CASE NO. 11-1775-E-P
CASE NO. 12-1655E-PC
CONSOLIDATED

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY

PUBLIC VERSION

DIRECT TESTIMONY

OF

J. RICHARD HORNBY

On behalf of the
Consumer Advocate Division
Of the
Public Service Commission
Of West Virginia

Dated: June 18, 2013 (Revised July 1, 2013)

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I. Introduction and Qualifications

Q Please state your name, business address, and position.

A My name is J. Richard Hornby. I am a Senior Consultant at Synapse Energy Economics, 485 Massachusetts Avenue, Cambridge, MA 02139.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues. Its primary focus is on electricity resource planning and regulation including computer modeling, service reliability, resource portfolios, financial and economic risks, transmission planning, renewable energy portfolio standards, energy efficiency, and ratemaking. Synapse works for a wide range of clients including attorneys general, offices of consumer advocates, public utility commissions, and environmental groups, U.S. Environmental Protection Agency, Department of Energy, Department of Justice, Federal Trade Commission and National Association of Regulatory Utility Commissioners. Synapse has over twenty professional staff with extensive experience in the electricity

Q Please summarize your work experience and educational background.

A I have over thirty years of experience in the energy industry, primarily in utility regulation and energy policy. Since 1986, as a regulatory consultant I have provided expert testimony and litigation support on natural gas and electric utility resource planning, cost allocation and rate design issues in over 120 proceedings in the United States and Canada. During that period my clients have included utility regulators, consumer advocates, environmental groups, energy marketers, gas producers, and utilities. Prior to 1986 I served as Assistant Deputy Minister of Energy for Nova Scotia where I helped prepare the province's first comprehensive energy plan and served on a federal-provincial board responsible for regulating exploration and development of offshore oil and gas reserves.

I was the lead author of reports projecting long-term avoided energy supply costs in New England prepared in 2007, 2009 and 2011. I was co-author of *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers*, a 2006 report prepared for the National Association of Regulatory Utility Commissioners (NARUC). In the past five years, I have filed testimony in electric resource planning cases in Arkansas, Kentucky, Michigan and West Virginia.

I have a Bachelor of Industrial Engineering from the Technical University of Nova Scotia, now the School of Engineering at Dalhousie University, and a Master of Science in Energy Technology and Policy from the Massachusetts Institute of Technology (MIT).

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia.

Q Have you testified previously before the West Virginia Public Service Commission?

A Yes. In 1988, I submitted testimony on gas transportation rate design in Case No. 240-G. In 1990, I submitted testimony regarding fuel adjustments to rates for Monongahela Power Company (Case No. 90-196-E-GI) and Potomac Edison Company (Case No. 90-197-E-GI). In May 2013 I submitted testimony regarding the application by Monongahela Power Company and The Potomac Edison

Company to acquire additional ownership interest in the Harrison plant (Case No. 12-1571-E-).

Q What is the purpose of your testimony?

The CAD retained Synapse to assist in their review of the application by Appalachian Power Company (APCo) for approval of the acquisition of 1,647 MW of coal-fired generating capacity presently owned by an affiliate, Ohio Power Company, in Case No. 12-1655-E-PC. My testimony describes my analysis of whether the proposed Asset Transfer is reasonable.

The CAD had also retained Synapse to assist in their review of the application by APCO and Wheeling Power Company (WPCo) (collectively, the Companies), in Case No. 11-1775-E-P for an evaluation of a possible merger.

Q What data sources did you rely upon to prepare your review of the Companies' request?

A My review relies primarily upon the Direct Testimony and Exhibits of Company in both this asset transfer case 12-1655 ("Asset Transfer Case") and the merger case 11-1775 ("Merger Case"). In the Asset Transfer case, I rely upon the direct testimony and exhibits of witness Torpey, and APCO's responses to data requests in this proceeding the Companies' June 2012 Update to the Integrated Resource Plan (IRP) it filed in Virginia as well as projections and data regarding future wholesale market prices of natural gas, electric energy and electric capacity.

Q Are you sponsoring any exhibits?

A Yes, I am sponsoring the following exhibits:

Exhibit (JRH-1) Resume of James Richard Hornby

Exhibit __(JRH-2)	APCo Summary Results – Expansion Plans through 2023 and Base scenario Cumulative Present Worth (CPW) by resource alternative by year
Exhibit __(JRH-3)	APCo Projected Capacity Position Before, and After, acquiring New Capacity
Exhibit __(JRH-4)	CPW of selected AEP resource alternatives under Base Scenario assuming the overnight cost of new NGCC is $1,000/kW
Exhibit __(JRH-5)	Costs of Existing Ohio Gas Capacity
Exhibit __(JRH-6)	PJM Capacity Market Prices (RTO) $/MW-day, Actual and Projected
Exhibit __(JRH-7)	APCo Fuel and Energy Price Input Assumptions and CPW Results by Scenario
Exhibit __(JRH-8)	EIA AEO 2012 Fuel Input Assumptions for selected Cases
Exhibit __(JRH-9)	Natural Gas Prices ($/MMBtu). Actual and Projected
Exhibit __(JRH-10)	PJM Energy Market Prices ($/MWh), Actual and Projected
Exhibit __(JRH-11)	Comparison of PJM Market Price Projections – APCo Base scenario, Synapse AEO 2012 Reference Gas scenario, FirstEnergy
Exhibit __(JRH-12)	Synapse AEO 2012 Reference Gas scenario Results
Exhibit __(JRH-13)	APCo Responses to Selected Data Requests
Exhibit___(JRH-14)	Synapse report on PJM Capacity market

II. Summary, Conclusions and Recommendations

Q Please summarize the proposed Asset Transfer.

A The Companies propose to acquire 1,647 MW of existing coal-fired capacity at the Amos and Mitchell plants located in West Virginia. The acquisition would occur through an initial transfer of that capacity from Ohio Power Company (OPCO), an affiliate, to AEP Generation Resources (AEP GenCo), an unregulated merchant power affiliate, and a subsequent transfer from AEP Generation Resources to APCO. Under the Asset Transfer APCO would acquire 67% of Amos Unit 3 ("AM3") or 867MW, which would give it a 100% ownership of that plant. APCo would also acquire a 50% interest in Mitchell Units 1 and 2 ("ML12") or 780MW. APCO would acquire these units at their net book value for approximately $1 billion net of accumulated depreciation.

Q Please summarize APCO's rationale for the proposed Asset Transfer.

A APCO is projecting a deficit of 98 MW between its PJM unforced capacity ("UCAP") obligation in 2014 and the capacity it currently owns or controls.[1] This projection assumes APCO receives approval to merge with WPCO effective January 1, 2014, APCO forecasts its capacity deficit will increase to 1,535 MW by 2020 due to the scheduled retirement of several existing coal units and projected load growth. According to Company witness Torpey, APCO's economic analysis of five resource alternatives indicates that the Asset Transfer is the least-cost solution over their thirty year study period (2011-2040).

[1] The unforced capacity of a generating unit is less than its installed capacity because it reflects the probability of outages based on prior performance.

Q. **Please summarize the major findings from your review of APCO's request.**

A My two major finding are as follows:

First, the Asset Transfer will result in APCO having a significant surplus of capacity through 2020 if the merger with WPCO is not completed within that timeframe. In contrast, acquiring AMOS 3 would meet APCo's capacity requirements through 2020 if the merger with WPCO is not completed.

Second, even if the APCO and WPCO merger occurs within the 2020 time horizon, APCO still faces uncertainty in the long-term in terms of future load, costs of new resource alternatives, natural gas prices, PJM wholesale capacity market prices, PJM wholesale energy market prices, and regulation of carbon emissions. Some version of the AM3 Transfer resource alternative will balance the goals of minimizing rates and of stabilizing rates in the face of uncertainty better than the Asset Transfer. (The AM3 Transfer resource alternative entails acquiring AMOS 3 now and acquiring additional capacity through purchases and new construction through 2018).

Q Please summarize your major conclusion and recommendation regarding the proposed Asset Transfer.

A My conclusion is that the proposed Asset Transfer is not reasonable and is adverse to the public interest. Instead, acquiring Amos 3 is a preferable strategy for meeting customer requirements at reasonable rates.

I recommend that the Commission approve only the acquisition of Amos 3 at this time. The Commission should also require the Company to reassess the resource alternatives available to it from June 2017 onward, including hedging strategies, based upon the results of an RFP for capacity and associated energy in various quantities for various durations.

III. BACKGROUND

Q Please summarize APCO's projected deficit in capacity and energy.

A APCO's projected deficit in capacity and energy is based upon its assumption that it will receive approval to merge with WPCO effective January 1, 2014 and on an impending change in its responsibility for owning or controlling sufficient capacity to meet its reserve obligations and annual load. The latter change arises from the fact that the existing AEP Pool Agreement under which APCo has been operating expires on December 31, 2013 and will be replaced by a Bridge Agreement with its affiliates on January 1, 2014. At the end of the Bridge Agreement (May 31, 2015) APCO will operate under a new Power Coordination Agreement ("PCA") with its affiliates. Under the PCA, APCO will be required to own or control sufficient capacity to meet its reserve obligations and annual load.

Based on the assumed merger with WPCO, APCO is projecting a deficit of 98 MW between its PJM unforced capacity ("UCAP") obligation in 2014 and the capacity it currently owns or controls. APCO forecasts its capacity deficit will increase to 1,335 MW by 2020 due to the scheduled retirement of several existing coal units in 2015 and projected load growth through. WPCO's contribution to the PJM UCAP obligation through 2020 is expected to be approximately 550MW.

Q. Please summarize the economic evaluation APCo conducted to evaluate its resource alternatives for eliminating its deficit in capacity and energy.

A. APCo evaluated the resource alternatives for eliminating its deficit in capacity in three major steps.

First, APCO identified five possible resource alternatives for eliminating its deficit in capacity and meeting the demand and energy requirements of its customers through 2040. APCo has labeled these alternatives as Market, Optimization, Asset Transfer, AM3 Transfer and ML12 Transfer.

Second, APCo developed three scenarios to represent the range of possible market conditions under which it might operate through 2040. APCo labels the three scenarios Base, Lower Band and Higher Band.

Third, the Company developed projections of the revenue requirements associated with each resource alternative under each of the three future scenarios. The Company developed those projections by simulating the operation of its system for each resource alternative under each scenario using Strategist, a computer simulation model.

Q. Please summarize the capacity expansion plans APCo identified through its economic analysis.

A. Under the Asset Transfer resource alternative APCo would acquire 1,647 MW in 2014 which would meet its requirements through 2024. Under the AM3 Transfer, ML12 Transfer and Optimization resource alternatives APCo would acquire up to 1,547 MW by 2020 through a combination of purchases of capacity through 2017 plus acquisition of various mixes and types of generating capacity through purchases and construction. Under its Market resource alternative APCo's analysis indicated that it would purchase up to 1,349 MW by 2020 and 1,489 by 2024. (Note that APCo constrained Strategist from choosing to purchase or building generating capacity prior to 2024 under the Market scenario).

Figure 1, drawn from Exhibit___(JRH-2), provides a summary of the quantities and types of capacity APCO would acquire under each of its resource alternatives through 2020.

Figure 1

APCo Resource Alternatives through 2020 (ICAP) in MW								
		2014	2015	2016	2017	2018	2019	2020
Comment		Bridge Agreement to May 2015			APCo can bid into PJM Base auctions starting May 2014 for 2017/2018 year			
Resource Alternative	Resource Portfolio (1)							
Asset Transfer	AMOS 3	867	867	867	867	867	867	867
	Mitchell 1 & 2	780	780	780	780	780	780	780
	Sub-Total	1,647	1,647	1,647	1,647	1,647	1,647	1,647
Market	Purchases	***122***	***1,255***	***1,338***	***1,305***	***1,338***	***1,334***	***1,349***
AM3 Transfer	AMOS 3	867	867	867	867	867	867	867
	Purchases (2)		***388***	***471***	***438***			
	new gas capacity (3)					**680**	680	680
	Sub-Total	867	1,255	1,338	1,305	1,547	1,547	1,547
ML12 Transfer	Mitchell 1 & 2	780	780	780	780	780	780	780
	Purchases (2)		***475***	***558***	***525***			
	new gas capacity (3)					**768**	768	768
	Sub-Total	780	1,255	1,338	1,305	1,548	1,548	1,548
Optimization	Purchases	***122***	***1,255***	***1,338***	***1,305***			
	new gas capacity (3)					**1,448**	1,448	1,448

APCo's economic analysis indicates that it would have to acquire additional capacity from 2024 onward under all five resource alternatives under each of its three scenarios.

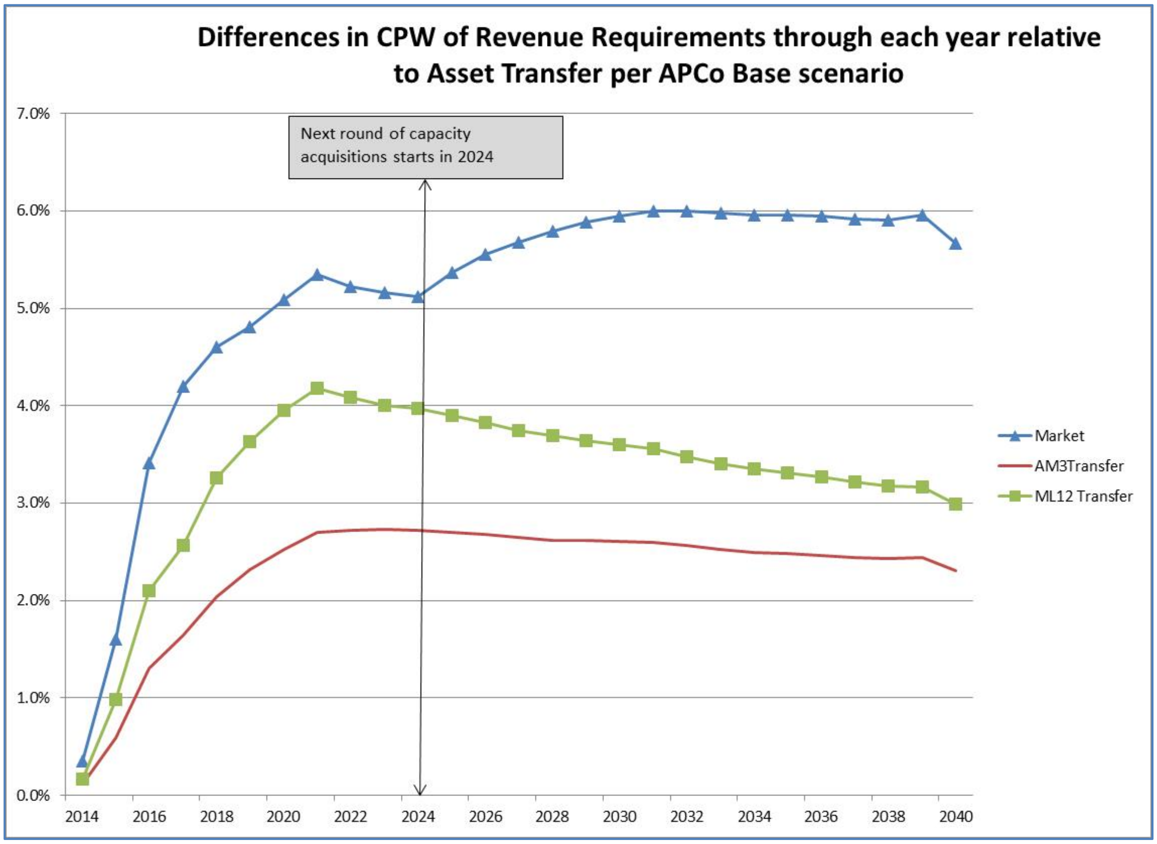
Q. Please summarize APCo's estimate of the revenue requirements of those five resource alternatives

A. APCO's economic analyses indicate that the Asset Transfer resource alternative would have the lowest cumulative present worth ("CPW") of revenue requirements over the 2011-2040 study period under each of its three scenarios. Throughout my testimony I report CPW results for the period 2014 to 2040, since the revenue requirements do not begin to differ until 2014. I also report some CPW results for the period 2014 to 2025 since APCo faces somewhat less uncertainty through that period.

Under its Base scenario, APCO projects that the CPW's of the AM3 Transfer, ML12 Transfer, Market and Optimization strategies would be higher than the

Asset Transfer by 2%, 2.6%, 4.9 %, and 4.5% respectively. Figure 2, drawn from Exhibit___(JRH-2), plots the difference between the CPW of the Asset Transfer and the CPW's of the AM3 Transfer, ML12 Transfer and Market strategies in each year of the study period according to APCo's estimates.

Figure 2



Q. Please summarize APCo's rationale for proposing the Asset Transfer to eliminate its deficit in capacity and energy.

A. According to Mr. Torpey, APCo concluded that the Asset Transfer was the least-cost solution, and in the long-term interest of APCo's customers based upon the results of its economic analyses.

Q. Please describe the approach you used to determine if the proposed Asset Transfer was reasonable.

A. I treated the Company's application as equivalent to a request for rate relief and reviewed that request in the same level of detail as a base rate filing. Specifically I reviewed the validity of the key input assumptions underlying the Company's projection of revenue requirements for each resource option under each future scenario. I followed this rate-making proceeding approach because APCo will ultimately seek to recover the fixed and variable costs associated with the Asset Transfer in its rates.

Q. Will ratepayers bear the majority of the financial risk under any resource strategy that the Company ultimately implements?

A. Yes. Ratepayers bear the majority of the financial risk under any resource strategy the Company ultimately implements because their rates are based upon the revenue requirements that result from that strategy. In particular they bear the risk of paying the fixed costs of each new resource APCo acquires because the Company will recover those fixed costs in its base rates regardless of whether that resource ultimately proves to be part of a least cost solution in the long-term.

Q. How do the incremental revenue requirements associated with the Asset Transfer you expect the Company to seek through a future increase in its base rates compare with the increase in base rates it requested in its most recent general rate proceeding.

A. If the Asset Transfer is approved, CAD witness Harris estimates that APCo would ultimately request an increase in rates in the order of $99 million. By comparison, that is approximately twice the amount the Commission approved in APCO's most recent general rate case ($51.8 million per the Commission's March 30, 2011 order in Case No. 10-0699-E-42T)

Q. Is it more difficult to assess the reasonableness of its request in this proceeding than its request in a general rate proceeding?

A. Yes. In order to determine the reasonableness of a utility-requested revenue requirement in any type of rate proceeding, the parties generally follow two basic steps. They review the Company's support for the input values it has used to calculate its revenue requirements and also the mathematical accuracy of its calculation of revenue requirements based upon those input values. While I do not wish to minimize the time and effort that parties put into verifying the reasonableness of the revenue requirements in general rate proceedings, I consider it more difficult to execute those two steps in the type of long-term resource planning proceeding in which we are currently engaged.

In this proceeding the parties must verify the Company's support for assumptions for 30 years as well as the mathematical accuracy of its calculations using those assumptions. In contrast, in a general rate proceeding in West Virginia, the parties review the utility's calculation of revenue requirements for a historical test year, thus many of the inputs are actual or close to actual costs, and the costs are limited to one year.

Given the uncertainty associated with the values of key input assumptions over that planning horizon it is particularly important that all parties have a clear understanding of the basis for the Company's key input assumptions regarding resource costs and of the range of future market and regulatory conditions it may face. It is particularly important to "stress test" those assumptions under a range of realistic possible future scenarios.

IV. ASSESSMENT OF APCo ECONOMIC ANALYSIS

Q Please summarize the method APCo used to analyze the economics of the resource alternatives it considered.

A. APCo used a computer simulation model, Strategist, to analyze the economics of five resource alternatives over a 30 year period, 2011 to 2040, under each of its three scenarios. APCo did this by running Strategist 15 times, i.e., three runs per resource alternative for five resource alternatives.

For a given resource alternative APCo would enter its forecast of customer demand and energy by year, the characteristics of its existing resources, APCO's predetermined resource selections and constraints, and the characteristics of new resources that it allowed Strategist to choose between. For example, for the AM3 Transfer resource alternative APCo required Strategist to acquire AM3 Transfer in 2014 and prohibited Strategist from adding any additional new resources until 2018.

To evaluate that resource alternative for a given scenario, APCo would then enter that scenario's forecast prices for coal, natural gas and PJM energy market prices. Finally, APCo would then run Strategist to meet the forecast demand each year by allowing Strategist to add further new resources when needed, subject to APCo's predetermined timing constraints, and to meet energy requirements each year by dispatching each available resource in order of its relative production cost, i.e., in economic merit order.

The outputs from a Strategist run are year by year projections of variable costs for each resource, existing and new, plus year by year projections of incremental fixed costs associated with the acquisition of new resources. APCo used those projections to calculate the year by year incremental revenue requirements for that resource alternative under that scenario.

Q What areas of concern did you identify in your review of the Company's economic evaluation?

A My review of the Company's economic evaluation identified concerns with the load forecast assumption underlying its projected capacity deficit, the resource alternatives it evaluated and the future scenarios it evaluated.

APCo Projected Capacity Position

Q Please summarize APCo's projected capacity deficit.

A APCo is projecting a UCAP deficit of 98 MW in 2014 increasing to 1,335 MW by 2020. That projection assumes APCo and WPCo will receive approval to merge effective January 1, 2014, and also reflects the scheduled retirement of several of its existing coal units in 2015 and projected load growth through 2020. APCO is proposing the Asset Transfer to address that projected capacity deficit.

Q What is your concern with the Company projection of its capacity deficit?

A My concern arises from the capacity acquisition implications of a rejection of, or multi-year delay in, the merger of APCo and WPCo.

There is possibility that the merger may not be approved, or if approved that its effective date may be delayed. For example, APCO must have approval of the Virginia State Corporation Commission to implement the merger.

However, staff of the Virginia State Corporation Commission has filed testimony opposing the merger.[2]

[2] Pre-Filed Testimony of Patrick W. Carr, page 17

If the merger is not approved, or if its effective date is delayed a few years, APCo will have a much smaller capacity deficit. For example its deficit by 2020 would be 776, rather than 1,335, as shown on line 11 of in Figure 3 drawn from Exhibit___(JRH-3).

If the merger is delayed, or does not occur, and the Asset Transfer is approved APCo would have a significant surplus of capacity, for example 759 MW by 2020, as shown on line 12 of Figure 3. In contrast, if APCO just acquires AMOS 3 at this point, and the merger was delayed through 2020, APCo would have sufficient capacity to cover its deficit through that year, as shown on line 13 of Figure 3. Moreover, if APCO acquires AMOS 3 now and the merger is only delayed a few years, APCo retains the flexibility to meet its capacity deficit through some version of its AM3 Transfer resource alternative. As shown in Figure 1, the AM3 Transfer alternative consists of acquiring AMOS 3 now and of acquiring additional capacity between 2015 and 2020 through a combination of purchases and construction of new gas capacity. Line 9 of Figure 3 indicates that the AM3 Transfer would meet APCO's requirements, albeit with somewhat higher purchases from 2015 through 2017 as indicated in Figure 1.

Figure 3

APCo projection of PJM stand-alone Capacity Position (UCAP) in MW										
Line	**I. Assumes APCo/WPCo merger effective 2014**		**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1	**PJM UCAP Obligation**	**APCO**	6,326	6,426	6,577	6,566	6,594	6,639	6,684	6,717
2		**WPCO**	-	538	553	551	555	559	558	561
3		**Total**	**6,326**	**6,964**	**7,130**	**7,117**	**7,149**	**7,198**	**7,242**	**7,278**
4	**Existing Capacity + Demand Side**	**Capacity**	6,376	6,675	5,654	5,500	5,506	5,504	5,538	5,531
5		**Demand Side**	133	190	232	287	348	369	384	410
6		**Total**	**6,509**	**6,865**	**5,886**	**5,787**	**5,854**	**5,873**	**5,922**	**5,941**
	Surplus / (Deficit)									
7		**Before new capacity**	183	(99)	(1,244)	(1,330)	(1,295)	(1,325)	(1,320)	(1,337)
8		**with Asset Transfer**	183	1,427	292	205	240	210	215	198
9		**with AM3 Transfer**	183	690	(92)	(93)	(89)	105	110	93
	II. Assumes APCo/WPCo merger not approved / delayed		2013	2014	2015	2016	2017	2018	2019	2020
10	**PJM UCAP Obligation**	**APCO**	6,326	6,426	6,577	6,566	6,594	6,639	6,684	6,717
	Surplus / (Deficit)									
11		**Before new capacity**	183	439	(691)	(779)	(740)	(766)	(762)	(776)
12		**with Asset Transfer**	183	1,965	845	756	795	769	773	759
13		**with AMOS 3**	183	1,228	104	22	61	36	40	26
	UCAP of resource alternatives									
14		**Asset Transfer**		1,526	1,536	1,535	1,535	1,535	1,535	1,535
15		**AM3 Transfer**		789	1,152	1,237	1,206	1,430	1,430	1,430
16		**AMOS 3**		789	796	801	802	802	802	802

APCo Resource Alternatives

Q. Do you agree with each of the Company's assumptions regarding the capital cost of a new NGCC?

A No. In its evaluation of resource alternatives using Strategist APCo assumes the capital cost of a new NGCC, excluding financing, to be **BEGIN CONFIDENTIAL END CONFIDENTIAL**. That capital cost is referred to as an "overnight" cost.

APCo's assumption is substantially higher than the capital cost of approximately $1,000 per kW implied by Mr. Torpey's statement on page 20 of his Direct Testimony that $662/Kw is a 35% discount from the overnight cost of a new NGCC. That estimate is also higher than recent published assumptions from various other sources, which range between $800/kW to $1,000/kW. Those other sources include the Monongahela Power August 2012 Resource Plan, the PacifiCorp 2013 IRP, Energy Information administration ("EIA") Annual Energy Outlook ("AEO") AEO 2012, AEO 2013 and a June 2011 report by the Brattle Group for PJM. The only source with a projection above $1,000/KW is a 2012 Black and Veatch report for the National Renewable Energy Lab.

Q. Have you prepared revised projections of revenue requirements using a lower capital cost estimate for new NGCC units?

A. Yes. I have prepared revised projections using a capital cost of $1,000/kW. Based upon that lower projection the differentials between the CPW of the Asset Transfer and the CPW's of the AM3 Transfer and the ML12 Transfer resource alternatives drop from AEP's estimates of 2.3% and 3.0% to 1.3% and 1.8% respectively. Figure 4, drawn from Exhibit___(JRH-4), presents the difference between the CPW of the Asset Transfer assuming $1,000/kW and the CPW's of AM3 Transfer and ML12 Transfer with the same assumption.

FIGURE 4

APCo Base Scenario CPW Results as Filed and at NGCC at $1,000/kW

CPW results (2014-2040)	Resource Alternative		
	Asset Transfer	AM3	ML12
APCo as filed	$31,543,275	$32,265,395	$32,479,749
Cost / Savings over Asset Transfer		$ 722,120	$ 936,474
		2.3%	3.0%
APCo with new NGCC at $1000/kW	$ 31,298,668	$31,714,344	$31,876,347
Cost / Savings over Asset Transfer		$ 415,676	$ 577,680
		1.3%	1.8%

Q Did your review find that the Company failed to evaluate lower cost existing gas capacity resources owned by OPCo?

A Yes. According to response to CAD IRP-4.3, APCo selected the Amos and Mitchell capacity as resource alternatives based upon its qualitative screening of

"…all of the assets of Ohio Power Company, which have historically been used to provide power to APCo.." However, it appears that APCO failed to consider other potentially cost-effective existing gas capacity owned by OPCo.

OPCo has natural gas fired units which AEP acquired for, and used, to supply the AEP pool. This capacity consists of a gas-fired combined cycle unit, the 830 MW Waterford unit AEP acquired in 2005 and a gas-fired combustion turbine capacity at the Darby facility AEP acquired in 2007. According the press releases AEP issued when it acquired those units, they each have a much lower net book value than the Amos or Mitchell units, as indicated in Figure 5 from Exhibit___(JRH-5).

FIGURE 5

OPCo Existing Gas Capacity		
Unit	**Type**	**AEP Acquisition Cost/kW**
Waterford	821 MW CC	$ 268
Darby	480 MW CT	$ 224

In a response to CAD data request B-5 in the merger case APCo stated that its opportunity to acquire capacity from OPCo was limited to the AMOS 3 and Mitchell units *because those were the only units that AEP management decided to make available to it*.

It is interesting to note that AEP GenCo will acquire and retain most of those existing low capital cost gas units. The fact that these units are located in Ohio should not be an issue since AEP has been using them to meet the AEP fleet requirements.

Q. Please summarize APCo's rationale for not soliciting bids for long-term power purchase agreements or existing CT and CC capacity.

A. Mr. Torpey, on page 18, maintains that the costs of capacity and energy APCo has assumed for a new NGCC are a reasonable proxy for the bids APCo would receive in response to a solicitation for a long-term PPA for capacity and energy. On page 18 he maintains that these APCo projections are also reasonable proxies for the bids APCo would receive in response to a solicitation to buy existing CT and CC units.

Q. Please comment on Mr. Torpey's position regarding bids for long-term power purchase agreements or existing CT and CC capacity.

A. Mr. Torpey's position does not withstand scrutiny. First, APCo's assumption regarding the capital cost of a new NGCC is high, as I have noted.

Second, parties who would submit bids to provide APCo capacity and/or energy under a long-term PPA or through the purchase of an existing generating unit would have their own estimates of the long-term market value of that capacity and energy. It is reasonable to expect prospective bidders to have a range of estimates of that long-term market value. For example, in this proceeding APCo has presented three different long-term market scenarios, i.e. Base, Lower Band and Higher Band. In addition, some prospective bidders might offer more attractive bids than others because of their particular financial circumstances. For example, approximately 6,000 MW of new NGCC capacity cleared in the PJM Base Residual Auction ("BRA") for 2015/2016 and another 5,000 MW cleared in the 2016/2017 BRA.[3] Some of the owners of that new capacity may be interested in entering a long-term agreement in order to obtain a guaranteed annual revenue stream.

[3] *2016/2017 RPM Base Residual Auction Results*, PJM, Table 8.

Finally, under four of its resource alternatives APCo would be acquiring significant quantities of capacity and energy starting in 2018. Therefore, the fact that some prospective bidders might bid to begin offering APCO capacity and energy in the 2017/2018 PJM delivery year should not be considered a problem.

APCo Scenarios

Q. Please summarize the three future scenarios the Company modeled in Strategist in order to evaluate the five resource alternatives it considered.

A. APCo evaluated its five resource alternatives under three scenarios. They are:

1. Base. This scenario assumes PJM capacity prices of $85 per MW-day in calendar 2014 but forecasts those prices to increase substantially from 2015 onward. For 2014 this scenario assumes coal delivered to APCo units at $85 per ton for CAPP CSX and $17.50 per ton for Powder River Basin. It assumes natural gas delivered at $5.86 based on a Henry Hub price of $5.38/MMBtu. It assumes PJM energy prices of $50.22/MWh on-peak and $$30.17/MWh off-peak.
2. Higher Band. This scenario assumes delivered prices for coal and natural gas prices are approximately 17% to 19% percent higher than Base scenario levels, and PJM energy market prices are 19% higher.
3. Lower Band. This scenario assumes delivered prices of coal and natural gas prices are each 11 percent lower than Base scenario levels, and PJM energy market prices are 8% lower.

The Company developed its commodity price projections for these scenarios in September 2011.

Q What areas of concern did you identify in your review of the Company's three scenarios?

A My review identified concerns with APCo's projections of PJM wholesale capacity prices and with its assumed correlation between natural gas prices and coal prices.

PJM Capacity Price Projections

Q What is your concern with APCo's projection of PJM capacity prices?

A APCo's projections of PJM capacity prices for 2015 and 2016 are materially higher than the actual prices PJM has set for those years. Of more concern is the fact that APCo's projection of PJM capacity prices from 2017 onward is dramatically higher than any other projections I have seen. For example APCo's forecast from 2017 onward is substantially higher than either of the two projections that FirstEnergy used in the analyses it presented in the Harrison acquisition case. In addition, APCo's high projections are not consistent with the fact that PJM Capacity market prices have averaged 55% of the net cost of new entry ("net CONE") over the past 7 auctions. Finally. APCo's projections are not consistent with the market fundamentals driving PJM capacity market prices according to a review I recently completed. That review is provided as Exhibit___(JRH-14) to this testimony.

APCo's forecast of capacity market prices from 2014 onward are plotted as a solid line in Figure 6, which is drawn from Exhibit___ (JRH-6). That Figure also plots, as a dashed line, actual capacity prices through 2017 which have been set in the Base Residual Auctions held to date. Finally the Figure plots my projections as a line with triangles. My projection assumes capacity prices from June 2017 onward will average 55% of the net cost of new entry ("net CONE") from the 2016/2017 BRA escalating at APCo's assumed rate of inflation.

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Figure 6 PJM Capacity Market Prices, Actuals and Projected

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APCo's assumption of very high PJM capacity prices makes resource alternatives that rely upon existing coal unit capacity, and even new "steel in the ground" gas capacity appear more attractive than resource alternatives that would include purchases of capacity under long-term contracts at prices tied to the PJM capacity market. In addition, these projections tend to favor the Asset Transfer alternative because APCo projects to be a net seller of capacity through 2024 under that strategy.[4] APCo's calculation of the revenue requirements of each resource alternative includes an estimate of the revenues that alternative would receive

[4] Torpey Direct Testimony, JFT Exhibit No. 2, page 21.

from the sale of capacity into PJM, or the cost that alternative would incur to buy capacity from PJM. Thus, the higher the projected capacity price the higher the estimate of revenues from the sale of surplus capacity under the Asset Transfer resource alternative.

Assumed Correlation between coal prices and natural gas prices

Q Please summarize APCo's assumed correlation between coal prices and natural gas prices.

A APCo evaluates its five resource alternatives under three future scenarios that APCo considers will represent the range of plausible future market conditions under which APCo may operate in the future. APCo's projections of natural gas prices and coal prices for its Lower Band scenario and its Higher Band scenario assume that the prices of those two fuels are closely correlated, approximately 96% and 92% respectively.

In other words APCo assumes that coal prices will move in the same direction and at approximately the same rate of change as natural gas prices. For example, APCo's projected natural gas prices in its Lower Band scenario are approximately 11% less than in its Base scenario and its projected coal prices in the Lower Band are also approximately 11% lower.

As a result of those price assumptions, the economics of each of the resource alternatives relative to the Asset Transfer do not change materially under either the Lower Band or the Higher Band scenarios. For example, the absolute CPW of each resource alternative is approximately 5% less under the Lower Band than under the Base scenario. As a result, the CPW differentials of the resource alternatives relative to the Asset Transfer do not change materially.

The values of those input assumptions and the results for the resource alternatives are summarized in Figure 7, drawn from Exhibit___(JRH-7).

Q Do you agree with APCo's assumed correlation between coal prices and natural gas prices?

A. No. APCo's assumption regarding coal prices moving exactly in tandem with gas prices is not correct. As a result the outputs from APCO's Lower Band and Higher Band scenarios do not provide an adequate assessment of the performance of its resource alternatives under a realistic range of market conditions.

Q. What is the basis for your assertion that APCo's assumed correlation between coal prices and natural gas prices is not correct?

A. My assertion is based on two points. First, a review of EIA projections for natural gas and coal prices under several different future cases presented in AEO 2012 indicates that the EIA modeling does not indicate that coal prices will always move in the same direction, and by the same relative amounts, as natural gas prices. Instead, in some cases coal prices go up and natural gas prices go down. In other cases both prices increase but not by the same amounts. That review is presented in Figure 8 drawn from Exhibit___(JRH-8).

Figure 8

Change in Coal Minemouth Price from AEO 2012 Reference Case vs Change in Henry Hub Gas Price

AEO 2012 Case	2015	2025	2035
High economic growth	-11%	8%	53%
Low economic growth	-23%	-4%	-2%
Low coal cost	255%	754%	851%
High coal cost	591%	807%	1470%
High EUR	1%	2%	4%
Low EUR	-1%	3%	8%

Second, Kentucky Power Company ("KPCo), an affiliate of APCo, used this exact same set of commodity price projections and scenarios in the analyses it filed in the Big Sandy case.[5] In testimony filed in that proceeding, my colleague, Dr. Jeremy Fisher, presented analyses demonstrating that the assumed correlations were not reasonable.

Q If APCo's assumed correlation between coal prices and natural gas prices is not correct, what is the implication for its choice of future scenarios?

A. Since APCo's assumption that coal prices move almost exactly in tandem with gas prices is not correct, its Higher Band and Lower Band scenarios based on that assumed correlation do not represent a reasonable range of future market conditions.

Q Have you developed an additional scenario in order to evaluate the performance of the resource alternatives under a broader range of future market conditions?

A Yes. I refer to that additional scenario as the Synapse AEO 2012 Reference Gas scenario.

As its name implies this scenario uses the APCo coal prices from its Base scenario and the AEO 2012 Reference Case natural gas prices at the Henry Hub. In this scenario the projection of delivered natural gas prices equals the AEO Henry Hub projections plus the adders that APCo applied to its projection of Henry Hub prices in the Base scenario. I developed projections of PJM energy market prices for this scenario by applying the system-wide heat rates implicit in

[5] Direct Testimony of Jeremy Fisher, March 2011, Case No. 2011-00401, Kentucky Public Service Commission

APCo's projection of energy market prices to my projection of delivered natural gas prices. (The system-wide heat rate measures the relationship between the energy market prices in a given time period and the delivered gas prices in that period).

My projections of Henry Hub prices and PJM energy prices for the Synapse AEO 2012 Reference Gas scenario are presented in Exhibit___(JRH-9) and Exhibit____(JRH-10) respectively. This scenario uses my projection of PJM capacity prices from Exhibit___(JRH-6) and assumes the capital cost of a new NGCC will be $1,000/kW.

Q Why did you choose the Reference Case gas forecast from AEO 2012 rather than from AEO 2013?

A I chose the Reference Case gas forecast from AEO 2012 rather than from AEO 2013 based upon an analysis of Henry Hub price projections that Synapse prepared as part of the 2013 Avoided-Energy-Supply-Component Study ("AESC 2013 Study") for energy efficiency program administrators throughout New England. The AESC 2013 Study is scheduled to be released by mid-July. Our analysis of gas forecasts concluded that the AEO 2012 Reference Case forecast of Henry Hub prices provided a better starting point than the AEO 2013 Early Release forecast because the AEO 2012 Forecast was closer to current NYMEX futures as well as to forecasts published by other parties. The AESC 2013 Study has developed a forecast of Henry Hub prices from the AEO 2012 Reference Case by making three adjustments. The first is a downward adjustment to reflect the major change the EIA has made in its forecast methodology for Henry Hub prices and that the EIA has reflected in its AEO 2013 forecasts. The next two adjustments are increases to reflect our assessment of the market price marginal gas plays will require by 2020 and our assessment of the increased costs producers are likely to incur to reduce the adverse impacts of fracturing. The resulting AESC 2013 Base Case forecast of Henry Hub prices is quite close to the AEO 2012 Reference Case forecast. Since the AESC 2013 has not been finalized and published I chose the AEO 2012 Reference Case as a reasonable forecast.

Q. How do the forecasts of PJM market prices under the APCo Base Scenario and the Synapse AEO 2012 Reference Gas scenario compare to the scenarios FirstEnergy used in its analysis of the proposed Harrison acquisition?

A The forecast of PJM market prices under the APCo Base Scenario is comparable to FirstEnergy's forecasts of PJM market prices under the Economic Recovery case it used to analyze its resource alternatives in Case No. 12-1571-E-PC. The forecasts of PJM market prices under the Synapse AEO 2012 Reference Gas scenario are comparable to FirstEnergy's forecasts of PJM market prices under its Status Quo case in Case No. 12-1571-E-PC.

These comparisons are based on public information from Case No. 12-1571-E-PC, specifically the levelized cost of purchasing capacity and energy from the PJM market at a 75% capacity factor. As indicated in Figure 9, from Exhibit___(JRH-11), the levelized cost of purchasing capacity and energy from the PJM market at a 75% capacity factor under the APCo Base Scenario is $70/MWh, comparable to the FirstEnergy Economic Recovery case of $75/MWh. The levelized cost of purchasing capacity and energy from the PJM market at a 75% capacity factor under the Synapse AEO 2012 Reference Gas scenario is $58/MWh, comparable to the FirstEnergy Status Quo case of $59/MWh.

Figure 9 ($/MWh)

Levelized Costs of Purchasing Capacity and Energy from PJM at 75% capacity Factor ($2013/MWh, 2015-2034)			
Scenario	Capacity	Energy	TOTAL
APCo Base scenario	$ 14	$ 56	$ 70
FirstEnergy Economic Recovery case	$ 10	$ 65	$ 75
Synapse AEO 2012 Reference Gas scenario	$ 8	$ 50	$ 58
FirstEnergy Status Quo case	$ 6	$ 53	$ 59

Q Have you evaluated the performance of APCo's five resource alternatives under that scenario?

A Yes. I developed projections of the revenue requirements associated with each of APCo's five resource alternative under the Synapse AEO 2012 Reference Gas scenario. In order to present projections that reflect changing only that one assumption, these projections accept APCO's assumption that it will serve the WPCO load starting in 2014.

I developed those projections by simulating the operation of APCo's system for each resource alternative using the same Strategist computer model that APCo had used. Under the Synapse AEO 2012 Reference Gas scenario Strategist chooses to acquire 768 MW of NGCC capacity in 2018 under the AM3 Transfer alternative rather than 680 MW of CT under the APCo Base scenario.

In the next section of my testimony I compare the results from the Synapse AEO 2012 Reference Gas scenario to APCo's results for its Base scenario.

I. ASSESSMENT OF APCo PROPOSED ASSET TRANSFER

Q. Please compare the results of APCo's economic analysis of resource alternatives under its Base scenario to the results of your economic analysis of those alternatives under the Synapse AEO 2012 Reference Gas scenario.

A. In its economic analyses of resource alternatives under the Base scenario APCo projects the Asset Transfer resource alternative will have the lowest revenue requirement CPW over the 2011-2040 study period. APCo projects that the CPW's of the AM3 Transfer, ML12 Transfer, Market and Optimization strategies would be higher than the Asset Transfer by 2%, 2.6%, 4.9 %, and 4.5% respectively.

My economic analyses of resource alternatives under the Synapse AEO 2012 Reference Gas scenario projects the Asset Transfer resource alternative continues to have the lowest CPW of revenue requirements over the 2011-2040 study period for serving the combined load of APCo and WPCo. However the cost advantage of the Asset Transfer over the other resource alternatives is much smaller under the Synapse AEO 2012 Reference Gas scenario. In particular the CPW's of the AM3 Transfer, ML12 Transfer and Market strategies are only 0.4%, 0.8% and 1.8% higher than the Asset Transfer respectively.

Figure 10, drawn from Exhibit___(JRH-12), summarizes the differences between the key inputs for the two scenarios as well as the differences in estimates of revenue requirements through 2040.

Figure 10

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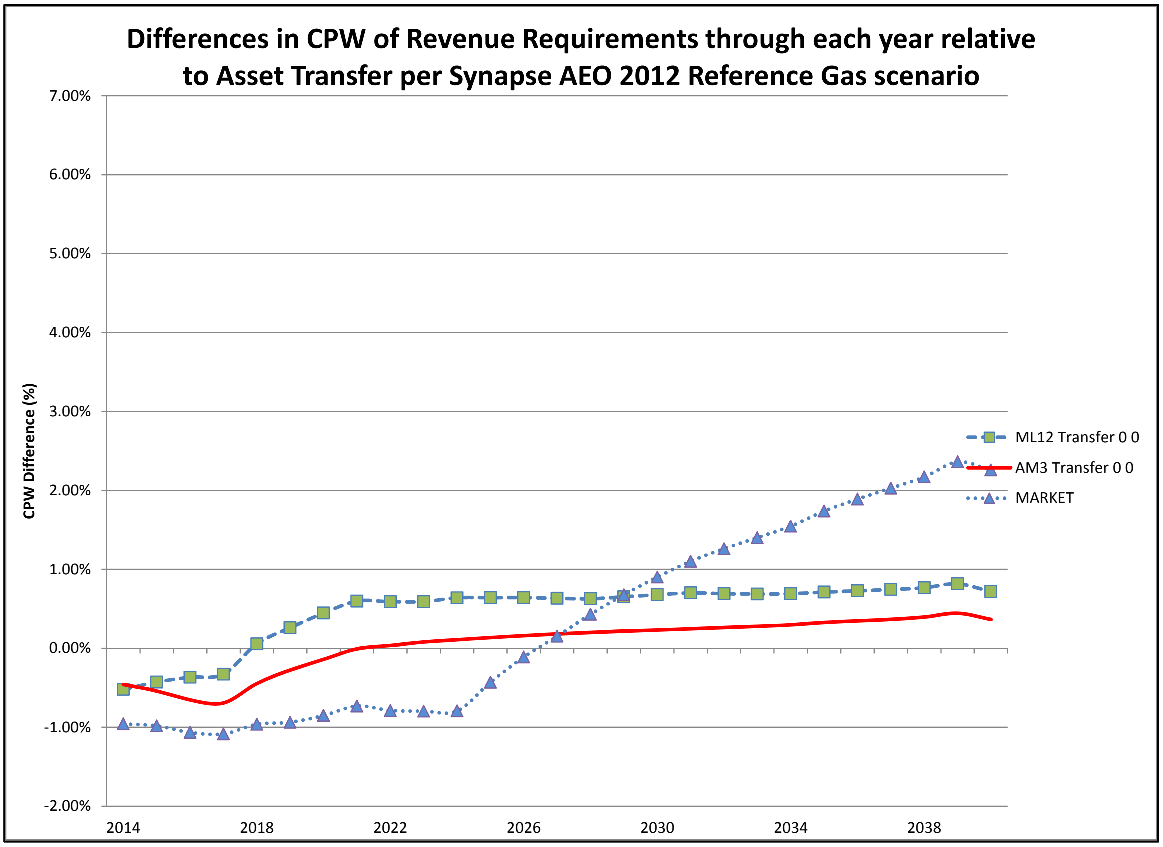
Figure 11, drawn from Exhibit___(JRH-12), plots the difference between the CPW of the Asset Transfer and the CPW's of the AM3 Transfer, ML12 Transfer and Market strategies in each year of the study period under my scenario.

FIGURE 11



The total CPW of the ML12 Transfer, AM3 Transfer, and Market resource alternatives through approximately 2020 are lower than the Asset Transfer. Those three resource alternatives become more expensive than the Asset Transfer on a cumulative basis in 2018, 2021 and 2030, respectively.

Q. What are the implications of your economic analyses of alternatives under the Synapse AEO 2012 Reference Gas scenario for APCo's request for approval of the proposed Asset Transfer.

A. APCo is requesting approval for the Asset Transfer on the grounds that it is the least-cost solution according to the results of APCo's economic analyses. The results of my economic analyses under the Synapse AEO 2012 Reference Gas scenario indicate that the Asset Transfer is only the least-cost solution mathematically for the set of projections that APCo has considered and assuming that APCo and WPCo are merged. The problem is that APCo's projections for key inputs such as future load, costs of new resource alternatives, natural gas prices, PJM wholesale capacity market prices, PJM wholesale energy market prices and regulation of carbon emissions are all subject to considerable uncertainty through 2040. That uncertainty increases the further one projects into the future. In the face of that uncertainty a difference in the CPW of revenue requirements through 2040 between the Asset Transfer alternative and the AM3 Transfer alternative that ranges between 1.3% and 0.4% is not sufficient justification to choose the Asset Transfer over the AM3 Transfer. Moreover, through 2025, a shorter time horizon with somewhat less uncertainty, the Market portfolio is less expensive than the Asset Transfer. Through that period the AM3 Transfer and ML12 Transfer resource alternatives are only slightly more expensive (0.2% and 0.8% respectively).

It is interesting to note that KPCo, an affiliate of APCo, using the same scenarios as APCo is using in this proceeding, ultimately decided to convert its Big Sandy unit 1 to a gas unit even though KPCo's projected the CPW of that option would be 3.6% higher than retrofitting Big Sandy unit 2 to comply with new environmental constraints.

Q. What is the key advantage of the AM3 Transfer alternative relative to the proposed Asset Transfer?

A. The key advantage of the AM3 Transfer alternative over the Asset Transfer is the flexibility it provides APCo to balance, in the face of uncertainty, the potentially conflicting goals of minimizing rates and of stabilizing rates. (The ML12 Transfer alternative has essentially the same advantages as AM3 Transfer but I focus on the AM3 Transfer. As noted above, the AM3 Transfer has a slightly lower CPW than the ML 12 Transfer.)

First, the AM3 Transfer alternative gives APCo considerable flexibility to respond to uncertainty regarding the timing of the APCo/WPCo merger. If APCO acquires AMOS 3 at this point, and the APCo/WPCo merger is delayed several years, or not approved. APCo will have sufficient capacity to cover its deficit through 2020. On the other hand, if APCO acquires AMOS 3 now and the merger is only delayed a few years, APCo retains the flexibility to meet its capacity deficit by acquiring additional capacity between 2015 and 2020 through a combination of purchases and construction of new gas capacity as it contemplates under the AM3 Transfer alternative.

Second, the AM3 Transfer alternative gives APCo considerable flexibility to take advantage of opportunities that may arise to acquire capacity and energy through a long-term power purchase agreement and/or the acquisition of an existing generating unit. Under the AM3 Transfer APCo assumes it will buy capacity on a short-term basis through 2017 and bring on a new gas CT or NGCC in 2018. Thus, under this alternative APCo would have time to issue a RFP for long-term capacity and energy and assess the resulting bids by early 2014, before making major cost commitments to the construction of new CT or NGCC units

Third, the AM3 Transfer alternative gives APCo the flexibility to further diversify its capacity and energy mix by adding more capacity from gas and other resources through 2024.

V. Conclusions and Recommendations

Q Please summarize the major findings from your analysis of the Companies' proposal.

A My two major finding are as follows:

First, the Asset Transfer will result in APCO having a significant surplus of capacity through 2020 if the merger with WPCO is not completed within that timeframe. In contrast, acquiring AMOS 3 would meet APCo's capacity requirements through 2020 if the merger with WPCO is not completed.

Second, even if the APCO and WPCO merger occurs within the 2020 time horizon, APCO still faces uncertainty in the long-term in terms of future load, costs of new resource alternatives, natural gas prices, PJM wholesale capacity market prices, PJM wholesale energy market prices, and regulation of carbon emissions. Some version of the AM3 Transfer resource alternative will balance the goals of minimizing rates and of stabilizing rates in the face of uncertainty better than the Asset Transfer. (The AM3 Transfer resource alternative entails acquiring AMOS 3 now and acquiring additional capacity through purchases and new construction through 2018).

Q Please summarize your major conclusion and recommendation regarding the proposed Asset Transfer.

A My conclusion is that the proposed Asset Transfer is not reasonable and is adverse to the public interest. Instead, acquiring Amos 3 is a preferable strategy for meeting customer requirements at reasonable rates.

I recommend that the Commission approve only the acquisition of Amos 3 at this time. The Commission should also require the Company to reassess the resource alternatives available to it from June 2017 onward, including hedging strategies, based upon the results of an RFP for capacity and associated energy in various quantities for various durations.

Q Does this complete your Direct Testimony?

A Yes.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA.
Senior Consultant, 2006 to present.
Provides analysis and expert testimony regarding planning, market structure, ratemaking and supply contracting issues in the electricity and natural gas industries. Planning cases include evaluation of resource options for meeting tighter air emission standards (e.g. retrofit vs. retire coal units) in Kentucky, West Virginia and U.S. Midwest as well as development of long-term projections of avoided costs of electricity and natural gas in New England. Ratemaking cases include electric utility load retention rate in NS, various gas utility rate cases and evaluation of proposals for advanced metering infrastructure (smart grid or AMI) and dynamic pricing in MD, PA, NJ, AR, ME, NV, DC and IL.

Charles River Associates (formerly Tabors Caramanis & Associates), Cambridge, MA.
Principal, 2004-2006, *Senior Consultant,* 1998–2004.
Expert testimony and litigation support in energy contract price arbitration proceedings and various ratemaking proceedings. Productivity improvement project for electric distribution companies in Abu Dhabi. Analyzed market structure and contracting issues in wholesale electricity markets.

Tellus Institute, Boston, MA.
Vice President and Director of Energy Group, 1997–1998.
Manager of Natural Gas Program, 1986–1997.
Presented expert testimony on rates for unbundled retail services, analyzed the options for purchasing electricity and gas in deregulated markets, prepared testimony and reports on a range of gas industry issues including market structure, strategic planning, market analyses, and supply planning.

Nova Scotia Department of Mines and Energy, Halifax, Canada.
Member, Canada-Nova Scotia Offshore Oil and Gas Board, 1983–1986.
Assistant Deputy Minister of Energy 1983–1986.
Director of Energy Resources 1982-1983
Assistant to the Deputy Minister 1981-1982

Nova Scotia Research Foundation, Dartmouth, Canada, *Consultant*, 1978–1981.
Canadian Keyes Fibre, Hantsport, Canada, *Project Engineer*, 1975–1977.
Imperial Group Limited, Bristol, England, *Management Consultant*, 1973–1975.

EDUCATION

M.S., Technology and Policy (Energy), Massachusetts Institute of Technology, 1979.
B.Eng., Industrial Engineering (with Distinction), Dalhousie University, Canada, 1973

APCo Resource Alternatives through 2020 (ICAP) in MW

Resource Alternative	Resource Portfolio (1)	2014	2015	2016	2017	2018	2019	2020
Comment		Bridge Agreement to May 2015			APCo can bid into PJM Base auctions starting May 2014 for 2017/2018 year			
Asset Transfer	AMOS 3	867	867	867	867	867	867	867
	Mitchell 1 & 2	780	780	780	780	780	780	780
	Sub-Total	1,647	1,647	1,647	1,647	1,647	1,647	1,647
Market	Purchases	***122***	***1,255***	***1,338***	***1,305***	***1,338***	***1,334***	***1,349***
AM3 Transfer	AMOS 3	867	867	867	867	867	867	867
	Purchases (2)		***388***	***471***	***438***			
	new gas capacity (3)					**680**	680	680
	Sub-Total	867	1,255	1,338	1,305	1,547	1,547	1,547
ML12 Transfer	Mitchell 1 & 2	780	780	780	780	780	780	780
	Purchases (2)		***475***	***558***	***525***			
	new gas capacity (3)					**768**	768	768
	Sub-Total	780	1,255	1,338	1,305	1,548	1,548	1,548
Optimization	Purchases	***122***	***1,255***	***1,338***	***1,305***			
	new gas capacity (3)					**1,448**	1,448	1,448

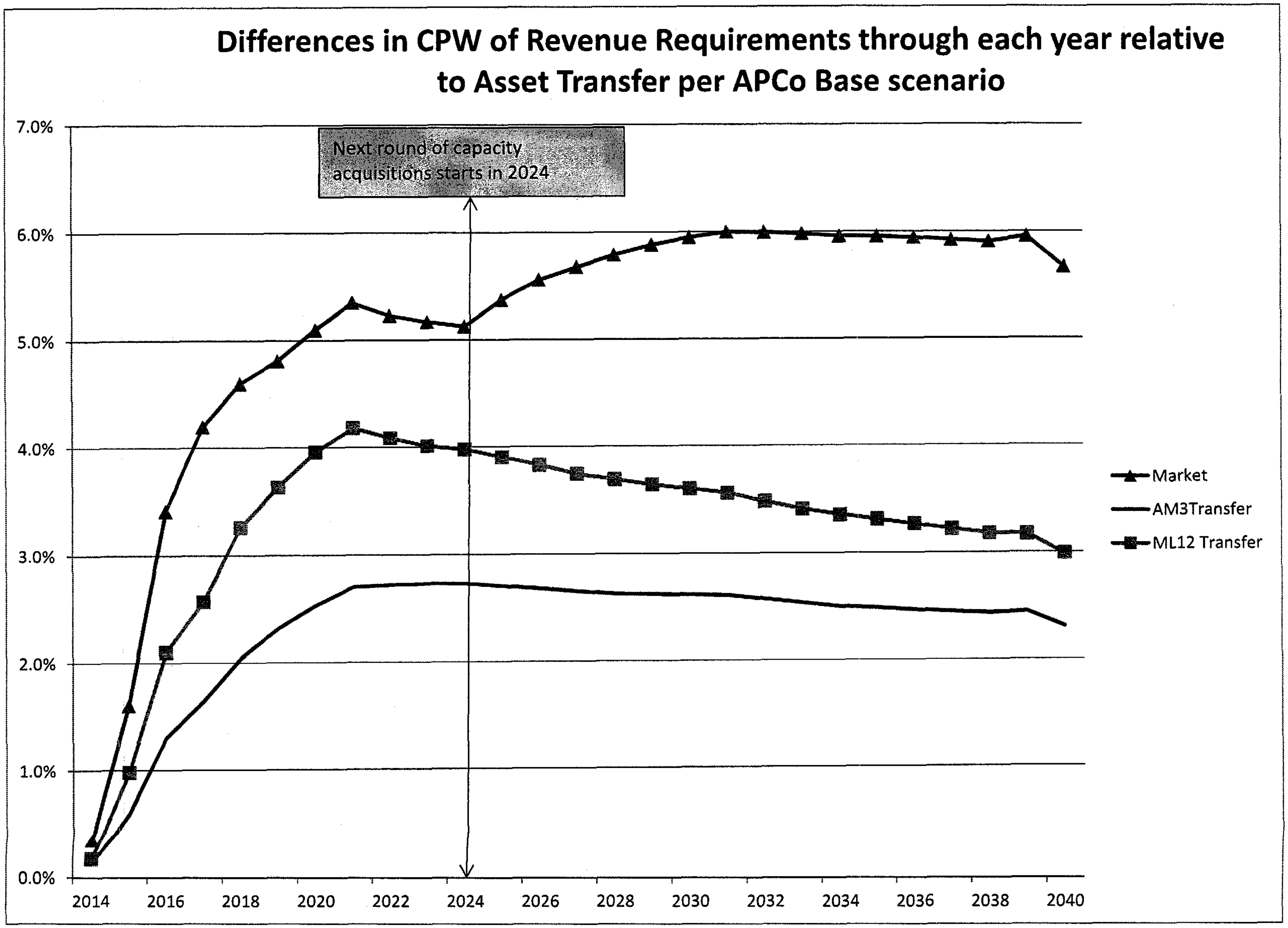
Sources

1. JFT Exhibit No. 2 page 23, Torpey Direct Testimony

2. Purchases = Market Purchases - Capacity Acquired in 2014

3. Same quantity of new gas capacity acquired in 2018 under each scenario but capacity type varies

Resource Altenative / Scenario	Base	Low Band	High Band
AM3 transfer	CT	CT	CC
ML12 Transfer	CC	CT	CC


Differences in CPW of Revenue Requirements through each year relative to Asset Transfer per APCo Base scenario
Next round of capacity acquisitions starts in 2024
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Market
AM3Transfer
ML12 Transfer

Exhibit___(JRH-3)

Line	APCo projection of PJM stand-alone Capacity Position (UCAP) in MW									
Line	I. Assumes APCo/WPCo merger effective 2014		2013	2014	2015	2016	2017	2018	2019	2020
1	PJM UCAP Obligation	APCO	6,326	6,426	6,577	6,566	6,594	6,639	6,684	6,717
2		WPCO	-	538	553	551	555	559	558	561
3		**Total**	**6,326**	**6,964**	**7,130**	**7,117**	**7,149**	**7,198**	**7,242**	**7,278**
4	Existing Capacity + Demand Side	Capacity	6,376	6,675	5,654	5,500	5,506	5,504	5,538	5,531
5		Demand Side	133	190	232	287	348	369	384	410
6		**Total**	**6,509**	**6,865**	**5,886**	**5,787**	**5,854**	**5,873**	**5,922**	**5,941**
	Surplus / (Deficit)									
7		Before new capacity	183	(99)	(1,244)	(1,330)	(1,295)	(1,325)	(1,320)	(1,337)
8		with Asset Transfer	183	1,427	292	205	240	210	215	198
9		with AM3 Transfer	183	690	(92)	(93)	(89)	105	110	93
	II. Assumes APCo/WPCo merger not approved / delayed		2013	2014	2015	2016	2017	2018	2019	2020
10	PJM UCAP Obligation	APCO	6,326	6,426	6,577	6,566	6,594	6,639	6,684	6,717
	Surplus / (Deficit)									
11		Before new capacity	183	439	(691)	(779)	(740)	(766)	(762)	(776)
12		with Asset Transfer	183	1,965	845	756	795	769	773	759
13		with AMOS 3	183	1,228	104	22	61	36	40	26
	UCAP of resource alternatives									
14		Asset Transfer		1,526	1,536	1,535	1,535	1,535	1,535	1,535
15		AM3 Transfer		789	1,152	1,237	1,206	1,430	1,430	1,430
16		AMOS 3		789	796	801	802	802	802	802
Notes	1	Row 3 - Row 2								
	2	7.7% per Response WVCAG 5-1, attachment 4, pages 1 and 4								
	3, 4, 5, 6	Figure 1, Torpey Direct Testimony								
	7	Row 6 - Row 3								
	8	Row 6 - Row 3 + Row 14								
	9	Row 6 - Row 3 + Row 15								
	10	Row 1								
	11	Row 11 - Row 10								
	12	Row 11 - Row 10 + Row 12								
	13	Row 11 - Row 10 + Row 13								
	14	Figure 1, Torpey Direct Testimony								
	15, 16	Synapse workbook for Exhibits 2 and 3								

APCo Base Scenario CPW Results as Filed and at NGCC at $1,000/kW

CPW results (2014-2040)	Resource Alternative		
	Asset Transfer	AM3	ML12
APCo as filed	$31,543,275	$32,265,395	$32,479,749
Cost / Savings over Asset Transfer		$ 722,120	$ 936,474
		2.3%	3.0%
APCo with new NGCC at $1000/kW	$ 31,298,668	$31,714,344	$31,876,347
Cost / Savings over Asset Transfer		$ 415,676	$ 577,680
		1.3%	1.8%

OPCo Existing Gas Capacity		
Unit	**Type**	**AEP Acquisition Cost/kW**
Waterford (1)	821 MW CC	$ 268
Darby (2)	480 MW CT	$ 224

Sources - AEP Press releases, Exhibit___(JRH-13)

Exhibit___(JRH-6)

REDACTED

REDACTED

Summary of Expansion Plan Modeling Input Assumptions and Results

	Inputs to Scenarios				Outputs from Scenarios		
	Natural Gas (Avg. Burner Tip at Dresden)	Coal (Delivered, at Amos 1)	PJM Capacity Market Price	PJM Energy market Price (All Hours)	Asset Transfer CPW	Market CPW	AM3 CPW
2014$ (Unless otherwise stated)	Levelized $/MMBtu	Levelized $/MMBtu	Levelized $/MW-day	Levelized $/MWh	M$	M$	M$
2014 - 2040							
Scenarios							
Base	$8.5	$4.0	[redacted]	$49.0	31,543,275	33,321,009	32,265,395
Low	$7.5	$3.6	[redacted]	$45.0	29,961,593	31,469,823	30,578,328
High	$10.0	$4.7	[redacted]	$58.5	33,971,626	36,345,215	34,836,390
% Change from Base	**Change in Inputs to Scenarios**				**Change in Outputs from Scenarios**		
Low	-11%	-11%	-8%	-8%	-5%	-6%	-5%
High	19%	17%	6%	19%	8%	9%	8%
change in coal price vs change in natural gas price							
Low		96%					
High		92%					

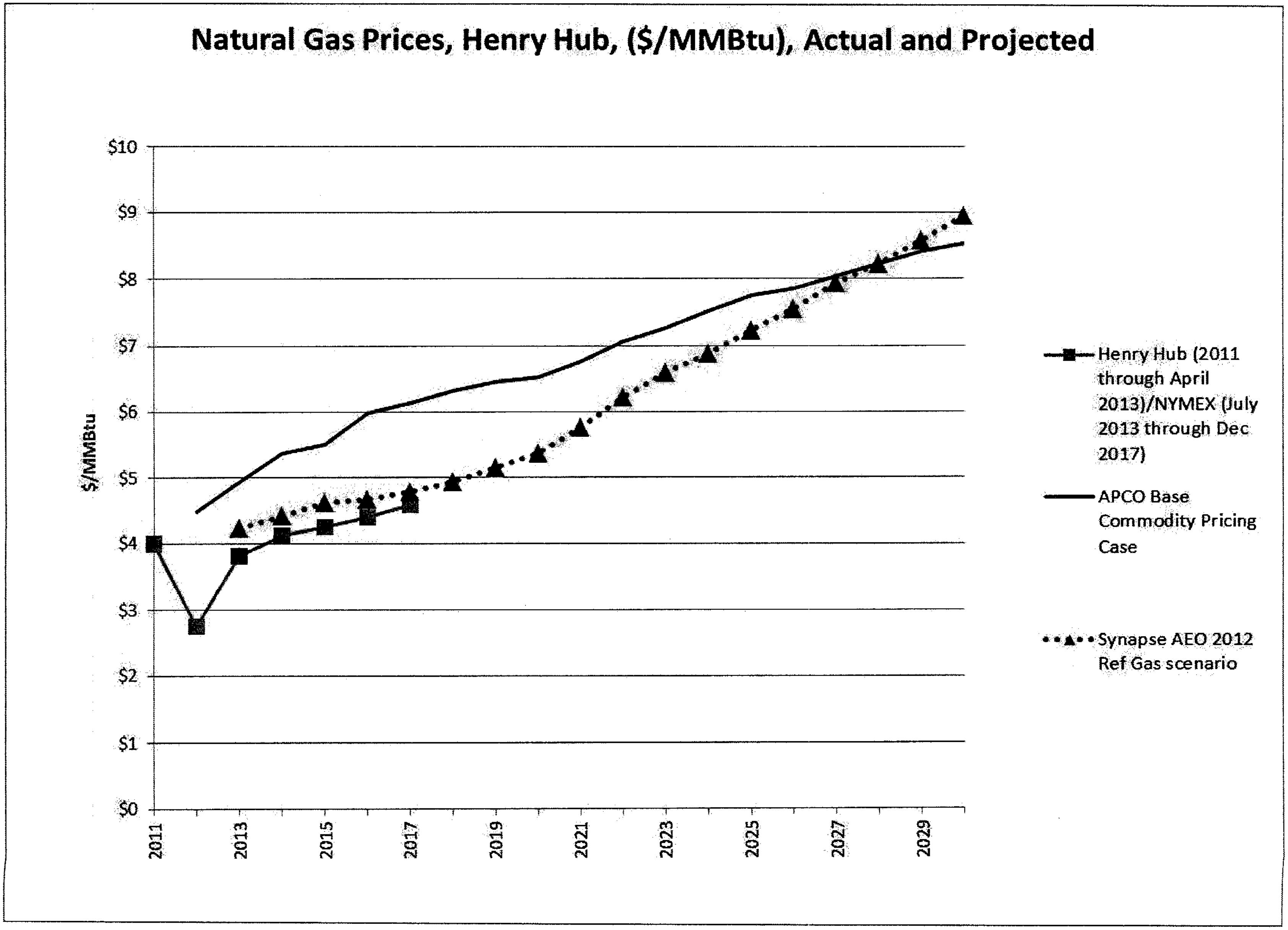
Exhibit____(JRH-8)

AEO 2012 Forecasts for selected years

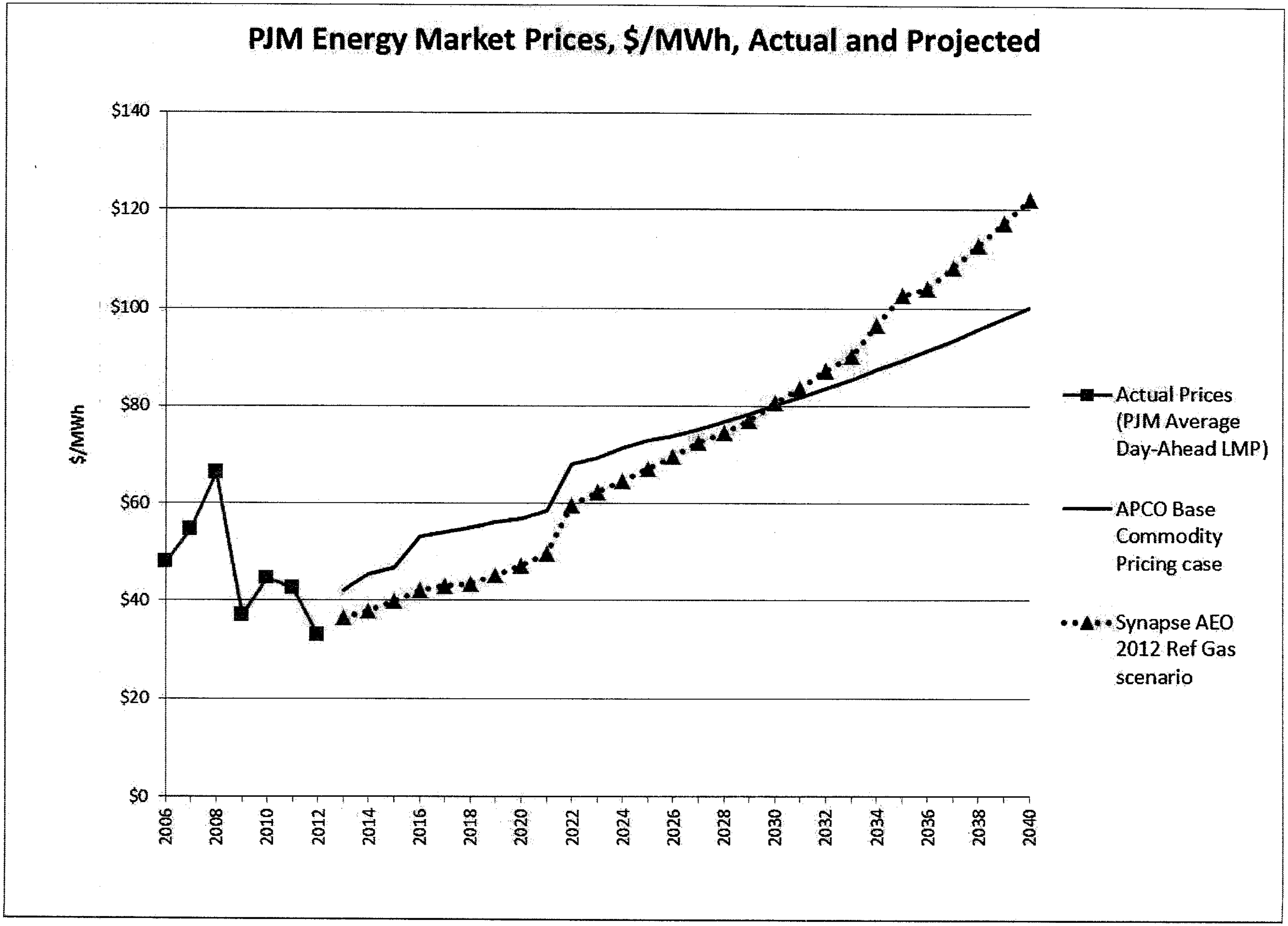
AEO 2012 Case Name		2015	2025	2035
Reference Case	Gas Price (HH, $2010 /MMBtu)	4.29	5.63	7.37
	Coal (minemouth, $2010/MMBtu)	2.08	2.23	2.56
High economic growth	Gas Price (HH, $2010 /MMBtu)	4.36	6.17	7.58
	Coal (minemouth, $2010/MMBtu)	2.08	2.25	2.60
	Change in gas price vs Reference	1.7%	9.6%	2.8%
	Change in coal price vs Reference	-0.2%	0.8%	1.5%
	Change in Coal Price vs Change in Gas Price	-10.9%	8.2%	52.8%
Low economic growth	Gas Price (HH, $2010 /MMBtu)	4.06	5.10	6.60
	Coal (minemouth, $2010/MMBtu)	2.11	2.24	2.57
	Change in gas price vs Reference	-5.4%	-9.6%	-10.4%
	Change in coal price vs Reference	1.2%	0.4%	0.2%
	Change in Coal Price vs Change in Gas Price	-22.5%	-3.7%	-1.9%
Low coal cost	Gas Price (HH, $2010 /MMBtu)	4.12	5.40	6.94
	Coal (minemouth, $2010/MMBtu)	1.87	1.54	1.31
	Change in gas price vs Reference	-4.0%	-4.1%	-5.8%
	Change in coal price vs Reference	-10.1%	-31.1%	-48.9%
	Change in Coal Price vs Change in Gas Price	255%	754%	851%
High coal cost	Gas Price (HH, $2010 /MMBtu)	4.38	5.99	7.89
	Coal (minemouth, $2010/MMBtu)	2.33	3.36	5.24
	Change in gas price vs Reference	2.0%	6.3%	7.1%
	Change in coal price vs Reference	11.7%	50.7%	104.8%
	Change in Coal Price vs Change in Gas Price	591%	807%	1470%
High EUR	Gas Price (HH, $2010 /MMBtu)	3.94	4.77	5.99
	Coal (minemouth, $2010/MMBtu)	2.08	2.23	2.54
	Change in gas price vs Reference	-8.3%	-15.4%	-18.7%
	Change in coal price vs Reference	-0.1%	-0.3%	-0.8%
	Change in Coal Price vs Change in Gas Price	0.8%	1.7%	4.4%
Low EUR	Gas Price (HH, $2010 /MMBtu)	4.58	6.93	8.26
	Coal (minemouth, $2010/MMBtu)	2.08	2.25	2.58
	Change in gas price vs Reference	6.8%	23.0%	12.1%
	Change in coal price vs Reference	0.0%	0.6%	1.0%
	Change in Coal Price vs Change in Gas Price	-0.5%	2.7%	7.9%

EUR: Estimated Ultimate Recovery per tight oil and shale gas well

Exhibit___(JRH-9)



Exhibit___(JRH-10)



Levelized Costs of Purchasing Capacity and Energy from PJM at 75% capacity Factor ($2013/MWh, 2015-2034)

Scenario	Capacity	Energy	TOTAL
APCo Base scenario (1)	$ 14	$ 56	$ 70
FirstEnergy Economic Recovery case (2)	$ 10	$ 65	$ 75
Synapse AEO 2012 Reference Gas scenario (1)	$ 8	$ 50	$ 58
FirstEnergy Status Quo case (3)	$ 6	$ 53	$ 59

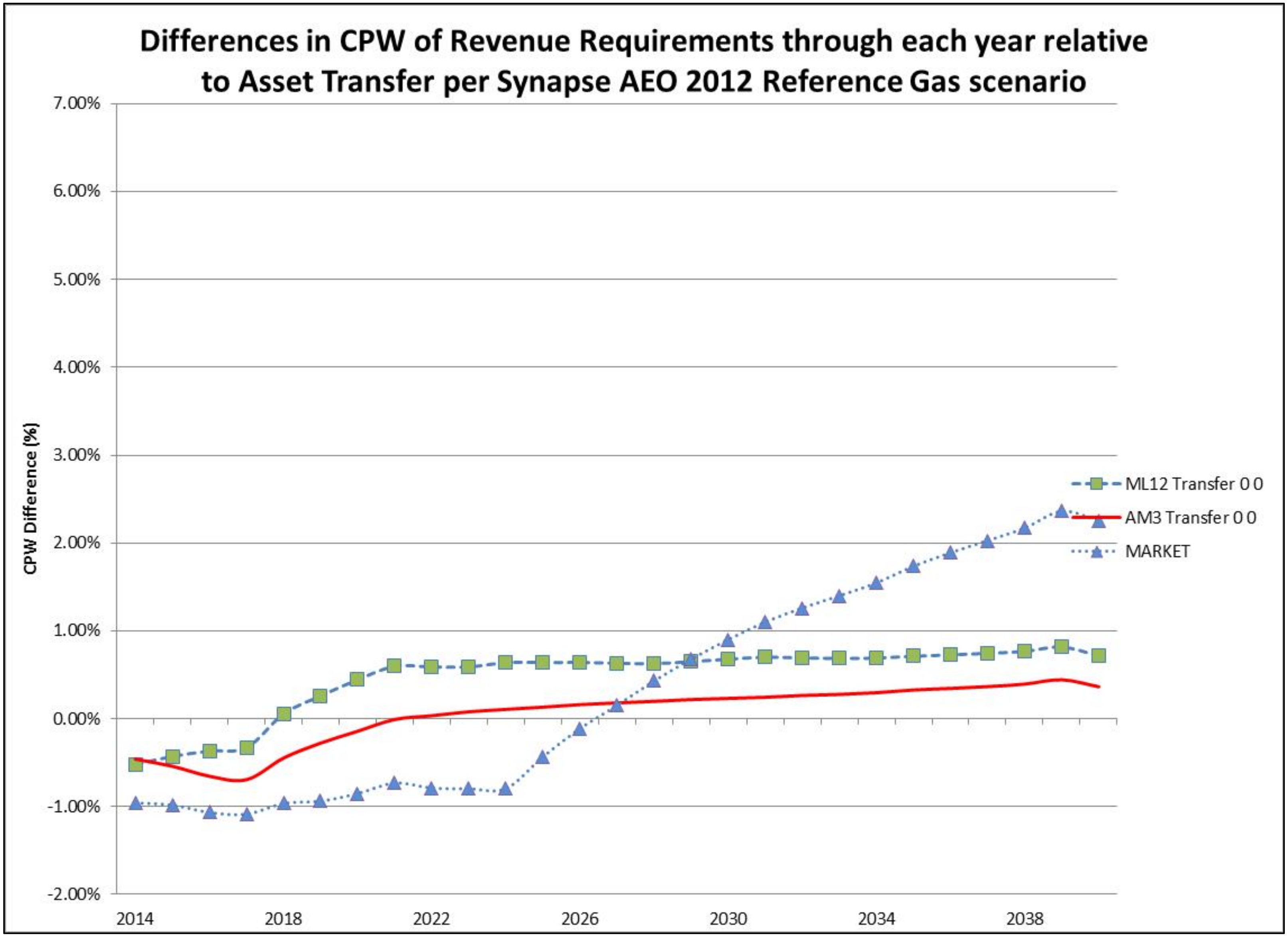
Sources

1. Synapse derivation from APCo Base Scenario projections of energy and capacity prices, *Exh JRH 11 APCo and Synapse scenarios vs FirstEnergy.xls*
2. Exhibit___(JRH-4), page 1, Hornby Direct, Case No. 12-1571-E-PC
3. Exhibit___(JRH-8), page 1, Hornby Direct, Case No. 12-1571-E-PC

REDACTED

Summary of Resource Alternative Modeling Input Assumptions and Results

	Input assumptions				Expansion Plan Cost /(Savings) over Asset Transfer Portfolio (Cumulative Present Worth					
	Natural Gas (TCO delivered)	PJM Capacity Market Price	PJM Energy market Price (All Hours)	NGCC Capital cost (Overnight)	Market		AM3 transfer		M12 Transfer	
2014$ (Unless otherwise stated)	Levelized $/MMBtu	Levelized $/MW-day	Levelized $/MWh	2011 $/kW	$ in 1,000's	%	$ in 1,000's	%	$ in 1,000's	%
2014 - 2040 Scenarios										
APCO Base Scenario	$8.7	[redacted]	$70	[redacted]	1,777,734	5.6%	722,120	2.3%	936,474	3.0%
Synapse AEO 2012 Ref Gas	$7.7	$181	$65	$1,000	802,727	2.6%	129,569	**0.4%**	254,774	0.8%
2014 - 2025 Scenarios										
APCO Base Scenario	$7.8	[redacted]	$61	[redacted]	1,017,916	5.78%	511,990	2.91%	739,793	4.20%
Synapse AEO 2012 Ref Gas	$6.3	$147	$52	**$1,000**	(94,103)	-0.5%	28,868	**0.2%**	139,320	0.8%


Differences in CPW of Revenue Requirements through each year relative to Asset Transfer per Synapse AEO 2012 Reference Gas scenario
CPW Difference (%)
7.00%
6.00%
5.00%
4.00%
3.00%
2.00%
1.00%
0.00%
-1.00%
-2.00%
2014
2018
2022
2026
2030
2034
2038
ML12 Transfer 0 0
AM3 Transfer 0 0
MARKET

DATA RESPONSES AND PRESS RELEASES

APPALACHIAN POWER COMPANY &
WHEELING POWER COMPANY
WEST VIRGINIA CASE NO. 11-1775-E-P
SECOND REQUEST FOR INFORMATION - CAD

Request B-5

Merger Petition, December 16,2011. Testimony of Chris Potter. Pages 8 and 9 refer to the corporate separation of Ohio generating assets. In Testimony filed on March 30,2012 in Case No. 11-346-EL-SSO, AEP witness Powers stated that AEP's current proposal was that AEP Ohio would transfer all its generating assets at net book value (NBV) to AEP Generation Resources (Genco) by January 1, 2014, and Genco would subsequently transfer the Mitchell generating plant and Ohio Power Company's share of Unit No, 3 of the Amos plant at their NBV to APCo and Kentucky Power Company.

a. Please provide APCo's most recent analysis of the benefits and cost of acquiring a share of the Mitchell generating plant and Ohio Power Company's share of Unit No. 3 of the Amos plant
b. Please explain why AEP's current proposal does not include APCo receiving a share of the Waterford gas plant that Genco will acquire from AEP Ohio
c. Please explain why AEP's current proposal does not include APCo receiving a share of the Darby gas plant that Genco will acquire from AEP Ohio.

Request B-5

A. The Company's most recent analysis of the cost and benefits of APCo acquiring an 80% share of the Mitchell plant and the remaining interest in Amos unit 3 was done under the following assumptions:

- APCo is a member of the proposed 3 Company pool (PCSA) that was filed at FERC (and was later withdrawn) in February of 2012
- Kentucky Power received the remaining 20% interest in the Mitchell plant
- The Wheeling Power load obligation was assumed by APCo and the full requirements wholesale supply contract between Wheeling Power and Ohio Power was terminated
- The Current AEP Interconnection Agreement and the IAA were terminated
- The period analyzed was the 12 months ending October of 2011

Because the requested information involves materials which are voluminous, the materials will be made available during regular business hours at American Electric Power in Columbus, Ohio, by arrangement.

B.and C. These assets, which were owned by CSP up until it was merged into OPCo on December 31, 2011, were not offered to APCo to meet its capacity and energy needs.

APPALACHIAN POWER COMPANY & WHEELING POWER COMPANY WEST VIRGINIA CASE NO. 11-1775-E-P FOURTH REQUEST FOR INFORMATION - CAD

Request A-34

Refer to page 5 of the IRP Update regarding the proposed Transfer of OPCO assets:

f. Please list each OPCO generating unit that AEP proposes to transfer to AEP Generation Resources and the value at which it proposes to transfer each asset.

g. Please provide all analyses upon which the decision to transfer these Mitchell and Amos assets to APCO assets is based, with all input assumptions and calculations in operational electronic format with all formulas intact.

h. Did AEP consider different possible assets and combinations of assets, to transfer to APCO, eg Mitchell only, Amos only, Waterford and Amos, etc?

i. If no please explain why not.

ii. If yes, please identify each possible asset transfer AEP considered and explain why it chose the Mitchell plus Amos transfer rather than any other possible asset transfer.

Response A-34

f. Please see CAD A-34, Attachment 1 for the list of OPCO generating units that AEP proposes to transfer to AEP Generation Resources. The generating units are anticipated to be transferred at the net book value of the units at the time of the transfer.

g. Please see the Companies' response to CAD Set 2 Question B-5.

h. Yes.

i. Not applicable.

ii. AEP reviewed the capacity and energy needs of APCO and KPCO and the assets of OPCO, and the transfers that AEP proposed in the filing were selected for the location of the assets, the baseload nature of the assets, the fact that the assets had environmental controls that permitted long term operation of the facilities without immediate and substantial capital investment, the assets capabilities matched the needs of the two operating companies, and the fact that these assets were among the assets that had been supplying APCO's and KPCO's needs through the AEP Pool.

AEP Ohio Owned Generating Units

(March 15, 2012)

Plant	Unit No.	Fuel	Location	SCR	FGD
Cardinal	1 (Note A)	Coal	Brilliant, OH	√	√
Conesville	3	Coal	Conesville, OH		
Conesville	4 (Note B)	Coal	Conesville, OH	√	√
Conesville	5	Coal	Conesville, OH		√
Conesville	6	Coal	Conesville, OH		√
Darby	1-6	Gas	Mount Sterling, OH		
Gen. J.M. Gavin	1	Coal	Cheshire, OH	√	√
Gen. J.M. Gavin	2	Coal	Cheshire, OH	√	√
J.M. Stuart	1 (Note B)	Coal	Aberdeen, OH	√	√
J.M. Stuart	2 (Note B)	Coal	Aberdeen, OH	√	√
J.M. Stuart	3 (Note B)	Coal	Aberdeen, OH	√	√
J.M. Stuart	4 (Note B)	Coal	Aberdeen, OH	√	√
John E. Amos	3 (Note C)	Coal	Winfield, WV	√	√
Kammer	1	Coal	Moundsville, WV		
Kammer	2	Coal	Moundsville, WV		
Kammer	3	Coal	Moundsville, WV		
Mitchell	1	Coal	Moundsville, WV	√	√
Mitchell	2	Coal	Moundsville, WV	√	√
Muskingum River	1	Coal	Waterford, OH		
Muskingum River	2	Coal	Waterford, OH		
Muskingum River	3	Coal	Waterford, OH		
Muskingum River	4	Coal	Waterford, OH		
Muskingum River	5	Coal	Waterford, OH	√	
Philip Sporn	2	Coal	New Haven, WV		
Philip Sporn	4	Coal	New Haven, WV		
Picway	5	Coal	Lockbourne, OH		
Racine	1-2	Hydro	Racine, OH		
W.C. Beckjord	6 (Note B)	Coal	New Richmond, OH		
Waterford	1-4	Gas	Waterford, OH	√	
William H. Zimmer	1 (Note B)	Coal	Moscow, OH	√	√

Note A The Cardinal Plant consists of three coal-fired steam units, with Unit No. 1 owned by Ohio Power and Unit Nos. 2 and 3 owned by Buckeye Power, Inc. ("Buckeye").

Note B Ohio Power jointly owns unit 4 with Duke Energy Ohio, LLC and Dayton Power and Light Co. The jointly-owned units are Conesville 4, Stuart 1-4, Beckjord 6 and Zimmer 1. Stuart Diesel units 1-4, which are not listed above, will also transfer to AEP Generation Resources.

Note C Ohio Power owns two-thirds and APCo owns one-third of Amos Unit No. 3.

Note: Ohio Power also has certain contractual entitlements to purchase power, which will transfer to AEP Generation Resources.

Home / Newsroom / Corporate News Releases

AEP completes purchase of Darby plant from DPL Energy

COLUMBUS, Ohio, April 25, 2007 – Columbus Southern Power, a utility subsidiary of American Electric Power (NYSE: AEP), today completed the purchase of the Darby Electric Generating Station from DPL Energy, LLC, a subsidiary of DPL Inc.

The purchase, valued at approximately $102 million, was announced in November 2006.

The Darby plant, located approximately 20 miles southwest of Columbus, Ohio, near Mount Sterling, is a natural-gas, simple-cycle power plant with a nominal generating capacity of 480 megawatts and a summer capacity of approximately 450 megawatts. The plant began commercial operation in 2001.

Acquisition of the Darby plant will help AEP keep pace with the growth in peak demand in its eastern service area and help tl company maintain the 15 percent reserve margin required by the PJM Interconnection to ensure reliability. AEP will operate Darby plant as part of the company's generation pool that provides power to AEP's utility units serving customers in Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia.

American Electric Power is one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile netwo that includes more 765 kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, th interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's headquarters are in Columbus, Ohio.

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 2 of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations a based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially fi those in the forward-looking statements are: electric load and customer growth; weather conditions, including storms; availab sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and the performance of AEP's generating plants; AEP's ability to recover regulatory assets and stranded costs in connection with deregulation; AEP's ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; AEP's ability to build or acquire generating capacity when needed at acceptable prices and terms to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulati including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rat

AEP to purchase Waterford plant from PSEG

COLUMBUS, Ohio, May 27, 2005 – American Electric Power (NYSE: AEP), through its Columbus Southern Power utility subsidiary, has agreed to purchase the Waterford Energy Center from an affiliate of Public Service Enterprise Group (NYSE: F for $220 million.

The transaction, which is contingent on the receipt of required regulatory approvals, is expected to close in the third quarter 2005.

The Waterford Energy Center is a natural-gas-fired combined-cycle power plant, located in southeastern Ohio, with nominal generating capacity of 821 megawatts. The plant began commercial operation in August 2003.

"The purchase of the Waterford plant is part of a broad strategy to meet the growing electricity needs of customers in our eastern seven states," said Michael G. Morris, AEP's chairman, president and chief executive officer. "We had anticipated purchasing capacity in the PJM marketplace in the 2006-2007 time frame to meet our needs. This acquisition will reduce our reliance on the marketplace.

"With a customer base as large as ours, we will need to add capacity each year to keep pace with annual growth in peak demand of approximately 2 percent in our eastern system and to maintain the 15 percent reserve margin required by the PJN Interconnect to ensure reliability," Morris said. "Our plan includes a combination of the construction of new plants, like the cl -coal generation projects we are pursuing, and -- if the price is right -- the acquisition of recently completed gas-fired mercha plants in this region, plants that seldom operate today because of significantly higher natural gas prices and more generation the market than the owners had forecast."

AEP has filed with the Public Utilities Commission of Ohio seeking cost recovery for a 600-megawatt power plant using Integrated Gasification Combined Cycle (IGCC) clean-coal technology. The plant, which will be the largest commercial-scale IGCC plant in the United States, will be built in southern Ohio, once cost-recovery approval is received from the Ohio commission, and be in operation by 2010.

A second 600-megawatt IGCC plant is under consideration by AEP for Ohio, West Virginia or Kentucky, but no decision has been announced.

"Any gas-fired generation we add through either acquisition or construction will complement, not replace, our plans for IGC(Morris said. "The IGCC capacity we add to our system will be baseload generation used to meet the expected day-to-day ne of our customers. The gas capacity we add will be mid-merit generation designed for use when electricity demand is higher t average."

When the transaction closes, AEP will operate Waterford as part of the company's generation pool that provides power to AI utility units serving customers in Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia.

American Electric Power owns more than 36,000 megawatts of generating capacity in the United States and is the nation's largest electricity generator. AEP is also one of the largest electric utilities in the United States, with more than 5 million customers linked to AEP's 11-state electricity transmission and distribution grid. The company is based in Columbus, Ohio.

These reports made by AEP and its registrant subsidiaries contain forward-looking statements within the meaning of Section of the Securities Exchange Act of 1934. Although AEP and its registrant subsidiaries believe that their expectations are basec reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to b materially different from those projected. Among the factors that could cause actual results to differ materially from those in forward-looking statements are: electric load and customer growth; weather conditions; available sources and costs of fuels; availability of generating capacity and the performance of AEP's generating plants; the ability to recover regulatory assets an stranded costs in connection with deregulation; new legislation and government regulation including requirements for reduc emissions of sulfur, nitrogen, carbon and other substances; resolution of pending and future rate cases, negotiations and oth regulatory decisions (including rate or other recovery for environmental compliance); oversight and/or investigation of the energy sector or its participants; resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.); AEP's ability to reduce its operation and maintenance costs; the success of disposing of investments that no longer match AEP's corporate profile; AEP's ability to sell assets at attractive prices and on other attractive terms; international and country-specific developments affecting foreign investments including the dispositio any current foreign investments; the economic climate and growth in AEP's service territory and changes in market demand a demographic patterns; inflationary trends; AEP's ability to develop and execute on a point of view regarding prices of electri natural gas, and other energy-related commodities; changes in the creditworthiness and number of participants in the energy trading market; changes in the financial markets, particularly those affecting the availability of capital and AEP's ability to refinance existing debt at attractive rates; actions of rating agencies, including changes in the ratings of debt and preferred stock; volatility and changes in markets for electricity, natural gas, and other energy-related commodities; changes in utility regulation, including the establishment of a regional transmission structure; accounting pronouncements periodically issued b accounting standard-setting bodies; the performance of AEP's pension plan; prices for power that AEP generates and sells a wholesale; and changes in technology and other risks and unforeseen events, including wars, the effects of terrorism (includir increased security costs), embargoes and other catastrophic events.

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AEP AMERICAN ELECTRIC POWER

AEP completes purchase of Lawrenceburg Plant

COLUMBUS, Ohio, May 16, 2007 – American Electric Power (NYSE: AEP), through its AEP Generating Co. subsidiary, today completed the purchase of the Lawrenceburg Generating Station in Indiana from an affiliate of Public Service Enterprise Grou (NYSE: PEG).

The purchase, valued at approximately $325 million, was announced in January.

The Lawrenceburg plant, adjacent to AEP's Tanners Creek Plant in Lawrenceburg, Ind., is a combined-cycle, natural-gas powe plant with a generating capacity of 1,096 megawatts. The plant began commercial operation in June 2004.

Acquisition of the Lawrenceburg plant will help AEP keep pace with the growth in peak demand in its eastern service area an help the company maintain the 15 percent reserve margin required by the PJM Interconnection to ensure reliability. AEP will operate the Lawrenceburg plant as part of the company's generation pool that provides power to AEP's utility units serving customers in Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia.

American Electric Power is one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile netwo that includes more 765 kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, th interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's headquarters are in Columbus, Ohio.

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 2 of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations a based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially fi those in the forward-looking statements are: electric load and customer growth; weather conditions, including storms; availab sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and the performance of AEP's generating plants; AEP's ability to recover regulatory assets and stranded costs in connection with deregulation; AEP's ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; AEP's ability to build or acquire generating capacity when needed at acceptable prices and terms to recover those costs through applicable rate cases or competitive rates; new legislation, litigation and government regulati including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rat or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp. and related matters); AE ability to constrain operation and maintenance costs; the economic climate and growth in AEP's service territory and changes market demand and demographic patterns; inflationary and interest rate trends; AEP's ability to develop and execute a strate based on a view regarding prices of electricity, natural gas and other energy-related commodities; changes in the creditworthiness of the counterparties with whom AEP has contractual arrangements, including participants in the energy trading market; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including the potential for new legislation or regulation in Ohio and membership in and integration into regional transmission organizations; accounting pronouncements periodically issued by accounting standard-setting bodies; the performance of AEP's pension and other postretirement benefit plans; prices for power that AEP generates and sell at wholesale; changes in technology, particularly v respect to new, developing or alternative sources of generation; other risks and unforeseen events, including wars, the effect terrorism (including increased security costs), embargoes and other catastrophic events.

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AEP AMERICAN ELECTRIC POWER

**APPALACHIAN POWER COMPANY &
WHEELING POWER COMPANY
WEST VIRGINIA CASE NO. 11-1775-E-P
FIFTH REQUEST FOR INFORMATION - CAD**

Request A-64

The Company models the addition of new gas combined-cycle units in Strategist, as in the Company's Build case, represented by the Strategist file "BUILD PORTFOLIO (REALISTIC DSM) UNDER FTCSAPR COMMODITY PRIC.FSV"'

a. How are the capital costs of those units modeled?

b. Is the entire capital cost included as construction cost without AFUDC?

c. Are capital costs instead modeled in part as construction costs without AFUDC and in part as a portion of the fixed O&M input?

d. If yes, please provide the calculations, in machine readable electronic format, that clearly show the ways in which the capital cost of a new gas combined-cycle unit is translated in Strategist.

Response A-64

a. The capital costs for new additions are captured in Input.PRV.Alternative Data. Base Costs without AFUDC.

b. Yes the entire cost is included in the Base Cost without AFUDC input.

c. No, capital costs are only modeled as Base Costs without AFUDC.

d. N/A

APPALACHIAN POWER COMPANY
WEST VIRGINIA CASE NO. 12-1655-E-PC
FIRST REQUEST FOR INFORMATION - CAD

Request IRP-4

For each of the 5 plans described on page 11 and 12 of Exhibit A, Were supply- and demand-side resource additions predetermined and input into Strategist for a given year, or was Strategist allowed to optimize its resource selection by choosing from a variety of resources?

1. Please indicate the scenarios in which APCO allowed Strategist to optimize the resource additions, including acquisition of Mitchell and Amos.

2. Please indicate the scenarios in which APCO predetermined its resource expansion portfolio prior to the execution of Strategist modeling.

3. For scenarios in which APCO predetermined its resource expansion portfolio prior to modeling, please provide the analyses supporting the choice of those additional resources.

Response IRP-4

1. Only the generic supply side resources were allowed to optimize in each of the plans described on page 11 and 12 of Exhibit A attached to the Petition. The demand-side resources were reflected in the Company's load in all of the 5 plans.

2. APCo evaluated five portfolios under three pricing scenarios. Under the Asset Transfer, AM3 Transfer, and ML12 Transfer portfolios, the Amos 3 and Mitchell assets were assumed to be transferred and Strategist allowed the generic units to optimize.

3.Ohio Power's generating assets were not reviewed on a unit by unit basis. Rather, all the assets of Ohio Power Company, which historically have been used to provide power to APCo, were qualitatively screened to determine the generating units to be analyzed, along with other viable resource options for APCo.

The qualitative analysis was not reduced to any report, presentation or electronic file at the time of the analysis. The slide provided in CAD IRP-04, Attachment 1, was prepared at a later date. See CAD IRP-04, Attachment 2, for a chart that was prepared to depict the thought process behind the qualitative analysis.

AEP APPALACHIAN POWER
A unit of American Electric Power

Selection of Amos Unit 3 and Mitchell Plant

- The following criteria were used to select Amos Unit 3 and Mitchell Plant from Ohio Power assets historically relied upon by APCo and KPCo for pool energy and capacity

Criteria	Amos Unit 3	Mitchell Plant
Baseload Unit?	✓	✓
Environmentally-Controlled?	✓	✓
Jurisdiction Location?	✓	✓
Appropriate size for need?	✓	✓
Reasonable Cost?	✓	✓
Existing Joint Ownership?	✓	

A. Units Evaluated on Criteria of Staff 2-024

Plant	Amos	Mitchell	Mitchell	Cardinal	Gavin	Gavin
Unit	3	1	2	1	1	2
MW	867	770	790	592	1,319	1,319
Baseload Unit?	✓	✓	✓	✓	✓	✓
Environmental Controlled?	✓	✓	✓	✓	✓	✓
Located in Juris. of APC/WPC or KPC?	✓	✓	✓			
Appropriate Size for Need?*	✓	✓	✓	✓		
Reasonable Cost?	✓	✓	✓	✓	✓	✓
Existing Joint Ownership with APC?	✓					

*Gavin's 1300 MW units were less attractive because forced outage of a single unit exposes APCo and KPCo to larger capacity and energy losses than the Mitchell and Cardinal units and potentially would involve joint ownership issues with the unregulated Genco.

B. Other Ohio Power Owned Units: Slated for Retirement in 2015 or Acquired through Merger with CSP

Plant	Unit	Retired by 6/1/2015	Historically Provided Pool Cap & Energy?	Jointly Owned With 3rd Parties
Beckjord	6	Yes	NA	NA
Conesville	3	Yes	NA	NA
Kammer	1	Yes	NA	NA
Kammer	2	Yes	NA	NA
Kammer	3	Yes	NA	NA
Muskingum	1	Yes	NA	NA
Muskingum	2	Yes	NA	NA
Muskingum	3	Yes	NA	NA
Muskingum	4	Yes	NA	NA
Muskingum	5	Yes	NA	NA
Picway	5	Yes	NA	NA
Sporn	2	Yes	NA	NA
Sporn	4	Yes	NA	NA
Conesville	4	No	No	Yes
Conesville	5	No	No	No
Conesville	6	No	No	No
Darby	1-6	No	No	No
Waterford	1	No	No	No
Zimmer	1	No	No	Yes

APPALACHIAN POWER COMPANY
WEST VIRGINIA CASE NO. 12-1655-E-PC
SECOND REQUEST FOR INFORMATION - CAD

Request IRP-12

Did the Company identify any existing gas-fired combined cycle units or plants as potential candidates for purchase or a power purchase agreement?

a. If so, please explain the rationale for considering those plants and the sources used to prepare this list.

i. Why did the Company decide not to move forward with the transfer of those units?

b. If none, please explain why not.

Response IRP-12

See the Company's response to CAD IRP-04.

APPALACHIAN POWER COMPANY
WEST VIRGINIA CASE NO. 12-1655-E-PC
SECOND REQUEST FOR INFORMATION - CAD

Request IRP-13

Did the Company identify any existing gas-fired combustion turbine units or plants as potential candidates for purchase or a power purchase agreement?

a. If so, please explain the rationale for considering those plants and the sources used to prepare this list.

i. Why did the Company decide not to move forward with the transfer of those units?

b. If none, please explain why not.

Response IRP-13

See Company's response to CAD IRP-04.

APPALACHIAN POWER COMPANY
WEST VIRGINIA CASE NO. 12-1655-E-PC
THIRD REQUEST FOR INFORMATION - WVCAG

Request 3-1

Referring to the scenarios presented in Exhibit A of the petition and in the June 2012 IRP Update:

a. Do any of these scenarios allow Strategist to optimize from a portfolio composed of all of the following resource options: market purchases, new build, and purchase of share of Amos 3 and Mitchell? If so, please state which scenario(s)?

b. Did the "market" scenario presented in Exhibit A (p. 11) allow Strategist to optimize the selection of both new build and market purchases post-2025, or only new build?

c. Did the "optimization" scenario presented in Exhibit A (p. 11) allow Strategist to optimize the selection of both new build and market purchases post-2018, or only new build?

d. Did the "asset transfer" scenario presented in Exhibit A (p. 11) include the procurement of replacement capacity for Amos and Mitchell after the plants' projected retirement dates (2033 and 2031, according to the response to WVCAG Set 1 Q 10 in Case No. 11-1775-E-P)? If not, why not?

Response 3-1

a. No.
b. Both new build and market purchase options could be selected.
c. Both new builds and market purchases could be selected.
d. No. The retirement dates for Amos and Mitchell were assumed to be 2040.

APPALACHIAN POWER COMPANY
WEST VIRGINIA CASE NO. 12-1655-E-PC
THIRD REQUEST FOR INFORMATION - WVCAG

Request 3-10

Admit that four of the scenarios presented in Exhibit A of the petition ("market", "optimization", "AM3 transfer", and "ML12 transfer") are not available to the Company because they rely on PJM capacity market purchases during years in which the Company has selected FRR status.

a. If you do not admit this, please explain how the Company plans to purchase capacity under these scenarios given their FRR status.

Refer to the Strategist modeling runs referenced in WVCAG Discovery Request Set 1 Q1 in Case No. 12-1655-E-PC and WVCAG Discovery Request Set 1 Q 23 in Case No. 11-1775-E-P.

Response 3-10

Deny. To the extent necessary, the Company would need to purchase capacity from resources that were not committed elsewhere.

APPALACHIAN POWER COMPANY
WEST VIRGINIA CASE NO. 12-1655-E-PC
FOURTH REQUEST FOR INFORMATION - WVCAG

Request 4-2

Each party other than an affiliate that has contacted APCo (or any affiliate of APCo) in 2013 regarding the offer of generating assets for purchase and/or the offer of a power sales contract. In addition please provide the following information for each party contacted:

a. Date of initial contact,

b. Amount of capacity available

c. Generating unit name,

d. Copies of any offers and responses thereto

Response 4-2

Neither APCo nor its affiliates has received an offer of a power sales contract from an existing PJM asset in 2013. APCo, or an affiliate has been contacted confidentially, during 2013, about purchasing existing assets within PJM.

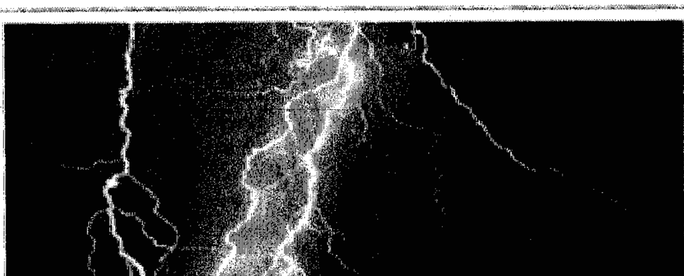
Because the response to these questions involve materials which are confidential, the materials will be made available for inspection during regular business hours at APCo's offices in Charleston, WV, by arrangement.

Synapse
Energy Economics, Inc.

Market Fundamentals That Will Affect PJM RPM Capacity Prices from June 2017 Onward

June 7, 2013

AUTHORS
Pat Knight, Rick Hornby



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PJM Interconnection (PJM) is a regional transmission organization (RTO) which coordinates the movement of wholesale electricity in all or parts of thirteen states and the District of Columbia. It also operates wholesale markets for electric energy, electric capacity as well as ancillary services (including synchronized reserve and regulation). The utilities who participate in these markets are presented in Table 1 grouped according to their Load Delivery Area ('LDA') as defined by PJM.

The prices for capacity in the wholesale market operated by PJM, referred to as the Reliability Pricing Model ('RPM'), set the value for wholesale generating capacity as well as for reductions in peak demand. This report presents a high-level review of major demand and supply factors that will affect prices for capacity in the RPM in the long term, from Delivery Year 2017/2018 onward.[1] Our report begins with a review of capacity prices for the most recent seven Delivery Years for which PJM has set capacity prices, i.e., 2010 through 2015. The report then examines the demand and supply fundamentals that will affect capacity prices for Delivery Years from 2017 onward. (The report does not consider prices for delivery years prior to 2009 because PJM set them administratively, and it does not consider the prices that may be established for 2016 in the upcoming May 2013 auction because our focus is on capacity prices in the long-term.)

[1] Delivery Years run June 1 through May 31.

Table 1. LDAs in PJM

LDA Region		LDA - Utility	Utility
[illegible]		AEP	American Electric Power
		APS	Allegheny Power
		ATSI	American Transmission Systems, Inc.
		ComEd	Commonwealth Edison
		Dayton	Dayton Power & Light
		DEOK	Duke Energy Ohio and Kentucky
		DLCO/DQE	Duquesne Lighting Company
		Dom	Dominion
[illegible]	Western MAAC	MetEd	Metropolitan Edison
		Penelec	Pennsylvania Electric
		PPL (inc. UGI)	PPL Electric Utilities
	Eastern MAAC	RECO	Rockland Electric (East)
		AE	Atlantic Electric
		DPL	Delmarva Power & Light
		DPL South	
		JCPL	Jersey Central Power & Light
		PECO	PECO Energy
		PSEG	Public Service Electric & Gas
		PSEG North	
	South West MAAC	BGE	Baltimore Gas & Electric
		PEPCO	Potomac Electric Power

1. Purpose and Operation of PJM Capacity Market (RPM)

A. Purpose of RPM

PJM is responsible for ensuring reliable service in the RTO. PJM accomplishes that goal through the RPM by acquiring sufficient capacity to meet peak demand plus a reserve margin and by providing suppliers of traditional capacity and demand response ("DR') resources sufficient compensation to bid their resources into the RPM and to develop new resources when necessary.[2]

To ensure reliable service in a given future delivery year PJM begins by setting the minimum level of capacity that each Load Serving Entity ('LSE') operating in each LDA of the RTO must control in

[2] PJM, "Reliability Pricing Model," http://pjm.com/markets-and-operations/rpm.aspx.

that year.[3] PJM expresses that minimum capacity obligation as an Installed Reserve Margin ('IRM') and a Forecast Pool Requirement (FPR) The IRM and FPR represent the same level of required reserves but are expressed in different terms of capacity value. The IRM expresses the required installed capacity (ICAP) reserve as a percent of the forecast peak load, whereas the FPR provides the total unforced capacity (UCAP).[4] The IRM is typically in the order of 115% of projected peak demand.[5]

PJM sets this capacity obligation or IRM, and acquires the capacity and DR resources needed to meet it, three years in advance of the delivery year. PJM acquires these resources through a series of auctions - the Base Residual Auction (BRA) and up to three Interim Auctions. The BRA is held three years in advance, for example the BRA for the 2016 planning year will be held in May 2013. PJM conducts the BRA three years in advance to allow suppliers who need to develop new resources sufficient lead time to do so; three years is the estimated time required to bring a new conventional combustion turbine ('CT") unit into service.

The actual capacity obligation established for a delivery year is the quantity of capacity that actually clears in the BRA for that delivery year. The load serving entities ('LSEs') in each LDA are obliged to control, and pay for, capacity based on their specific capacity obligation.[6] The price for capacity established by the RPM auction for any given delivery year represents the market value of capacity in that delivery year.

B. Establishment of Market Clearing Price

The RPM is designed on the assumption that the long-run marginal source of new capacity will be a new gas-fired combustion turbine (CT) and therefore that the long-run market price for capacity will be set by the amount of revenue the developer of a new gas-fired CT would require in order to bring such a unit online. PJM refers to this revenue amount as the Net Cost of New Entry ("Net CONE"). CONE is the projected fixed cost of building and operating such a unit; Net CONE is CONE minus the margin revenues the unit is projected to earn from sales of energy and ancillary services under average market conditions. Thus the BRA for a given delivery year is explicitly designed to clear at a capacity price equal to, or close to, Net CONE if a new gas-fired CT is the marginal source of new capacity in that auction for that year.

PJM sets the actual quantity of capacity that has to be acquired for a given delivery year, as well as the market clearing price for that capacity, at the intersection of the demand curve which PJM establishes prior to the auction and the supply curve of resources that parties actually bid into the auction.

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[3] "A Load Serving Entity (LSE) is any entity that has been granted authority or has an obligation pursuant to state or local law, regulation, or franchise to sell electric energy to end users that are located within the PJM RTO." PJM, "Requirements of a Load Serving Entity (LSE)." http://www.pjm.com/~/media/training/core-curriculum/ip-lse-201/requirements-of-an-lse.ashx.

[4] Source: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-planning-period-parameters-report.ashx; page 1, "Reserve Requirement Parameters"

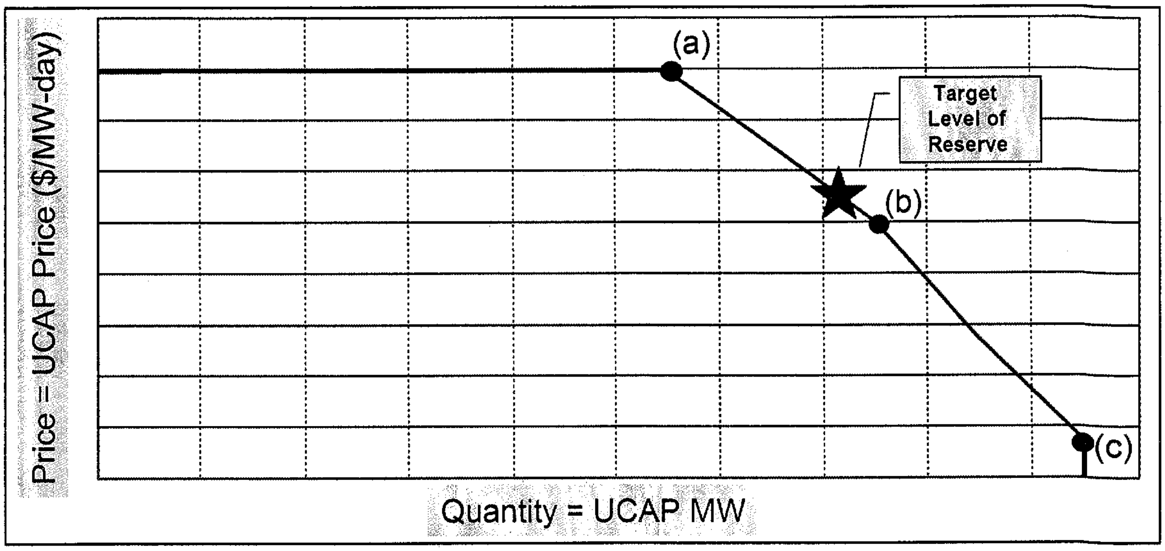
[5] PJM, "RPM BRA Planning Parameters," https://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx.

[6] LSEs provide electricity supply service to retail customers.

Demand Curve

PJM sets the demand curve, referred to as the Variable Resource Requirement ("VRR") curve, administratively. The curve is plotted as price, on the y axis, versus quantity, on the x axis. Figure 1 is an illustrative example of PJM's VRR curve.[7]

Figure 1. Illustrative example of PJM VRR curve.



The administrative VRR curve consists of three key points:

- Point A is equal to a y axis value of 1.5 times the Net Cost of New Entry ("net CONE") and an x axis quantity equal to 3% less than the target IRM;
- Point B is Net CONE at the target IRM plus 1%; and
- Point C is 20% of Net CONE at a supply 5% greater than the target Installed Reserve Margin.

Supply Resources and Curve

Beginning in the 2014/2015 delivery year, demand resources in PJM were categorized into three product types: Limited demand resources, extended summer demand resources, and annual demand resources.[8] Each of these demand resources differs according to the dates, times, and durations of PJM-initiated load management events to which they are required to respond.

The supply curve reflects the actual quantities and prices of resources that are bid into the BRA. Figure 2 shows the supply curves resulting from the 2015/2016 for the RTO. There are separate supply curves for annual plus extended summer resources and for limited summer resources. The RTO market clearing prices for those two categories of resources in that BRA were $136/MW-day and $118.54/MW-day respectively.

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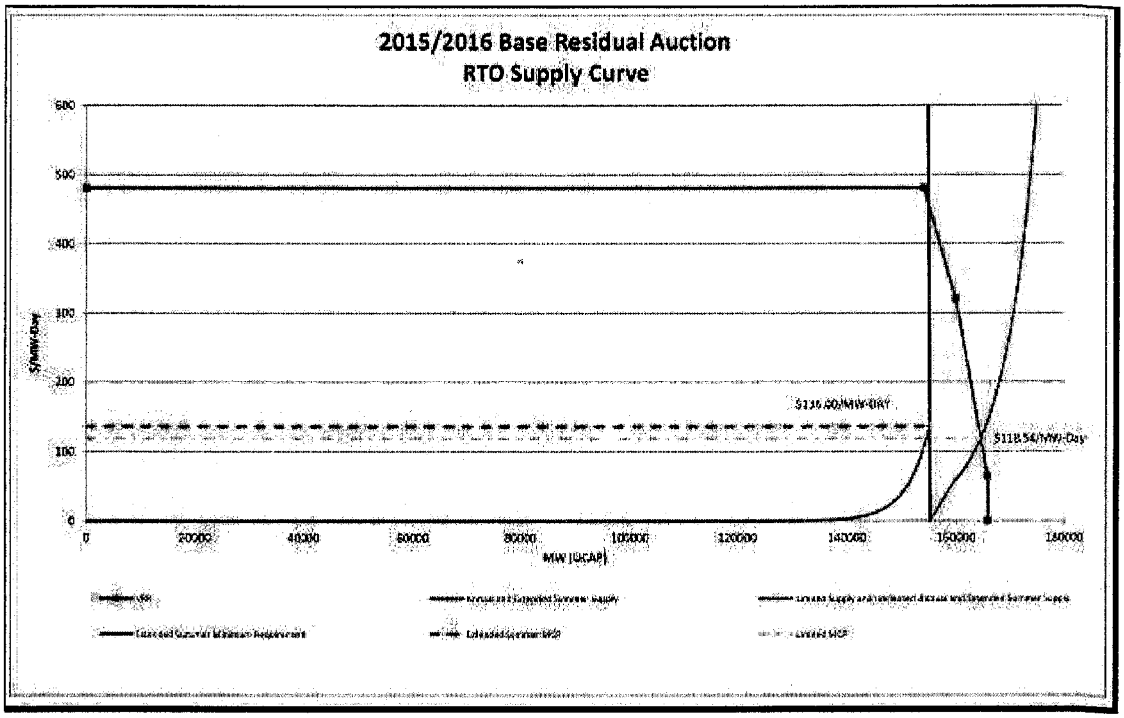
[7] PJM, "PJM Capacity Market Operations, Manual 18: PJM Capacity Market, Revision 18," http://www.pjm.com/~/media/documents/manuals/m18.ashx. See Exhibit 1.
[8] PJM, "DR Product Training," http://www.pjm.com/~/media/training/core-curriculum/ip-rpm/demand-response-product-training.ashx. See Page 7.

Figure 2. RTO Demand and Supply Curves for 2015/2016 BRA



Incremental Prices in Constrained LDAs

Prior to each BRA PJM prepares a Capacity Emergency Transfer Objective/Limit (CETO/CETL) study to estimate the ability of each LDA to import capacity in case the resources located within its footprint are not sufficient to meet its IRM.[9] PJM conducts this study to identify any LDAs whose transmission constraints justify a separate auction.

CETL is a measure of the actual MW the LDA can import on its existing transmission system while CETO is PJM's target MW import quantity for that LDA. If the CETL/CETO ratio is less than 115%, PJM may consider establishing a separate capacity price for that LDA through a separate auction.

[9] PJM, "PJM Capacity Market Operations, Manual 14b: PJM Region Transmission Planning Process, Revision 23," http://www.pjm.com/sitecore%20modules/web/~/media/documents/manuals/m14b.ashx.

Table 2 presents the CETL/CETO ratios for each of the auctions which have resulted in separate prices for certain LDAs.[10]

Table 2. CETL (MW) / CETO (MW) and CETL/CETO ratio (MW) by LDA

Delivery Year	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017
Region / LDA					
MAAC	6,377 / 5,600 114%	4,460 / 4,190 106%	5,694 / 2,020 282%	6,156 / 100 6,156%	6,495 / 5,220 124%
EMAAC	9,079 / 7,400 123%	7,095 / 7,050 101%	8,189 / 5,790 141%	9,177 / 3,860 238%	8,916 / 6,140 145%
SWMAAC	7,400 / 5,990 124%	6,725 / 5,740 117%	7,719 / 5,420 142%	8,373 / 4,720 177%	8,342 / 5,840 143%
PS	6,356 / 6,290 101%	5,868 / 5,950 99%	5,721 / 4,880 117%	6,220 / 4,600 135%	6,581 / 6,450 102%
PSNORTH	2,755 / 2,720 101%	2,570 / 2,620 98%	2,372 / 2,110 112%	2,972 / 2,240 133%	2,936 / 2,450 120%
DPLSOUTH	1,746 / 1,520 115%	2,123 / 1,350 157%	1,925 / 1,410 137%	1,822 / 1,510 121%	1,864 / 1,580 118%
PEPCO		4,483 / 4,030 111%	5,606 / 3,500 160%	6,522 / 3,380 193%	6,655 / 2,730 244%
ATSI				5,418 / 5,280 103%	7,881 / 5,390 146%

2. RPM Empirical Evidence versus Economic Theory

The economic theory underlying the design of the RPM posits that the capacity market will reach equilibrium of demand and supply in the long-term. That theoretical equilibrium assumes that demand will increase by an increment each year and that the market will meet the incremental increase in annual demand by acquiring an increment of capacity of exactly the same size from a new CT unit. Under those theoretical market equilibrium conditions the BRA is designed to clear at Net CONE year after year.

A. RPM Empirical Evidence

Our review of the seven BRAs conducted to date indicates that the RPM has not reached that theoretical market equilibrium, and that new CT units have not been the marginal resource in most auctions

Actual BRA Prices

BRA prices have cleared at, or above, Net CONE in auctions for specific Delivery Years in a few LDAs. However, no LDA has seen its capacity price clear at Net CONE year after year. In other words no LDA has seen its market reach the theoretical equilibrium.

[10] PJM, "RPM BRA Results," https://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx.

BRA prices, on a capacity-weighted basis, have averaged approximately 48% of NET CONE over the past seven auctions, as reported in Table 3. When the 2012/13 and 2013/14 delivery years are excluded, this average rises to 53%.[11]

Table 3. 76 Year Average BRA Price as Per Cent of Net CONE.

	7-year Average Net CONE (UCAP) ($/MW-day)	7-year Resource Clearing Price ($/MW-day)	7-year Average Ratio of Resource Clearing Price to Net CONE (UCAP)
RTO	$273.09	$92.83	34%
MAAC	$216.33	$152.41	70%
EMAAC	$245.23	$156.02	64%
SWMAAC	$216.33	$152.41	70%
PS	$245.23	$170.28	69%
PSNORTH	$245.23	$189.39	77%
DPLSOUTH	$245.23	$167.81	68%
PEPCO	$216.33	$155.41	72%
Capacity-weighted Average	$254.63	$123.43	48%
Capacity-weighted Average (excluding 2012/13 and 2013/14)	$252.20	$133.53	53%

As indicated in Figure 3, prices in some Delivery Years in some LDAs did reach or exceed 100% of Net, i.e., RTO in 2010, DPL South in 2012 and PEPCO in 2013. However in the subsequent Delivery Years the prices in each of those LDAs declined substantially below Net CONE. For example, the 2010 BRA price for RTO exceeded Net Cone, but the average BRA price for that LDA over seven auctions was $93/MW-day, approximately 34% of the average Net CONE of $273 per MW-day. Moreover, the BRA prices for most Delivery Years in most LDAs cleared below Net CONE. Figure 3 plots the BRA prices as a percent of Net CONE from each auction. As reported in Table 5, in some BRAs the prices for some LDAs are identical.

[11] The resulting prices in the 2012/13 and 2013/14 RTO years are outliers due to increased DR and the addition of the ATSI LSE.

Figure 3. Market Price as a percent of Net CONE by LDA.

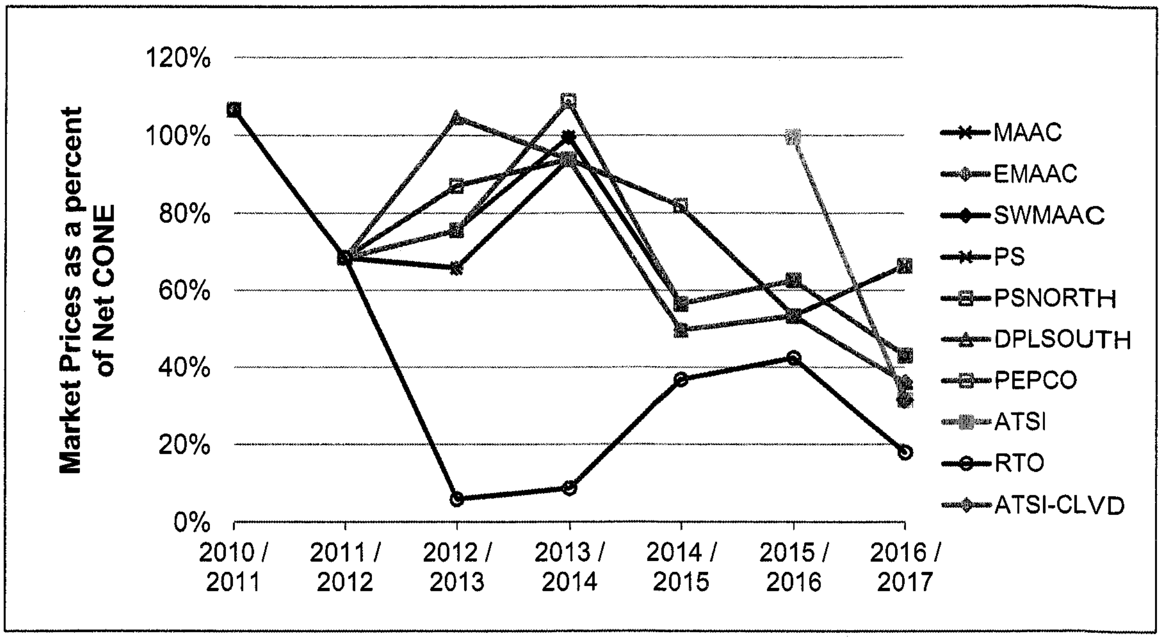


Table 4 shows the value of Net CONE that PJM set for each BRA.

Table 4. Net CONE (UCAP) ($/MW-day) by LDA[12]

	2010/ 2011	2011/ 2012	2012/ 2013	2013/ 2014	2014/ 2015	2015/ 2016	2016/ 2017
RTO	$163.46	$160.76	$276.09	$317.95	$342.23	$320.63	$330.53
MAAC	$163.46	$160.76	$176.44	$227.20	$241.91	$267.61	$276.90
EMAAC	$163.46	$160.76	$212.50	$261.06	$275.02	$313.84	$329.94
SWMAAC	$163.46	$160.76	$176.44	$227.20	$241.91	$267.61	$276.90
PS	$163.46	$160.76	$212.50	$261.06	$275.02	$313.84	$329.94
PSNORTH	$163.46	$160.76	$212.50	$261.06	$275.02	$313.84	$329.94
DPLSOUTH	$163.46	$160.76	$212.50	$261.06	$275.02	$313.84	$329.94
PEPCO	$163.46	$160.76	$176.44	$227.20	$241.91	$267.61	$276.90
ATSI						$358.22	$362.64
ATSI-CLVD							$362.64

[12] PJM, "RPM BRA Planning Parameters," https://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx.

Table 5 shows the resource clearing prices from the most recent seven BRAs.

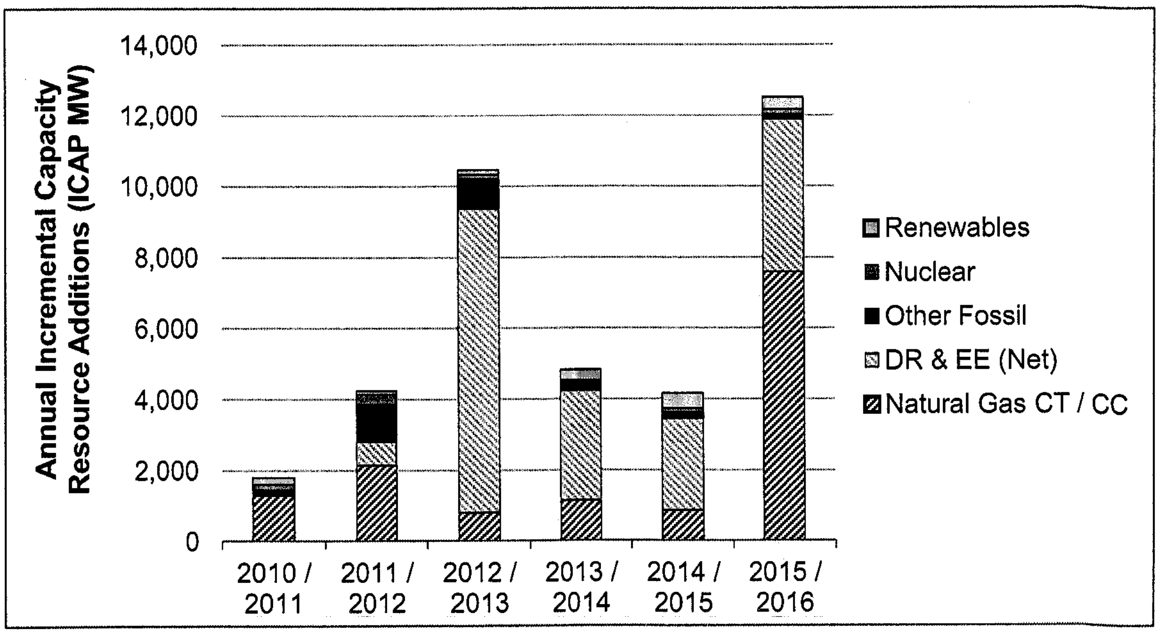
Table 5. Resource clearing price ($/MW-day) by LDA[13]

	2010/ 2011	2011/ 2012	2012/ 2013	2013/ 2014	2014/ 2015	2015/ 2016	2016/ 2017
RTO	$174.29	$110.00	$16.46	$27.73	$125.99	$136.00	$59.37
MAAC	$174.29	$110.00	$133.37	$226.15	$136.50	$167.46	$119.13
EMAAC	$174.29	$110.00	$139.73	$245.00	$136.50	$167.46	$119.13
SWMAAC	$174.29	$110.00	$133.37	$226.15	$136.50	$167.46	$119.13
PS	$174.29	$110.00	$139.73	$245.00	$136.50	$167.46	$219.00
PSNORTH	$174.29	$110.00	$185.00	$245.00	$225.00	$167.46	$219.00
DPLSOUTH	$186.12	$110.00	$222.30	$245.00	$136.50	$167.46	$119.13
PEPCO	$174.29	$110.00	$133.37	$247.14	$136.50	$167.46	$119.13
ATSI						$357.00	$114.23
ATSI-CLVD							$114.23

Actual Marginal Resources

Prior to the 2015 and 2016 auctions the marginal resources were primarily demand response, transmission upgrades, and renewable capacity rather than new gas-fired CTs or CCs, Figure 4 demonstrates that as of the 2015/2016 auction new gas-fired CTs and CCs represented only approximately one-third of the capacity additions since the 2010/2011 BRA. Capacity additions include new resources, reactivated resources, and upratings of existing resources.

Figure 4. Annual Incremental Capacity Resource Additions.



[13] PJM, "RPM BRA Results," https://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx.

B. Operation of RPM from June 2017 Onward

The RPM capacity market will only reach equilibrium of demand and supply in the long-term, and correspondingly clear at a price equal to Net CONE year after year, if the three key underlying economic assumptions prove to be accurate. As noted above, those three key assumptions are as follows:

1. demand will increase by an increment each year,
2. the marginal resource each year will be a new CT unit, and
3. The market will meet the incremental increase in annual demand by acquiring an increment of capacity of exactly the same size from a new CT unit.

If future market conditions are different from some, or all, of those underlying assumptions, it is unlikely that the BRA clearing price will clear at or near Net CONE in every LDA year-after-year on a sustained basis. Our analyses of market fundamentals, presented in the next section of this report, suggests that future market conditions are, in fact, likely to be different than most of these underlying assumptions, and thus that future BRAs are likely to clear at prices considerably lower than Net CONE.

It is important to note that if BRAs for several planning years consistently clear at prices corresponding to an excess of capacity while there is net growth in resources, the value of CONE could be reduced automatically.[14] PJM also has the authority to propose a new value for Net CONE based upon a different calculation method and/or proxy marginal resource. In fact, PJM is required it to review the calculation of CONE every three years.[15]

3. Market Fundamentals That Will Affect Operation of the RPM in the Long-Term

The RPM capacity market will only reach equilibrium of demand and supply in the long-term, and correspondingly clear at a price equal to Net CONE year after year, if the three key underlying economic assumptions prove to be accurate. Those three key assumptions are as follows:

1. demand will increase by an increment each year,
2. the marginal resource each year will be a new CT unit, and
3. the market will meet the incremental increase in annual demand by acquiring an increment of capacity of exactly the same size from a new CT unit.

Each of those assumptions is open to question. This section presents the analyses supporting our position that future market conditions are likely to be different from these assumptions.

[14] PJM OATT, substitute Third Revised Sheet No. 586 as of September 18, 2009.
[15] 126 FERC ¶61,275, Order Accepting Tariff Provisions in Part, Rejecting Tariff Provisions in Part, Accepting Report, and Required Compliance Filings, March 26, 2009.

A. Will demand increase by a material increment each year?

The anticipated need for capacity additions in the RPM is driven primarily by projected retirements of existing fossil units in the near-term, particularly in the 2016 BRA, and by projected growth in peak demand in the long-term. Our analysis confirms that a significant quantity of existing coal capacity is likely to be retired in 2015 and 2016 but indicates that peak demand may grow more slowly than PJM is projecting.

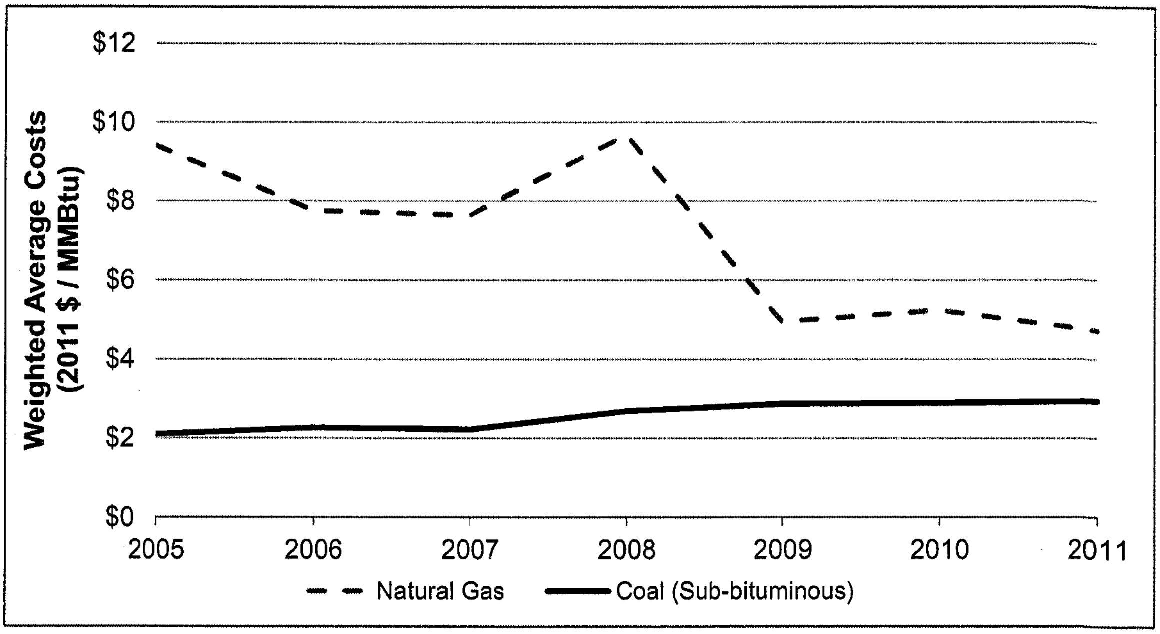
Fossil Unit Retirements

A significant quantity of existing coal capacity is projected to be retired by 2016 due to the costs of complying with tighter environmental regulations and to the decline in wholesale electric energy prices as a result of reductions in natural gas prices relative to coal prices.

New, stricter environmental regulations are adding to the costs of operating coal-fired power plants. Pollutants currently under regulation include sulfur dioxide, nitrogen oxides carbon monoxide, ozone, and particulate matter, as part of the National Ambient Air Quality Standards (NAAQS). Advanced compliance with sulfur dioxide, nitrogen oxides, and mercury will be required starting in 2015 as part of the CSAPR and MATS programs, which may require the installation of control technologies such as flue gas desulfurization (FGD), Selective catalytic reduction (SCR), baghouse technology, and activated carbon injection (ACI). Many existing coal plants will have to comply with Section 316(b) of the Clean Water Act, which requires that "the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." These new cooling requirements may require coal plants to slow water intake velocities or to reduce the entrainment and impingement of aquatic organisms through the use of new cooling systems. Finally, many coal plants may have to comply with new regulation of coal ash and steam effluent under the Resource Conservation and Recovery Act. This rulemaking, which may come into effect between 2014 and 2019, will require coal utilities to regulate siting of new coal ash depositories, ash pond liner installation, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and dam safety impoundments.

More efficient natural gas extraction techniques, particularly hydraulic fracturing, have enabled the extraction of large reserves of shale gas at relatively low cost which has driven gas prices down substantially relative to past levels. **Figure 5** presents the decline in natural gas prices relative to coal prices.

Figure 5. Weighted average costs of fossil fuels



As natural gas prices decline relative to coal prices, natural gas units are setting energy market prices at lower levels in more hours. As a result, many older, less efficient coal units are earning less margin from their sale of energy into wholesale markets are being dispatched in fewer hours, resulting in reduced revenues from the PJM energy market.

The majority of coal unit retirements are expected to occur by 2015, because many units will be required to comply with new environmental regulations by that date.

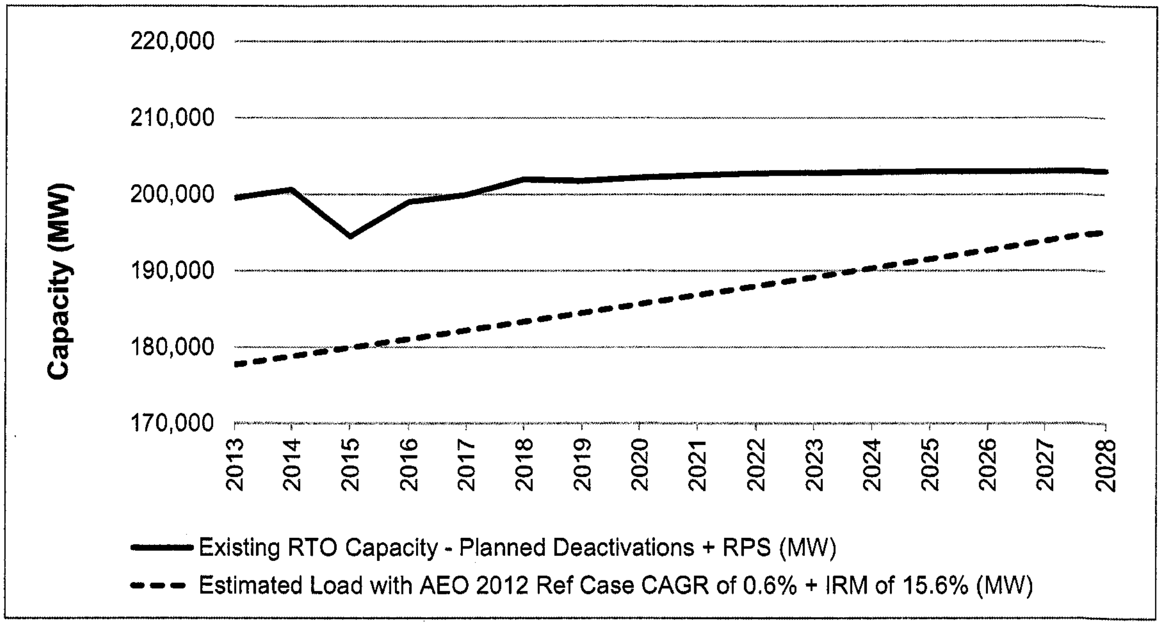
Growth in Peak Demand

The expectation that the capacity market will reach equilibrium in the long-term assumes that peak demand will continue to increase by material annual increments indefinitely. This assumption is questionable.

As of 2013 PJM was projecting that peak demand would increase at a compound annual rate (CAGR) of 1.14% between 2013 and 2028.[16] Our analyses, described below, indicate that peak demand may grow more slowly due to a slow recovery from the current recession and the increasing emphasis being placed upon energy efficiency and DR. Those factors could cause load to remain relatively flat or increase only slightly during the next decade. With low or no growth in peak demand, the need for new capacity will be delayed. For example, if peak load grows according to the AEO 2012 Updated Reference Case capacity forecast, rather than the PJM forecast, no new capacity of any type will be required within the 2013-2027 period as shown in **Figure 6**.

[16] PJM, "PJM Load Forecast Report, January 2013," http://www.pjm.com/~/media/documents/reports/2013-load-forecast-report.ashx.

Figure 6. PJM Forecast Capacity Obligation adjusted for AEO 2012 Reference Case CAGR versus Existing Capacity + new non-renewable capacity + renewable capacity required by state renewable portfolio standards net retiring coal capacity



First, the PJM forecast as of 2012 is not consistent with other recent load forecasts from public sources. For example, EIA provides a capacity forecast for the Reliability First Corporation / East Electricity Market Module (EMM) in its Annual Energy Outlook Report (AEO). The AEO 2012 updated reference case shows annual capacity growth of only 0.62% from 2013-2028. Figure 7 compares PJM's forecast load growth for the MAAC sub-region to the growth in capacity forecast in the Reference Case AEO 2012.

Figure 7. PJM 2013 Load Forecast Comparison to AEO 2012 Capacity Forecast CAGR MAAC 2013-2028

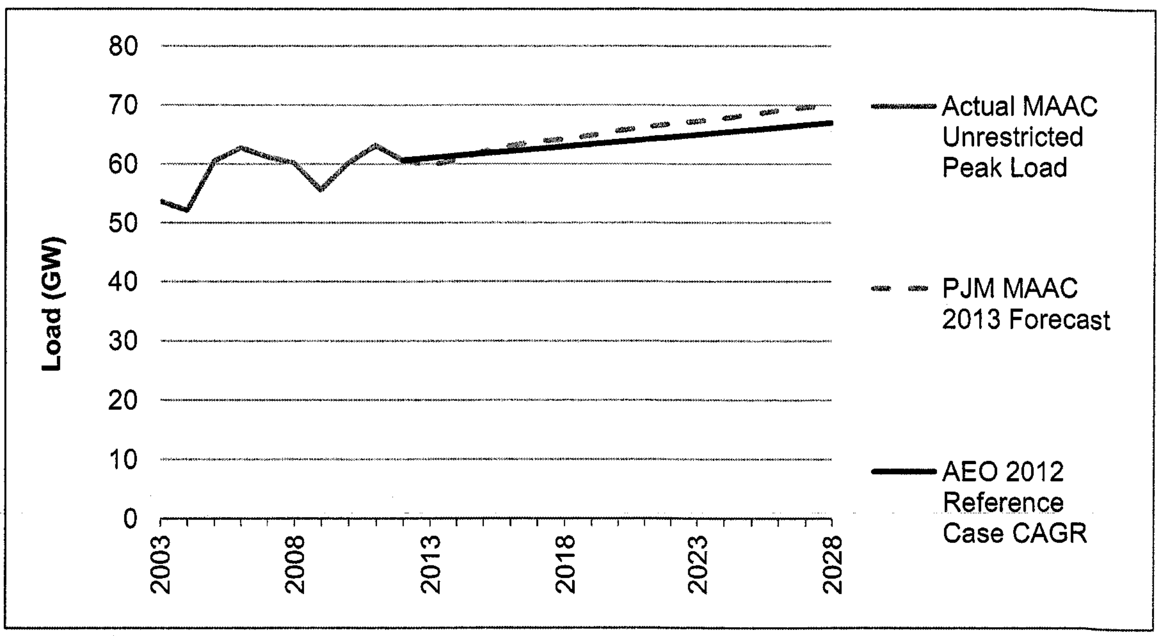
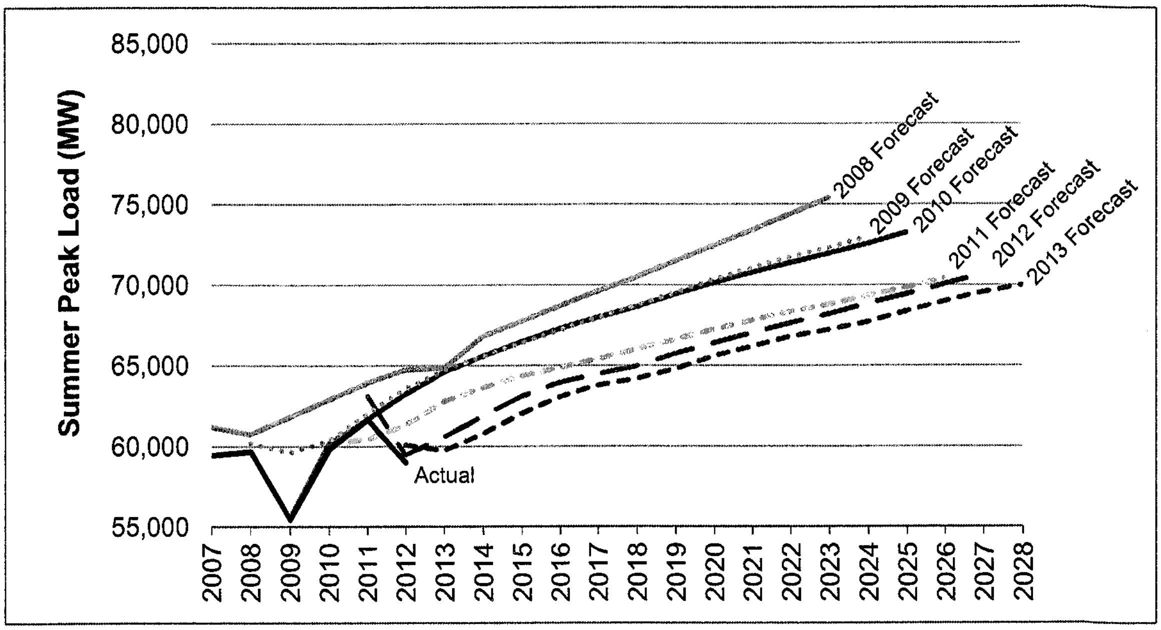


Figure 8 illustrates the progressive decline in summer peak load forecasts for the Mid-Atlantic region from 2008 through 2013. Even with those reductions it is not clear that the 2013 forecast is accurately reflecting the apparent trend toward slower load growth. That Figure also shows how for all of the years in which there is comparable historical data, the forecasts have still overestimated the actual summer peak load.

Figure 8. Forecasted and actual Summer Peak Load for Mid-Atlantic PJM Region. Note that the y-axis has been truncated in order to better show the variation between forecasts.



In addition to macroeconomic conditions, slowing load growth is attributable to increased energy efficiency initiatives and demand response programs. The PJM load forecast only reflects reductions from energy efficiency and demand resources that have cleared in RPM auctions. As a result the PJM load forecast may be over-estimating future load because it does not reflect reductions from demand resources that have not been bid into the RPM and from improvements in efficiency resulting from future federal and state initiatives. Federal and state initiatives to boost investment in energy efficiency and other conservation and demand-side measures have the potential to reduce future load below the level assumed in the RPM auction parameters.

On the federal level, the Energy Policy Acts of 2005 and 2007 set equipment and appliance efficiency standards and provided federal tax incentives for energy efficiency. The American Recovery and Reinvestment Act of 2009 provided $16.8 billion for energy efficiency and renewable energy programs, including $3.2 billion in energy efficiency and conservation block grants, $5 billion in weatherization assistance, $3.1 billion to state energy plans, and $4.4 to modernize the electric grid with, among other things, demand response equipment. The American Clean Energy and Security Act of 2009 (ACES), currently before the Senate, includes a combined efficiency and renewable electricity standard, support for state energy efficiency programs, smart grid advancement (including peak demand reduction goals), building energy efficiency programs, lighting and appliances efficiency programs, and industrial energy efficiency programs. In addition to federal efficiency programs, all states within the PJM region have energy efficiency programs in place, including both regulations and incentive-based voluntary programs. PJM states are also setting new targets for energy savings and peak demand reductions, and requiring they be met by law. For example, in Pennsylvania, Act 129 of 2008 requires all electric and gas utilities to participate in an energy efficiency and conservation program. By May 2011, each electric distribution company (EDC) must reduce consumption by a minimum of 1% below the PUC's 2009-2012 peak load forecast and reduce peak demand by 4.5% of annual system peak in the 100 highest hours of demand measured against its 2007-2008 forecast. By May 2013, consumption must be decreased by 3% of the 2009-2010forecast, and incremental increases to the peak load reduction target will be made if savings from the 2011 reduction are greater than the costs. In New Jersey, the Energy Master Plan (EMP) calls for a reduction in peak load of 17% below 2011 levels and a reduction in electricity demand of 3,634 MWh by 2020.

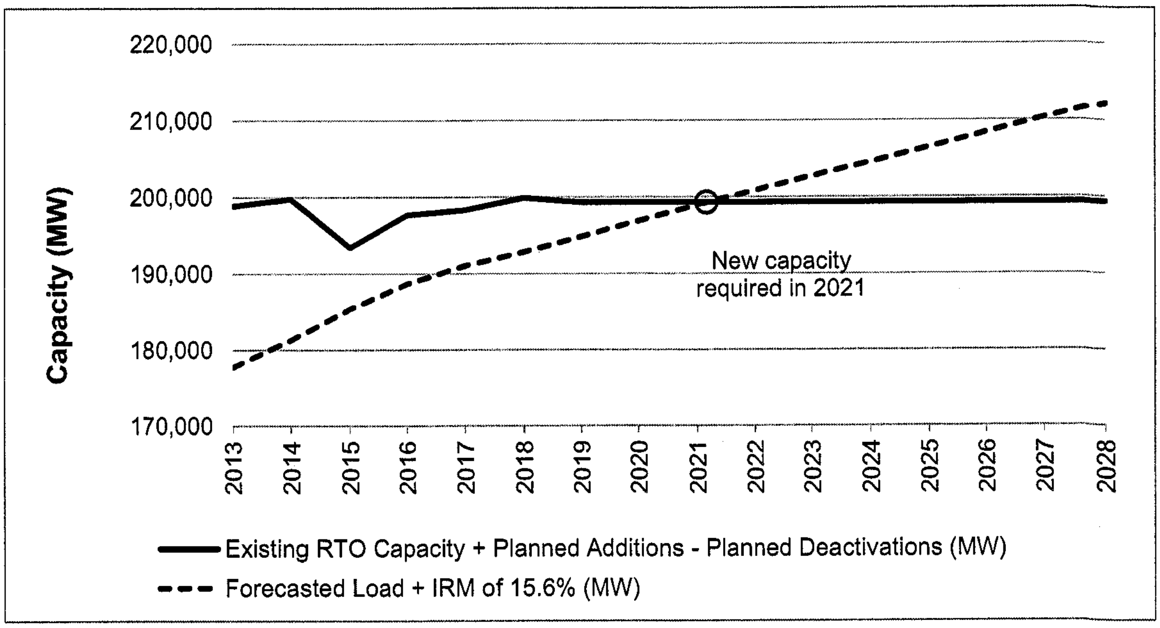
B. Will a new CT be the marginal resource each year?

The expectation that the capacity market will reach equilibrium in the long-term also assumes that the marginal resource each year will be a new CT unit. This assumption is also questionable. As noted earlier, the dominant marginal resources to date have been demand response, transmission upgrades, and renewable capacity. In addition, with the decline in natural gas costs, new NGCCs are being brought into service even though capacity prices are well below Net CONE.

Fossil Unit Capacity Additions

Our analysis of PJM projections indicates that new capacity resources would be required for the 2019 BRA if one considers only the projected IRM, existing capacity and planned retirements. However, a review of the quantities and on-line dates of non-renewable capacity in the PJM interconnection queue indicates that no additional capacity additions will be required until 2021, as shown in **Figure 9**. That Figure plots the PJM forecast of capacity requirements and our estimate of available capacity. That estimate equals existing capacity plus annual non-renewable capacity expected to come online in PJM minus capacity expected to be retired.

Figure 9. PJM Forecast Capacity Obligation versus Existing Capacity + New non-renewable capacity net retiring coal capacity



Transmission Upgrades

Transmission system upgrades and expansions have the potential to connect new capacity to the system as well as to eliminate, or reduce, constraints on the ability of certain LDAs to import capacity into their areas. Therefore these upgrades have the effect of making more capacity available to meet peak demand.

PJM reviews and approves upgrades and expansions to the existing transmission system in order to ensure reliable service. As part of that process PJM periodically prepares a Regional Transmission Expansion Plan (RTEP).[17] In preparing this transmission plan and determining the priority of investments in upgrades PJM prepares a market efficiency analysis to determine which currently planned reliability upgrades would also have an economic benefit if accelerated or modified, as well as to identify new transmission upgrades that may have economic benefits.

Table 6. **Transmission projects in service (2009-2012) and transmission projects under construction or in engineering and planning phase (2013-2016) by LDA**shows the number of transmission projects completed from 2009 to 2012 as well as the projects under construction or in the engineering & planning stages through 2016.[18]

[17] PJM, "PJM 2011 Regional Transmission Expansion Plan," http://www.pjm.com/~/media/documents/reports/2011-rtep/2011-rtep-book-1.ashx.
[18] PJM, "Transmission Construction Status," http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx. (Accessed April 3, 2013).

Table 6. Transmission projects in service (2009-2012) and transmission projects under construction or in engineering and planning phase (2013-2016) by LDA

	Transmission Projects In Service				Transmission Projects Under Construction or in Engineering & Planning			
	2009	2010	2011	2012	2013	2014	2015	2016
MAAC	95	50	113	88	65	90	119	36
EMAAC	62	27	68	52	23	49	61	15
SWMAAC	14	5	29	15	8	21	9	12
PS	24	11	24	31	4	26	34	3
PEPCO		5	15	7	7	16	1	6
ATSI				2	13	10	87	9

Except for DPL South, in every other region, the transmission projects completed through 2012 have increased the CETL/CETO ratios of each LDA, reducing their need for price adders.

Renewable Portfolio Standard Capacity Additions

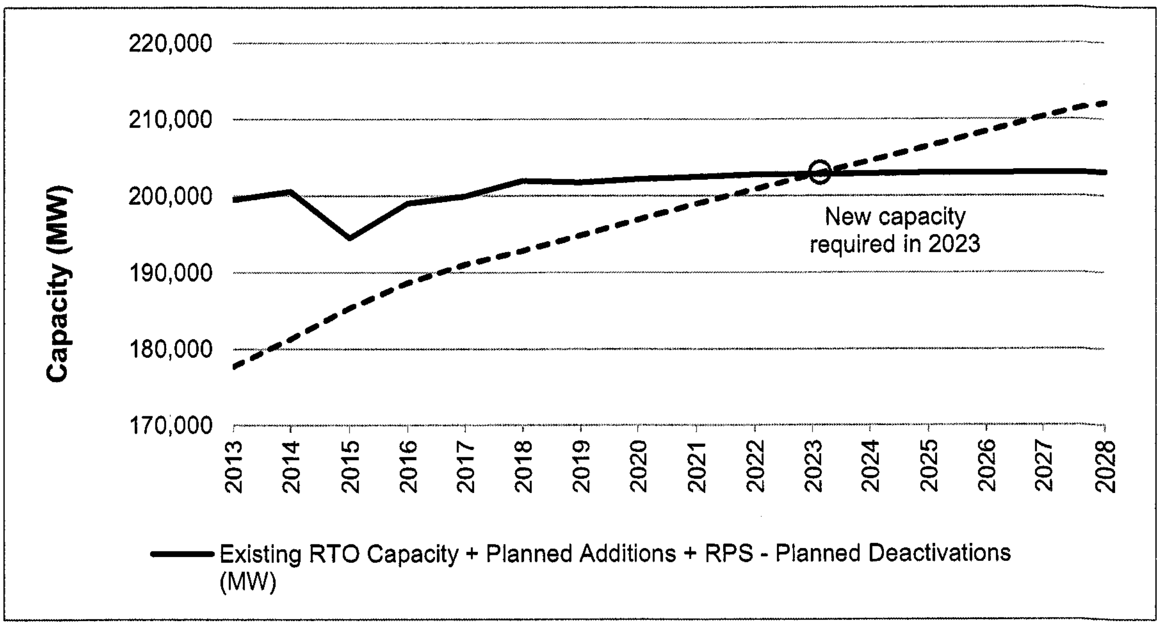
All states with utilities participating in the PJM capacity market, except for West Virginia and Indiana, currently have a Renewable Portfolio Standard (RPS). These standards require the LSEs in those states to supply a portion of their annual energy from renewable resources, with the portions often required to increase over time. As a result, new renewable capacity will be added to meet the increases in RPS portions required by law each year over the next decade. The addition of that renewable capacity is expected to put downward pressure on capacity prices over the next ten to 15 years, since renewable capacity is typically bid into BRAs as a price taker.

New Jersey's RPS, which is one of the most aggressive in the country, requires 11.3% of retail electricity sales to be generated from qualifying renewable sources by 2015, increasing to 20.4% by 2021.[19] In Maryland, 18% of electricity sales must be from tier 1 resources plus an additional 2% from solar resources by 2022.[20, 21] The solar set-aside alone is projected to result in 2,500 MW of new capacity. Overall, PJM has 2,076 MW of new wind capacity under construction, and another 11,732 MW in its transmission queue.[22]

Renewable resource capacity additions could delay the year in which other new capacity is required by two years, from the 2021 mentioned earlier to 2023. The potential impact of new renewable resource capacity developed with RPS requirements in states served by PJM is illustrated in Figure 10.

[19] Database of State Incentives for Renewables and Efficiency (DSIRE), "New Jersey," http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NJ05R&re=0&ee=0. (Accessed March 15, 2013).
[20] Database of State Incentives for Renewables and Efficiency (DSIRE), "Maryland," http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MD05R&re=0&ee=0. (Accessed March 15, 2013).
[21] Tier 1 resources include solar, wind, qualifying biomass, methane from the anaerobic decomposition of organic materials in a landfill or a waste water treatment plant, geothermal, ocean fuel cells powered by methane or biomass, and small hydroelectric plants.
[22] PJM, "Generation Queue," http://www.pjm.com/planning/generation-interconnection/generation-queue-active.aspx. (Accessed March 15, 2013).

Figure 10. PJM Forecast Capacity Obligation versus Existing Capacity + New non-renewable capacity + renewable capacity required by state renewable portfolio standards net retiring coal capacity



Synapse estimated the quantity of new renewable capacity developed to comply with RPS that PJM would recognize in a BRA in three steps. First we calculated the annual MWh energy required from new renewables in order to meet the RPS of each state each year by type of resource.[23] Then, we calculated the implied quantity of installed capacity of new renewable resources as annual MWh energy from renewables divided by 8,760 hours per year times the typical capacity factor for the type of resource. We assumed 30% for wind, 13% for solar and 85% for biomass. Finally, we calculated the quantity of new renewable capacity that PJM would recognize in a BRA by multiplying the installed capacity from step two by the "intermittent resource capacity factors" that PJM has established for capacity planning purposes.[24, 25] The intermittent resource capacity factors for wind and solar resources are 13% and 38% respectively. Over this period, the estimated quantity of capacity from RPS resources grows at a CAGR of 16%.

Our analyses indicate that substantial new RPS capacity will be available in PJM, even if the RPM market continues to clear at a low price, because capacity from renewables is driven by RPS requirements rather than compensation from the RPM. All of the PJM state RPS policies include cost recovery mechanisms and special funding to cover the costs of compliance. Each of the PJM RPS programs include penalty-supported funds including Alternative Compliance Payments (ACP) and Solar Alternative Compliance Payments (SACP) that also serve as de facto cost caps. Each of the states also has special public benefits funds in place to support development of renewable energy sources. These funds are generally supported by surcharges on customer's electricity

[23] Database of State Incentives for Renewables and Efficiency (DSIRE), https://dsireusa.org. (Accessed April 3, 2013)

[24] PJM, "PJM Load Forecast Report, January 2012," http://www.pjm.com/~/media/documents/reports/2012-pjm-load-report.ashx.

[25] PJM, "PJM Capacity Market Operations, Manual 19: PJM Load Forecasting and Analysis, Revision 22," http://www.pjm.com/sitecore%20modules/web/~/media/documents/manuals/m19.ashx. See Appendix B.

rates.[26] In Maryland, if an electricity supplier purchases solar renewable energy credits (REC) directly from a renewable on-site generator to meet the solar set-aside requirement, the duration of the contract term for the solar RECs may not be less than 15 years.[27]

In all states ACPs and SACPs serve as both cost caps and penalties for noncompliance with the RPS. Other penalties include suspension or revocation of the electric power supplier's license, disallowance of cost recovery, and prohibition of accepting new customers (as in New Jersey and Delaware).[28] In Maryland, shortfall payments are reduced on a sliding scale through 2023. These penalties, along with cost recovery mechanisms and special funding programs, help ensure that RPS targets will be met and that capacity growth from renewable resources in PJM will be sustained through the next decade.

Demand Response

There is considerable remaining potential for further reductions in demand from DR in many areas of PJM. This is particularly true in regions such as West Virginia where capacity prices have been relatively low too date. The potential for incremental demand response has been estimated in a number of reports. These include a report Synapse prepared for the Environmental Protection Agency in 2011, *A Review of Demand Response Potential in the United States,* and two earlier reports that the Brattle Group prepared for the Electric Power Research Institute (EPRI) and the Federal energy Regulatory Commission (FERC) respectively, they are, *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010 – 2030)*, and *A National Assessment of Demand Response Potential.*

The Synapse report found it reasonable to expect incremental DR (i.e., DR above and beyond what is expected under a business as usual scenario) to achieve reductions in demand of up to 44 gigawatts (GW) nationally by 2019, or 5 percent of the business-as-usual forecast national peak demand load of 912 GW. This incremental quantity of DR is approximately equal to the total level of DR expected under a BAU scenario (38 GW); thus, achieving the incremental potential would approximately double the DR in 2019 compared to BAU. The incremental reductions in demand are primarily projected to be achieved in the large commercial and industrial (C&I) customer sector.

4. Conclusion

In order for wholesale capacity prices in PJM's RPM to approximate Net CONE of a gas-fired CT year after year three key conditions must be met:

1. demand must increase by a material increment each year,
2. the marginal resource each year must be a new CT unit, and

[26] Union of Concerned Scientists, "Renewable Electricity Standards Toolkit," http://go.ucsusa.org/cgi-bin/RES/state_standards_search.pl?template=main. (Accessed March 18, 2013).
[27] Ibid.
[28] Ibid.

3. the market must meet the incremental increase in annual demand by acquiring an increment of capacity of exactly the same size from a new CT unit.

Our analysis of the PJM RPM market fundamentals suggests that actual market conditions over the coming decade may not meet those three criteria. Demand may not increase by a material increment each year due to the impacts of energy efficiency, demand response and other changes in the US economy. The marginal resource may not be a new CT unit each year due to the availability of other, less expensive resources including new gas CCS, transmission upgraders, renewable capacity and demand response. Finally, the market may not meet the incremental increases in annual demand by acquiring increments of capacity of exactly the same size from new CT units because of the lumpiness of investments in CT capacity.