,022	$399,022
		Capacity	$9,907	$25,988	$43,813
		Total	$408,929	$425,010	$442,835
Susquehanna	**1&2**	Energy	$631,912	$631,912	$631,912
		Capacity	$14,256	$37,395	$63,045
		Total	$646,168	$669,308	$694,957

RPM Proposal

We calculated market revenues for the four power stations assuming that RPM is implemented beginning in 2006 by using price information provided by PJM to the stakeholder working group on the Reliability Pricing Model (RPM).[13]

The table below shows the base case capacity prices as predicted by the RPM simulation. Note that this shows an immediate rise in capacity prices in PECO, but a short term drop followed by a subsequent rise in prices in PPL.[14]

Table 5: Capacity Clearing Price in the RPM Base Case

Capacity Clearing Price – RPM Base Case

Phase	Period	PECO	PPL	Market
1	2006-07	$56	$56	$56
2	2007-08	$114	$25	$25
3	2008-09	$114	$56	$56
4	2009-10	$115	$94	$68

Extracted from "Reliability Pricing Model, Prototype Simulation" presentation at PJM RAM WG meeting 1/26/05

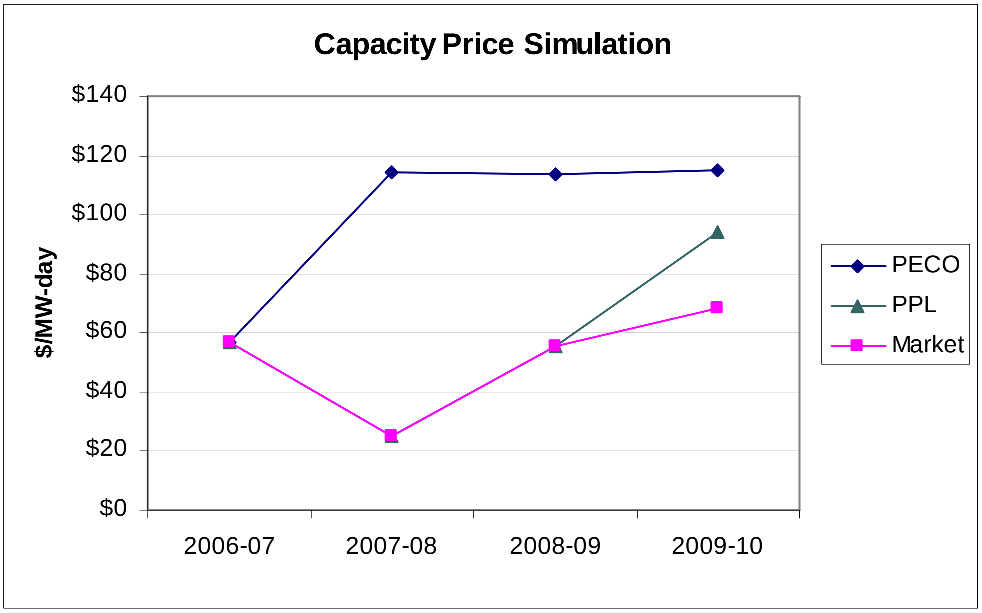

Figure 6: Forecast of Future Capacity Prices in PECO and PPL and the PJM Market

[13] Extracted from "Reliability Pricing Model, Prototype Simulation" presentation by PJM at the RAM WG meeting 1/26/05.

[14] The price fluctuations reflect the pricing zones in the RPM proposal. In the first year of RPM, PJM is a single price zone; in the second year, PECO becomes a separate zone (with higher prices) and PPL stays in "rest of PJM" (which experiences a price drop); in the fourth year, both PECO and PPL are separate zones

The graph and chart below show that capacity payments take a major jump in 2007-2008 for Eddystone and Limerick, and a lesser increase in 2009-10 for Montour and Susquehanna. The "2004 Actual" shows the historical capacity prices in 2004. The "Business as Usual (BAU) Mid Case" reflects a non-RPM future with capacity prices set at the six-year historical average in PJM. The remaining cases are the current PJM estimates of capacity prices with the RPM demand curve.

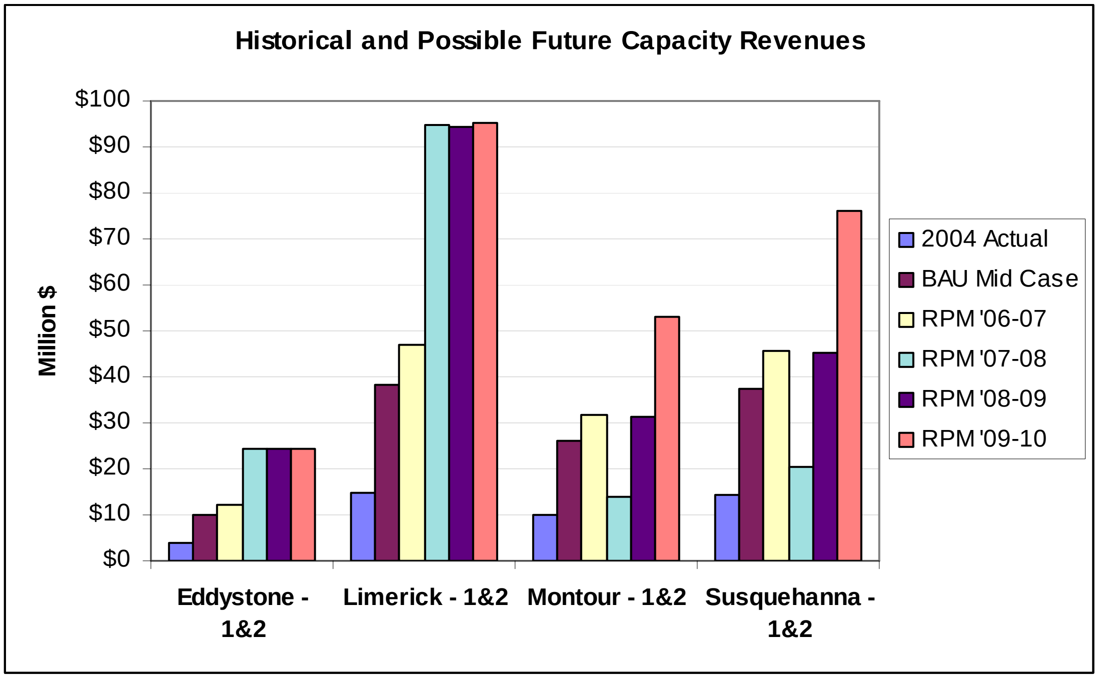

Figure 7: Forecast of Future Capacity Revenues at the Various Generating Facilities

Table 6: Future Capacity Revenues in the RPM Case

Capacity Revenue Comparisons ($1000)

Facility	2004 Actual	Mid Case	2006-07	2007-08	2008-09	2009-10
Eddystone - 1&2	$3,762	$9,804	$11,977	$24,267	$24,135	$24,398
Limerick - 1&2	$14,686	$38,273	$46,755	$94,727	$94,214	$95,241
Montour - 1&2	$9,972	$25,988	$31,747	$14,053	$31,292	$52,837
Susquehanna - 1&2	$14,349	$37,395	$45,683	$20,221	$45,028	$76,031
Total Capac Rev	$42,768	$111,460	$136,163	$153,268	$194,670	$248,507

The total RPM demand curve price impact on capacity revenues for these four facilities in 2009-10 is a $200 million increase compared to revenues in 2004.

IV. Discussion and Conclusions

A comparison of capacity revenues based on the various scenarios shows that by 2009 the RPM revenues significantly exceed even the High Case of the current capacity structure. That means that annual capacity revenues under an RPM approach would surpass any single year of capacity revenues since PJM implemented its wholesale capacity markets. Because of the locational variance in capacity prices, the Eddystone and Limerick plants would earn significantly higher revenues by 2007; the Montour and Susquehanna plants would not see as large an increase until 2009.

Table 7: Breakdown of Revenue Sources as a Function of Resource Capacity Policy

Revenue Sources ($1000)

				Existing Capacity Market			RPM Market	
Station	Units	Category	2004	Low	Mid	High	2007-08	2009-10
- **Eddystone**	**1&2**	Energy	134,597	117,738	117,738	117,738	117,738	117,738
		Capacity	3,762	3,738	9,804	16,529	24,267	24,398
		Total	138,359	121,475	127,542	134,267	142,004	142,136
Limerick	**1&2**	Energy	870,302	721,980	721,980	721,980	721,980	721,980
		Capacity	14,686	14,590	38,273	64,524	94,727	95,241
		Total	884,988	736,570	760,253	786,505	816,708	817,221
Montour	**1&2**	Energy	461,766	399,022	399,022	399,022	399,022	399,022
		Capacity	9,972	9,907	25,988	43,813	14,053	52,837
		Total	471,738	408,929	425,010	442,835	413,075	451,860
Susquehanna	**1&2**	Energy	760,273	631,912	631,912	631,912	631,912	631,912
		Capacity	14,349	14,256	37,395	63,045	20,221	76,031
		Total	774,621	646,168	669,308	694,957	652,133	707,943
All Units		Energy	2,226,938	1,870,652	1,870,652	1,870,652	1,870,652	1,870,652
		Capacity	42,768	42,491	111,460	187,912	153,268	248,507
		Total	2,269,706	1,913,143	1,982,113	2,058,564	2,023,920	2,119,159

In terms of total dollar impacts, the RPM 2009 capacity revenues are close to $250 million dollars. When compared with today's revenues of just over $40 million dollars, RPM 2009 is about five times larger. When compared with the historical average revenues (Mid Case) of about $110 million, RPM 2009 capacity compensation is twice as large. These impacts are shown in the bar graph below.

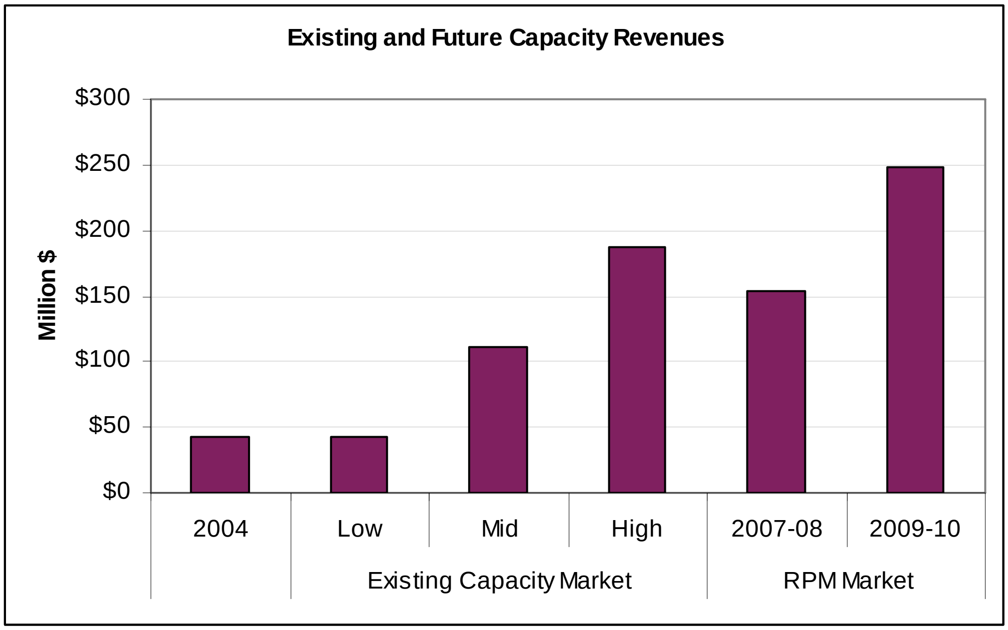

Figure 8: Forecast of Future Capacity Revenues at the Various Generating Facilities Under the Different Capacity Policies

Another way of analyzing the various scenarios is to look at the percentage of total revenues that the capacity revenues provide. Table 7 below shows that with today's historically low capacity prices, capacity revenues contribute 2-3% of total revenues for the four plants evaluated.[15] The average value for all four plants is 2%. Under the Mid Case for future revenues (the average revenues for the last six years), the capacity revenues contribute 6-8 % for each plant with an average of 6% for all four plants. In the RPM 2009 case, the capacity revenues range from 11-17% for each plant with an average of 12% for all four plants. Under RPM, the contribution of capacity revenues as a percentage of total revenues will increase by a factor of six times today's percentage contribution. When compared to the average contribution provided by capacity revenues over the last six years (the Mid Case), RPM doubles that percentage from 6% to 12%.

[15] For the purposes of this paper, we are only including energy and capacity revenue estimates for the total revenue values. It is possible that the four plants are receiving some additional compensation for the occasional provision of reserves or other compensated services. However, large base load plants, such as these four (and particularly the two nuclear units) are often fully dispatched for the energy market and not eligible for additional compensation.

Table 7: Breakdown of Revenue Sources as a Function of Resource Capacity Policy

Revenue Source Percentages

Station	Units	Category	2004	Existing Capacity Market Low	Mid	High	RPM Market 2007-08	2009-10
- **Eddystone**	**1&2**	Energy	97%	97%	92%	88%	83%	83%
		Capacity	3%	3%	8%	12%	17%	17%
		Total	100%	100%	100%	100%	100%	100%
Limerick	**1&2**	Energy	98%	98%	95%	92%	88%	88%
		Capacity	2%	2%	5%	8%	12%	12%
		Total	100%	100%	100%	100%	100%	100%
Montour	**1&2**	Energy	98%	98%	94%	90%	97%	88%
		Capacity	2%	2%	6%	10%	3%	12%
		Total	100%	100%	100%	100%	100%	100%
Susquehanna	**1&2**	Energy	98%	98%	94%	91%	97%	89%
		Capacity	2%	2%	6%	9%	3%	11%
		Total	100%	100%	100%	100%	100%	100%
All Units		Energy	98%	98%	94%	91%	92%	88%
		Capacity	2%	2%	6%	9%	8%	12%
		Total	100%	100%	100%	100%	100%	100%

From a policy point of view, one of the unanswered questions is what these higher capacity payments will achieve in regard to these four plants. It is reasonable to assume that these plants are already earning significant inframarginal revenues in the energy market, because their marginal fuel cost (coal and nuclear) is significantly below the cost of natural gas.[16] When one also takes into account the history of these plants[17], the higher capacity payments under RPM appear to be unrelated to any current financial hardship or enhanced services that are being provided. These higher payments take on the characteristics of complete windfalls. If this is the case, this poses serious questions about how an RPM-type compensation mechanism can produce wholesale power rates that meet the "just and reasonable" standard of the Federal Power Act. This paper concludes with that observation and encourages further discussion about and research into this topic.

[16] This is true despite the significant increases in coal costs over the last few years. Even if coal fuel prices doubled from early 2000 levels, natural gas fuel costs are still significantly higher.

[17] These plants were all reviewed as part of Pennsylvania's restructuring process and were eligible to receive stranded cost payments at the time that they were divested from their prior vertically integrated utility company. When one also considers the many years that these four plants operated under cost-of-service regulation (with its explicit allowance for a recovery of capital costs over time), it is possible that most of the capital costs of these plants have already been flowed back to investors.

Appendix A – Historical Revenue Analysis

Table 8: Historical Capacity Factors and Estimated Revenues

Historical Capacity Factors and Estimated Revenues											
						1999	2000	2001	2002	2003	2004
					PJM Capacity Price	52.9	60.6	95.3	33.4	17.5	17.7
					RT Energy Prices						
					PECO Peak	*36.8*	*36.1*	45.0	36.5	48.8	53.7
					PECO All-hours	28.4	28.5	33.1	28.2	38.7	45.0
					PPL Peak	*36.1*	*34.0*	41.2	35.3	47.1	50.4
					PPL All-Hours	28.2	27.1	31.1	27.4	37.3	42.8
Station	Units	Capacity	Type	Fuel		1999	2000	2001	2002	2003	2004
Eddystone	**1&2**	581	ST	Coal	CapFac	41.1%	46.3%	56.7%	47.1%	53.7%	49.1%
					Energy Price ($/MWh)	38.2	36.7	43.4	36.9	48.1	53.8
					Eng Rev ($1000)	$79,929	$86,561	$125,124	$88,607	$131,382	$134,597
					Cap Price ($/MW-day)	52.9	60.6	95.3	33.4	17.5	17.7
					Cap Rev ($1000)	$11,210	$12,841	$20,218	$7,083	$3,713	$3,762
					Total Rev ($1000)	$91,139	$99,401	$145,342	$95,689	$135,095	$138,359
Limerick	**1&2**	2,268	NUC	NUC	CapFac	*92.1%*	*95.3%*	*93.1%*	97.1%	97.6%	97.4%
					Energy Price ($/MWh)	28.4	28.5	33.1	28.2	38.7	45.0
					Eng Rev ($1000)	$519,526	$539,387	$611,753	$544,485	$751,710	$870,302
					Cap Price ($/MW-day)	52.9	60.6	95.3	33.4	17.5	17.7
					Cap Rev ($1000)	$43,759	$50,125	$78,924	$27,649	$14,495	$14,686
					Total Rev ($1000)	$563,285	$589,512	$690,677	$572,134	$766,205	$884,988
Montour	**1&2**	1,540	ST	Coal	CapFac	65.6%	71.3%	69.2%	72.1%	75.2%	73.0%
					Energy Price ($/MWh)	33.6	31.1	37.3	31.8	42.2	46.9
					Eng Rev ($1000)	$297,814	$298,930	$348,360	$309,355	$427,482	$461,766
					Cap Price ($/MW-day)	52.9	60.6	95.3	33.4	17.5	17.7
					Cap Rev ($1000)	$29,713	$34,035	$53,591	$18,774	$9,842	$9,972
					Total Rev ($1000)	$327,526	$332,966	$401,950	$328,129	$437,324	$471,738
Susquehanna	**1&2**	2,216	NUC	NUC	CapFac	*85.6%*	*86.2%*	*86.9%*	89.6%	91.4%	91.5%
					Energy Price ($/MWh)	28.2	27.1	31.1	27.4	37.3	42.8
					Eng Rev ($1000)	$467,719	$453,656	$524,244	$477,260	$661,246	$760,273
					Cap Price ($/MW-day)	52.9	60.6	95.3	33.4	17.5	17.7
					Cap Rev ($1000)	$42,755	$48,975	$77,115	$27,015	$14,163	$14,349
					Total Rev ($1000)	$510,475	$502,631	$601,359	$504,275	$675,409	$774,621
Notes:	Capacity values are for summer from EIA-920 data.										
	Fossil CF values from 1998 through 2002 are gross capacity factors from the CEMS data by way of Agrea										
	Second set of values from 2002 through 2004 are net capacity factors derived from EIA-920 data.										
	Nuclear News "U.S. Capacity Factors: Still on the Rise" by E. M. Blake, May 2004.										
											5/20/2005

Appendix B – Production Costs

Although we do not have recent operating costs for these facilities since they were sold to private owners, we do have costs for a number of previous years. Although some fuel costs have risen, the general view is that various economies have reduced other operating costs under private ownership.

The table below summarizes those costs for the late 1990's. For the nuclear plants Limerick and Susquehanna those total production costs are in the range from $13 to $17 per MWh. The Montour coal plant is also quite economical with production costs about $19 per MWh. Eddystone is an anomaly with costs averaging nearly twice as much as the nuclear plants. One likely possibility is that the oil steam and combustion turbine units at this station are boosting the overall production costs.

Table 9: Total Plan Production Costs* 1995-2000 ($/MWh)

	PLANT							
	EDDYSTONE		LIMERICK		MONTOUR		SUSQUEHANNA	
Year	Non-Fuel Cost	Tot Prod Cost	Non-Fuel Cost	Tot Prod Cost	Non-Fuel Cost	Tot Prod Cost	Non-Fuel Cost	Tot Prod Cost
1995	11.99	33.05	10.05	14.52	3.60	18.24	12.24	17.85
1996	9.10	32.15	9.60	14.13	5.05	20.26	10.61	16.20
1997					3.86	18.77	10.39	16.12
1998	11.56	34.12	9.59	14.43	3.68	18.05	11.56	17.22
1999	10.06	34.06	9.37	13.82	4.04	17.74	10.62	16.54
2000	5.62	34.98	6.39	10.52				
Grand Total	9.66	33.67	9.00	13.48	4.05	18.61	11.08	16.79
* From the Utility Data Institute (UDI) 2000 dataset with most data from FERC 1 Forms.								

With the exception of Eddystone, recent and future energy prices have been and are likely to continue to be twice as much or more than the plant production costs. Capacity payments further increase the revenue margin.

A further look at the Eddystone station from the FERC Form 1 reports indicates that in 2000 the average cost of delivered coal was $1.498/Million-BTU. Using a fairly high heat rate of 11,000 BTU/kWh, this gives an equivalent fuel cost of $16.4/MWh. Thus the total production cost for the Eddystone coal units in 2000 is reasonably about $22/MWh.

What about current production costs? Price data from the EIA Electric Power Monthly indicate that delivered coal costs in PA have increased by approximately 25% from 2000 to 2004. This would produce a $4 to $5 per MWh increase in fuel-based production costs. Energy prices have increased by about $15/MWh in that period.

Appendix C – Energy Futures Prices

Energy futures market data is not available for the specific regions, not even from PJM East. As the table below shows the closest relevant market is probably PJM West.

Table 10: Long-Term Electricity Forward Markets as of May 11, 2005

Long- Term Forward Markets May 11, 2005 ($/MWh) †

Region	Zone	Jun '05	Jul '05	Jul/Aug '05	Sep '05	Q4 '05	Jan/Feb '06	Mar/Apr '06	May '06	Cal 2006	Cal 2007
East	Mass Hub	68.25	79.25	77.50	67.75	70.75	94.00	71.75	65.00	75.50	72.50
East	PJM West	58.05	67.60	70.80	57.55	55.05	69.55	62.70	57.10	61.85	59.85
East	N.Y. Zone-G	75.05	86.45	84.45			77.10			78.95	
East	N.Y. Zone-J	92.15	112.05	110.55			96.35			97.95	
East	N.Y. Zone-A	60.75	70.00	69.00			68.35			65.35	
East	Ontario*	66.75	77.25	76.25			75.75			74.50	
East	TVA, into	53.55	63.35	64.15			62.45			56.00	
Central	Cinergy, Into	53.50	63.00	64.00	51.90	49.75	62.05	58.40	54.00	55.90	54.50
Central	NI Hub	51.00	59.85	62.25	51.00	49.00	61.75	57.75	53.45	54.60	52.40
Central	Entergy, Into	54.20	57.55	60.25	55.40	56.00	61.65	59.15	54.75	58.35	55.50
Central	ERCOT	60.30	65.00	68.05	61.15	58.00	63.00	61.40	58.10	61.95	51.35

*Ontario prices are in Canadian dollars
† All forward prices are for on-peak delivery

We have historical data on the price relationships between peak and off-peak prices between PJM West and PJM East and its sub regions. For 2004 the average prices for these locations were:

Table 11: PJM 2004 Real-time Energy Prices ($/MWh)

PJM 2004 Real-time Energy Prices ($/MWh)

Year	2004	**WESTERN HUB**	
Price	Period		
Month	Off-Peak	Peak	All-Hours
Annual	35.43	49.93	42.35

Year	2004	**EASTERN HUB**	
Price	Period		
Month	Off-Peak	Peak	All-Hours
Annual	37.59	54.91	45.85

Year	2004	**PECO**	
Price	Period		
Month	Off-Peak	Peak	All-Hours
Annual	37.04	53.68	44.98

Based on these historical relationships the projected all-hours prices based on the forward markets are as below.

Table 12: Projects All-Hours Energy Prices for PECO

PECO All-Hours Energy Price Forecast ($/MWh)	
2006	55.7
2007	53.9

These are considerably higher than the equivalent all-hours PECO price of $45.0/MWh in 2004 and indicate that the mid case energy price averages based on the period 2002-2004 (PECO all-hours $37.3/MWh) used in the previous analyses are very conservative in estimating future energy revenues.