BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan	))))))	**Case No. 11-346-EL-SSO** **Case No. 11-348-EL-SSO**
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority	))))	**Case No. 11-349-EL-AAM** **Case No. 11-350-EL-AAM**

DIRECT TESTIMONY OF
JONATHAN A. LESSER
ON BEHALF OF FIRSTENERGY SOLUTIONS CORP.

May 4, 2012

PUBLIC VERSION

TABLE OF CONTENTS

I. INTRODUCTION, PURPOSE, AND SUMMARY OF CONCLUSIONS

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Jonathan A. Lesser. I am President of Continental Economics, Inc., an economic consulting firm that provides litigation, valuation, and strategic services to law firms, industry, and government agencies. My business address is 6 Real Place, Sandia Park, NM 87047.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS, EMPLOYMENT EXPERIENCE, AND EDUCATIONAL BACKGROUND.

A. I am an economist with substantial experience in market analysis in the energy industry. I have over 25 years of experience in the energy industry working with utilities, consumer groups, competitive power producers and marketers, and government entities. I have provided expert testimony before numerous state utility commissions, as well as before the Federal Energy Regulatory Commission ("FERC"), state legislative committees, and international venues.

Before founding Continental Economics, I was a Partner in the Energy Practice with the consulting firm Bates White, LLC. Prior to that, I was the Director of Regulated Planning for the Vermont Department of Public Service. Previously, I was employed as a Senior Managing Economist at Navigant Consulting. Prior to that, I was the Manager, Economic Analysis, for Green Mountain Power Corporation. I also spent seven years as an Energy Policy Specialist with the Washington State Energy Office, and I worked for Idaho Power Corporation and the Pacific Northwest Utilities Conference Committee (an electric industry trade group), where I specialized in electric load and price forecasting.

I hold MA and PhD degrees in economics from the University of Washington and a BS, with honors, in mathematics and economics from the University of New Mexico. My doctoral fields of specialization were applied microeconomics, econometrics and statistics, and industrial organization and antitrust. I am the coauthor of three textbooks, including *Environmental*

Economics and Policy (1997), *Fundamentals of Energy Regulation* (2007), and, most recently, *Principles of Utility Corporate Finance* (2011). I have prepared economic impact studies estimating the job effects of electric generating facility construction and operation, and performed studies to examine how jobs are destroyed by uneconomic generation investments. My studies have been published both in peer-reviewed and trade journals. I have attached a copy of my curriculum vitae as Exhibit JAL-1.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am a member of the International Association for Energy Economics, the Energy Bar Association, and the Society for Benefit-Cost Analysis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of FirstEnergy Solutions Corp. ("FirstEnergy Solutions" or "FES").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO ("PUCO")?

A. Yes. I testified in Case Nos. 08-917-EL-UNC and 08-918-EL-UNC, generally referred to as the "POLR Remand" proceeding. I also testified in Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM and 11-350-EL-AAM, in Case Nos. 11-501-EL-FOR and 11-502-EL-FOR, and most recently in Case No. 10-2929-EL-UNC.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses several facets of the Modified Electric Security Plan ("Modified ESP" or "ESP") submitted by AEP Ohio on March 30, 2012, including its proposed two-tier capacity pricing, fuel adjustment clause, competitive sourcing of its standard service offer load, nonbypassable generation resource rider, and retail stability rider.

Q. WHAT ROLE SHOULD AEP OHIO'S MODIFIED ESP PLAY IN OHIO'S COMPETITIVE MARKET FOR RETAIL ELECTRIC GENERATION SERVICE?

A. The Modified ESP is intended to allow AEP Ohio to provide a Standard Service Offer ("SSO") using an ESP – in what Ohio has said should otherwise be a diverse and innovative market for CRES.[1] More than ten years ago, Ohio declared that retail electric generation and aggregation services, among others, would be competitive services in Ohio.[2] Ohio also directed electric distribution utilities such as AEP Ohio to offer consumers an SSO to which they always may default from the CRES market. AEP Ohio has the option of providing an SSO either through an ESP or a Market Rate Offer ("MRO"), which uses a competitive bidding process to establish the SSO price. In either case, because the SSO is a default option for consumers, the SSO under the Modified ESP either must fairly represent market pricing (the MRO) or be more favorable in the aggregate than market pricing (the ESP).

As part of the Modified ESP, AEP Ohio is once again forgoing development of an MRO. To be consistent with state policy, the Modified ESP must still provide consumers with unbiased choices over the selection of electricity supplies and suppliers, encourage market access for cost-effective supply of retail electric service, and ensure effective competition in the provision of retail electric service. Therefore, the Modified ESP should not foreclose market competition or otherwise distort competitive retail electric markets. It also should not degrade Ohio's effectiveness in the global economy by erecting barriers to market competition. As I discuss below, in fact, the Modified ESP will restrain market competition, create market inefficiencies, and impose higher costs on Ohio customers, contrary to state policy.

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[1] *See* R.C. 4928.02(C), (D). "It is the policy of this state to do the following throughout this state: (C) Ensure diversity of electricity supplies and suppliers, by giving consumers effective choices over the selection of those supplies … (D) Encourage innovation and market access for cost-effective supply- and demand-side retail electric service …"

[2] *See* R.C. 4928.03.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING AEP OHIO'S PROPOSED CAPACITY CHARGES?

A. AEP Ohio once again proposes a two-tiered capacity pricing structure that is arbitrary, discriminatory, and anti-competitive. Specifically, as discussed in the testimony of AEP Ohio witness Allen,[3] AEP Ohio proposes to charge a minority of Competitive Retail Electric Service ("CRES") providers a "Tier 1" capacity rate of $145.79/MW-day, which is the delivered PJM market price for capacity for the 2011-2012 PJM Planning year.[4] However, AEP Ohio will not adjust the Tier 1 price to reflect the much lower PJM delivered market prices in the 2012/13 and 2013/14 planning years of $19.89/MW-day and $33.87/MW-day, respectively. Thus, if the Modified ESP terms take effect on June 1, 2012, as AEP Ohio proposes, Tier 1 customers paying the lower "market-based" capacity price will, in fact, pay a capacity price that is over 600% higher than the actual market price through May 31, 2013, over 300% higher than the actual market price between June 1, 2013 and May 31, 2014, and 5% lower than the actual market price for the period between June 1, 2014 and May 31, 2015. Furthermore, AEP Ohio intends to limit Tier 1 pricing to just 21% of shopping load in 2012,[5] 31% in 2013, and 41% between January 1, 2014 and May 31, 2015. All remaining load will be forced to pay the arbitrary $255/MW-day capacity price.

As proposed by AEP Ohio, non-SSO customers will pay much more for capacity than all other customers in PJM (all of whom will pay the market price). In fact, AEP Ohio's SSO customers and non-SSO customers will pay approximately $1.58 billion more for capacity under AEP Ohio's assorted pricing schemes as compared to market-based pricing. I have estimated that the annual job losses resulting from this above-market pricing will average 6,492 over the term of

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[3] Direct Testimony of William Allen, March 30, 2012 ("Allen Direct").

[4] The PJM planning year goes from June 1 through May 31 of the subsequent year. Thus, the 2011/12 planning year ends on May 31, 2012.

[5] For 2012 only, governmental aggregation may exceed the 21% cap.

the Modified ESP. The Modified ESP should include and reflect PJM market pricing for each planning year.

AEP Ohio claims that its Tier 1 and Tier 2 prices will allow CRES providers to pay "subsidized" capacity prices because the prices are below AEP Ohio's alleged full embedded capacity costs. In fact, AEP Ohio will overcharge for capacity because it has substantially overstated its actual capacity costs, whether examined on an avoided cost[6] or a full embedded cost basis. A reasonable estimate of AEP Ohio's full embedded costs, based on 2010 data, with an appropriate energy credit for off-system sales is \$93.64/MW-day.[7]

Once AEP Ohio's corporate separation takes place – now scheduled for January 1, 2014 – AEP Ohio should no longer have capacity costs that exceed market pricing. Yet it proposes to satisfy its FRR obligation to non-SSO load by purchasing capacity from a supposedly independent affiliate, AEP Generation Resources, at the arbitrary and above-market price of approximately \$211/MW-day, as compared the equivalent RPM delivered market price of \$118.59/MW-day[8] for this period. It also proposes to purchase capacity for its SSO load for the first five months of 2015 at the arbitrary and above-market price of \$255/MW-day.

These wholesale transactions must be approved by the Federal Energy Regulatory Commission ("FERC") under its standards for affiliate transactions, known as the "Edgar Policy."[9] The Edgar Policy addresses concerns over affiliate abuse between utility subsidiaries. As FERC stated in *Edgar*, "In an arm's-length (unaffiliated) transaction, the buyer has no

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[6] *See* Testimony of Robert B. Stoddard for a further discussion of avoided or "to go" costs.

[7] This estimate includes an adjustment for capacity equalization payments based on information provided by AEP Ohio.

[8] For the 17-month period, between January 1, 2014 and May 31, 2015, the average PJM RPM delivered price will be: ((\$33.87 x 5) + (\$153.89 x 12)) / 17 = \$118.59.

[9] *See Boston Edison re: Edgar Electric Company*, 55 FERC 61,382 (1991) ("*Edgar*"). In a recent case, FERC specifically addressed capacity pricing in PJM by applying its Edgar Policy. *See Duke Energy Indiana, Inc*., *et al*. 136 FERC 61,001 (2011).

economic incentive to favor anyone but the least-cost supplier (considering price and nonprice factors).”[10]

FERC consistently has required that affiliate transactions be priced at market to avoid harm to captive wholesale or retail customers that otherwise would result from cross-subsidies. Yet, in this case, AEP Ohio is proposing to purchase capacity at an above-market price, which would provide an anti-competitive cross-subsidy to AEP Generation Resources at the expense of captive CRES providers and all non-SSO load. This is directly contrary to the plain language of FERC’s Edgar Policy.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING AEP OHIO’S PROPOSED FUEL ADJUSTMENT CLAUSE?

A. AEP Ohio’s fuel adjustment clause (“FAC”) proposal is confusing and unnecessary. First, even though AEP Ohio proposes to merge and thus simplify all other previously separate charges for Columbus Southern Power Company (“CSP”) and Ohio Power Company (“OPC”), AEP Ohio intends to keep the FAC charges separate. This makes no sense. Second, there is no reason to delay the start of the merged FAC until June 1, 2013. The only result of delaying the merged FAC will be to reduce retail competition in the OPC service territory. Specifically, by allowing OPC retail customers to pay a lower FAC than CSP customers, OPC customers will face artificially low electric prices, which will reduce retail competition in OPC’s service territory.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING AEP OHIO’S PROPOSED COMPETITIVE PROCUREMENTS FOR SSO LOAD?

A. AEP Ohio fails to provide any details regarding its proposed competitive procurements for SSO load, stating that those details would be provided in future filings once the PUCO approves the Modified ESP in its entirety. AEP Ohio also states that it will proceed with an energy-only competitive procurement of 5% of SSO load in prior to 2015 only if it is “made

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[10] 55 FERC 61,382, 62,168.

whole." However, AEP Ohio does not define what is meant by "made whole," or how it would propose to collect the additional revenues needed. As a result, this proposed competitive procurement could adversely affect retail competition, depending on whether AEP Ohio was "made whole" using its proposed Retail Stability Rider. Moreover, AEP Ohio never states whether its unregulated affiliates, AEP Retail and AEP Generation Resources, would be allowed to participate in the competitive procurement.[11] This is especially important because, as I discuss in my testimony, AEP Ohio's proposed capacity charges will provide anti-competitive cross-subsidies to AEP Generation Resources and AEP Retail.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING AEP OHIO'S PROPOSED NONBYPASSABLE GENERATION RESOURCE RIDER "PLACEHOLDER," WHICH IT FIRST INTENDS TO USE TO RECOVER THE COSTS OF THE TURNING POINT SOLAR FACILITY?

A. There is no economic basis for establishing a GRR placeholder for the Turning Point Solar facility ("Turning Point"). As I explain in Section V, a nonbypassable "placeholder" for the costs of Turning Point establishes an expectation of higher prices in the future that will restrict competition. The reason is that potential shopping customers will be less likely to purchase electricity from CRES providers if they believe they will be forced to pay for in-state solar RECs, or any other capacity, twice: first, through their CRES provider and second, through the nonbypassable GRR.

Moreover, AEP Ohio's argument that the need for Turning Point, or any resource whose costs it seeks to recover through a nonbypassable GRR, can be considered independently of the costs of such resources are incorrect. Need and cost are <u>inexorably</u> linked, because the demand for electricity depends on its price. That is why the PUCO cannot establish a "placeholder" GRR, which AEP Ohio says will be used for Turning Point during this Modified ESP, without also

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[11] In response to a discovery request, AEP Ohio does state that AEP Generation Resources could participate in the partial SSO auction and the energy-only auction of 100% of SSO load proposed for the first five months of 2015. Ohio Power Company's Response to the Office of the Ohio Consumers' Counsel's Discovery Requests, OCC-INT-2-036, -037 and -038, attached hereto as Exhibit JAL-7.

considering the actual costs of Turning Point and, thus, the magnitude of the proposed GRR. Furthermore, as I discuss in Section V, the data provided by AEP Ohio shows that the estimated levelized cost of Turning Point is greater than the average market price of in-state solar renewable energy credits ("solar RECs").

Q. WHAT ARE YOUR CONCLUSIONS REGARDING AEP OHIO'S PROPOSED RETAIL STABILITY RIDER?

A. The Retail Stability Rider ("RSR") is yet another "bite" at the stranded generation cost "apple" by AEP Ohio. In Case No. 10-2929-EL-UNC, AEP Ohio argued that it should be allowed to charge captive CRES providers a capacity price of approximately $355.72/MW-day, the price that the company claims is its full embedded cost of capacity using a "formula rate" approach.[12] In the instant proceeding, AEP Ohio argues that it will provide "discounted" capacity to CRES providers (and, hence, its non-SSO customers) in exchange for a nonbypassable charge designed to collect $284 million over the term of the Modified ESP. The proposed RSR should be rejected, because it is a revenue-based true-up mechanism <u>identical</u> in form to the mechanism that AEP Ohio had proposed in the Electric Transition Plan ("ETP") proceeding, and which the company agreed to <u>drop</u> in the Stipulation it filed in that same proceeding.[13] Moreover, the RSR is completely incompatible with corporate separation, after which AEP Ohio will no longer own the generating resources for which it seeks to collect RSR revenues. As such, I conclude that RSR revenues would be an anti-competitive cross-subsidy paid to AEP Generation Resources, in violation of AEP Ohio's own Corporate Separation Plan.[14]

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[12] *See In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2929-EL-UNC, Direct Testimony of Kelly Pearce, March 23, 2012.

[13] *In the Matter of the Application of Columbus Southern Power Company for Approval of Electric Transition Plan and Application for Receipt of Transition Revenues*, Case No. 99-1729-EL-ETP, et al., Stipulation and Recommendation, May 8, 2000 ("ETP Proceeding Stipulation").

[14] *In the Matter of the Application of Ohio Power Company for Approval of Full Legal Separation and Amendment to its Corporate Separation Plan*, Case No. 12-1126-EL-UNC, Ohio Power Company's

II. THE PROPOSED TWO-TIERED CAPACITY PRICING SCHEME IS ARBITRARY, INEFFICIENT, AND ANTICOMPETITIVE

A. <u>AEP Ohio's Proposed Capacity Pricing Will Not Benefit Customers</u>

Q. CAN YOU SUMMARIZE AEP OHIO'S PROPOSED CAPACITY PRICING SCHEME IN THE MODIFIED ESP?

A. Yes. AEP Ohio proposes a two-tiered capacity price for non-SSO load. Tier 1 customers would be charged the PJM RPM delivered capacity price for the 2011-2012 PJM planning year, which is \$145.79/MW-day. [15] The Tier 1 price will be available to 21% of shopping load through the remainder of 2012, 31% of shopping load in 2013, and 41% of shopping load in 2014 through May 31, 2015. AEP Ohio proposes to charge Tier 1 customers this same price for the duration of the Modified ESP. In other words, AEP Ohio does not intend to allow even Tier 1 customers to pay the actual RPM market price over the term of the Modified ESP. Tier II customers will pay an even higher price of \$255/MW-day for capacity. Following AEP Ohio's corporate separation and transfer of all generating assets to AEP Generation Resources,[16] the same above-market pricing will continue with all resulting revenues, plus any revenues from the RSR, simply remitted from AEP Ohio to AEP Generation Resources.[17]

In addition, AEP Ohio will pay AEP Generation Resources \$255/MW-day for all capacity provided in connection with any and all SSO energy-only auctions conducted by AEP Ohio prior to June 1, 2015.[18] Beginning on June 1, 2015, AEP Ohio will participate in the PJM Reliability Pricing Model ("RPM") capacity market. Beginning on June 1, 2015, therefore, AEP

(cont.)

Application for Approval of its Full Legal Corporate Separation and Amendment to its Corporate Separation Plan, March 30, 2012 ("2012 Corporate Separation Plan").

[15] Allen Direct, pp. 6-7.

[16] *See* 2012 Corporate Separation Plan.

[17] Direct Testimony of Phillip Nelson, March 30, 2012 ("Nelson Direct"), p. 7, lines 14-18 and p. 8, lines 1-3.

[18] Nelson Direct, p. 6, lines 20-22 and p. 7, lines 18-21. *See* Exhibit JAL-7.

Ohio will obtain its capacity resources through the PJM RPM auctions for its remaining SSO customers. CRES providers serving AEP Ohio's non-SSO customers will obtain capacity from the market through the RPM auctions.

Q. HOW DO THE PROPOSED TIER 1 AND TIER 2 PRICES COMPARE WITH THE PJM RPM DELIVERED CAPACITY PRICES FOR THE TERM OF THE PROPOSED MODIFIED ESP?

A. Table 1 provides a comparison of the PJM RPM delivered capacity prices for the 2012/13 through 2014/15 planning years, and the proposed Tier 1 and Tier 2 prices. As this table shows, over the three-year time frame, even the $145.79/MW-day Tier 1 capacity price is, on average, more than double the average PJM RPM market delivered price (i.e., the clearing price adjusted for scalars and losses). The Tier 2 capacity price of $255/MW-day is almost four times greater than the average PJM RPM market delivered price.

Table 1: Differences Between Modified ESP Capacity Prices and PJM RPM Prices

PJM Planning Year	Billed RPM Capacity Rate ($/MW-day)	AEP Tier 1 Price ($/MW-day)	AEP Tier 2 Price ($/MW-day)	Tier 1 Excess Over Market	Tier 2 Excess Over Market
	[1]	[2]	[3]	[4]	[5]
2012/13	$19.89	$145.79	$255.00	633%	1182%
2013/14	$33.87	$145.79	$255.00	330%	653%
2014/15	$153.89	$145.79	$255.00	-5%	66%
2012-2015 Average	**$69.22**	**$145.79**	**$255.00**	**111%**	**268%**

Notes:
[1]: Source: PJM RPM auction results spreadsheets
[2]: Source: AEP Modified ESP
[3]: Source: AEP Modified ESP
[3]: Equals { [2] / [1] } - 1.
[5]: Equals { [3] / [1] } - 1.

Q. DOES AEP OHIO PROVIDE A BASIS FOR THE QUANTITIES IT PROPOSES TO PROVIDE UNDER TIER 1 PRICING?

A. No. AEP Ohio witness Allen states that the caps on access to market-based pricing will "encourage increasing levels of customer shopping during the transition period before the

Company's SSO load is served though an auction."[19] However, caps on the availability of market-based pricing could only have the effect of restraining shopping. This contradicts state policy that seeks to enhance competition.[20]

Q. DO YOU AGREE WITH AEP OHIO WITNESS ALLEN'S TESTIMONY THAT CUSTOMERS WILL RECEIVE A $989 MILLION "BENEFIT" UNDER AEP OHIO'S PROPOSED TWO-TIER PRICING PLAN?[21]

A. No. The "benefit" to which Mr. Allen alludes is based on a false comparison. Specifically, Mr. Allen assumes that AEP Ohio is <u>entitled</u> to charge CRES providers and SSO customers between June 1, 2012 and May 31, 2015, $355.72/MW-day for capacity, which AEP Ohio claims is its full embedded capacity cost, and thus any reductions in the capacity price AEP Ohio charges below that full embedded cost is a "benefit" to its customers. However, as shown in Table 1, these "discounted" capacity prices greatly exceed the market price of capacity in PJM over the term of the ESP. Thus, what AEP Ohio considers to be a "benefit" is, in fact, an above-market cost it intends to impose on all of its customers.

Q. HAVE YOU ESTIMATED THE ABOVE-MARKET COST AEP OHIO INTENDS TO CHARGE FOR CAPACITY DURING THE MODIFIED ESP?

A. Yes. To do this, I first used the "full cost capacity" per-MWh prices shown in AEP Ohio witness Thomas's Exhibit LJT-2, which are based on AEP Ohio's claimed full embedded cost of capacity of $355.72/MW-day.[22] I then estimated the equivalent per-MWh capacity prices at the proposed Tier 1 and Tier 2 capacity prices using simple ratios.[23] I also calculated the equivalent

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[19] Allen Direct, p. 6, lines 8-10.

[20] *See* R.C. 4928.02.

[21] Allen Direct, p. 8, line 18 - p. 9, line 4.

[22] *See* Direct Testimony of Laura J. Thomas ("Thomas Direct"), p. 15, lines 16-18.

[23] For example, the equivalent per-MWh residential price in PY12/13 at $255/MW-day is calculated as: ($255/$355.72) *x* $30.01/MWh = $21.51/MWh.

per-MWh prices based on the PJM RPM market delivered prices in each year. The results are shown in Table 2 below.

Table 2: Implied Capacity Prices (per-MWh), by Customer Class

Thomas per-MWh Capacity Prices @ 355.72/MW-day

Class	PY12/13	PY13/14	PY14/15
Residential	$30.01	$28.64	$28.83
Commercial	$23.01	$21.90	$22.45
Industrial	$17.29	$15.57	$15.82

Source: Exhibit LJT-2

per-MWh Capacity Price @ $145.79/MW-day

Class	PY12/13	PY13/14	PY14/15
Residential	$12.30	$11.74	$11.82
Commercial	$9.43	$8.98	$9.20
Industrial	$7.09	$6.38	$6.48

per-MWh Capacity Price @ $255/MW-day

Class	PY12/13	PY13/14	PY14/15
Residential	$21.51	$20.53	$20.67
Commercial	$16.49	$15.70	$16.09
Industrial	$12.39	$11.16	$11.34

PJM RPM Capacity Price per MWh

Class	PY12/13	PY13/14	PY14/15
Residential	$1.68	$2.73	$12.47
Commercial	$1.29	$2.09	$9.71
Industrial	$0.97	$1.48	$6.84

Next, I used AEP Ohio witness Allen's load data shown on page 2 of his Exhibit WAA-4 to calculate the relative cost over the prevailing PJM RPM market price for each planning year.[24] The results of my analysis are shown in Exhibit JAL-2. As this exhibit shows, under the Modified ESP, AEP Ohio will receive for capacity provided to non-SSO load in excess of $776 million over the PJM RPM delivered market prices during the three years of the Modified ESP. SSO customers who are part of AEP Ohio's proposed competitive procurement will pay an excess of $36 million over the 2014/15 PJM RPM delivered market price. All remaining SSO customers, who according to AEP Ohio witness Allen are paying the alleged embedded capacity

[24] While my analysis accepts Mr. Allen's shopping estimates, I offer no opinion on whether his estimates are reasonable.

cost of $355/MW-day,[25] will pay an excess of $766 million over the PJM RPM market prices. In total, AEP Ohio's SSO and non-SSO customers will be forced to pay almost **$1.6 billion** in excess of market prices for capacity under the Modified ESP. That is a cost to all AEP Ohio customers, not a benefit.

B. The RPM-Based Market Price Is The Only Just And Reasonable Price.

Q. WHAT IS YOUR OPINION REGARDING THE CAPACITY PRICE THAT SHOULD BE CHARGED BY AEP OHIO TO BOTH SSO CUSTOMERS AND CRES PROVIDERS?

A. The PJM RPM market-clearing price for capacity is the most economically efficient price for capacity. It is not a subsidized price, and it is compensatory.

The RPM market prices[26] are what all other load serving entities in PJM pay for capacity, either directly through their participation in the RPM auctions or indirectly through bilateral contracts whose prices are governed by actual and expected RPM prices. Moreover, as I discuss below, under the 2012 Corporate Separation Plan, the PJM RPM market price is the price AEP Generation Resources should charge AEP Ohio for the capacity it requires as an FRR entity, and that AEP Ohio presumably will pay to meet its capacity obligations after it participates in the PJM RPM beginning June 1, 2015.

Q. BECAUSE AEP GENERATION RESOURCES WILL SELL CAPACITY BILATERALLY TO AEP OHIO, COULD THE PRICE DIFFER FROM THE PJM RPM MARKET PRICE?

A. It could, but for the period between January 1, 2014, when corporate separation is expected to take place, and May 31, 2015, when the Modified ESP would expire, the PJM RPM prices are already known. Therefore, the only logical bilateral sales price would be based on the

[25] Allen Direct, p. 9, lines 5-13.

[26] Because of transmission constraints, capacity prices in some constrained zones are higher than the overall PJM RTO market price of capacity.

known PJM RPM market prices. If AEP Ohio agrees to pay AEP Generation Resources a higher capacity price, that will represent an anticompetitive cross-subsidy. I discuss this further in Section II.D, below.

Q. WHY IS THE CAPACITY PRICE AEP OHIO CHARGES CRES PROVIDERS A TRANSFER PRICE?

A. A transfer price is a price that one part of a firm charges another part. In some cases, there is no external market for the commodity or service sold internally. In other cases, there is an external market. For example, suppose a firm has an upstream and downstream division. The upstream division generates electricity, all of which supplies the downstream division's electric arc furnace for manufacturing steel. The electric generating division "sells" the electricity it generates to the steel manufacturing division. The transfer price is the sales price of electricity "sold" by the generating division to the steel manufacturing division. Similarly, AEP Ohio's capacity price can be thought of as a transfer price of capacity sold directly to SSO customers and indirectly to non-SSO customers through their CRES providers.

For the former, the capacity price is embedded within AEP Ohio's Base Generation Rate ("BGR"). For the latter, because CRES providers must purchase capacity from AEP Ohio to serve AEP Ohio's non-SSO distribution customers, it can also be thought of a transfer price. Rather than purchasing capacity from the market, which in this case is the PJM RPM, AEP Ohio's SSO customers and CRES providers must purchase capacity "internally" from AEP Ohio.

Q. IS THE PROPOSED $255/MW-DAY CAPACITY PRICE THAT AEP OHIO WILL CHARGE TIER II CRES PROVIDERS AND THEIR NON-SSO CUSTOMERS, AS WELL AS SSO CUSTOMERS WHOSE ENERGY LOAD IS AUCTIONED OFF, AN ECONOMICALLY EFFICIENT TRANSFER PRICE?

A. No. A standard economic exercise associated with transfer pricing is to determine the economically efficient price. When there is an external market for the good being "transferred" internally, the most efficient price is the external market-clearing price. If the transfer price is higher than the market price, then the "downstream" division would be better off buying the commodity directly from the market. If the price is set lower than the market price, then the upstream division is losing money by subsidizing the downstream division's purchase of the commodity. Thus, the most economically efficient transfer price is the PJM RPM market price.

Q. DOES AEP OHIO AGREE THAT THE MOST ECONOMICALLY EFFICIENT PRICE IS THE RPM PRICE?

A. No. AEP Ohio has previously argued that, because it is an FRR entity, it should be allowed to charge the <u>higher</u> of the RPM market price or its full embedded costs.

Q. DOES AEP OHIO'S ARGUMENT MAKE ECONOMIC SENSE?

A. No. Markets reward efficiency. The most efficient producers earn the highest profits and, because markets encourage producers to become more efficient, they reward customers. In contrast, AEP Ohio wants to charge CRES providers its embedded capacity costs if the market price is below those costs, but charge the market price if its embedded costs are below market.

Besides being self-serving, AEP Ohio's argument is contrary to the entire purpose of the RPM capacity market, which is to provide transparent market signals that encourage economically efficient generating capacity investment decisions. If AEP Ohio were correct, there would be no economic incentive for any generator to participate in the PJM RPM. Instead, we would return to the pre-transition model of fully-regulated electric service. This is not the goal of the State of Ohio, or of PJM, within which AEP Ohio operates.

Finally, AEP Ohio's argument it is completely at odds with how AEP Generation Resources will operate after corporate separation, as that company will sell capacity at a market price. It contradicts basic economic principles to suggest that it is economically efficient to charge an above-market price, including during the bridge period after AEP Ohio transfers all of its generating capacity to AEP Generation Resources, until June 1, 2015, when AEP Ohio will participate in the PJM RPM.

Q. IS THE MARKET PRICE A SUBSIDIZED PRICE?

A. No. The market-clearing price in a competitive market is <u>not</u> a subsidized price. A subsidized price allows inefficient suppliers, those who would not be economically viable in the market, to remain in business. In some cases, the market price may be less than an individual generator's embedded costs. In other cases, the market price will be higher than an individual generator's embedded costs. That is the entire point of the market. By establishing a competitive market price for capacity, efficient price signals are provided to all current and potential participants, who can then make reasoned investment decisions.

Q. ARE CRES PROVIDERS "TAKING ADVANTAGE" OF AEP OHIO BY PAYING A PRICE FOR CAPACITY BELOW AEP OHIO'S CLAIMED EMBEDDED COST OF CAPACITY?

A. No. AEP Ohio ignores several salient facts. First, until earlier this year, AEP Ohio previously sold capacity to CRES providers at the PJM RPM price.[27] If CRES providers had known that AEP would later decide to charge an above-market price, they could have themselves applied to PJM to become FRR providers, supplying their own capacity by either using their own resources or through bilateral contracts with resources that were not obligated to the RPM. Because AEP Ohio was initially selling capacity at the PJM RPM market price and had not provided notice that it would switch to a much-higher cost-based price, CRES providers were indifferent to relying on AEP Ohio for their capacity requirements. Second, because of the three-year advance notice provision in the RAA, CRES providers must obtain all of their capacity from AEP Ohio through May 31, 2015, after which AEP Ohio will no longer be an FRR entity. CRES providers are captive to AEP Ohio until that time. Thus, it is not CRES providers who are "taking advantage" of AEP Ohio, it is AEP Ohio that has taken advantage of CRES providers through a "bait and switch" approach to capacity pricing.

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[27] March 7, 2012 Entry in Case No. 10-2929-EL-UNC. This entry allowed AEP Ohio to charge a tiered capacity price to CRES providers through May 31, 2012.

Q. IF, BEGINNING ON JUNE 1, 2015, AEP OHIO IS PAID THE RPM MARKET PRICE FOR ALL OF ITS CAPACITY, AND THAT PRICE IS LESS THAN AEP OHIO'S EMBEDDED CAPACITY COST, WILL AEP OHIO THEREFORE BE SUBSIDIZING ALL LOAD SERVING ENTITIES WHO PURCHASE THAT CAPACITY THROUGH THE RPM?

A. No. AEP Ohio's arguments have no validity. First, there is no "entitlement" or "guarantee" to recover its embedded capacity costs in the market. In fact, it is possible that AEP Ohio (or, after corporate separation, AEP Generation Resources) could end up recovering all of its embedded capacity costs and more from revenues arising from capacity and energy sales. That is how the PJM markets work. Baseload generating plants, such as nuclear plants, do not recover all of their embedded costs from capacity revenues alone. Instead, they recover most of those costs from energy market sales because the variable operating cost of nuclear plants is quite low.[28] On the other hand, gas-fired peaking units that run only sporadically recover most of their embedded costs from the capacity market and relatively little from the energy market. Like nuclear plants, most coal-fired power plants are baseload plants. Thus, one would expect them to recover significant portions of their embedded costs from margins on energy sales.

The fact that the market price of capacity may be less than AEP Ohio's embedded cost of capacity does <u>not</u> mean AEP Ohio is subsidizing anyone. It means that the market can supply <u>capacity</u> more efficiently than AEP Ohio can. That, of course, is the purpose of markets. If Farmer Jones can grow wheat at a cost less than the market price, but Farmer Smith cannot, then Farmer Jones will supply wheat to the market. Farmer Smith will not. That does not mean Farmer Smith is forced to "subsidize" wheat consumers; it means Farmer Smith is not an efficient wheat producer.

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[28] This is why, as Mr. Stoddard explains in his accompanying testimony, that the avoided or "to go" costs for a generating unit can be negative. It means that, even in the absence of any specific capacity payments, a generating unit can recover all of its embedded costs and earn a risk-compensatory rate of return.

C. <u>AEP Ohio Should Not Be Authorized to Charge an Embedded Cost Rate of More than $93.64/MW-day.</u>

Q. WHAT IS THE BASIS FOR YOUR ARGUMENT THAT AEP OHIO SHOULD NOT BE AUTHORIZED TO CHARGE AN EMBEDDED COST RATE OF MORE THAN $93.64/MW-DAY?

A. As I explained in detail in my testimony in Case No. 10-2929-EL-UNC,[29] AEP Ohio agreed to forego recovery of stranded generation costs as part of its Stipulation in the Electric Transition Plan ("ETP") proceeding. AEP Ohio had proposed to recover these costs based on "lost revenues," which is precisely what it wishes to do with its proposed nonbypassable RSR for the Modified ESP. Thus, I conclude that AEP Ohio is attempting to recover stranded generation costs that it had previously agreed to collect only to the extent possible in a competitive market. Furthermore in its 2012 Corporate Separation Plan, filed on March 30, 2012, AEP Ohio admits that it is not allowed to recover stranded costs.[30] Therefore, AEP Ohio should be required to charge all of its customers, whether SSO customers directly or non-SSO customers indirectly through their CRES providers, the PJM RPM market price for capacity.

Q. ARE YOU SUGGESTING THAT AEP OHIO BE AUTHORIZED TO CHARGE AN EMBEDDED COST CAPACITY RATE OF $93.64/MW-DAY TO ALL CUSTOMERS?

A. No. The most economically efficient capacity price, and the one that AEP Ohio should charge all of its customers, is the PJM RPM market price. The purpose of the $93.64/MW-day embedded capacity cost value I derive, as discussed below, is simply to demonstrate that AEP Ohio's claimed embedded capacity cost of $355.72/MW-day and, hence, AEP Ohio witness

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[29] *See* Case No. 10-2929-EL-UNC, Direct Testimony of Jonathan Lesser, April 4, 2012, pp. 37-45. (Attached as Exhibit JAL-3).

[30] AEP Ohio Corporate Separation Plan, March 30, 2012, p. 7: "Under SB 3, all of these generation assets were subjected to market and EDUs therefore were given a temporary opportunity to recover stranded generation investments during a transition period. That transition period is over. EDUs can no longer recover stranded generation investments, and transferring the generation assets based on an arbitrary determination of their current fair market value rather than net book value would be inappropriate."

Allen's claim that its customers will, collectively, "save" $989 million over the three-year term of the Modified ESP, have neither a regulatory nor a factual basis.

Q. HOW DID YOU ESTIMATE THE $93.64/MW-DAY EMBEDDED CAPACITY COST?

A. An extended discussion of the rationale for my calculation can be found in my previously filed testimony in Case No. 10-2929-EL-UNC.[31] The general principles I used to develop my embedded capacity cost estimate are as follows:

1. All capital investments in generating facilities, including its purchase of the Waterford and Darby generating plants, that were made by AEP Ohio after the ETP transition date of January 1, 2001, are to be recovered through the competitive market.[32] Thus, the embedded capacity cost is properly based on pre-2001 generating plant in service only. In its 2012 Corporate Separation Plan, AEP Ohio admits that the transition period for recovery of stranded generation costs is over, stating that, "Under SB 3, <u>all</u> of these generation assets were subjected to market and EDUs therefore were given a temporary opportunity to recover stranded generation investments during a transition period. That transition period is over. <u>EDUs can no longer recover stranded generation investments, and transferring the generation assets based on an arbitrary determination of their current fair market value rather than net book value would be inappropriate</u>."[33]

2. A formula-rate embedded capacity cost calculation properly refunds all profits earned from both off-system capacity and energy sales: if captive customers are required to pay for capacity, they are entitled to all of the profit margins above AEP Ohio's proposed return on its generating capital investment, which contribute to the recovery of the embedded capacity costs. Otherwise, the realized return on equity necessarily will exceed the allowed return on equity, which is neither just nor reasonable.

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[31] *See* Case No. 10-2929-EL-UNC, Direct Testimony of Jonathan Lesser, April 4, 2012, pp. 45-57. (Attached as Exhibit JAL-4).

[32] R.C. § 4928.01(A)(28); R.C. § 4928.38 ("the utility shall be fully on its own in the competitive market.")

[33] 2012 Corporate Separation Plan, p. 7 (emphasis added).

3. All of AEP Ohio's post-2000 capital investments in environmental emissions control equipment previously have been recovered through an environmental investment carrying cost rider ("EICCR"), which the PUCO clearly established as a bypassable charge to be paid by SSO customers, because such generation was for their benefit. Such charges should not, therefore, be embedded in a capacity cost charged to non-SSO customers through their CRES providers. Arguments that, but for these capital investments, AEP Ohio would be unable to operate many of its generating plants, and thus not earn offsetting capacity and energy revenues from off-system sales either to Pool Agreement members or other entities, are incorrect, because AEP Ohio's investments in environmental control equipment is paid for separately.

4. Arguments previously made by AEP Ohio that it is allowed to recover stranded costs from CRES providers, because the ETP Stipulation only addressed stranded costs recovered from retail customers, are false. As an FRR entity, AEP Ohio is obligated to meet a capacity requirement based on its entire retail load. Whether some of that retail load is served by CRES providers, or directly by AEP Ohio, is immaterial. AEP Ohio itself states that "CRES providers who choose not to self-supply merely act as a middle-man [sic] on capacity flowing from AEP Ohio."[34] The mere fact that the state compensation mechanism is collected from CRES providers should not alter the analysis. Charging discriminatory prices to identical customers for the same service is economically inefficient and contrary to state policy.

Q. WHAT WAS THE VALUE OF THE MARGIN YOU ESTIMATED FROM ENERGY OFF-SYSTEM SALES FOR AEP OHIO IN 2010?

A. The details of my calculation are shown in Table 3, which is reproduced from my testimony in Case No. 10-2929-EL-UNC. As shown on line [20] of this table, I estimated a total contribution to embedded costs of $178 million from AEP Ohio's off-system sales for resale, after subtracting out the estimated energy off-system sales margin provided by AEP Ohio's Darby and Waterford generating plants, which were acquired by AEP Ohio in 2007 and 2005, respectively, after the January 1, 2001 transition date to competition.

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[34] Direct Testimony of Richard E. Munczinski, filed March 23, 2012 in Case No. 10-2929-EL-UNC, at p. 5, lines 22-23.

Q. HOW DID YOU CALCULATE THE ENERGY OFF-SYSTEM SALES MARGINS FOR THOSE TWO PLANTS?

A. As shown on line [19] of Table 3, I estimated the energy off-system sales margin for Darby and Waterford by using those plants' share of total reported generation (line [12]) relative to total energy production (line [11]), and multiplying that ratio by the total estimated contribution to embedded costs from off-system energy sales (line [18]).

Table 3: AEP Ohio Net Energy and Capacity Margins

Line No.	Type	FERC Account	CSP	OPC	TOTAL
	Steam Power Generation				
[1]	501	Fuel	**$ 345,294,261**	**$ 1,146,205,314**	$ 1,491,499,575
[2]	503	Steam from Other Sources	$ -	$ -	$ -
[3]	504	Steam Transfers (credit)	$ -	$ -	$ -
[4]	509	Emissions Allowances	$ 5,727,736	$ 8,473,508	$ 14,201,244
[5]	510	Maintenance Supervision and Engineering	$ 2,327,198	$ 12,473,218	$ 14,800,416
[6]	512	Maintenance of Boiler Plant	$ 44,791,005	$ 107,219,065	$ 152,010,070
[7]	513	Maintenance of Electric Plant	$ 7,662,253	$ 22,984,446	$ 30,646,699
	Hydraulic Power Generation				
[8]	544	Maintenance of Electric Plant	$ -	$ 2,051,934	$ 2,051,934
	Other Power Generation				
[9]	547	Fuel	$ 2,928,243	$ -	$ 2,928,243
[10]	**Total Energy-related Production Costs**		**$ 408,730,696**	**$ 1,299,407,485**	**$ 1,708,138,181**
[11]	**Total Power Production (MWh)**		12,521,147	48,768,500	$ 61,289,647
[12]	*Power production - Darby/Waterford (MWh)*		641,627	-	641,627
[13]	**Net pre-2001 GPIS power production (MWh)**		**11,879,520**	**48,768,500**	**60,648,020**
[14]	**Average energy-only production costs ($/ MWh)**		$ 32.6432	$ 26.6444	$ 27.8699
[15]	**Total Reported Energy Sales for Resale (MWh)**		6,397,937	25,595,610	31,993,547
[16]	**Estimated Variable Production Costs, Sales for Resale**		$ 208,849,336	$ 681,979,704	$ 890,829,041
[17]	**Total Reported Energy-related Revenues from Sales for Resale**		$ 295,218,916	$ 778,113,468	$ 1,073,332,384
[18]	**Total Energy Offsystem Sale Contribution to Embedded Generation Costs**		**$ 86,369,580**	**$ 96,133,764**	**$ 182,503,343**
[19]	**Adjustment for Darby/Waterford energy margins**		**$ 4,425,877**	**$ -**	**$ 4,425,877**
[20]	**Net Contribution to Embedded Generation Costs, pre-2001 GPIS**		**$ 81,943,703**	**$ 96,133,764**	**$ 178,077,466**

Notes:

[1] Source: 2010 FERC Form-1 Report, pp. 320-21, plus deferred fuel costs reported in Acct. 182.3.
[2] Source: 2010 FERC Form-1 Report, pp. 320-21.
[3] Source: 2010 FERC Form-1 Report, pp. 320-21.
[4] Source: 2010 FERC Form-1 Report, pp. 320-21.
[5] Source: 2010 FERC Form-1 Report, pp. 320-21.
[6] Source: 2010 FERC Form-1 Report, pp. 320-21.
[7] Source: 2010 FERC Form-1 Report, pp. 320-21.
[8] Source: 2010 FERC Form-1 Report, pp. 320-21.
[9] Source: 2010 FERC Form-1 Report, pp. 320-21.
[10] Equals: [1] + [2] + ... + [9].
[11] Source: 2010 FERC Form-1 Report, p. 401a.
[12] Source: 2010 FERC Form-1 Report, p. 403.1.
[13] Equals: [11] - [12].
[14] Equals: [10] / [13].
[15] Source: 2010 FERC Form-1 Report, p. 311. (Non-requirements only)
[16] Equals: [14] x [15].
[17] Source: 2010 FERC Form-1 Report, p. 311. (Non-requirements only)
[18] Equals: [17] - [16].
[19] Equals: { [12] / [11] } x [18].
[20] Equals: [18] - [19].

Q. DO YOU CONSIDER THIS RATIO APPROACH TO ESTIMATING THE CONTRIBUTION OF DARBY AND WATERFORD TO TOTAL ENERGY OFF-SYSTEM SALES PROFITS TO BE REASONABLE?

A. Yes. Because AEP Ohio does not breakdown off-system sales by generating unit. In other words, the company cannot determine the specific MWh sales contribution of each generating unit to the 32 million MWh of off-system sales shown on line [15] of Table 3. Thus, a ratio approach is the best alternative to estimating the contribution to embedded generation costs from the Darby and Waterford generating plants.

Q. HOW DO YOU USE THE $178 MILLION CONTRIBUTION TO EMBEDDED COSTS YOU SHOW IN TABLE 3?

A. I use this value to determine an adjusted embedded capacity cost value for AEP Ohio's pre-2001 generation plant in service ("GPIS"). Specifically, as I discussed in my testimony in Case No. 10-2929-EL-UNC, AEP Ohio has no legitimate basis for claiming these additional profits, which would otherwise provide it with an even higher return on equity ("ROE") than the 11.15% value used by AEP Ohio witness Pearce to calculate his embedded capacity cost value of $355.72/MW-day.[35]

Q. IN YOUR TESTIMONY IN CASE NO 10-2929-EL-UNC, YOU DERIVED AN EMBEDDED CAPACITY COST VALUE OF $78.53/MW-DAY. WHY HAS YOUR ESTIMATE CHANGED?

A. In my previous testimony, I did not credit back to AEP Ohio the portion of capacity equalization payments made possible by the company's acquisition of the Darby and Waterford generating plants. These two generating plants were acquired in 2005 and 2007, after the January 1, 2001 transition date to electric competition, and were designated as merchant facilities. In my testimony in Case No. 10-2929-EL-UNC, I credited back to AEP Ohio the margins from these

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[35] *See* Case No. 10-2929-EL-UNC, Direct testimony of Jonathan Lesser, April 4, 2012, p. 50, lines 15-17, showing that AEP Ohio's actual ROE under Mr. Pearce's formulation would be 15.13%.

two plants derived from energy off-system sales.[36] However, I did not similarly credit AEP Ohio with the capacity equalization payments made possible by these two plants, which arise because of AEP Ohio's surplus capacity and sales of such capacity under the Pool Agreement. Thus, to be consistent, I have "credited" these two plants' contribution to the $490 million of capacity equalization revenues AEP Ohio received in 2010.

Q. HOW DID YOU ESTIMATE THE CONTRIBUTION FROM DARBY AND WATERFORD TO THE TOTAL CAPACITY EQUALIZATION REVENUES?

A. I used the same general approach that I used to calculate the energy credit for Darby and Waterford. Specifically, I first determined the fraction of AEP Ohio's overall generating capacity represented by Darby and Waterford. Specifically, these two generating plants have a combined rated capacity of 1,245 MW, which represents just over 10% of AEP Ohio's generating capacity of 12,216 MW, as reported on page 2 of AEP Ohio's "Factsheet." (Attached as Exhibit JAL-5).

I then credited back to AEP Ohio this percentage of the approximately $490 million in total capacity equalization payments shown in AEP Ohio witness Kelly Pearce's Exhibits KDP-3 and KDP-4.[37] The estimated overall capacity equalization payment credit is $49,958,598 million, as shown on line [6] of Table 4.

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[36] *Id.*, p. 54, Table 6, line [19], crediting $4,425,877 of off-system energy sales margins back to AEP Ohio stemming from production at the Darby and Waterford generating plants.

[37] *See* Case No. 10-2929-EL-UNC, Direct Testimony of Kelly Pearce, March 20, 2012, Exhibits KDP-4 and KDP-5, p. 4, line 6.

Table 4: AEP Ohio Pre-2001 Embedded Capacity Cost

Line No.	Item	CSP	OPC	TOTAL
[1]	Annual Production Fixed Cost, as Reported	$477,093,822	$660,504,310	**$1,137,598,132**
	Capacity Equalization Payments Adjustment			
[2]	*Capacity Equalization Payments Reported*	$30,785,441	$459,410,726	$490,196,167
[3]	Darby/Waterford Capacity (MW)	1,245	1,245	1,245
[4]	AEP Ohio Total Capacity	12,216	12,216	12,216
[5]	Darby/Waterford Percent of Total AEP Ohio Capacity	10.19%	10.19%	10.19%
[6]	**Adjustment for Darby/Waterford Capacity Equalization Payment Share**	**$3,137,514**	**$46,821,083**	**$49,958,598**
[7]	(Energy-only contribution to embedded costs adjustment)	($81,943,703)	($96,133,764)	($178,077,466)
	Depreciation Expense Adjustment			
[8]	*Depreciation Expense , as Reported*	$59,590,281	$256,957,852	**$316,548,133**
[9]	*Annual Depreciation Expense, GPIS 12/31/2000*	$49,879,103	$93,139,354	**$143,018,457**
[10]	***Calculated Depreciation Rate Adjustment***	***($9,711,178)***	***($163,818,498)***	***($173,529,676)***
	Return on Rate Base Adjustment			
[11]	*Return on Rate Base, as Reported*	$129,071,540	$311,327,830	**$440,399,370**
[12]	*Allowed Return*	8.63%	8.62%	
[13]	*Return on Net GPIS 12/31/2000, as of 12/31/2010*	$36,139,860	$24,265,334	**$60,405,194**
[14]	***Calculated Return on Rate Base Adjustment***	***($92,931,680)***	***($287,062,496)***	***($379,994,176)***
	Income Tax Adjustment			
[15]	*Income Tax Expense , as Reported*	$45,891,012	$123,339,938	**$169,230,950**
[16]	*ITC, as Reported*	($1,658,786)	($407,172)	**($2,065,958)**
[17]	*Income Tax Rate*	36.8399%	39.7482%	
[18]	*Income Tax on Adjusted Return on Rate Base*	$13,313,888	$9,645,034	**$22,958,922**
[19]	*ITC, Revised Based on 12/31/2000 GPIS*	($1,658,786)	($407,172)	($2,065,958)
[20]	***Calculated Income Tax Adjustment***	***($32,577,124)***	***($113,694,904)***	***($146,272,028)***
[21]	**Total Adjustments to Annual Production Cost, as Reported**	**($214,026,171)**	**($613,888,579)**	**($827,914,749)**
[22]	**Revised Annual Production Costs**	**$263,067,651**	**$46,615,731**	**$309,683,383**
[23]	5 CP Coincident Peak Demand (MW)	4,126.2	4,934.6	9,060.8
[24]	**Revised Daily Capacity Cost ($/MW-day)**	**$174.67**	**$25.88**	**$93.64**

Notes:

[1] Source: Exhibit KDP-3, p. 4 and KDP-4, p. 4.
[2] Source: Exhibits KDP-3 and KDP-4.
[3] Source: AEP Ohio, 2011 LTFR, Reported Summer Capacity 2010
[4] Source: AEP Ohio Factsheet. https://aepohio.com/global/utilities/lib/docs/factsheets/AEPOhioFactSheet1-2012.pdf
[5] Equals: [3] / [4].
[6] Equals: [5] x [2].
[7] Source: Table 3, line [20].
[8] Source: Exhibit KDP-3, p. 4 and KDP-4, p. 4.
[9] Source: Table 3, line 5.
[10] Equals: [4] - [3].
[11] Source: Exhibit KDP-3, p. 4 and KDP-4, p. 4.
[12] Source: Exhibit KDP-3, p. 5 and KDP-4, p. 5.
[13] Equals: Net pre-2001 GPIS x [7].
[14] Equals: [8] - [6].
[15] Source: Exhibit KDP-3, p. 18 and KDP-4, p. 18.
[16] Source: Exhibit KDP-3, p. 18 and KDP-4, p. 18.
[17] Source: Exhibit KDP-3, p. 18 and KDP-4, p. 18.
[18] Equals: [13] x [17].
[19] No material change to ITC estimate.
[20] Equals: {[13] - [10] } + {[14] - [11]}.
[21] Equals: [6] + [7] + [10] + [14] + [20].
[22] Equals: [1] + [21].
[23] Source: Exhibit KDP-3, p. 2 and KDP-4, p. 2.
[24] Equals: [22] / [23] / 365.

Table 4 follows the same methodology shown in Table 7 of my previous testimony in Case No. 10-2929-EL-UNC. Specifically, I began with the annual production fixed cost reported by AEP Ohio witness Pearce in his testimony in Case No. 10-2929-EL-UNC, and shown on line [1] of Table 4, and adjusted it to reflect only pre-ETP generating resources. This includes the $178 million adjustment for contributions to embedded cost margins shown in Table 3, and adjustments to his depreciation expense, return, and income tax calculations. In total, these adjustments resulted in a reduction of Dr. Pearce's reported fixed costs of $1,137,598,132 to $309,683,383, as shown on line [22] of Table 4. Converting this value to a MW-day value results in my revised embedded cost of capacity value of $93.64/MW-day, as shown on line [24] of Table 4.

Q. WHAT DOES THE $93.64/MW-DAY VALUE REPRESENT?

A. The $93.64/MW-day value represents the embedded cost of AEP Ohio's pre-2001 generating plant, eliminating all post-2001 investment that was to be recovered in the competitive market. This value also credits back to AEP Ohio customers the profits AEP Ohio earned from off-system energy sales, the profits of which should legitimately accrue to captive customers under a formula rate. Otherwise, as I discussed previously, AEP Ohio would earn an excessive return on equity.

D. AEP Ohio's Capacity Pricing After Corporate Separation Must Be Based On the RPM Market Price To Avoid Anticompetitive Cross-Subsidies.

Q. HOW WILL AEP OHIO OBTAIN THE CAPACITY IT REQUIRES TO MEET ITS FRR OBLIGATION AFTER CORPORATE SEPARATION AND UNTIL IT IS NO LONGER A FRR ENTITY AS OF JUNE 1, 2015?

A. Separate arrangements will be made for SSO load and non-SSO load. For SSO load, AEP Ohio witness Nelson states that, "between the time of Corporate Separation and the delivery date of the January 1, 2015 SSO energy auction, the Genco will sell wholesale power to AEP Ohio under a full requirements agreement to supply AEP Ohio's non-shopping retail load."[38]

[38] Nelson Direct, p. 6, lines 15-18.

Thus, during 2014, AEP Generation Resources will accept as payment all generation-related revenues that AEP Ohio receives from SSO customers.[39] AEP Ohio also will pay AEP Generation Resources $255/MW-day for capacity provided in connection with the energy-only auction of 5% of AEP Ohio's SSO load that may occur in 2014.[40] Also, for the five-month period January-May, 2015, AEP Generation Resources will charge AEP Ohio $255/MW-day for all capacity of SSO customers.[41] Because these are wholesale transactions between two affiliates – AEP Generation Resources and AEP Ohio – the Federal Energy Regulatory Commission ("FERC") must approve the proposed contract, as Mr. Nelson acknowledges.[42]

For non-SSO load, AEP Generation Resources may charge AEP Ohio a "blended" price for capacity, based on the relative shares of Tier 1 and Tier 2 loads. Using the data from AEP Ohio witness Allen's Exhibit WAA-4, this blended price will be $212.91/MW-day in calendar year 2014 and $210.23/MW-day for the period January 1, 2015 through May 31, 2015.[43]

Q. AT WHAT PRICE WILL AEP GENERATION SELL CAPACITY TO AEP OHIO SO THAT AEP OHIO CAN MEET ITS RESPONSIBILITY AS AN FRR ENTITY TO NON-SSO LOAD?

A. According to AEP Ohio witness Nelson,

> [r]evenues that AEP Ohio may receive from PJM in connection with capacity payments made by CRES providers under PJM's Reliability Assurance Agreement ("RAA") would be remitted to the Genco in return for Genco

[39] Nelson Direct, p. 7, lines 7-13.

[40] *See* Nelson Direct, p. 7, lines 18-21 (referring to the "energy only auctions occurring while AEP Ohio is still an FRR entity in PJM"). *See also* Exhibit JAL-7.

[41] Nelson Direct, p. 6, lines 20-22.

[42] Nelson Direct, p. 7, lines 3-6.

[43] Calculated as follows: Page 2 of Exhibit WAA-4 shows total connected loads and CRES loads that will receive Tier 1 prices in each PJM planning year (June – May). Thus, for planning year 2013/14, the average capacity price is (16,942 *x* $145.79 + (48,261 – 16,942) *x* $255) / 48,261 = $216.66/MW-day. Similarly, for planning year 2014/15, the weighted price will be $210.23/MW-day. Thus, in calendar year 2014, we take a weighted average of the two planning year prices to determine the blended capacity price that AEP Generation will charge: (7/12) *x* $216.66 + (5/12) *x* $210.23 = $212.91/MW-day. Starting January 1, 2015, AEP Generation will just be charging AEP Ohio the $210.23/MW-day price.

providing capacity to AEP Ohio to fulfill AEP Ohio's Fixed Resource Requirement (FRR) obligations.[44]

AEP Ohio also will remit all revenues from the RSR to AEP Generation Resources.[45] What this means is that AEP Ohio will first inform PJM what to bill CRES providers for capacity. Then, PJM will remit those payments to AEP Ohio. Lastly, AEP Ohio will then remit the funds back to AEP Generation Resources, together with all RSR revenues.

Q. IS FERC APPROVAL REQUIRED FOR THE CAPACITY PRICES THAT WILL BE CHARGED TO CRES SUPPLIERS AFTER CORPORATE SEPARATION?

A. Yes. In addition to the full requirements (i.e., energy plus capacity) wholesale contract between two affiliates for SSO load, what Mr. Nelson describes for non-SSO load is a separate, wholesale capacity-only contract. This capacity-only wholesale contract also must be approved by FERC.

Q. WHAT DO YOU CONCLUDE THE CONTRACTUAL RELATIONSHIP WILL BE BETWEEN AEP GENERATION RESOURCES AND AEP OHIO?

A. AEP Ohio and AEP Generation Resources are likely to have three wholesale contracts that address the capacity transactions described in the Modified ESP. The first contract would be a capacity-only contract to serve Tier 1 and Tier 2 CRES providers for non-SSO load, which will be based on a blend of the $255/MW-day and the $145.79/MW-day prices charged under the Modified ESP until May 30, 2015. The second contract will be a wholesale full-requirements contract for all SSO load effective through December 31, 2014, although the basis for the pricing of that contract is not clear.[46] The second contract may also have a carve-out to address the energy-only auction that may take place for 5% of SSO load in 2014. The third contract would

[44] Nelson Direct, p. 7, lines 14-18.

[45] Nelson Direct, p. 8, lines 1-3.

[46] *See* Nelson Direct, p.6, lines 15-18. Mr. Nelson does not discuss the pricing under this contract.

be a capacity-only contract priced at $255/MW-day for the five-month period in 2015 when AEP Ohio intends to conduct an energy-only auction for 100% of its SSO load.

Q. WILL EITHER THE $255/MW-DAY OR BLENDED PRICE CAPACITY-ONLY CONTRACTS BE COST-BASED?

A. No. Neither the proposed Tier 1 – Tier 2 CRES blended price, capacity-only contract, nor the contract connected to the energy-only auctions for SSO customer load will be cost-based. Nor, as shown previously in Table 1, will they be market-priced contracts. Instead, they will be based on arbitrary above-market prices established by AEP Ohio.

Q. WILL AEP OHIO ARGUE THAT THESE CONTRACTS ARE ALL BELOW ITS TRUE COST OF CAPACITY AND THEREFORE A BENEFIT TO CUSTOMERS?

A. Yes. Mr. Allen's testimony argues that AEP customers will receive $989 million in "benefits" from below embedded cost capacity prices in the Modified ESP. Thus, I presume AEP Ohio will also argue that all three contracts will be priced "below cost."

Q. WHAT WILL THE RELATIONSHIP BE BETWEEN AEP OHIO AND AEP GENERATION RESOURCES AFTER CORPORATE SEPARATION?

A. Under AEP Ohio's corporate separation plan, AEP Ohio and AEP Generation Resources will be separate and <u>independent</u> entities.

Q. WHY IS THE FACT THAT AEP OHIO AND AEP GENERATION RESOURCES WILL BE INDEPENDENT SIGNIFICANT?

A. It is significant because, as an <u>independent</u> entity, AEP Ohio should have an economic incentive to obtain the capacity needed to meet its FRR obligation for the 17-month period after corporate separation at the lowest price. This would mean entering into bilateral contracts for capacity at prices that are based on the PJM RPM market-clearing price. At the time of corporate separation, the PJM delivered capacity price will be $33.87/MW-day. That price will increase on June 1, 2014 to $153.89/MW-day.

Instead, AEP Ohio proposes to enter into contracts with its independent AEP Generation Resources affiliate at an above-market price, thereby providing AEP Generation Resources with an anticompetitive cross-subsidy. Whether these prices are below AEP Ohio's claimed embedded capacity cost is immaterial. The fact that AEP Ohio intends to enter into contracts with AEP Generation Resources at prices that are all above the PJM RPM market price, is anticompetitive.

Q. DOES FERC POLICY SUPPORT ABOVE-MARKET WHOLESALE CONTRACTS BETWEEN AFFILIATES?

A. No. Such a cross-subsidized affiliate transaction is directly contrary to FERC policy to promote competitive markets, as discussed in its long-standing Edgar Policy. Specifically, in *Edgar*, FERC established three possible ways to demonstrate that a contract between affiliates was not abusive, none of which AEP Ohio will be able to demonstrate under the terms of the proposed contracts between AEP Generation Resources and AEP Ohio.

First, a utility can submit evidence of direct head-to-head competition between affiliated and non-affiliated suppliers either in a formal solicitation or in an informal negotiation process.[47] In the Modified ESP, AEP Ohio provides no evidence that the proposed capacity prices it intends to charge under the three different contracts are the result of any competitive solicitation. Rather, they are presented as a *fait accompli*.

Second, a utility can present evidence of the prices that non-affiliated buyers were willing to pay for similar services from that project.[48] This second type of evidence is credible only to the extent that the non-affiliated buyers are in the same relevant market as the purchaser and are not subject to market power by the seller or its affiliates. Again, AEP Ohio has not provided such evidence.

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[47] 55 FERC 61,382, 62,168.

[48] 55 FERC 61,382, 62,168-69.

Third, a utility can provide "benchmark" evidence of the prices, terms and conditions of sales by non-affiliated sellers. This can include purchases made by the utility itself or by other buyers in the relevant market. As FERC has stated, however, two major considerations with respect to the credibility of benchmark evidence are whether the benchmark sales are contemporaneous and whether they are for similar services when compared to the original transaction.[49] Yet again, AEP Ohio has not provided such evidence.

Q. DOES FERC HAVE A HISTORY OF APPROVING WHOLESALE CONTRACTS THAT CAN HARM CAPTIVE WHOLESALE AND RETAIL CUSTOMERS?

A. No. FERC does not have a history of approving wholesale contracts that are not market-based and, as a result, harm captive wholesale or retail customers.[50] In this case, because AEP Ohio will not allow CRES providers to self-supply capacity prior to June 1, 2015, CRES providers are captive customers that would be harmed by AEP Ohio's cross-subsidization of AEP Generation Resources.

Q. IS AN ABOVE-MARKET PURCHASE PRICE FOR CAPACITY CONSISTENT WITH AEP GENERATION RESOURCES' STATUS AS AN INDEPENDENT AFFILIATE?

A. No. There is no basis for AEP Ohio, as an <u>independent</u> affiliate, to enter into contracts with AEP Generation Resources at arbitrary, above-market prices that are neither cost-based nor market-based. The only possible reason for AEP Ohio to enter into such contracts is to provide a cross-subsidy to AEP Generation Resources, which as an economist I believe violates the pro-

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[49] *Id*.

[50] *See*, e.g., *FirstEnergy Corp*., 94 FERC 61,182 (2001). "As the Commission has explained in previous cases, there is a concern whenever a public utility can transact with an affiliated power marketer in such a way as to transfer benefits from captive ratepayers to its shareholders. Where, as here, the power marketer seeks to sell power to its affiliated public utilities, the potential for affiliate abuse would stem from the marketing affiliate (FE Services) selling to the franchised public utilities (FE Operating Companies) at a price above the prevailing market price to the benefit of shareholders. To guard against this potential abuse, the Commission requires that sales by a power marketer to an affiliated public utility with a franchised service area be made at the lowest price for energy sold to the public utility by non-affiliates" (*internal citations omitted*).

market principles set out in *Edgar*. Such a cross-subsidy, and the exercise of market power as a monopolist, also runs afoul of the plain language of Ohio policy set forth in R.C. 4928.02(H) and (I), respectively.

Q. ARE YOU AWARE OF FERC APPROVING WHOLESALE CAPACITY CONTRACTS BETWEEN AFFILIATES THAT ARE NEITHER COST-BASED NOR MARKET-BASED?

A. No. FERC has expressed a strong preference for market-based capacity pricing. In limited cases, FERC has approved cost-based capacity contracts called "reliability must run" ("RMR") contracts. FERC considers such contracts a "last resort" and they have no applicability under the circumstances here.[51]

Q. ARE YOU AWARE OF ANY OTHER TYPE OF COST-BASED, CAPACITY-ONLY CONTRACTS THAT FERC HAS APPROVED IN REGIONS WITH ORGANIZED CAPACITY MARKETS?

A. No.

Q. WILL THE PROPOSED FULL-REQUIREMENTS CONTRACT TO SERVE SSO LOAD BETWEEN AEP GENERATION RESOURCES AND AEP OHIO BE CONSISTENT WITH FERC POLICY?

A. The contract is unlikely to be consistent with FERC policy, given that market pricing for capacity and energy is substantially lower than the aggregate revenue expected to be transferred to AEP Generation Resources by AEP Ohio. AEP Ohio, as a truly independent company, would enter into such a contract only if the overall price for energy and capacity were lower than the equivalent market price. AEP Ohio claims that the non-fuel generation charges that will be paid to AEP Generation Resources are equivalent to AEP Ohio's claimed full embedded cost of \$355.72/MW-day,[52] yet market pricing for capacity between January 1, 2014 and May 31, 2015 is only 20% of that allegedly cost-based rate. It would make economic sense for AEP Ohio to enter

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[51] *See e.g., Bridgeport Energy LLC*, 118 FERC 61,243 (2007), P 41.

[52] Allen Direct, p. 9, lines 5-13.

into the proposed full-requirements contract with AEP Generation Resources only if the overall price for energy and capacity was comparable to or below the market price.

Q. WITH REGARD TO THE PRICING OF CAPACITY PROVIDED TO AEP OHIO TO SATISFY ITS FRR OBLIGATION TO NON-SSO LOAD AFTER CORPORATE SEPARATION AND BEFORE JUNE 1, 2015, WHAT HAS AEP OHIO PROPOSED IN DOCKET NO. 10-2929-EL-UNC?

A. AEP Ohio has proposed in its Capacity Case, Case No. 10-2929-EL-UNC, that the contract between AEP Ohio and AEP Generation Resources would be based on AEP Ohio's full embedded costs for the capacity resources as reported by AEP Ohio on its FERC Form 1 for 2012 and 2013.[53] AEP Ohio's 2012 data would be used to set the price that AEP Generation Resources would charge AEP Ohio for capacity during the 2013/2014 planning year, which would include the first five months following the planned corporate separation to be effective January 1, 2014.[54] AEP Ohio's 2013 data would be used to set AEP Generation Resources' capacity price for the 2014/2015 planning year. Thus, capacity would be priced during the bridge period between corporate separation and June 1, 2015 not on AEP Ohio's costs to acquire capacity during the bridge period but on AEP Ohio's historic costs as a prior owner of capacity.

Remarkably, although AEP Generation Resources will immediately transfer away all ownership interest in two of the transferred generating facilities (Amos and Mitchell) transferred to it by AEP Ohio,[55] the capacity price charged to non-SSO load would continue to include the costs of these two generating plants.[56] In other words, AEP Ohio proposed in the Capacity Case that AEP Generation Resources include the costs of two large generating units that AEP

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53 Case No. 10-2929-EL-UNC, Hearing Transcript, Vol. II, pp. 276-83 (AEP Ohio witness Pearce).

54 *Id.* It is possible that all AEP East Pool members could waive the January 1, 2014 termination date and terminate the Pool Agreement earlier than January 1, 2014, if corporate separation also were approved prior to January 1, 2014. In such a case, AEP Ohio's 2012 FERC Form 1 data also would be used to set AEP Generation Resources' capacity price on and after June 1, 2013.

55 *See* Direct Testimony of Robert Powers, March 30, 2012, p. 21, lines 20-23.

56 Case No 10-2929-EL-UNC, Hearing Transcript, Vol. II, pp. 277-78. (AEP Ohio witness Pearce).

Generation Resources no longer owns in its contract with AEP Ohio for non-SSO load. A contract that reimburses AEP Generation Resources for costs associated with generating plants it does not own is clearly unreasonable, regardless of the underlying formula rate application. It forces non-SSO customers to provide a cross-subsidy to AEP Generation Resources.

Yet it is this same formula rate application that AEP Ohio argues should be used as the basis for its claim that capacity pricing at less than $355/MW-day is a "benefit" of the Modified ESP. To the contrary, the Commission should rely on RPM market-based pricing to establish the appropriate capacity charge during the bridge period since AEP Ohio's cost to acquire capacity during the bridge period, absent any undue cross-subsidy, should approximate RPM market-based pricing.

Q. WILL AEP GENERATION RESOURCES' CHARGING MULTIPLE CAPACITY PRICES TO AEP OHIO BE CONSISTENT WITH FERC AND PUCO POLICIES TO PROMOTE COMPETITIVE CAPACITY MARKETS?

A. No. The proposed capacity contracts with multiple prices would be unduly discriminatory and result in economically inefficient cross-subsidies. As I discussed previously, FERC policy does not favor such pricing, favoring instead market prices. Furthermore, cross-subsidies violate AEP Ohio's Corporate Separation Plan.[57] Finally, the proposed capacity prices would be contrary to state policy as set forth in R.C. 4928.02(H) and (I).

E. <u>AEP Ohio's Above-market Capacity Prices Will Have Adverse Economic Impacts on the Ohio Economy.</u>

Q. WILL AEP OHIO'S PROPOSED CAPACITY PRICING SCHEME HAVE ADVERSE IMPACTS ON THE OHIO ECONOMY?

A. Yes. As I discussed previously and accepting AEP Ohio's claims as true for purposes of this analysis, AEP Ohio SSO and non-SSO customers will be forced to pay $1.58 billion in

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[57] 2012 Corporate Separation Plan, Attachment A, Item 1(3) "Cross-subsidies between an electric utility and its affiliates are prohibited."

excess capacity costs while the Modified ESP is in effect. The economic impacts of customers paying $1.58 billion in excess capacity costs will ripple through the entire Ohio economy. For example, households forced to spend more money on subsidized generation will reduce their spending on other goods and services, affecting businesses that cater to those consumers. Similarly, businesses paying increased electric bills must either reduce their output, increase their prices, or both. These impacts will, in turn, lead to job losses, which will in turn further reduce consumer spending, causing even greater economic losses.

Q. DO YOU AGREE THAT THE MODIFIED ESP WILL LEAD TO SIGNIFICANT JOB REDUCTIONS IN OHIO, AS ALLEGED BY AEP OHIO WITNESS POWERS?[58]

A. No. Moreover, AEP Ohio witness Dias's claim that, "As a whole, the proposed ESP II enhances the states effectiveness in the global economy,"[59] is at odds with AEP Ohio's proposal to charge customers above-market capacity prices.

Q. IS ALLOWING AEP OHIO TO CHARGE A PRICE FOR CAPACITY THAT IS, ON AVERAGE, TWO TO FOUR TIMES GREATER THAN THE PJM MARKET PRICE, A JOB-CREATING STRATEGY FOR THE STATE OF OHIO?

A. No. This is a common fallacy. Rather than focusing on the overall competitiveness of markets, AEP Ohio has focused on speculative job losses it would inflict on its own workforce if it is forced to charge a market price. It completely ignores the adverse economic impacts of forcing all AEP Ohio distribution customers to pay above-market costs for electricity.

Q. DO ABOVE-MARKET ELECTRICITY COSTS CAUSE WIDESPREAD JOB LOSSES?

A. Yes. For example, in an April 2010 Order that rejected a proposed contract between Deepwater Wind and National Grid, the Rhode Island PUC stated:

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[58] Direct Testimony of Robert Powers, March 30, 2012, p. 18, line 1.

[59] Direct Testimony of Selwyn Dias, March 30, 2012, p. 4, lines 1-2.

> It is basic economics to know that the more money a business spends on energy, whether it is renewable or fossil based, the less Rhode Island businesses can spend or invest, and the more likely existing jobs will be lost to pay for these higher costs.[60]

Yet, AEP Ohio is specifically advocating that for the next three years its business and residential customers be forced to pay capacity prices that are two to four times higher than the average PJM market price so as to prevent job losses at AEP Ohio. In other words, AEP Ohio's position is that the entire Ohio economy should be sacrificed to prevent possible job losses at AEP Ohio.

The Rhode Island PUC realized this was economic nonsense. Because Ohio has far more manufacturing industry and is more electric-intensive than Rhode Island, lower cost electricity is even more important for the future economic well-being of Ohio.

Because of the interconnections among industries, and between industries and households, a change in the price of just one good or service can cause ripple effects throughout the Ohio economy. Positive ripple effects add jobs and increase disposable income as more workers are hired, more equipment and supplies are purchased from other local businesses, more wages are paid to employees, and more taxes are paid to government entities. Conversely, negative ripple effects result in job loss and decreased disposable income. These impacts are called multiplier effects or multipliers. In other words, the impacts of uneconomic generation investments would "ripple" through the entire Ohio economy, leading to job losses and reductions in economic output.

Q. HOW CAN THE IMPACTS OF UNECONOMIC GENERATION INVESTMENTS ON THE OHIO ECONOMY AND ON JOBS BE EVALUATED?

A. There are two general methods that are used to analyze economic impacts. The first method uses what is called a "computable general equilibrium" ("CGE") modeling framework.

[60] *In Re: Review of New Shoreham Project Pursuant to R.I. Gen Laws § 39-26.1-7*, Docket No. 4111, Report and Order, April 2, 2010, at 82 (emph. added). The Rhode Island PUC's decision was effectively overridden by subsequent legislation, but the point still stands.

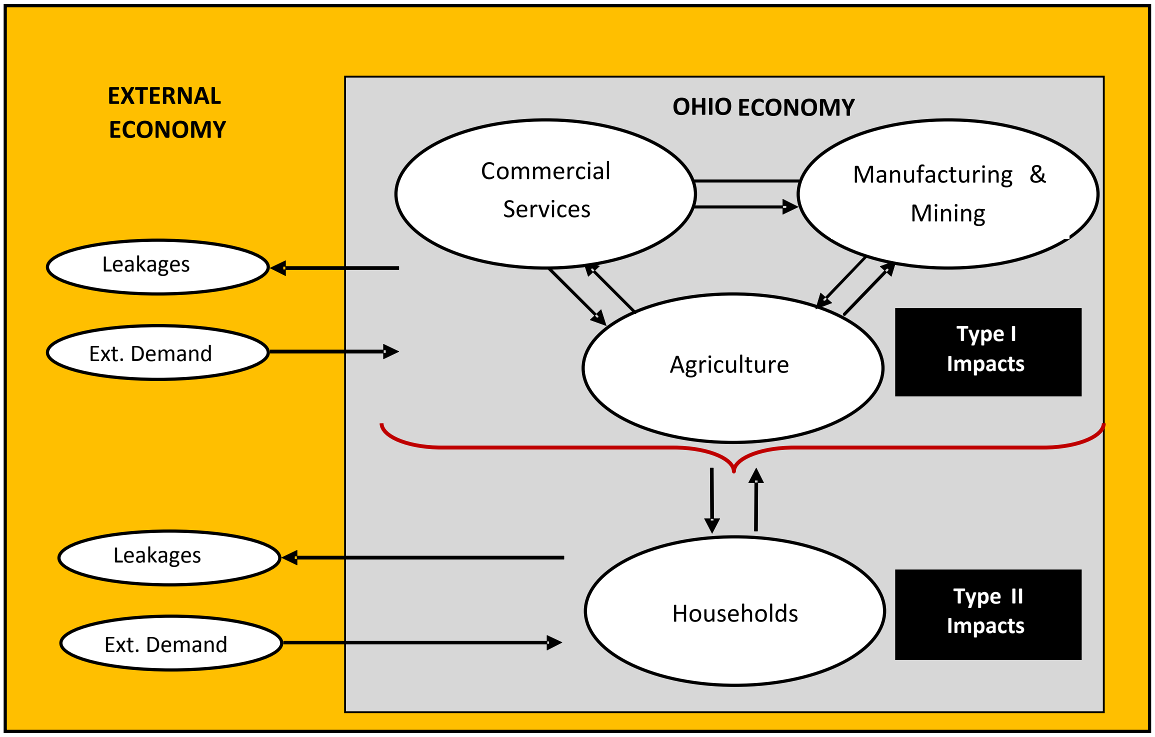
The second method, which I have used to analyze the impact of the Modified ESP, is called an "input-output" ("I/O") modeling framework.

Q. PLEASE EXPLAIN HOW AN I/O MODEL WORKS.

A. Input-output analysis traces the interdependencies of an economy, specifically the sales and purchases of goods among all of the sectors of an economy.[61] For example, constructing a new high-voltage transmission line will require the purchase of concrete that will be used as foundations for transmission towers. But to manufacture that concrete, firms must purchase inputs including sand, gravel, and electricity. Similarly, transmission towers will be made of steel that is manufactured in steel mills that use iron ore, which is mined by other firms. Moreover, construction requires the use of many workers who then spend their wages on all varieties of goods and services. An input-output framework is designed to trace all of those relationships. Figure 1 shows the general analytical framework for an I/O model.

[61] Nobel Prize winning economist Wassily Leontief is generally considered to be the "father" of Input-Output analysis. For an introduction to I/O modeling, see his treatise *Input–Output Economics*, 2nd Ed. (New York: Oxford University Press 1986).

Figure 1: I/O Model Structure



In Figure 1, the Ohio economy is broken down into manufacturing & mining, commercial services, and agriculture. There is also a household sector and, in some cases, a separate government sector. Purchases outside the state are considered "leakages." On the other hand, sales by business and industry of goods and services to outside the state economy are treated as external demand. External demand increases the level of economic activity within the state.

There are also household impacts. Ohio households purchase goods and services from in-state industries, as well as from out-of-state firms. Moreover, out-of-state households purchase goods and services from Ohio firms. If household impacts on the economies (e.g., the wages households earn that are spent on goods and services), are excluded from the economy, the resulting economic impacts are called "Type I impacts." If households are included, the resulting economic impacts are called "Type II impacts."

For each sector of the economy modeled, the I/O model also traces employment and wages. Thus, concrete manufacturing within the local economy may require an average of, say, 10 employees for every million dollars of concrete produced, while grocery stores may employ 30 people for every million dollars of retail sales. Type II impacts include changes in household spending that result from policy changes, such as changes in income tax rates, as well as how changes in industrial output affect wages paid and expenditures households make on goods and services.

Q. PLEASE EXPLAIN HOW YOU ESTIMATE THE IMPACT OF AEP OHIO'S ABOVE-MARKET CAPACITY PRICING.

A. To perform this analysis, I have used one of the most well-known economic impact models, the **IM**pact for **PLAN**ning ("IMPLAN") model.[62] IMPLAN is the most well-known and widely used I/O model and is used by numerous government agencies at both the federal and state levels, including the Ohio Department of Development.

Q. PLEASE EXPLAIN HOW IMPLAN WORKS.

A. The IMPLAN model begins with the most current national transactions matrix developed by the current National Bureau of Economic Analysis Benchmark Input-Output Model. The model breaks down the U.S. economy into over 500 separate economic sectors in agriculture, manufacturing, commercial services, and government. Next, the model creates state and county-level values by adjusting the national level data, such as removing industries that are not present in a particular state or economy.

The model also estimates imports and exports using what are called <u>regional purchase coefficients</u> ("RPCs"). A RPC measures the proportion of the total supply of a commodity or service required to meet a particular industry's intermediate demands and final demands that are

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[62] IMPLAN was first developed in the late 1970s by the U.S. Forest service to analyze the economic impacts of different forestry policies. The current version of IMPLAN is maintained by MIG Inc., formerly known as the Minnesota IMPLAN group. MIG was founded in 1993 by Scott Lindall and Doug Olson as an outgrowth of their work at the University of Minnesota, which began in 1984. This developmental work closely involved the U.S. Forest Service's Land Management Planning Unit in Fort Collins, and Dr. Wilbur Maki at the University of Minnesota.

produced locally. The larger the RPC value, the greater the percentage of total regional demand that is met through local supplies, and the fewer expenditures that "leak out" of the local economy. The larger the local economy, e.g., an entire state rather than an individual county within a state, the larger will be the RPC values. RPCs are important for estimating the economic impacts of higher electricity prices, because the larger the leakages out of the Ohio economy, the less the overall impacts will be in the state.

One of the key features of IMPLAN (and all I/O models) is the calculation of "multipliers." Multipliers capture how the impacts of a policy change ripple through the local economy. Because AEP Ohio proposes that businesses and residential consumers spend an extra $1.58 billion on electricity over the next three years (not including the impacts of the proposed nonbypassable rider to pay for the Turning Point Solar facility), businesses and individuals would have $1.58 billion less to spend on all other goods and services.

A business that is compelled to pay an above-market price for AEP Ohio's capacity would likely reduce its output, increase the price of the goods and services it sells, or both. An electric-intensive business might even decide to relocate out-of-state; for example, aluminum smelting companies left the Pacific Northwest after their electric rates were increased and relocated to other countries offering lower price electricity. If the business reduced its production, it would purchase fewer supplies from other businesses, which, in turn, would respond to decreased demand for the goods and services they produce by purchasing fewer supplies from other businesses, and so forth. And, of course, all of those other businesses would also pay more for electricity. In other words, the impacts of uneconomic generation investments would ripple through the Ohio economy.

If the impacts on households were also considered, the multiplier would increase. Not only would businesses reduce their output because of the costs of uneconomic generation investments, but households would have less disposable income. Moreover, job losses at businesses affected by the costs of uneconomic generation investments would reduce wage payments, thereby reducing overall household income. Reduced wages would also mean that state and local governments would collect fewer tax revenues, causing them to reduce expenditures. The resulting Type II impacts on the Ohio economy, therefore, would be even greater.[63]

Q. PLEASE EXPLAIN HOW YOU ESTIMATED THE IMPACTS ON EMPLOYMENT IN OHIO RESULTING FROM AEP OHIO'S PROPOSAL.

A. To model the economic impacts of uneconomic generation investments on the Ohio economy, I assumed that businesses and consumers would reduce their purchases of other goods and services by an equivalent amount, i.e., an individual household forced to spend $100 more on electricity would consequently spend $100 less on all other goods and services. I also assumed that households would continue to purchase the same proportions of those other goods and services. For example, if an individual had previously spent $200 annually on haircuts and three times as much, or $600, annually on clothes, I assumed he would continue to spend three times more for clothes as haircuts, but at lower levels, *e.g.*, $190 on haircuts and $570 (3 x $190) on clothes. Similarly, businesses paying more for electricity would reduce purchases of all of the other inputs they used to produce their goods and services by the same percentages, thus maintaining the same relative proportions of each.[64]

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[63] In addition to calculating standard Type I and Type II multipliers, IMPLAN can also calculate what are called "SAM multipliers." SAM stands for "Social Accounts Matrix," and is a more detailed breakdown of transactions within an economy. Specifically, whereas the typical input-output framework captures production and consumption, it leaves out some income transactions, such as taxes, savings, and transfer payments. IMPLAN allows users to capture these components as well, and thus derive what are called SAM multipliers. SAM multipliers are a form of Type II multiplier. Thus, SAM multipliers incorporate direct, indirect, and induced impacts, while accounting for the effects of savings, taxes, and transfer payments. Exhibit JAL-6 provides a mathematical description of an I/O model, including how multipliers are estimated.

[64] The Leontief input-output framework assumes what are called "fixed production coefficients." This means that firms cannot substitute inputs, e.g., using more natural gas instead and less electricity, to produce the same output. The production coefficients are called "technical coefficients" in the I/O modeling framework. Although this assumption does not hold in the long-run, it is reasonable for short-run impact studies. See Exhibit JAL-6 for a discussion of how this analysis was performed.

Next, I derived an overall employment multiplier for the Ohio economy, equal to the weighted average of the individual sector employment multipliers, excluding the electricity sector.[65] I then estimated an overall weighted average RPC value. That is, I determined the fraction of total expenditures that, on average, businesses and individuals spend at Ohio firms.[66] Next, I estimated the weighted average number of jobs per millions of dollars of output for all industries in the state. Then, I estimated a weighted average value for jobs per million$ of output in the Ohio economy. Finally, using the overall RPC value, the weighted average job multiplier, and the weighted average jobs per million$ of output, I was able to calculate the total job impacts of per million$ of increased generation costs in the state.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSIS?

A. For my analysis, I have focused on the above-market costs of capacity, which as shown in Table 1 will impose an additional cost of $1.58 billion on ratepayers over the 36-month period of the Modified ESP through May 2015 for which the non-market-based capacity charge is planned. The results are summarized in Table 5.

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65 In IMPLAN, Sector 31 is "Electric power generation, transmission, and distribution."

66 It is also important to remember that a percentage of the wages individual employees are paid is transferred as payroll taxes. The assumed overall payroll tax rate is 15%, which includes both Social Security and Medicare.

Table 5: Annual Lost Jobs Caused by Above-Market Capacity Costs

Line No.	Item	Value
[1]	Total above-market Capacity Cost (Millions of 2012$)	$1,568.7
[2]	Non-SSO Load Above-market Capacity Cost (Millions of 2012$)	$766.4
[3]	2009 - 2012 Deflator	1.042
[4]	Above-market Capacity Cost (Millions of 2009$)	$1,505.5
[5]	*Non-SSO Load Above-market Capacity Cost (Millions of 2009$)*	*$735.5*
[6]	Average Annual Cost (2009$, 36 month ESP)	$501.8
[7]	*Average Annual Cost (2009$, non-SSO customers)*	*$245.2*
[8]	Ohio Regional Purchase Coefficient	62.6%
[9]	Ohio Jobs Multiplier	2.88
[10]	Ohio Jobs / Million 2009$ Output	7.17
[11]	Avg. Annual Job Loss over 36-month ESP term	6,489
[12]	*Avg. Annual Job Loss - Non-SSO Customers Only*	*3,170*

Notes:

[1]	Source: Exhibit JAL-2
[2]	Source: Exhibit JAL-2
[3]	Source: U.S. EIA, Annual Energy Outlook 2012, Table A20.
[4]	Equals [1] / [3].
[5]	Equals [2] / [3].
[6]	Equals [4] / 3.
[7]	Equals [5] / 3.
[8]	Source: IMPLAN, Ohio Database and methodology described in Exh. JAL-6
[9]	Source: IMPLAN, Ohio Database and methodology described in Exh. JAL-6
[10]	Source: IMPLAN, Ohio Database and methodology described in Exh. JAL-6
[11]	Equals: [6] x [8] x [9] x [10].
[12]	Equals: [7] x [8] x [9] x [10].

As Table 5 shows, the above-market capacity costs AEP Ohio intends to charge would, on average, result in an average loss of almost 6,500 Ohio jobs each year during the three years of the Modified ESP. That is more double the 3,256 AEP Ohio employees.[1] This is the true economic impact of AEP Ohio's proposed capacity costs, not Mr. Powers' unsubstantiated threat. If we focus solely on the $766 million in above-market capacity costs AEP Ohio intends

[67] According to the response to FES-INT—2-008, AEP Ohio has 3,256 employees, of whom 2,870 are based in Ohio.

to charge non-SSO customers, the resulting job losses would be 3,170 per year, larger than the 2,870 AEP Ohio employees based in Ohio.

Q. DOES AEP OHIO CONSIDER THE ADVERSE ECONOMIC IMPACTS OF ABOVE-MARKET CAPACITY PRICES ON THE OHIO ECONOMY?

A. No. In fact, AEP Ohio witness Powers states:

> This Commission should not consider altering AEP Ohio's proposed ESP in a manner that will cause financial harm to the Company. Doing so would force AEP Ohio to significantly reduce its spend [sic] in Ohio and inevitably lead to significant job reductions in Ohio (where thousands of AEP employees and contractors work and pay taxes). Such a result would run directly counter to the State policy (in Section 4928.02(N), Ohio Revised Code) to facilitate Ohio's effectiveness in the global economy.[68]

Mr. Powers also resorts to the tired canard of "fair competition," along with a veiled threat to the PUCO: "A reasonable transition to market for AEP Ohio is needed to truly promote fair competition and to avoid causing serious financial harm to AEP Ohio, which would leave AEP Ohio with no choice but to substantially curtail spending in Ohio and pursue its legal options."[69] Thus, according to Mr. Powers, AEP Ohio's economic policy is simply: "What's good for AEP Ohio is good for the Ohio economy." That is not true, as my analysis of the job-killing impacts of above-market capacity prices in Ohio shows.

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[68] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143 Ohio. Rev. Code in the Form of an Electric Security Plan, et al., Case Nos. 11-346-EL-SSO, et al.*, Direct Testimony of Robert Powers, March 30, 2012 ("Powers Direct"), p. 17, line 21- p. 18, line 4.

[69] *Id.*, p. 17, lines 8-11.

III. FUEL ADJUSTMENT CLAUSE

Q. IS AEP OHIO PROPOSING ANY CHANGES TO THE FUEL ADJUSTMENT CLAUSE ("FAC")?

A. Yes. AEP Ohio is proposing two changes. First, AEP Ohio witness Nelson testifies that the company is proposing to modify the FAC to account for renewable energy credits ("RECs") in a separate, bypassable Alternative Energy Rider ("AER").[70] Second, AEP Ohio witness Roush testifies that AEP Ohio proposes to maintain separate FACs for CSP and OPC until June 1, 2013.[71]

Q. WHY DOES AEP OHIO WISH TO DELAY IMPLEMENTATION OF A SINGLE FAC FOR THE MERGED COMPANIES UNTIL JUNE 1, 2013?

A. According to Mr. Roush, the impacts of merging the FAC and the Phase-in Recovery Rider ("PIRR") will have opposite rate impacts on CSP and OPC customers. "Thus, merging the FAC rate at the same time that the PIRR is implemented on a merged basis limits the impact on both CSP and OPCo Rate Zone customers and is a benefit of Ohio's proposed ESP."[72]

Mr. Roush provides the following table of impacts, supposedly to demonstrate the benefit of maintaining the separate FAC charges until 2013.[73]

($/MWh)	CSP Rate Zone	OPCo Rate Zone
Merge FAC	-3.65	+2.39
Merge PIRR	+2.96	-2.37
Net Impact	-0.69	+0.02

[70] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143 Ohio. Rev. Code in the Form of an Electric Security Plan, et al., Case Nos. 11-346-EL-SSO, et al.*, Direct Testimony of David Roush, March 30, 2012 ("Roush Direct"), p. 17, lines 1-15.

[71] Roush Direct, p. 5, lines 10-17.

[72] Roush Direct, p. 5, lines 7-9.

[73] Roush Direct, p. 6, lines 3-6.

Q. DO YOU AGREE WITH MR. ROUSH?

A. No. The PIRR, which is designed to recover additional fuel costs that have been deferred and are considered a regulatory asset, does not begin until 2013. Thus, in 2012, SSO customers will only pay the FAC. As shown in Exhibit DMR-1, the current FAC is $0.0399 /kWh ($39.90 / MWh) for CSP customers and $0.0335 / kWh ($33.50 / MWh) for OPC customers. On a merged basis, page 1 of Exhibit DMR-1 shows the FAC to be $0.0361 / kWh ($36.10 / MWh). Thus, merging the FAC rates reduces the CSP FAC by $3.80 MWh and increases the OPC FAC by $2.60 /MWh.[74]

If the FAC is not merged, then these FAC charges will remain the same in the first year of the Modified ESP. In 2013, the merged FAC will be $0.0360 / kWh ($36.00/MWh).

Q. WHAT HAPPENS IN 2013?

A. In 2013, the PIRR takes effect. The increase for all AEP Ohio customers will average $31.00/MWh, as shown on page 2 of Exhibit DMR-1. Thus, if the FAC is kept separate in the first year of the Modified ESP, in the second year CSP customers will see a slight decrease attributable to the merged FAC of -$3.90/MWh, plus the PIRR of $31.00, or a total increase of $27.10/MWh over the first-year ESP rates. OPC customers would see a $2.50/MWh increase in their FAC from $33.50/MWh to $36.00/MWh, and thus a total increase of $2.50 + $31.00 = $33.50/MWh. Therefore, rather than experiencing equal rate increases due to the PIRR starting in June 2013, OPC customers would experience an increase that was 24% greater than CSP customers.[75] Thus, Mr. Roush's proposal would <u>exacerbate</u> the rate changes felt by OPC customers relative to CSP customers.

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[74] These are not the same as the incorrect values shown in Mr. Roush's testimony, but are instead based on the data he presents on page 1 of Exhibit DMR-1.

[75] Calculated as ($33.50 / $27.10) – 1 ~ 24%.

Q. WOULD FORCING OPC CUSTOMERS TO ABSORB A LARGER PERCENTAGE RATE INCREASE THAN CSP CUSTOMERS BENEFIT OPC CUSTOMERS?

A. No. Forcing OPC customers to experience larger rate shock than CSP customers is not a benefit, and is contrary to established ratemaking principles of limiting rate shock. Mr. Roush's logic of offsetting rate changes makes no sense. Moreover, maintaining separate charges directly contradicts the goal of combining previously separate charges for CSP and OPC customers to simplify those charges.

Q. WILL MR. ROUSH'S PROPOSAL ADVERSELY AFFECT RETAIL COMPETITION?

A. Yes. The key to efficient retail (and wholesale) competition is ensuring that customers see the correct prices, from which they can make the most efficient decisions regarding how they obtain their electric supply. Mr. Roush's proposal allows OPC retail customers to pay artificially low electric prices, which will clearly reduce retail competition in OPC's service territory. At the same time, CSP customers will be forced to pay higher electric prices, which may be one reason why Mr. Roush shows proposed rate changes for CSP's "typical" GS-4 customers to be 0% and 1%, whereas similar OSP customers see increases of 3%.[76] It thus appears that AEP Ohio is proposing to "simplify" its rate structure by developing combined rates beginning in June 2012, except for the FAC charges, possibly in an attempt to reduce migration of OPC customers to CRES providers.

[76] Roush Direct, p. 16, line 1. The table shows increases for two levels of consumption for each class of customer.

IV. PROPOSED COMPETITIVE PROCUREMENT FOR SSO LOAD

Q. WHAT DOES AEP OHIO PROPOSE AS A COMPETITIVE PROCUREMENT FOR ITS SSO LOAD?

A. AEP Ohio proposes three levels of competitive procurement. Prior to January 1, 2015, and six months after the PUCO approves the Modified ESP, AEP Ohio proposes an energy-only auction of 5% of its SSO load.[77] Beginning January 1, 2015, AEP Ohio proposes an energy-only auction of 100% of its SSO load.[78] Beginning June 1, 2015, a competitive bidding process ("CBP") will determine the full requirements for SSO load.[79]

Q. ARE COMPETITIVE PROCUREMENTS FOR SSO LOAD GENERALLY BENEFICIAL FOR CUSTOMERS?

A. Yes. However, AEP Ohio's proposed competitive procurements are so devoid of detail that one cannot determine whether customers will be better or worse off as a result. As usual, AEP Ohio states that the "details" will be addressed in subsequent proceedings.[80]

Q. DOES AEP WITNESS POWERS DISCUSS THE PROPOSED COMPETITIVE PROCUREMENT FOR 5% OF SSO LOAD THAT MIGHT OCCUR IN 2013/2014?

A. Yes. Rather than provide any details regarding the auction itself, Mr. Powers' discussion is focused solely on the financial impacts to AEP Ohio. Specifically, he states:

> The terms and conditions of such an auction need to be clearly circumscribed up front and AEP Ohio must be made whole to avoid the financial exposure it would otherwise face, including financial impacts of the early auction under the AEP Pool Agreement. Specifically, <u>based on the express condition of financially being made whole</u>, AEP Ohio is willing to conduct an energy-only, slice-of-system auction for 5% of the SSO load, with delivery beginning six months after final orders are both

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77 Powers Direct, pp. 20-21.

78 Powers Direct, pp. 19-20.

79 Powers Direct, p. 20.

80 Powers Direct, p. 20, lines 1-2 and p. 21, lines 4-5.

issued adopting the ESP as proposed and the corporate separation plan as filed.[81]

Q. DOES AEP OHIO PROVIDE ANY DETAIL OF WHAT "BEING MADE FINANCIALLY WHOLE" WOULD ENTAIL?

A. No. Depending on how AEP Ohio intends to propose that it be "made whole," the overall effects may be to stifle retail competition. For example, currently AEP Ohio recovers purchased power costs through the Fuel Adjustment Clause ("FAC"). Thus, AEP Ohio could recover the additional costs of auctioned SSO load through the FAC. In doing so, AEP Ohio would also be free to sell additional off-system energy and capacity into the market. If, therefore, natural gas prices increase and, as a consequence, the marginal cost of generating electricity with natural gas becomes greater than the marginal cost of generating with coal, then the auction will allow AEP Ohio to increase its profits in the off-system market.

AEP Ohio states that, for the January-May 2015 auction, it intends to charge the auction winners an above-market price of $255/MW-day for capacity.[82] The proposed capacity price for the 5% auction in 2014 also appears to be $255/MW-day.[83] However, it is possible that being "made whole" may include reimbursement to AEP Ohio for its claimed $355/MW-day embedded capacity costs. Given that AEP Ohio has provided no details, the PUCO is left to speculate.

Q. WILL AEP RETAIL AND AEP GENERATION RESOURCES BE ALLOWED TO BID IN THE SSO AUCTION?

A. AEP Ohio provides no information in its testimony regarding that question. In discovery, AEP Ohio has stated that AEP Generation Resources would be able to participate in the SSO auctions.[84] However, because of AEP Ohio's proposed capacity pricing, which will cross-subsidize AEP Generation Resources, and the resulting potential for AEP Generation Resources

[81] Powers Direct, p. 20, line 20 – p. 21, line 3 (emphasis added).

[82] Nelson Direct, p. 6, lines 20-22.

[83] Nelson Direct, p. 7, lines 18-21. *See* Exhibit JAL-7.

[84] *See* Exhibit JAL-7.

to subsidize AEP Retail, allowing either of these unregulated entities to compete in any auction for SSO load without preventing such cross-subsidies would be anti-competitive.

Q. HOW COULD AEP GENERATING RESOURCES CROSS-SUBSIDIZE AEP RETAIL?

A. Suppose that AEP Generation Resources is allowed to bid to serve the auctioned SSO load, either directly or through AEP Retail. If AEP Generation Resources is paid an above-market price for capacity by AEP Ohio, then it can clearly undercut the market prices offered by other, unaffiliated CRES providers to serve that load. If AEP Retail offers to serve the SSO auction load using energy provided by AEP Generation Resources, then AEP Retail can similarly offer a below-market price, again undercutting other unaffiliated CRES providers. Thus, having received above-market prices for capacity from AEP Ohio, AEP Generation Resources would be able to subsidize AEP Retail.

Q. COULD AEP OHIO RECOVER THE COSTS ASSOCIATED WITH THE 5% COMPETITIVE PROCUREMENT IN 2013/2014 THROUGH THE PROPOSED RETAIL STABILITY RIDER?

A. Yes. As I discuss in Section VI of my testimony, the nonbypassable nature of the proposed Retail Stability Rider would be problematic, because it would lead to cross-subsidies. Specifically, it would force customers who purchase electricity from CRES providers to subsidize AEP Ohio's participation in the SSO auction, and thus increase the cost of purchasing electricity from a CRES provider. It would also force the remaining 95% of SSO customers being served directly by AEP Ohio to subsidize AEP Ohio's participation in the SSO auction.

Q. IF AEP OHIO REQUIRES THAT CUSTOMERS FULLY REIMBURSE IT FOR REVENUES "LOST" DUE TO COMPETITIVE PROCUREMENTS, WILL AEP OHIO CUSTOMERS BENEFIT FROM A COMPETITIVE PROCUREMENT?

A. No. Customers will not benefit. In fact, once the associated administrative costs of a competitive procurement are taken into account,[85] it actually could increase the overall costs paid by AEP Ohio customers.

Q. COULD RECOVERY OF COSTS ASSOCIATED WITH THE COMPETITIVE PROCUREMENT AFFECT THE ESP V. MRO COMPARISON PREPARED BY AEP OHIO WITNESS THOMAS?[86]

A. Yes. However, there is no evidence in Ms. Thomas's testimony that she even considered how recovering "lost revenues" due to a competitive procurement, nor the administrative costs of a competitive procurement that AEP Ohio customers would be required to pay, would affect her ESP v. MRO comparisons.[87]

Q. SHOULD THE PUCO APPROVE THE MODIFIED ESP IN ORDER TO SECURE AEP OHIO'S COMMITMENT TO A COMPETITIVE PROCUREMENT FOR SSO LOAD IN 2013/2014?

A. Not in the form proposed by AEP Ohio with an undefined "make whole" entitlement. AEP Ohio's proposal is akin to its request to be allowed to establish a "placeholder" Generation Resource Rider (discussed below) for the Turning Point Solar facility without first addressing the actual costs of that facility until a later proceeding.[88] AEP Ohio similarly is asking the PUCO to approve a "make whole" guarantee before AEP Ohio provides any details on its proposed

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[85] *See* Roush Direct, p. 13, lines 16-19.

[86] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143 Ohio. Rev. Code in the Form of an Electric Security Plan, et al., Case Nos. 11-346-EL-SSO, et al.*, Direct Testimony of Laura Thomas, March 30, 2012 ("Thomas Direct").

[87] See the accompanying testimony of FES witness Schnitzer for a detailed discussion of the ESP/MRO comparison test performed by Ms. Thomas.

[88] The PUCO, in fact, required AEP Ohio to submit cost information for Turning Point, which I discuss in Section V.

competitive procurement. Given the potential for anti-competitive cross-subsidies with AEP Ohio's unregulated retail and generation affiliates, the possibility of higher overall costs paid by AEP Ohio customers, and the potentially adverse impacts on retail competition, especially if AEP Ohio seeks to recoup its costs through the nonbypassable Retail Stability Rider, the PUCO should not approve the Modified ESP to secure competitive procurement of 5% of AEP Ohio's SSO load in 2013/2014. An energy-only CBP for 100% of SSO load starting June 1, 2013, would be a reasonable alternative to what AEP Ohio has proposed.

V. GENERATION RESOURCE RIDER / TURNING POINT SOLAR

Q. WHAT IS THE PURPOSE OF AEP OHIO'S PROPOSED NONBYPASSABLE GENERATION RESOURCE RIDER ("GRR")?

A. AEP Ohio states that it is proposing the GRR in accordance with R.C. 4928.143(b)(2)(c) so as to collect the costs associated with "renewable and alternative capacity additions, as well as more traditional capacity constructed or financed by the Company and approved by the Commission."[89] According to AEP Ohio witness Nelson, during the term of the Modified ESP, AEP Ohio intends to use the GRR to recover the costs of its proposed Turning Point Solar project ("Turning Point"). He also states that no other projects are anticipated during the term of the Modified ESP, but the GRR he describes is designed to include other capacity additions in the future.[90]

Q. CAN YOU SUMMARIZE YOUR CONCLUSIONS REGARDING THE PROPOSED GRR?

A. Yes. First, AEP Ohio states that it only intends to recover the costs of Turning Point under the GRR during the ESP. In the 2010 LTFR proceeding,[91] AEP attempted to establish a

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89 Nelson Direct, p. 20, lines 12-14.

90 Nelson Direct, p. 20, lines 11-16.

91 *See In the Matter of the Long-Term Forecast Report of Ohio Power Company and Related Matters,* Case Nos. 10-501-EL-FOR, et al., ("2010 LTFR Proceeding").

"need" for Turning Point in a way that is obviously contrary to the plain language of R.C. 4928.143(B)(2)(c). Specifically, AEP Ohio attempted to conflate a "need" for Turning Point under two completely different statutory requirements—one that serves as a "safety valve" for acquiring retail electric generation resources needed to serve standard service offer ("SSO") customers, and the other for renewable generation needed to satisfy the state's alternative energy requirements.

Second, as I discuss below, AEP Ohio has no "need" for any generating resources in a resource planning sense. Nor, based on the shopping projections of AEP Ohio witness Allen, does AEP Ohio have a need for in-state solar RECs that would be provided by Turning Point. In fact, AEP Ohio currently has a surplus of in-state solar RECs for the foreseeable future because of its long-term purchased power agreement ("PPA") with the Wyandot Solar Facility ("Wyandot"), and recovers the costs of Wyandot on a bypassable basis, consistent with R.C. 4928.64(E). The plain language of R.C. 4928.64(E) states that recovery of renewable resource costs developed by an electric distribution utility ("EDU") must be recovered through a bypassable charge.[92] Yet, despite having acquired Wyandot based on the results of issuing a request for proposals ("RFP") in 2008, AEP Ohio has never again issued a similar RFP.[93] Yet, AEP Ohio never explains why it cannot acquire the solar RECs of Turning Point under the guidelines of R.C. 4928.64(E), as it did with Wyandot.

Third, AEP Ohio states that it intends to rely on the PJM capacity market beginning June 1, 2015. If AEP Ohio intends to rely on the market for all of its capacity needs, then it does not have to independently develop capacity resources. Moreover, AEP Ohio has no need for any new generating capacity and, after corporate separation takes place on January 1, 2014, AEP Ohio has

[92] R.C. 4928.64(E) states, "All costs incurred by an electric distribution utility in complying with the requirements of this section shall be bypassable by any consumer that has exercised choice of supplier under Section 4928.03 of the revised code."

[93] In 2009, AEP Ohio issued a RFP to acquire solar RECs for that year alone.

stated it will purchase capacity from its independent AEP Generation Resources affiliate until it can participate in the PJM RPM capacity market, beginning June 1, 2015. The only possible reason for developing a generating resource under the "safety valve" aspect of R.C. 4928.142(B)(2)(c) is because (1) the market cannot physically provide the "need" or (2) that an EDU can somehow develop resources at a below-market cost. AEP Ohio has never established either of these two criteria for Turning Point.

Fourth, AEP Ohio proposes to auction off 100% of its SSO energy load beginning January 1, 2015.[94] In that case, AEP Ohio will not need to develop its own energy resources and 100% of AEP Ohio's required solar RECs can be supplied by the winning bidders. As such, AEP Ohio will have zero "need" for in-state solar RECs from Turning Point.

Fifth, AEP argues that the cost of Turning Point is irrelevant to establishing "need." This is wrong. The "need" for any new generating capacity cannot be considered independently from the cost of such capacity, because electricity demand, like the demand for all other goods and services, is <u>always</u> affected by price. Moreover, the estimated costs of Turning Point, as filed in the confidential attachment to the Supplemental testimony of AEP Ohio witness Nelson,[95] show that it is more costly than the average market price of in-state solar RECs.

Sixth, the proposed GRR "placeholder" will have an adverse impact on retail electric competition, contrary to the goals set forth in R.C. 4928.02. The reason that even a "placeholder" can harm competition is because it introduces additional uncertainty for CRES providers and their customers of higher costs if they shop. Specifically, CRES providers (and, hence, their customers) would have to pay twice for resources acquired: first through the nonbypassable charge and second for the resources they must secure to serve their customers. This uncertainty over having to pay twice will raise CRES providers' costs to provide competitive retail electric services, thus reducing competition and providing AEP Ohio an unfair competitive advantage.

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94 Modified ESP, p. 11.

95 Supplemental testimony of Philip Nelson, May 2, 2012, Confidential Exhibit PJN-5.

A. <u>AEP Ohio Has No Need for any New Generating Capacity as Defined Under R.C. 4928.143(B)(2)(c)</u>

Q. WHAT DOES R.C. 4928.143(B)(2)(C) SPECIFICALLY STATE?

A. R.C. 4928.143(B)(2)(c) states that an electric distribution utility's ("EDU") Electric Security Plan may include:

> The establishment of a nonbypassable surcharge for the life of an electric generating facility that is owned or operated by the electric distribution utility, was sourced through a competitive bid process subject to any such rules as the commission adopts under division (B)(2)(b) of this section, and is newly used and useful on or after January 1, 2009, which surcharge shall cover all costs of the utility specified in the application, excluding costs recovered through a surcharge under division (B)(2)(b) of this section. <u>However, no surcharge shall be authorized unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility</u>. Additionally, if a surcharge is authorized for a facility pursuant to plan approval under division (C) of this section and as a condition of the continuation of the surcharge, the electric distribution utility shall dedicate to Ohio consumers the capacity and energy and the rate associated with the cost of that facility. Before the commission authorizes any surcharge pursuant to this division, it may consider, as applicable, the effects of any decommissioning, deratings, and retirements. (emphasis added).

Q. WHAT IS YOUR UNDERSTANDING OF THE LANGUAGE QUOTED ABOVE?

A. The language of R.C. 4928.143(B)(2)(c) is quite clear. Specifically, it requires a finding of "need" for generation in a resource planning sense, based on projections are submitted by the utility in a proceeding under R.C. 4928.143. Thus, for AEP Ohio to establish a "need" for Turning Point and, thus, recover the costs of Turning Point through a nonbypassable GRR, it would have to demonstrate that it has a need for new capacity and that Turning Point is the lowest-cost alternative for meeting that need. The Commission cannot make such a finding here.

Q. ARE YOU FAMILIAR WITH RESOURCE PLANNING CONCEPTS, INCLUDING LOAD FORECASTING?

A. Yes. I began my professional career as a forecaster for Idaho Power Company. I also developed load forecasts while employed at the Pacific Northwest Utilities Conference Committee ("PNUCC"), an industry trade group, where I worked closely with load forecasters at the Northwest Power Planning Council and the Bonneville Power Administration. Furthermore, as Manager, Economic Analysis at Green Mountain Power, I was part of the Resource Planning group, which prepared peak and energy load forecasts, and evaluated resource alternatives to meet those forecasted loads in a least-cost manner. At Green Mountain Power, I also worked with staff at the Electric Power Research Institute ("EPRI") to develop new methodologies to forecast loads at the distribution circuit level and determine least-cost alternatives, and was later presented with an "EPRI Innovators" award for those efforts. As an economic consultant, I have prepared load forecasts and worked with clients on resource planning issues. I have also published articles on new methodologies for resource planning and load forecasting, which are listed in the publications section of Exhibit JAL-1. Therefore, I consider myself to be an expert on load forecasting and resource planning issues.

Q. WHAT ARE THE GOALS OF ELECTRIC UTILITY RESOURCE PLANNING?

A. Utility resource planning involves first forecasting future energy and peak loads as accurately as possible, and then ensuring those loads can be met at the lowest expected cost with a portfolio of resources. In other words, the forecasting exercise first establishes whether there is a "need" for new resources–whether generating resources or energy efficiency resources.

Q. BASED ON YOUR EXPERIENCE WITH RESOURCE PLANNING, WHAT DOES THE "NEED" FOR NEW RESOURCES MEAN?

A. Prior to electric utility restructuring, all electric utilities had an obligation to serve. That meant that a utility was required to meet its customers' demand for electricity at all times, which utilities typically did by building generating plants or entering into long-term purchase contracts with other utilities. Therefore, "need" in a resource planning sense related to an electric utility having sufficient electric resources—either generating resources or energy efficiency resources—to meet customer demand at all times, and to ensure that the service provided was reliable. In other words, "need" really meant having enough electricity supplies to ensure the lights would always stay on, including a minimum amount of reserve capacity in case of forced outages. For example, PJM currently requires that all market participants have a minimum installed capacity reserve of just over 15% of their forecast peak load.

After electric utility restructuring, many vertically integrated utilities divested themselves of their generating resources and became EDUs. Customers of these utilities can purchase electricity from CRES providers, and thus the EDUs' obligation is to provide electricity sourced from the wholesale market to those remaining customers who either cannot or will not select an alternative CRES provider. This is the situation in Ohio and refers to SSO customers. Those customers' needs can be met either by auctioning off the right to provide them with electricity, as a number of Ohio EDUs have done, or by serving them with generation owned by the EDU, as is currently the case with AEP Ohio.

Q. ONCE A NEED FOR NEW RESOURCES TO MEET FUTURE DEMAND IS ESTABLISHED, HOW IS A PORTFOLIO OF RESOURCES SELECTED?

A. Once the need for new resources is determined, the resource planning exercise examines all of the available alternatives and selects those which meet that need at the lowest expected cost. The AEP East 2010 Integrated Resource Plan ("IRP"), which was filed as part of AEP Ohio's 2010 LTFR says something quite similar:

> The goal of resource planning for a largely regulated utility such as AEP is to cost-effectively match its energy supply needs with projected customer demand. As such the plan lays out the ***amount***, ***timing*** and ***type*** of resources that achieve this goal at the lowest reasonable cost, considering all the various constraints—reserve margins, emission limitations, renewable and energy efficiency

requirements—that are currently mandated or projected to be mandated (emphasis in original).[96]

Q. DOESN'T THAT LANGUAGE YOU HAVE QUOTED FROM AEP EAST'S 2010 IRP MEAN THERE IS A "NEED" FOR RENEWABLE RESOURCES THAT <u>DOES</u> FALL WITHIN THE LANGUAGE OF R.C. 4928.143(B)(2)(C)?

A. No. As I discuss below, renewable resource requirements are set out separately under R.C. 4928.64. The language of R.C. 4928.143(B)(2)(c) has nothing to do with renewable resource requirements.

Q. AS AN ECONOMIST AND AN EXPERT IN ELECTRIC UTILITY REGULATION AND PLANNING, HOW DO YOU INTERPRET THE LANGUAGE IN R.C. 4928.143(B)(2)(C) ADDRESSING "NEED"?

A. I interpret the language of R.C. 4928.143(B)(2)(c) as a type of market "safety valve." To understand what this means, we need to consider the market environment in which AEP Ohio operates.

AEP Ohio is a member of PJM, which operates several different types of electricity markets. These markets provide access to both EDUs and CRES providers with the energy and capacity needed to meet customer demand and reserve requirements established by PJM to ensure reliable electric service. Competitive markets work by equating supply and demand. As supply and demand change, so will market prices. For example, as shale gas production has increased, market prices for natural gas have decreased. Not only has that lowered the price of natural gas, it has also reduced the spot market prices of electricity, because the cost of generating electricity with natural gas has decreased. Of course, competitive market conditions can change over time, increasing and decreasing in response to changes in demand and changes in supply. However,

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[96] *See* AEP East Integrated Resource Plan, Executive Summary, page 1, attached to AEP Ohio's 2010 Long Term Forecast Report Supplement filed December 20, 2010 ("2010 LTFR Supplement") in *In the Matter of the Long-Term Forecast Report of Ohio Power Company and Related Matters*, Case No. 10-501-EL-FOR, *et al*.

competitive markets are also self-correcting. That is, expectations of high market prices lead to increased supplies, which reduce prices, and vice-versa.

Q. WOULD ALLOWING AEP OHIO TO BUILD A GENERATING RESOURCE THAT IS NOT "LEAST-COST" AND THEN LEVY A NONBYPASSABLE GRR FOR THAT RESOURCE MAKE ECONOMIC SENSE?

A. No. First, in <u>any</u> resource planning context, it does not make economic sense to build a resource that is not least-cost. For example, if two gas-fired generation alternatives, A and B, are identical in every respect, except that A has an overall cost of $100/MWh and B has an overall cost of $75/MWh, then it would not make economic sense to build A.

Similarly, forcing AEP Ohio customers—including customers who purchase electricity from CRES providers (who are already responsible for the alternative energy needs of their customers)—to pay a nonbypassable surcharge for an above-market cost resource makes no economic sense. The reason is that it would force all customers to pay above-market costs when there are lower-cost alternatives in the market. Moreover, forcing customers to pay above-market costs for electricity, including customers who either purchase electricity from CRES providers or wish to purchase from CRES providers, would stifle market competition. Shopping customers would be forced to pay twice for generation—first through the nonbypassable surcharge and second through the price charged by the CRES provider.

Q. CAN YOU SUMMARIZE THE ANALYSIS THAT AEP OHIO WOULD NEED TO PERFORM UNDER R.C. 4928.143(B)(2)(C) TO SHOW A NEED FOR INCLUDING A RESOURCE IN THE GRR BASED ON RESOURCE PLANNING PROJECTIONS?

A. Yes. There are three analytical steps AEP Ohio would need to perform. These are:

<u>Step 1:</u> Forecast future SSO customer energy and peak demand.

<u>Step 2:</u> Show that based on the forecast of energy and peak demand, additional resources will need to be acquired.

Step 3: Show that the expected future market prices of energy and capacity to meet that demand are higher than an identified least-cost alternative resource or portfolio of generating demand response and energy efficiency resources.

A fourth step would be to ensure that, if AEP Ohio develops any "least-cost" resources selected under Step 3, that its ratepayers are protected from unexpected and imprudent cost increases that negate the "least-cost" aspect of the resource.

Q. IS AEP OHIO DEVELOPING TURNING POINT TO MEET A NEED FOR NEW GENERATION, BECAUSE IT HAS INSUFFICIENT RESOURCES TO MEET PJM RESERVE REQUIREMENTS?

A. No. According to AEP Ohio's 2011 LTFR, AEP Ohio has sufficient resources to meet PJM reserve requirements.[97] AEP Ohio is not developing Turning Point to meet its overall need for generation. Instead, AEP Ohio has attempted to define its solar energy requirement under R.C. 4928.64(B) as identical to a "need" for new generating capacity under R.C. 4928.143(B)(2)(c). Thus, AEP Ohio is wrongly conflating the "need" for new generating capacity under R.C. 4928.143(B)(2)(c) with the renewable energy requirements set forth in R.C. 4928.64(B).

Q. IS THERE ANY EVIDENCE THAT TURNING POINT IS A "LEAST-COST" RESOURCE?

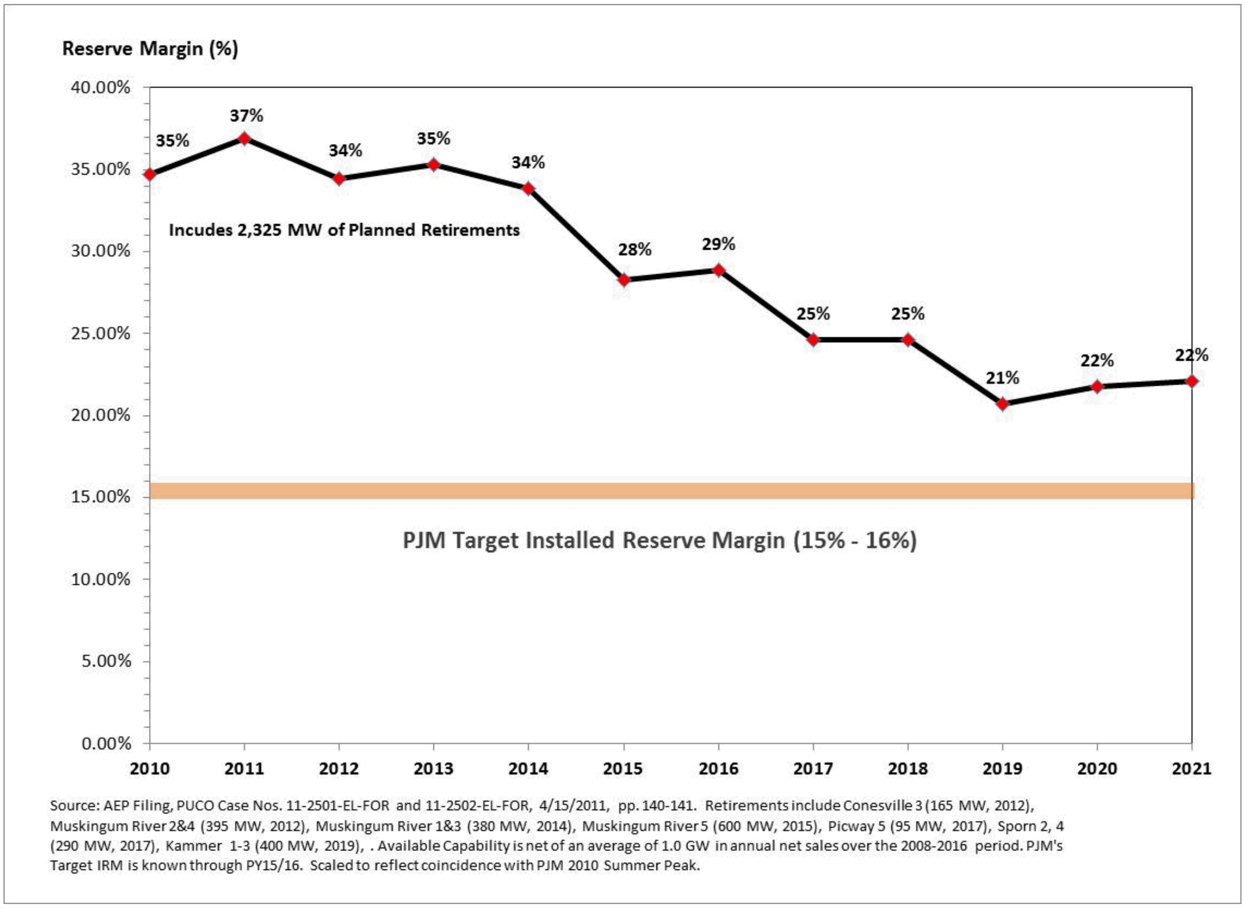
A. No. Clearly, solar PV resources such as Turning Point are not "least-cost" generating resources. Again, therefore, Turning Point does not meet the plain meaning of R.C. 4928.143(B)(2)(c). Moreover, this is why, as I discuss in Section VI.C, that "cost" is an integral part of any "need" determination, and why AEP Ohio has failed to establish that Turning Point is needed or that the GRR is needed.

[97] AEP Ohio Filing, PUCO Case Nos. 11-2501-EL-FOR and 11-2502-EL-FOR, 4/15/2011 ("2011 LTFR Report"), pp. 140-141.

Q. HAS AEP OHIO MET STEP 2 BY SHOWING THAT THERE IS A NEED FOR NEW GENERATING OR EFFICIENCY RESOURCES TO MEET ITS PROJECTED PEAK AND ENERGY LOADS IN A RESOURCE PLANNING SENSE?

A. No. According to AEP Ohio's own figures, as published in its 2011 LTFR Report, the Company's net capability of its generating assets well exceeds its peak load both now and into the foreseeable future.[98] This is illustrated in Figure 2 and includes both generator retirements and additional renewable resources, including Turning Point.

Figure 2: AEP Ohio Reserve Margin (2010 – 2021)



[98] 2011 LTFR Report, pp. 140-141.

As Figure 2 shows, even with 2,325 MW of planned retirements, AEP Ohio's available capacity remains far above the PJM installed reserve margin ("PJM IRM").[99]

Q. WILL NEW EPA REGULATIONS TO REDUCE MERCURY EMISSIONS, WHICH WERE ADOPTED IN DECEMBER 2011, AFFECT AEP OHIO'S RESERVE MARGIN?

A. Yes. AEP Ohio witness Nelson provides a list of AEP Ohio's generating plants that are expected to be retired by June 1, 2015.[100]

Q. DOES MR. NELSON INCLUDE RETIREMENTS THAT ARE ALREADY REFLECTED IN AEP OHIO'S 2011 LTFR?

A. Yes. I compared the plants listed in Exhibit PJN-2 with those shown on pp. 136-139 of the 2011 LTFR. Exhibit PJN-2 shows that AEP Ohio would accelerate retirement of Philip Sporn Units 2 and 4 from the Summer 2017 date shown on page 139 of the 2011 LTFR to 2015, accelerate retirement of the Picway 5 Unit from Summer 2017 to 2015, and accelerate retirement of the Kammer Plant from Summer 2019 to 2015.

Q. HOW DO THESE EARLIER PLANT RETIREMENTS AFFECT AEP OHIO'S RESERVE MARGIN?

A. The impact of the accelerated plant retirements is shown on Figure 3.

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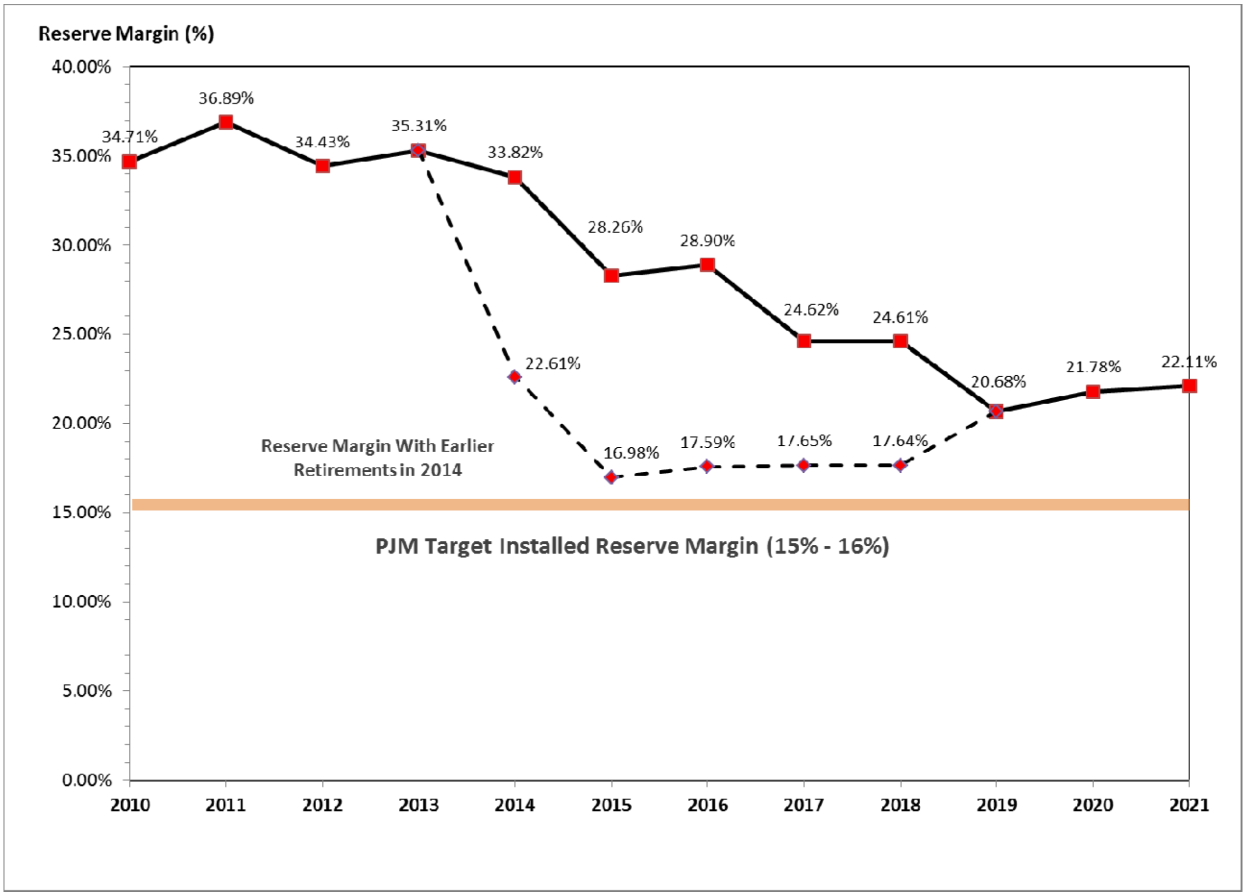
[99] 2011 LTFR Report, pp. 138-139.

[100] See Nelson Direct, Exhibit PJN-2, for a list of expected generation retirements by June 1, 2015.

Figure 3: AEP Ohio Reserve Margin with Accelerated Retirements Due to EPA Regulations (2010 – 2021)



As Figure 3 shows, even with accelerated retirements stemming from the EPA regulations, AEP Ohio's reserve margin will still be above PJM targets. Again, therefore, AEP Ohio has no "need" for new generating capacity in a resource planning sense.

Q. DOES AEP OHIO WITNESS NELSON ADMIT THE COMPANY HAS NO NEED FOR NEW GENERATING RESOURCES?

A. Yes. Mr. Nelson states, "AEP Ohio has had capacity and energy well in excess of its own internal customer's needs for a number of years and has been selling a significant amount of this surplus generation through the AEP Pool to its affiliates. In 2010 and 2011, AEP Ohio sold about 2,500 megawatts (MWs) and 2,200 MWs respectively to other AEP Pool members."[101]

Q. DO YOU AGREE WITH AEP OHIO WITNESS DIAS THAT THE PROPOSED NONBYPASSABLE GRR WILL HELP AEP OHIO "ADDRESS LONG-TERM CAPACITY NEED?"[102]

A. No. First, the testimony above shows that AEP Ohio has no long-term capacity need. Second, Mr. Dias's testimony is completely at odds with AEP Ohio's proposed corporate separation. As discussed by AEP Ohio witness Powers, as of June 1, 2015, AEP Ohio will rely on the PJM RPM to supply needed capacity. Mr. Powers states: "With the modified ESP II, AEP Ohio has committed to adjust its business plan to a fully competitive energy and capacity market by June 1, 2015 (once its FRR contractual obligation ends) to comply with the Commission's policy directive."[103] Furthermore, AEP Ohio proposes to auction off 100% of its SSO load as of January 1, 2015. If AEP Ohio intends to rely on the PJM RPM for all of its capacity needs and auction off 100% of its SSO load, then a nonbypassable GRR will not help AEP Ohio address a long-term capacity need that it does not have.

Q. HOW MUCH CAPACITY WILL TURNING POINT PROVIDE?

A. Because PJM applies a 38% summer capacity derating factor to solar PV capacity, the additional summer capacity supplied by Turning Point would be only 19.0 MW (0.38 x 49.9 MW = 19.0 MW).[104] Given that AEP Ohio's overall generating capacity is over 12,000 MW, the 19 MW of summer capacity provided by Turning Point would have a negligible impact on AEP Ohio's total capacity.

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[101] Nelson Direct, p. 12, lines 14-18.

[102] Dias Direct, p. 13, lines 10-11.

[103] Powers Direct, p. 14, lines 16-18.

[104] PJM, "2014/2015 RPM Base Residual Auction Results," p.11. http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx. PJM will hold the 2015/2016 Base Residual Auction in May of 2012.

B. AEP Ohio's Own Forecast of Shopping Loads Means That It Has No Need for the Solar RECS from Turning Point

Q. HOW MANY IN-STATE SOLAR RECS ARE PROVIDED UNDER AEP OHIO'S 20-YEAR PPA WITH WYANDOT?

A. According to its 2010 Supplemental LTFR filing, Wyandot provides 15,130 in-state solar RECs per year.

Q. WHAT IS AEP OHIO'S FORECAST OF RETAIL SHOPPING LOADS?

A. According to AEP Ohio witness Allen, as of March 1, 2012, 36.7% of AEP Ohio retail load had either switched or intended to switch to a CRES provider.[105] Mr. Allen projects that AEP Ohio retail shopping load will increase "to 65% of load for residential customers, 80% of load for commercial customers and 90% of load for industrial customers (excluding a single large customer) by the end of 2012."[106] Mr. Allen also states that he projects shopping load to remain at those levels through May of 2015.[107]

Q. GIVEN MR. ALLEN'S FORECAST OF SHOPPING LOADS, WILL AEP OHIO NEED TO ACQUIRE ANY ADDITIONAL SOLAR RECS?

A. No. As shown in Figure 4, Mr. Allen's shopping assumptions imply an in-state solar REC requirement for AEP Ohio of less than 10,000 solar RECs in 2020. In that case, AEP Ohio has no need for any additional in-state solar RECs at all, given that it has a 20-year power purchase agreement with the Wyandot solar facility, which began commercial operation in May 2010, is now providing it over 15,000 in-state solar RECs.[108]

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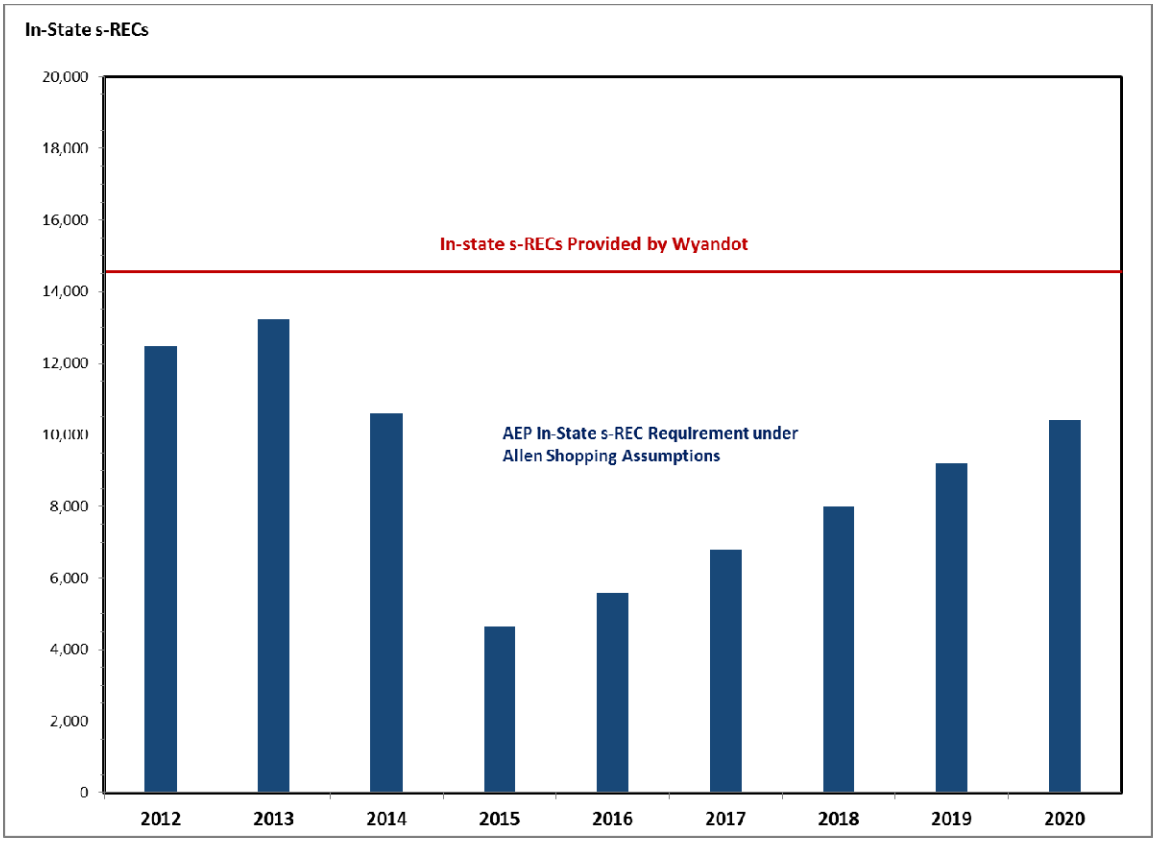
105 Allen Direct, p. 4, lines 1-7.

106 *Id.*, p. 5, lines 3-6.

107 *Id.*

108 *See In the Matter of the 2009 Annual Filing of Columbus Southern Power Company and Ohio Power Company Required by Rule 4901:1-35-10, Ohio Administrative Code*, Case No. 10-1261-EL-UNC, Direct Testimony of Joseph Hamrock, September 1, 2010, page 23, lines 16-21.

Figure 4: AEP Ohio In-State s-REC Requirements Using Allen Shopping Projections



As Figure 4 shows, under Mr. Allen's shopping load assumptions, Wyandot already provides AEP Ohio with surplus in-state solar RECs, and will have them at least through 2020.

Q. IF AEP OHIO'S OWN FORECAST OF RETAIL SHOPPING SHOWS THAT IT HAS NO NEED FOR IN-STATE SOLAR RECS, IS TURNING POINT "NEEDED" BY AEP OHIO?

A. No. Moreover, even if, arguendo, Turning Point were "needed" to meet AEP Ohio's in-state solar REC requirements, there would still be no justification for the costs of Turning Point to be collected through a nonbypassable GRR.

Q. WHY NOT?

A. For a resource to be included as a nonbypassable GRR under the requirements of R.C. 4928.143(B)(2)(c), it must be shown that it is a "least-cost" resource compared with what can be supplied by the market. (If it is demonstrated that the market cannot physically supply "needed" resources, then a resource developed under the auspices of R.C. 4928.143(B)(2)(c) must still be the least-cost alternative available for the EDU to develop.) AEP Ohio has never demonstrated this with regard to Turning Point.

C. The Need for New Resources and Their Cost Cannot be Addressed Independently

Q. DO YOU AGREE WITH AEP OHIO THAT THE "NEED" FOR TURNING POINT CAN BE ESTABLISHED INDEPENDENTLY OF ITS COSTS IN ORDER TO ESTABLISH A PLACEHOLDER GRR?

A. No. "Need" and "cost" are inexorably linked. For example, in the traditional resource planning sense, long-term forecasts of energy and peak loads must incorporate the effects of price, because the price of electricity is a key determinant of the demand for electricity. In fact, this is a key benefit that advocates of "Smart Meters" focus on. Specifically, by providing retail customers with real-time price information, they can make more efficient consumption decisions. Thus, a customer who sees a rapidly rising price of electricity on a hot summer's day will more likely take steps to reduce his electricity consumption in peak hours (e.g., using less air conditioning) or shifting consumption to off-peak hours (e.g., doing the laundry in the early morning).

In the same way, higher (lower) electric prices reduce (increase) the overall demand for electricity in the long-run. If forecast peak load declines by, say, 1,000 MW, then the amount of generating and demand response capacity needed to meet that forecast peak load decreases, and vice-versa.

This is why "need" cannot be divorced from "cost." The "need" for Turning Point depends on its estimated cost. Yet, AEP Ohio wishes the PUCO to determine there is a "need" for Turning Point and then consider the cost, having already established AEP Ohio's right to collect those costs through a nonbypassable GRR in a future proceeding. Such an approach is not only inconsistent with the basic requirements of resource planning, it would restrict competition by affecting retail customers' expectations of the relative prices of SSO and competitive electricity alternatives.

Q. HAS AEP OHIO PROVIDED ANY EVIDENCE THAT TURNING POINT IS A LEAST-COST SOLAR RESOURCE?

A. No. This goes back to a common-sense aspect of resource planning I discussed previously, using the example of two gas-fired generating plants, A and B. If A and B are otherwise identical, but B is less costly than A, then B is the preferred, "least-cost" resource. Similarly, if AEP Ohio can obtain in-state solar RECs at a cost of (say) $150/REC or at a cost of $400/REC, then it would not make economic sense for AEP Ohio to purchase the higher-cost RECs and recover those costs through a nonbypassable GRR. As many advertisements ask, "Why pay more?"

Q. HAS AEP OHIO PROVIDED ANY ESTIMATES OF THE COST OF TURNING POINT?

A. Yes. In response to a Commission Order dated April 25, 2012, AEP Ohio witness Nelson filed supplemental testimony on May 2, 2012.[109] Confidential Exhibit PJN-5 contains limited details on the estimated costs of Turning Point.

Q. DID AEP OHIO COMPETITIVELY BID TURNING POINT, AS REQUIRED UNDER R.C. 4928.123(B)(2)(C)?

A. No. Thus, even though AEP Ohio has argued that the cost of Turning Point should be incorporated under a nonbypassable charge under the "need" requirement of R.C. 4928.123(B)(2)(c), AEP Ohio did not competitively bid Turning Point, as required under R.C. 4928.123(B)(2)(c).

Furthermore, in its response to IEU-Ohio's INT-007 (attached as Exhibit JAL-8), AEP Ohio admitted that the agreement with Turning Point was not sourced through a competitive bid

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[109] *See* Case No. 11-346-EL-SSO, et al., Entry, April 25, 2012, par. 5.

process. Nor has AEP Ohio used any competitive market tools whatsoever to determine if there are other, lower-cost in-state solar resources available to it. For example, AEP Ohio could have issued a RFP for in-state solar RECs, as the FirstEnergy Utilities did earlier this year.

Q WHAT WERE THE RESULTS OF THE FIRSTENERGY UTILITIES' RFP?

A. On April 26, 2012, the FirstEnergy Utilities announced that, in response to its RFP for 1,000 in-state solar RECs, they received offers for over 15,000 solar RECs.[110] The results of the FirstEnergy Utilities auction clearly demonstrate that in-state solar RECs can be obtained in a competitive marketplace. Yet, AEP Ohio wishes to avoid even considering the competitive market for in-state solar RECs. Instead, AEP Ohio simply asserts there is a "need" and that it should be allowed to satisfy that "need" through a nonbypassable GRR.

Q. GIVEN THE ESTIMATED COSTS OF TURNING POINT AS REPORTED BY AEP OHIO, IS IT A LEAST-COST RESOURCE, OR EVEN A LEAST-COST SOLAR RESOURCE?

A. No. Turning Point is not a least-cost generating resource. The installed cost of a new gas-fired combined-cycle plant continues to be substantially less than any solar PV facility, including Turning Point.[111]

Q. HOW DO THE COSTS OF TURNING POINT REPORTED BY AEP OHIO WTINESS NELSON COMPARE WITH COSTS HE PREVIOUSLY PROVIDED IN JULY 2011?

A. They are significantly lower than the costs he provided for the same facility only ten months ago. Specifically, if one compares the assumed solar panel costs on page 1 of Exhibit PJN-5 to those reported in his previous confidential Exhibit PJN-4,[112] the assumed solar panel

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[110] "FirstEnergy's Ohio Utilities Meet 2012 Benchmarks for In-State Solar Renewable Energy," April 26, 2012. Attached as Exhibit JAL-9.

[111] *See* S. Kaplan, "Power Plant Characteristics and Costs," CRS Report for Congress, November 13, 2008, at 53, Table 13. Available at: http://www.fas.org/sgp/crs/misc/RL34746.pdf.

[112] Confidential Exhibit PJN-4, July 5, 2011.

costs for each of the three phases of development are one-third lower. Table 6 summarizes the assumed change in solar panel costs, based on quotes from the supplier, Isofoton, S.A.

Table 6: Change in Assumed Solar Panel Costs for Turning Point

[BEGIN CONFIDENTIAL MATERIAL]

Construction Phase	Exhibit PJN-4 2011 Cost ($/kW)	Exhibit PJN-5 2012 Cost ($/kW)	Percent Reduction
Phase 1	[redacted]		
Phase 2			
Phase 3			

[END CONFIDENTIAL MATERIAL].

Q. ARE THERE OTHER CHANGES IN THE ESTIMATED COSTS TO OPERATE AND CONSTRUCT TURNING POINT?

A. Yes. I compared Mr. Nelson's previous Confidential Exhibit PJN-4 with his new Confidential Exhibit PJN-5. The comparison is shown in Table 7. As can be seen, the overall equipment cost is reported as 34% lower than last year, including a 42% reduction in the cost for substation upgrades.

[BEGIN CONFIDENTIAL MATERIAL]

Table 7: Comparison of Nelson 2011 and 2012 Turning Point Cost Estimates

[redacted]

[END CONFIDENTIAL MATERIAL].

Q. DID AEP OHIO WITNESS NELSON PROVIDE A LEVELIZED COST FOR TURNING POINT IN HIS CONFIDENTIAL EXHIBIT PJN-5, AS HE DID IN HIS PREVIOUS CONFIDENTIAL EXHIBIT PJN-4?

A. No. I used the same methodology as Mr. Nelson did to calculate the levelized cost shown in Table 7. As shown in Table 7, the levelized cost has decreased from **[BEGIN CONFIDENTIAL MATERIAL]** [redacted] **[END CONFIDENTIAL MATERIAL]**.

Q. ARE THE PRICES REPORTED BY AEP OHIO WITNESS NELSON CONSISTENT WITH PUBLISHED MARKET DATA ON THE PRICE OF SOLAR PANELS?

A. Not according to a November 2011 report published by the National Renewable Energy Laboratory (NREL).[113] According to that report, the average price of solar panels in 2010 for large installations such as Turning Point was $1.64/watt. Higher efficiency panels, such as the ones manufactured by Isofoton, typically cost more than less efficient panels.[114] That price is consistent with the previously quoted prices shown in the July 2011 Exhibit PJN-4.

Q. DID MR. NELSON PROVIDE ANY ACTUAL INFORMATION ABOUT THE QUOTED PRICES FROM ISOFOTON OR OTHER BACK-UP INFORMATION ON THE COSTS?

A. No.

Q. IS THERE ANY PUBLISHED DATA ON THE AVERAGE MARKET PRICE OF IN-STATE SOLAR RECS?

A. Yes. Exhibit JAL-10 provides recent publicly available data on solar REC prices. As shown, the average price in April 2012 was $185. That price has steadily decreased over time. Most importantly, however, that average price is significantly less than the new estimate of the levelized cost of Turning Point, even with the lower capital costs reported in Table 7. Thus,

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[113] National Renewable Energy Laboratory, "2010 Solar Technologies Market Report," November 2011 ("NREL 2010 Market Report") http://www.nrel.gov/docs/fy12osti/51847.pdf.

[114] *Id*. pp. 59-60.

Turning Point is not even a least-cost in-state solar resource, based on reported data for in-state solar REC prices.

Q. HOW CAN THE MARKET PRICES FOR IN-STATE SOLAR RECS BE DECREASING IF THE TOTAL IN-STATE SOLAR REC REQUIREMENT IS INCREASING?

A. The answer is supply and demand. Specifically, as the supply of in-state solar RECs has increased, the market price is decreasing.

D. <u>Recovering the Costs of Turning Point Through a Nonbypassable Charge Would Be Anticompetitive</u>

Q. COULD AEP OHIO DEVELOP TURNING POINT WITHOUT RECOVERING THE COSTS THROUGH A NONBYPASSABLE GRR?

A. Of course. AEP Ohio is free to enter into an agreement with Turning Point at any time and recover the costs through a bypassable charge under R.C. 4928.64(E), just as it did with Wyandot.

Q. IF AEP OHIO CHOSE TO RECOVER THE COSTS OF TURNING POINT THROUGH A BYPASSABLE CHARGE UNDER R.C. 4928.64(E), WOULD IT BE REQUIRED TO ESTABLISH A "NEED" FOR TURNING POINT UNDER R.C. 4928.123(B)(2)(C)?

A. No. Furthermore, AEP Ohio does not explain in any of the testimony accompanying the Modified ESP, and has never previously explained, why the company is unwilling to take this obvious and easier approach to developing Turning Point.

Q. IF AEP OHIO CAN DEVELOP TURNING POINT WHENEVER IT WANTS AND RECOVER THE COSTS THROUGH A <u>BYPASSABLE</u> CHARGE, AS ALLOWED FOR UNDER R.C.4928.64(E), WHY DOES IT WANT TO ESTABLISH A NONBYPASSABLE GRR PLACEHOLDER FOR TURNING POINT?

A. The reasons are obvious. First, recovering the costs of Turning Point through a nonbypassable charge would eliminate all of AEP Ohio's financial risk associated with the facility, because it would be guaranteed recovery of Turning Point's costs from all distribution customers, including those who shop with CRES providers. Second, recovering the costs of Turning Point through a nonbypassable charge will restrict retail competition by making it more expensive for existing SSO customers to shop with CRES providers. In that sense, AEP Ohio's proposal is clearly anticompetitive.

Q. WHY WOULD IMPOSING A NONBYPASSABLE SURCHARGE THROUGH THE GRR FOR ANY RENEWABLE GENERATION THAT IS NOT NEEDED UNDER R.C. 4928.123(B)(2)(C) BE ANTICOMPETITIVE?

A. Imposing a nonbypassable surcharge to pay for renewable generation that is not needed under R.C. 4928.123(B)(2)(c) would be anticompetitive because CRES providers are also required to comply with the renewable energy requirements set forth in R.C. 4928.64(B)(2). Therefore, if a nonbypassable surcharge is imposed on AEP Ohio customers, then customers who purchase their electricity from CRES providers would be forced to pay twice for renewable energy. They would be forced to pay for renewable energy acquired by AEP Ohio through a nonbypassable GRR <u>plus</u> the costs of renewable energy purchased by their CRES provider to meet the requirements of R.C. 4928.64(B)(2).

Forcing CRES customers to pay <u>twice</u> for in-state solar RECs, while AEP Ohio's ESP customers only pay for Turning Point, harms those customers who have elected to shop and places CRES suppliers at an obvious competitive disadvantage, and thus forecloses competition. It would impose a barrier to entry in the form of an "entrance fee" for CRES suppliers to compete in the market, penalize existing CRES customers for shopping, and act as a disincentive to existing ESP customers choosing CRES providers. That is clearly anticompetitive.

Q. WHY WOULD IMPOSING A NONBYPASSABLE SURCHARGE FOR TURNING POINT BE CONTRARY TO ESTABLISHED STATE POLICY TO DEVELOP COMPETITIVE RETAIL ELECTRIC MARKETS?

A. Because imposing a nonbypassable surcharge for renewable resources such as Turning Point would penalize customers who wish to purchase electricity from CRES providers, such a charge would inhibit retail electric competition. That would be contrary to the plain language of R.C. 4928.02(A)-(D), and (H).

CRES providers already produce or procure all requisite energy, capacity and renewables to serve their retail customers. Forcing all AEP Ohio customers, including those who purchase electricity from CRES providers, to pay for Turning Point would be discriminatory and contrary to the language of R.C. 4928.02(A). It would restrict "the availability of unbundled and comparable retail electric service that provides consumers with the supplier, price, terms, conditions, and quality options they elect to meet their respective needs," contrary to the language of R.C. 4928.02(B). It would reduce the diversity of electric suppliers, contrary to the language of R.C. 4928.02(C). It would discourage market access, contrary to the language of R.C. 4928.02(D). And, by forcing CRES customers to pay twice for in-state solar RECs, once through the nonbypassable surcharge and again for the in-state solar RECs purchased or developed by their CRES provider, it would restrict effective competition in the provision of retail electric service, contrary to the language of R.C. 4928.02(H).

Q. WHY DOES ALLOWING AEP OHIO TO CREATE A NONBYPASSABLE GRR "PLACEHOLDER" ADVERSELY AFFECT MARKET COMPETITION?

A. The reason is that a nonbypassable "placeholder" sends a clear signal to CRES providers and customers who wish to shop that they will be forced to pay for AEP Ohio generating resources that they do not use. Consider a residential SSO customer examining alternative offers from CRES providers, all of whom must meet the state's in-state solar resource requirements. Any offer from a CRES provider will include the costs of the solar RECs the CRES provider must obtain to comply with the state requirement. A customer that is considering offers from CRES providers will incorporate an expectation of the nonbypassable placeholder to recover the costs of Turning Point into his evaluation of a decision to shop or remain a SSO customer. The expectation that the GRR will incorporate the costs of Turning Point means that this customer's expected shopping cost will increase.

Expectations of changing prices clearly affect economic decisions today. For example, suppose you are considering the purchase of a new car next year. If you expect gasoline prices to be $6 per gallon next year, then the type of car you purchase will likely be affected by that expectation. You will be more likely to purchase a car that gets 40 miles per gallon and less likely to purchase a car that gets only 10 miles per gallon.

Q. BUT IF A NONBYPASSABLE GRR INCREASES COSTS TO BOTH SSO AND SHOPPING CUSTOMERS BY THE SAME AMOUNT, HOW CAN A GRR PLACEHOLDER, OR EVEN AN ACTUAL GRR CHARGE, THWART COMPETITION?

A. The reason is that, by acquiring solar RECs under a nonbypassable GRR, AEP Ohio can reduce the costs of solar RECs under the bypassable Alternative Energy Rider ("AER") it has proposed in the Modified ESP or reduce the costs under the current Fuel Adjustment Charge. So, a SSO customer would expect to pay a GRR, but would also expect to pay a lower AER. However, a shopping customer, while also expecting to pay the same GRR, would not expect a lower AER, because the latter is a bypassable charge. Thus, relative to AEP Ohio's SSO price, the competitive market price would increase, which would reduce SSO customers' likelihood of migrating to CRES providers.

Q. DO YOU SEE ANY BENEFIT TO AEP DISTRIBUTION CUSTOMERS FROM A "PLACEHOLDER" GRR?

A. No. First, based on AEP Ohio's own forecast of shopping load, it has no need for the solar RECs that would be provided by Turning Point, the only generating facility AEP Ohio anticipates recovering costs from during the term of the Modified ESP. Moreover, nothing prevents AEP Ohio from developing Turning Point if it so chooses and recovering the costs of the solar RECs through the bypassable AER, as the company now does with the solar RECs it obtains from Wyandot.

Second, AEP Ohio has no need whatsoever for new generating resources, as it has surplus capacity and will continue to have surplus capacity for the duration of the Modified ESP.

Third, even a "placeholder" GRR imposes additional uncertainty on customers and CRES providers, who will reasonably interpret that "placeholder" as an expectation that AEP Ohio will attempt to impose the costs of Turning Point at a later time. Because doing so will effectively require shopping customers to pay twice for solar RECs, it will adversely reduce retail competition, contrary to state policy.

VI. RETAIL STABILITY RIDER

Q. WHAT IS THE RETAIL STABILITY RIDER ("RSR")?

A. The RSR is a proposed nonbypassable charge that would be levied on all AEP Ohio customers to compensate the company for "lost" revenues stemming from AEP Ohio's agreeing not to charge CRES providers what AEP Ohio claims are its full embedded costs of capacity of $355.72/MW-day, but instead charging customers various capacity prices, as I discussed previously in Section II.

Q. HOW DOES AEP OHIO CHARACTERIZE THE PROPOSED NONBYPASSABLE RETAIL STABILITY RIDER?

A. AEP Ohio characterizes the RSR as a way for AEP Ohio to recoup the costs associated with its providing "discounted capacity" to non-SSO load.[115] AEP Ohio witness Allen also likens the RSR to a generation decoupling mechanism, such as mechanisms that are sometimes used by

[115] *See* Allen Direct, p. 13, lines 6-12.

regulators to compensate utilities for reducing retail energy consumption by using energy efficiency programs. He states that the RSR "would provide financial stability for AEP Ohio."[116]

Q. DO YOU AGREE WITH AEP OHIO WITNESS ALLEN?

A. No. The proposed RSR is yet another way AEP Ohio is attempting to recover its stranded generation costs, despite having long-ago agreed to forego collection of those costs as part of its Stipulation in the ETP proceeding. The difference is that, rather than characterizing selling capacity to CRES providers at below what AEP Ohio claims are its embedded generating costs of $355.72/MW-day as a "subsidy,"[117] AEP Ohio portrays the RSR as standing between financial stability and financial ruin. This is wrong.

As I have previously discussed in Section II of my testimony, (1) AEP Ohio is not entitled to charge what it estimates as its full embedded cost to CRES providers, who are captive to AEP Ohio; (2) the PJM RPM market price of capacity is not a "subsidized" price, and should be the price charged to all CRES providers; (3) AEP Ohio's embedded capacity cost calculation suffers from severe flaws, including arguments that it is somehow entitled to 100% of the energy margins from off-system sales; and (4) as I showed previously in Section II, AEP Ohio wishes to charge CRES providers and its customers almost $1.6 billion in above-market capacity costs over the three-year term of the Modified ESP.

Q. HOW DOES AEP WITNESS POWERS JUSTIFY THE PROPOSED RSR?

A. In explaining the need for the RSR, AEP Ohio witness Powers states

> From the Company's perspective, the need for a RSR charge stems largely from the financial harm to AEP Ohio that would otherwise result from the modified ESP package as a whole. For example, the three-year FRR commitment the Company has with PJM to supply capacity for AEP Ohio load, as well as the

[116] *Id.*, p.14, lines 8-10.

[117] AEP Ohio makes this claim in Case No. 10-2929. *See, e.g.*, Direct Testimony of Richard Munczinski, March 23, 2012, p.9, lines 12-13 ("it is important that neither shareholders nor non-shopping customers subsidize CRES providers for use of AEP Ohio's capacity").

> obligations that AEP Ohio has under the existing system Pool Agreement, must be considered as AEP Ohio transitions to market.[118]

The "transition to market" noted by Mr. Powers began on January 1, 2001. There is simply no economic basis, nor a regulatory one based on the ETP Stipulation AEP Ohio signed 12 years ago, that the Company needs, or should be granted, an additional three years to extract above-market costs from captive customers and customers who wish to purchase electricity from CRES providers using a "lost revenue" mechanism.

Q. IN THE ETP PROCEEDING, DID AEP OHIO PROPOSE A LOST REVENUE RECOVERY MECHANISM TO RECOVER STRANDED GENERATION COSTS?

A. Yes. AEP Ohio had proposed to collect a generation transition charge ("GTC") from all switching customers. In the ETP Proceeding hearings, AEP Ohio witness Richard Munczinski stated that

> The filing requested for the GTC, the generation transition charge, the ability for us to seek the difference between our generation price and the market price. It did not guarantee recovery of these charges. It was just a test. And if the test ended up so that our generation prices were higher than market, we would recover the difference from a leaving customer. The stipulation -- in the stipulation we – dropped that option.[119]

Mr. Munczinski was describing a lost revenue transition charge, based on the difference between the market price of energy and AEP Ohio's embedded cost.

Q. WHAT DID THE ETP PROCEEDING STIPULATION STATE REGARDING THIS TRANSITION CHARGE?

A. Section IV of the ETP Proceeding Stipulation stated, in its entirety, "Neither Company will impose any lost revenue charges (generation transition charges (GTC)) on any switching

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118 Powers Direct, p. 18, lines 11-16 (emphasis added).

119 ETP Proceeding, Tr. Vol. III, 6/7/2000, p. 22, lines 18-24.

customer."[120] Yet, in the Modified ESP AEP Ohio is proposing to recover the same type of lost revenue charge, not just from switching customers, but also from SSO customers, so as to guarantee AEP Ohio a 10.5% return during the term of the Modified ESP. An example calculation of the RSR is shown in AEP Ohio witness Allen's Exhibit WAA-6.[121]

Q. DOES MR. ALLEN INCLUDE REVENUES AEP OHIO EARNS FROM OFF-SYSTEM ENERGY SALES?

A. No. In his testimony, Mr. Allen states that "I am defining non-fuel generation revenues as base generation revenues, Environmental Investment Carrying Cost Rider (EICCR) revenues and CRES capacity revenues." Thus, in calculating the 2011 return on equity ("ROE") shown in his Exhibit WAA-6, Mr. Allen ignores the profits AEP Ohio earned from its wholesale off-system capacity and energy sales.

Q. WHAT WERE AEP OHIO'S PROFITS ON OFF-SYSTEM ENERGY AND CAPACITY SALES IN 2011?

A. According to Exhibit JAL-11, AEP Ohio's allocated profits on off-system energy and capacity sales, after accounting for sharing under the Pool Agreement, totaled $204,087,000, including profits from off-system capacity sales to non-pool members of $71,216,148. Moreover, these are just the allocated profits. If all off-system energy and capacity sales were allocated based on the load ratio shares, then, using the 2011 data, total profits would be over $500 million. Unfortunately, we do not know the precise contribution to this value from AEP Ohio's own generating units. However, because AEP Ohio has surplus generating capacity, but other members do not, it is likely that AEP Ohio's generating units actual contribution is greater than the shared amount shown in Exhibit JAL-11.

[120] ETP Proceeding Stipulation, p. 3 (emphasis added).

[121] Allen Direct, p. 13, lines 19-21.

Q. HAVE YOU CALCULATED AEP OHIO'S ACTUAL RETURN ON EQUITY FOR 2011?

A. Yes. Using the data found in AEP Ohio's 2011 FERC Form-1 filing, I calculated AEP Ohio's actual return on equity ("ROE") to be 13.4%, as shown in Table 8. Similarly, in 2010, AEP Ohio's actual ROE was 14.28%.

Table 8: AEP Ohio Actual Return On Equity

Line No.	Item	2011	2010
[1]	Net Utility Operating Income	$668,772,655	$766,855,252
[2]	Total Rate Base	$6,965,022,836	$7,464,113,829
[3]	**Overall Return**	**9.60%**	**10.27%**
[4]	Avg Cost. of Debt	5.47%	5.82%
[5]	Debt Pct. Of Total Capitalization	47.9%	47.4%
[6]	Equity Pct. Of Total Capitalization	52.1%	52.6%
[7]	Weighted Cost of Debt	2.62%	2.75%
[8]	Cost of Equity - Pre tax	6.99%	7.52%
[9]	**After-tax Return on Equity**	13.40%	14.28%

Notes:
[1] Source: AEP Ohio 2011 FERC Form-1
[2] Source: AEP Ohio 2011 FERC Form-1
[3] Equals: [1] / [2].
[4] Source: AEP Ohio 2011 FERC Form-1
[5] Source: AEP Ohio 2011 FERC Form-1
[6] Source: AEP Ohio 2011 FERC Form-1
[7] Equals: [4] x [5].
[8] Equals: [3] - [7].
[9] Equals [8] / [6].

Q. DOES MR. ALLEN PROVIDE ANY BASIS FOR HIS 10.5% "TARGET" ROE?

A. No. Mr. Allen's target ROE is not supported by any analysis. Moreover, in Case No. 11-351-EL-AIR et al., AEP Ohio accepted a lower ROE for its distribution companies of 10.2%.

Mr. Allen even uses this 10.2% ROE on incremental distribution plant for the Distribution Investment Rider.[122]

Q. WHAT DO YOU CONCLUDE REGARDING THE PROPOSED RSR?

A. The proposed RSR is anti-competitive and will discourage retail competition, in direct conflict with the state's policy goals. The proposed RSR is yet one more attempt by AEP Ohio to recover above-market generation costs for which it long-ago agreed to forego recovery of using the same type of lost revenue mechanism. The PUCO should reject the RSR.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However I reserve the right to supplement my testimony as new information subsequently becomes available or in response to positions taken by other parties.

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[122] Allen Direct, p. 9, lines 20-22.

Jonathan A. Lesser, Ph.D.
President

SUMMARY OF EXPERIENCE

Dr. Jonathan Lesser is the President of Continental Economics, Inc., and has over 25 years of experience working for regulated utilities, governments, and as an economic consultant. He has extensive experience in valuation and damages analysis, from estimating the damages associated with breaking commercial leases to valuing nuclear power plants. Dr. Lesser has performed due diligence studies for investment banks, testified on generating plant stranded costs, assessed damages in commercial litigation cases, and performed statistical analysis for class certification. He has also served as an arbiter in commercial damages proceedings.

He has analyzed economic and regulatory issues affecting the energy industry, including cost-benefit analysis of transmission, generation, and distribution investment, gas and electric utility structure and operations, generating asset valuation under uncertainty, mergers and acquisitions, cost allocation and rate design, resource investment decision strategies, cost of capital, depreciation, risk management, incentive regulation, economic impact studies of energy infrastructure development, and general regulatory policy.

Dr. Lesser has prepared expert testimony and reports in cases before utility commissions in numerous U.S. states; before the Federal Energy Regulatory Commission (FERC); before international regulators in Latin America and the Caribbean; in commercial litigation cases; and before legislative committees in Connecticut, Maryland, New Jersey, Ohio, Texas, Vermont, and Washington State. He has also served as an independent arbiter in disputes involving regulatory treatment of utilities and valuation of energy generation assets.

Dr. Lesser is the author of numerous academic and trade press articles. He is also the coauthor of *Environmental Economics and Policy*, published in 1997 by Addison Wesley Longman, *Fundamentals of Energy Regulation*, published in 2007 by Public Utilities Reports, Inc., and *Principles of Utility Corporate Finance*, published in 2011 by Public Utilities Reports, Inc. Dr. Lesser is also a contributing columnist and Editorial Board member for *Natural Gas & Electricity*.

AREAS OF EXPERTISE

- State, federal, and international rate regulation – cost of capital, depreciation, cost of service, cost allocation, rate design, incentive regulation, and regulatory framework design
- Commercial damages estimation and litigation
- Cost-benefit analysis
- Regulatory policy and market design
- Economic impact analysis and input-output studies
- Environmental compliance and litigation
- Market power analysis
- Load forecasting and energy market modeling
- Energy asset valuation and due diligence

SELECTED EXPERT TESTIMONY AND REPORTS

Suiza Dairy

- U.S. District Court, District of Puerto Rico, Civil Case No. 04-1840. (*Vacqueria Tres Monjitas and Suiza Dairy, Inc. v. Jose O. Laboy, in his Official capacity, as the Secretary of the Department of Agriculture for the Commonwealth of Puerto Rico, and Juan R. Pedro-Gordian, in his official capacity, as Administrator of the Office of the Milk Industry Regulatory Administration for the Commonwealth of Puerto Rico*)

Subject: Addition of a "country risk" premium for the fresh milk dairy industry in the Commonwealth of Puerto Rico

Southwestern Electric Cooperative

- FERC proceeding regarding wholesale distribution rate application of Ameren Illinois (*Re: Midwestern ISO and Ameren Illinois*, Docket No. ER11-2777-002, et al.)

Subject: Allowed rate of return and capital structure

Exelon Corporation

- Proceeding before the New Jersey Board of Public Utilities (Docket No. EO-11050309)

Subject: PJM Capacity Market, Capacity Procurement, and Transmission Planning

FirstEnergy Solutions Corp.

- Proceeding before the Ohio Public Utilities Commission (Case Nos. 11-346-EL-SSO and 11-348-EL-SSO)

  Subject: AEP Ohio energy security plan, benefits of retail market competition.

Industrial Energy Users of Ohio

- Proceeding before the Ohio Public Utilities Commission (Case No. 08-917-EL-SSO)

  Subject: Determination of cost associated with "provider-of-last-resort" (POLR) service and AEP Ohio's use of option pricing models.

Southwest Gas Corporation

- FERC proceeding regarding rate application of El Paso Natural Gas Company (Docket No. RP10-1398-000)

  Subject: Development of risk-sharing methodology for unsubscribed and discount capacity costs.

Portland Natural Gas Shippers

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (Re: Portland Natural Gas Transmission System, Docket No. RP10-729-000)

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (Re: Portland Natural Gas Transmission System, Docket No. RP08-306-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Independent Power Producers of New York

- FERC proceeding (New York Independent System Operator, Inc., Docket No. ER11-2224-000)

Subject: Reasonableness of the proposed installed capacity demand curves and cost of new entry values proposed by the New York Independent System Operator.

Maryland Public Service Commission

- Merger application of FirstEnergy Corporation and Allegheny Energy, Inc. (I/M/O FirstEnergy Corp and Allegheny Energy, Inc., Case No. 9233)

  Subject: Proposed merger between FirstEnergy Corporation and Allegheny Energy. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power and merger synergies.

Alliance to Protect Nantucket Sound

- Proceeding before the Massachusetts Department of Public Utilities (Case No. D.P.U. 10-54)

  Subject: Approval of Proposed Long-Term Contracts for Renewable Energy With Cape Wind Associates, LLC.

Brookfield Energy Marketing, LLC

- FERC proceeding (*New England Power Generators Association, et al. v. ISO New England, Inc.,* Docket Nos. ER10-787-000, ER10-50-000, and EL10-57-000 (consolidated)).

  Subject: Proposed forward capacity market payments for imported capacity into ISO-NE.

Public Service Company of New Mexico

- Proceeding before the New Mexico Public Regulation Commission (Case No. 10-00086-UT)

  Subject: Load forecast for future test year, residential price elasticity study.

M-S-R Public Power Agency

- FERC proceeding (*Southern California Edison Co.*, Docket No. ER09-187-000 and ER10-160-000)

Subject: Allowed rate of return for construction work in progress (CWIP) expenditures for certain transmission facilities.

- FERC proceeding (*Southern California Edison Co.*, Docket No. ER10-160-000)

  Subject: Allowed rate of return for construction work in progress (CWIP) expenditures for certain transmission facilities.

Financial Marketers

- FERC proceeding (*Black Oak Energy, LLC v PJM Interconnection, L.L.C.*, Docket No. EL08-014-002)

  Subject: Allocation of surplus transmission line losses under the PJM tariff.

Southwest Gas Corporation and Salt River Project

- FERC proceeding regarding rate application of El Paso Natural Gas Company (Docket No. RP08-426-000)

  Subject: Analysis of proposed capital structure and recommended capital structure adjustments

New York Regional Interconnect, Inc.

- Proceeding before the New York Public Service Commission (Case No. 06-T-0650)

  Subject: Analysis of economic and public policy benefits of a proposed high-voltage transmission line.

Occidental Chemical Corporation

- FERC Proceeding (*Westar Energy, Inc.* ER07-1344-000)

  Subject: Compliance of wholesale power sales agreement with FERC standards

EPIC Merchant Energy, LLC, et al.

- FERC Proceeding (*Ameren Services Company v. Midwest Independent System Operator, Inc.,* Docket Nos. EL07-86-000, EL07-88-000, EL07-92-000 (Consolidated)

Subject: Allocation of revenue sufficiency guarantee costs.

Cottonwood Energy, LP

- Proceeding before the Public Utility Commission of Texas (*Application of Kelson Transmission Company, LLC for a Certificate of Convenience and Necessity for the Amended Proposed Canal to Deweyville 345 kV Transmission Line with Chambers, Hardin, Jasper, Jefferson, Liberty, Newton, and Orange Counties*, Docket No. 34611, SOAH Docket No. 473-08-3341)

  Subject: Benefits of transmission capacity investments.

Redbud Energy, LP

- Proceeding before the Oklahoma Corporation Commission (*Request of Public Service Company of Oklahoma for the Oklahoma Corporation Commission to Retain an Independent Evaluator,* Cause No. PUD 200700418)

  Subject: Reasonableness of PSO's 2008 RFP design.

The NRG Companies

- FERC Proceeding (*ISO New England Inc. and New England Power Pool,* Docket No. ER08-1209-000)

  Subject: Compensation of Rejected De-list Bids Under ISO-NE's Forward Capacity Market Design

Dynegy Power Marketing, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages accruing to Dynegy arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in NYISO during the summer of 2002.

Constellation Energy Group

- FERC proceeding (*Maryland Public Utility Commission, et al., v. PJM Interconnection, LLC*, Docket No. EL08-67-000)

  Subject: "Just and reasonableness" of PJM's Reliability Pricing Mechanism.

Government of Belize, Public Utility Commission

- Proceeding before the Belize Public Utility Commission, *In the Matter of the Public Utilities Commission Initial Decision in the 2008 Annual Review Proceeding for Belize Electricity Limited*.

  Subject: Arbitration and Independent Expert's report, in dispute between the Belize PUC and Belize Electricity Limited in an annual electric rate tariff review, as required under Belize law.

Federal Energy Regulatory Commission

- Technical hearings on wholesale electric capacity market design.

  Subject: Analysis of proposal to revise RTO capacity market design developed by the American Forest and Paper Association.

Dogwood Energy, LLC

- Proceeding before the Missouri Public Service Commission, *In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks - MPS and Aquila Case No. EO-2008-0046, Networks - L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.*, Case No. EO-2008-0046.

  Subject: Cost-benefit analysis to determine whether Aquila should join either the Midwest Independent System Operator (MISO) or the Southwest Power Pool (SPP).

Independent Power Producers of New York

- FERC proceeding (*Re: New York Independent System Operator, Inc.*, Docket No. ER08-283-000)

  Subject: Revisions to the installed capacity (ICAP) market demand curves in the New York control area, which are designed to provide economic incentives for new generation development.

Empresa Eléctrica de Guatemala

- Rate proceeding before the Comisión Nacional de Energía Eléctrica

  Subject: Rate of return for an electric distribution company

Electric Power Supply Association

- FERC proceeding (*Re: Midwest Independent Transmission System Operator, Inc.*, Docket No. ER07-1182-000)

  Subject: Critique of cost-benefit analysis by MISO Independent Market Monitor concluding that permanent establishment of Broad Constrained Area mitigation was appropriate.

Constellation Energy Commodities Group, LLC

- FERC proceeding regarding rate application for ancillary services by Ameren Energy (*Re: Ameren Energy Marketing Company and Ameren Energy, Inc*., Docket Nos. ER07-169-000 and ER07-170-000)
- Subject: Analysis and testimony on appropriate "opportunity cost" rates for ancillary services, including regulation service and spinning reserve service. Case settled prior to testimony being filed.

Suiza Dairy Corporation

- Rate proceeding before the Office of Milk Industry Regulatory Administration of Puerto Rico.
- Subject: Analysis and testimony on the appropriate rate of return for regulated milk processors in the Commonwealth of Puerto Rico.

DPL Inc.

- Proceeding before the Ohio Board of Tax Appeals (*DPL, Inc. and its subsidiaries v. William W. Wilkins, Tax Commissioner of Ohio*, Case No. 2004-A-1437)

  Subject: Economic impacts of generation investment and qualification of electric utility investments as "manufacturing" investments for purposes of state investment tax credits.

IGI Resources, LLC and BP Canada Energy Marketing Corp.

- FERC proceeding regarding the rate application by Gas Transmission Northwest Corporation (*Re: Gas Transmission Northwest*, Docket No. RP06-407-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Baltimore Gas and Electric Co.

- Maryland Public Service Commission (Case No. 9099)

Subject: Standard Offer Service pricing. Testimony focused on factors driving electric price increases since 1999, and estimates of rates under continued regulation

- Maryland Public Service Commission (Case No. 9073)

  Subject: Stranded costs of generation. Testimony focused on analysis of benefits of competitive wholesale power industry.

- Maryland Public Service Commission (Case No. 9063)

  Subject: Optimal structure of Maryland's electric industry. Testimony focused on the benefits of competitive wholesale electric markets. Presented independent estimates of benefits of restructuring since 1999.

Pemex-Gas y Petroquímica Básica

- Expert report in a rate proceeding. Presented analysis before the Comisión Reguladora de Energía on the appropriate rate of return for the natural gas pipeline industry.

BP Canada Marketing Corp.

- FERC proceeding regarding the rate application by Northern Border Pipeline Company (*Re: Northern Border Pipeline*, Docket No. RP06-072-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Transmission Agency of Northern California

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER09-1521-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER08-1318-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER07-1213-000)

Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER06-1325-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER05-1284-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket Nos. ER03-409-000, ER03-666-000)

  Subject: Analysis and development of recommendation for the appropriate return on equity, capital structure, and overall cost of capital.

State of New Jersey Board of Public Utilities

- Merger application of Public Service Enterprise Group and Exelon Corporation (*I/M/O The Joint Petition Of Public Service Electric And Gas Company And Exelon Corporation For Approval Of A Change In Control Of Public Service Electric And Gas Company And Related Authorizations, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-050*)

  Subject: Proposed merger between Exelon Corporation and PSEG Corporation. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power, value of changes in nuclear plant operations, and merger synergies.

Sierra Pacific Power Corp.

- FERC proceeding regarding the rate application by Paiute Pipeline Company (*Re Paiute Pipeline Company* Docket No. RP05-163-000)

  Subject: Depreciation analysis, negative salvage, and natural gas supplies. Case settled prior to filing expert testimony.

Matanuska Electric

- Regulatory Commission of Alaska rate proceeding (*In the Matter of the Revision to Current Depreciation Rates Filed by Chugach Electric Association, Inc*., Docket No. U-04-102)

  Subject: Analysis of the reasonableness of Chugach electric's depreciation study.

Duke Energy North America, LLC

- FERC proceeding (*Re: Devon Power, LLC*, et al., Docket No. ER03-563-030)

  Subject: Appropriate market design for locational installed generating capacity in the New England market to ensure system reliability.

Keyspan-Ravenswood, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in New York City during the summer of 2002.

Electric Power Supply Association

- FERC proceeding (*Re: PJM Interconnection, LLC*, Docket No. EL03-236-002)

  Subject: Analysis and critique of proposed pivotal supplier tests for market power in PJM identified load pockets.

Vermont Department of Public Service

- Vermont Public Service Board Rate Proceedings
  - Concurrent proceedings: *Re: Green Mountain Power Corp*., Dockets No. 7175 and 7176. Subject: Cost of capital and allowed return on equity under cost of service regulation, as well as under a proposed alternative regulation proposal.
  - *Re: Shoreham Telephone Company*, Docket No. 6914. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *Re: Vermont Electric Power Company*, Docket No. 6860. Subject: Development of a least-cost transmission system investment strategy

to analyze the prudence of a major high-voltage transmission system upgrade proposed by the Vermont Electric Power Company.

  - *Re: Central Vermont Public Service Company*, Docket No. 6867. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *Re: Green Mountain Power Corporation*, Docket No. 6866. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Pipeline shippers

- FERC proceeding regarding the rate application of Northern Natural Gas Company (*Re: Northern Natural Gas Company*, Docket No. RP03-398-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Arkansas Oklahoma Gas Corp.

- Oklahoma Corporation Commission rate proceeding (*Re: Arkansas Oklahoma Gas Corporation*, Docket No. 03-088)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

- Arkansas Public Service Commission rate proceedings
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 05-006-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 02-24-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Entergy Nuclear Vermont Yankee, LLC

- Vermont Public Service Board proceeding (*Re: Petition of Entergy Nuclear Vermont Yankee for a Certificate of Public Good*, Docket No. 6812)

  Subject: Analysis of the economic benefits of nuclear plant generating capacity expansion as required for an application for a Certificate of Public Good.

Central Illinois Lighting Company

- Illinois Commerce Commission rate proceeding (*Re: Central Illinois Lighting Company*, Docket No. 02-0837)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Citizens Utilities Corp.

- Vermont Public Service Board rate proceeding (*Tariff Filing of Citizens Communications Company requesting a rate increase in the amount of 40.02% to take effect December 15, 2001*, Docket No. 6596)

  Subject: Analysis of the prudence and economic used-and-usefulness of Citizens' long-term purchase of generation from Hydro Quebec, including the estimated environmental costs and benefits of the purchase.

Dynegy LNG Production, LP

- FERC proceeding (*Re: Dynegy LNG Production Terminal, LP*, Docket No. CP01-423-000). September 2001

  Subject: Analysis of market power impacts of proposed LNG facility development.

Missouri Gas Energy Corp.

- FERC rate proceeding (*Re: Kansas Pipeline Corporation*, Docket No. RP99-485-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Green Mountain Power Corp.

- Vermont Public Service Board rate proceedings
  - *In the Matter of Green Mountain Power Corporation requesting a 12.93% Rate Increase to take effect January 22, 1999*, Docket No. 6107. Subject: Analysis of the appropriate discount rate, treatment of environmental costs, and the treatment of risk and uncertainty as part of a major power-purchase agreement with Hydro-Quebec.

- *Investigation into the Department of Public Service's Proposed Energy Efficiency Utility*, Docket No. 5980. Subject: Analysis of distributed utility planning methodologies and environmental costs.
- *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Analysis of distributed utility planning methodologies and avoided electricity costs.
- *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Valuation of a long-term power purchase contract with Hydro-Quebec in the context of a determination of prudence and economic used-and-usefulness.

United Illuminating Company

- Connecticut Dept. of Public Utility Control proceeding (*Application of the United Illuminating Company for Recovery of Stranded Costs*, Docket No. 99-03-04)

  Subject: Development and application of dynamic programming models to estimate nuclear plant stranded costs.

COMMERCIAL LITIGATION EXPERIENCE

- *Lorali, Ltd., et al. v. Sempra Energy Solutions, LLC, et al*. Damages associated with abrogation of retail electric supply contract.
- *IMO Industries v. Transamerica.* Estimated the appropriate discount rate to use for estimating damages over time associated with a failure of the insurance companies to reimburse asbestos-related damage claims and the resulting losses to the firm's value.
- *John C. Lincoln Hospital v. Maricopa County.* Performed statistical analysis to determine the value of a class of unpaid hospital insurance claims.
- *Catamount/Brownell, LLC. v. Randy Rowland.* Prepared an expert report on the damages associated with breach of commercial lease.
- *Lyubner v. Sizzling Platters, Inc.*. Performed an econometric analysis of damage claims based on sales impacts associated with advertising.
- *Pietro v. Pietro*. Estimated pension benefits arising from a divorce case.
- *Nat'l. Association of Electric Manufacturers v. Sorrell.* Testified on the costs of labeling fluorescent lamps and the impacts of labeling laws on the demand for electricity.

ARBITRATION CASES

***TransCanada Hydro Northeast, Inc. v. Town of Littleton, New Hampshire*, (CPR File No. G-09-24).**

Subject: dispute regarding valuation for property tax purposes of a hydroelectric facility located on the Connecticut River.

Served as neutral on a three-person arbitration panel.

***Belize Electricity Limited v. Belize Public Utilities Commission* (Claim No. 512 of 2008)**.

Subject: Proceeding before the Supreme Court of Belize alleging that the Final Decision by the Belize Public Utilities Commission setting electric rates and tariffs for the 2008-2009 period were unreasonable and non-compensatory.

Prepared independent report on behalf of the Belize Supreme Court for arbitration of the dispute.

SELECTED BUSINESS CONSULTING EXPERIENCE

- For the COMPETE Coalition, prepared report on how electric competition creates economic growth.
- For an industry group, developed econometric model of the impacts of shale gas production on U.S. natural gas prices.
- For an environmental advocacy group, critically evaluated the financial implications of operating restrictions for an off-shore wind generating facility stemming from requirements under the U.S. Endangered Species Act.
- For a major investor-owned utility in the US, prepared a new system of short-term peak and energy forecasting models.
- For a major wholesale electric generation company, prepared comprehensive economic impact studies for use in FERC hydroelectric relicensing proceedings.
- For a major investor-owned utility in the Southwest US, prepared a detailed econometric model and wrote a comprehensive report on residential price elasticity that was required by regulators.
- For a major investor-owned utility in the Southwest US, developed a methodology to value nuclear plant leases that incorporated future uncertainty regarding greenhouse gas regulations.

- Faculty member, PURC/World Bank International Training Program on Utility Regulation and Strategy, University of Florida, Public Utility Research Center, Gainesville, FL, 2008 – 2009. Courses taught:
    - Sector Issues: Basic Techniques–Energy
    - Sector Issues in Rate Design: Energy
    - Sector Issues in Rate Design: Energy–Case Studies
    - Transmission Pricing Issues
- For a major solar energy firm, evaluated costs and benefits of alternative solar technologies; assisted with siting and transmission access issues.
- For industrial customers in the State of Vermont, prepared a position paper on the impacts of demand side management funding on electric rates and competitiveness.
- For a major New York brokerage firm, performed a fairness opinion valuation of a gas-fired electric generating facility.
- For electric utilities undergoing restructuring, developed comprehensive economic models to value buyer offers associated with nuclear power plant divestitures.
- For a large municipal electric utility in Florida, analyzed real option values of alternative proposed purchased generation contracts whose strike prices were tied to future natural gas and oil prices, and developed contract recommendations.
- For a municipal electric utility in Florida, developed an analytical model to determine risk-return tradeoffs of alternative generation portfolios, identify an efficient frontier of generation asset portfolios, and recommended asset purchase and sale strategies.
- For Central Vermont Public Service Corp. and Green Mountain Power Corp., developed analyses of distribution capacity investments accounting for uncertainty over future peak load growth.
- For a major electric utility in Latin America, developed risk management strategies for hedging natural gas supplies with minimal up-front investment; prepared training materials for utility staff; and wrote the utility's risk management Policies and Procedures Manual.
- For a major nuclear plant owner and operator in the U.S., prepared reports of the economic benefits of nuclear plant operation and development.
- For the Electric Power Supply Association, prepared numerous policy papers addressing wholesale electric market design and competition.

- For the California Energy Commission, developed a new policy approach to renewables feed-in tariffs and developed portfolio analysis models to develop an "efficient frontier" of generation portfolios for the state.
- For a major nuclear plant owner and operator, assessed the likelihood of relicensing a specific nuclear plant in New England, given state regulatory concerns over on-site spent fuel storage.
- For a large investor-owned utility in the Southeast, analyzed alternative environmental compliance strategies that directly incorporated uncertainty over future emissions costs, environmental regulations, and alternative pollution control technology effectiveness.
- For a Special Legislative Committee of the Province of New Brunswick, served as an expert advisor on the development of a deregulated electric power market.
- For the Bonneville Power Administration, developed models to assess the economic impacts of local generation resource development in Washington State and Oregon.
- For an electric utility in the Pacific Northwest, assisted in negotiations surrounding relicensing of a large hydroelectric generating facility.
- Served as an expert advisor for the Northwest Power Planning Council regarding future power supplies, load growth, and economic growth.

EDUCATION

- PhD, Economics, University of Washington
- MA, Economics, University of Washington
- BSc, Mathematics and Economics (with honors), University of New Mexico

EMPLOYMENT HISTORY

- 2009–Present: Continental Economics, Inc., President.
- 2004–2009: Bates White, LLC, Partner, Energy Practice.
- 2003–2004: Vermont Dept. of Public Service, Director of Planning.
- 1998–2003: Navigant Consulting, Senior Managing Economist.
- 1996–1998: Adjunct Lecturer, School of Business, University of Vermont.
- 1993–1998: Green Mountain Power Corporation, Manager, Economic Analysis.

- 1990–1993: Adjunct Lecturer, Dept. of Business and Economics, Saint Martin's College.
- 1986–1993: Washington State Energy Office, Energy Policy Specialist.
- 1984–1986: Pacific Northwest Utilities Conference Committee, Energy Economist.
- 1983–1984: Idaho Power Corporation, Load Forecasting Analyst.

PROFESSIONAL ACTIVITIES

- Reviewer, *Energy*
- Reviewer, *The Energy Journal*
- Reviewer, *Energy Policy*
- Reviewer, *Journal of Regulatory Economics*

PROFESSIONAL ASSOCIATIONS

- Energy Bar Association
- International Association for Energy Economics
- Society for Benefit-Cost Analysis

PUBLICATIONS

Peer-reviewed journal articles

- Lesser, J., "Gresham's Law of Green Energy," *Regulation*, Winter 2010-2011, pp. 12-18.
- Lesser, J., and E. Nicholson, "Abandon all Hope? FERC's Evolving Standards for Identifying Comparable Firms and Estimating the Rate of Return," *Energy Law Journal* 30 (April 2009): 105-132.
- Lesser, J. and X. Su. "Design of an Economically Efficient Feed-in Tariff Structure for Renewable Energy Development." *Energy Policy* 36 (March 2008) 981–990.
- Lesser, J. "The Economic Used-and-Useful Test: Its Origins and Implications for a Restructured Electric Industry." *Energy Law Journal* 23 (November 2002): 349–82.

- Lesser, J., and C. Feinstein. "Electric Utility Restructuring, Regulation of Distribution Utilities, and the Fallacy of 'Avoided Cost' Rules." *Journal of Regulatory Economics* 15 (January 1999): 93–110.
- Lesser, J., and C. Feinstein. "Defining Distributed Utility Planning." *The Energy Journal*, Special Issue, Distributed Resources: Toward a New Paradigm (1998): 41–62.
- Lesser, J., and R. Zerbe. "What Can Economic Analysis Contribute to the Sustainability Debate?" *Contemporary Policy Issues* 13 (July 1995): 88–100.
- Lesser, J., and R. Zerbe. "The Discount Rate for Environmental Projects." *Journal of Policy Analysis and Management* 13 (Winter 1994): 140–56.
- Lesser, J., and D. Dodds. "Can Utility Commissions Improve on Environmental Regulations?" *Land Economics* 70 (February 1994): 63–76.
- Lesser, J. "Estimating the Economic Impacts of Geothermal Resource Development." *Geothermics* 24 (Winter 1994): 52–69.
- Lesser, J. "Application of Stochastic Dominance Tests to Utility Resource Planning Under Uncertainty." *Energy* 15 (December 1990): 949–61.
- Lesser, J. "Resale of the Columbia River Treaty Downstream Power Benefits: One Road From Here to There." *Natural Resources Journal* 30 (July 1990): 609–28.
- Lesser, J., and J. Weber. "The 65 M.P.H. Speed Limit and the Demand for Gasoline: A Case Study for the State of Washington." *Energy Systems and Policy* 13 (July 1989): 191–203.
- Lesser, J. "The Economics of Preference Power." *Research in Law and Economics* 12 (1989): 131–51.

Books and contributed chapters

- Lesser, J., and L.R. Giacchino, *Principles of Utility Corporate Finance*, Vienna, VA: Public Utilities Reports, 2011.
- Lesser, J., and L.R. Giacchino. *Fundamentals of Energy Regulation*, Vienna, VA: Public Utilities Reports, 2007.
- Lesser, J., and R. Zerbe. "A Practitioner's Guide to Benefit-Cost Analysis." In *Handbook of Public Finance*, edited by F. Thompson, 221–68. New York: Rowan and Allenheld, 1998.
- Lesser, J., D. Dodds, and R. Zerbe. *Environmental Economics and Policy*, Reading: MA: Addison Wesley Longman, 1997.

Trade press publications

- Lesser, J. “Global Warming, Climate Change, er Climate Volatility: 2012 and Beyond,” *Natural Gas and Electricity* (January 2012): 22-24.
- Lesser, J., “Sunburnt: Solyndra, Subsidies, and the Green Jobs Debacle,” *Natural Gas & Electricity* (November 2011):30-32..
- Lesser, J., “Illinois an Example of when the Wind Doesn’t Blow,” *Natural Gas & Electricity* (September 2011):27-29.
- Lesser, J., “Salmon and Wind Dueling for Subsidies in the Pacific Northwest,” *Natural Gas & Electricity* (July 2011):18-20.
- Lesser, J., “Nuclear Fallout,” *Natural Gas & Electricity* (May 2011):31-33.
- Lesser, J., “Texas Two-Step: EPA’s Greenhouse Gas Permitting Takeover,” *Natural Gas & Electricity* (March 2011):21-23.
- Lesser, J., “Looking Forward: Energy and the Environment through 2012,” *Natural Gas & Electricity* (January 2011):30-32.
- Lesser, J., “First-Mover Disadvantage: Offshore Wind’s False Economic Promises,” *Natural Gas & Electricity* (November 2010): 26-28.
- Lesser, J., “Will the BP Disaster Affect Natural Gas and Electricity Markets?,” *Natural Gas & Electricity* (August 2010): 23-24.
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- Lesser, J., “Let the Tough Choices Begin: Affordable or Green?,” *Natural Gas & Electricity* (June 2010): 27-29.
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- "Competitive Energy Markets: How are they Working?" Constellation Executive Energy Forum, November 2, 2011.
- "The Failures of Transmission Planning and Policy," Harvard Electric Policy Group, February 25, 2010.
- "Financing the Smart Grid," Energy Bar Association Seminar, Washington, DC, December 4, 2009.

- "Renewable Power: At the Crossroads of Economics and Policy," Presentation to the Utilities State Government Organization, Newport, Rhode Island, July 13, 2009.
- "The Stimulus Act and Laws they Didn't Teach You in Law School," presentation to the 27th National Regulatory Conference, Williamsburg, VA, May 19, 2009.
- "Rate Recovery for Capital Intensive Generation: Rate Base and Construction Work in Progress," Law Seminars International, Las Vegas, NV, February 5, 2009.
- "Financial Risks Faced by Regulated Utilities: Implications for the Cost of Capital and Ratemaking Policies," Law Seminars International, Las Vegas, NV, February 7, 2008.
- "Alternative Regulatory Structures and Tariff Mechanisms: Practical approaches to providing low-cost, environmentally responsible energy and how to avoid some dangerous pitfalls." Western Energy Institute, October 1, 2007.
- "Economics and Energy Regulation." Law Seminars International, Washington, DC, March 15-16, 2007.
- "Energy in the Northeast: Resource Adequacy & Reliability." Law Seminars International, Boston, MA, October 16–17, 2006.
- "Energy in the Southwest: New Directions in Energy Markets and Regulations." Law Seminars International, Santa Fe, NM, July 14, 2006.
- "Energy and the Environment." Vermont Journal of Environmental Law, South Royalton, VT, March 10, 2006.
- "Electricity and Natural Gas Regulation: An Introduction." Law Seminars International, Washington, DC, March 17–18, 2005.

Exhibit JAL-2

Allen Claimed Capacity Price "Benefit"

CRES Tier 1

Class	PY12/13	PY13/14	PY14/15	TOTAL
Residential	$85,789,938	$86,200,426	$100,332,583	**$272,322,946**
Commercial	$55,662,250	$65,151,892	$78,433,984	**$199,248,126**
Industrial	$49,447,533	$62,492,458	$74,064,510	**$186,004,501**
Total	**$190,899,720**	**$213,844,777**	**$252,831,077**	**$657,575,574**

CRES Tier 2

Class	PY12/13	PY13/14	PY14/15	TOTAL
Residential	$26,978,460	$35,015,722	$28,178,824	**$90,173,006**
Commercial	$41,091,016	$39,704,072	$35,228,188	**$116,023,276**
Industrial	$34,141,639	$29,841,494	$25,227,636	**$89,210,769**
Total	**$102,211,116**	**$104,561,288**	**$88,634,648**	**$295,407,051**

TOTAL CRES

Class	PY12/13	PY13/14	PY14/15	TOTAL
Residential	$112,768,398	$121,216,148	$128,511,407	**$362,495,952**
Commercial	$96,753,267	$104,855,964	$113,662,171	**$315,271,402**
Industrial	$83,589,172	$92,333,952	$99,292,146	**$275,215,271**
Total	**$293,110,836**	**$318,406,065**	**$341,465,725**	**$952,982,625**

SSO Load Served by AEP Ohio 1/

Class	PY12/13	PY13/14	PY14/15	TOTAL
Residential	$0	$0	$0	**$0**
Commercial	$0	$0	$0	**$0**
Industrial	$0	$0	$0	**$0**
Total	**$0**	**$0**	**$0**	**$0**

SSO Auction

Class	PY12/13	PY13/14	PY14/15	TOTAL
Residential			$17,224,020	**$17,224,020**
Commercial			$7,507,126	**$7,507,126**
Industrial			$10,674,264	**$10,674,264**
Total			**$35,405,410**	**$35,405,410**

Total Allen "Benefit"	$988,388,036

Excess Capacity Cost Over PJM Market Prices

CRES Tier 1

PY12/13	PY13/14	PY14/15	TOTAL
$51,452,109	$45,956,017	($3,872,569)	**$93,535,558**
$33,383,171	$34,734,416	($3,027,341)	**$65,090,246**
$29,655,924	$33,316,593	($2,858,691)	**$60,113,825**
$114,491,204	**$114,007,026**	**($9,758,602)**	**$218,739,628**

CRES Tier 2

PY12/13	PY13/14	PY14/15	TOTAL
$62,976,845	$76,876,733	$28,287,171	**$168,140,749**
$95,920,321	$87,169,968	$35,363,639	**$218,453,928**
$79,698,126	$65,516,757	$25,324,636	**$170,539,519**
$238,595,292	**$229,563,458**	**$88,975,445**	**$557,134,195**

TOTAL CRES

PY12/13	PY13/14	PY14/15	TOTAL
$114,428,954	$122,832,750	$24,414,602	**$261,676,306**
$129,303,492	$121,904,384	$32,336,297	**$283,544,174**
$109,354,050	$98,833,350	$22,465,944	**$230,653,344**
$353,086,496	**$343,570,485**	**$79,216,843**	**$775,873,824**

SSO Load Served by AEP Ohio

PY12/13	PY13/14	PY14/15	TOTAL
$186,937,040	$131,404,965	$47,829,249	**$366,171,255**
$84,961,367	$58,909,343	$22,889,482	**$166,760,192**
$121,479,142	$81,496,157	$30,518,062	**$233,493,360**
$393,377,549	**$271,810,464**	**$101,236,793**	**$766,424,807**

SSO Auction

PY12/13	PY13/14	PY14/15	TOTAL
		$17,290,246	**$17,290,246**
		$7,535,990	**$7,535,990**
		$10,715,307	**$10,715,307**
		$35,541,543	**$35,541,543**

Total Excess Cost over Mkt:	$1,577,840,173

1/ Assumed to be charged embedded cost of $355.72/MW-day

Source: Allen, Exhibit WAA-4; Thomas Exhibit LJT-2

B. Because AEP Ohio Previously Agreed to Forego Collection of Stranded Costs and to Recover Its Generation Costs in the Competitive Markets, It Should not be Allowed to Impose an Above-Market Capacity Price that Includes Post-2001 Transition Costs, Including Environmental Compliance Expenditures

Q. HOW DID YOU DETERMINE THE AMOUNT BY WHICH THE NET BOOK VALUE OF AEP OHIO'S GENERATING PLANTS SINCE THE ETP PROCEEDING DECREASED BETWEEN JANUARY 1, 2001 AND DECEMBER 31, 2010?

A. Using the original cost (gross plant) and accumulated depreciation values for generation plant published in CSP's and OPC's respective FERC Form-1 filings, I first determined the net undepreciated GPIS for both companies as of January 1, 2001. I then applied the annual depreciation rates shown in Exhibit JHL-2 of the testimony of AEP Ohio witness John Landon in the ETP Proceeding to calculate the net undepreciated GPIS values for each company as of December 31, 2010. The results of my analysis are shown in Table 3.

Table 3: Reduction in Net Undepreciated GPIS Since 12/31/2000

Line No.	Item	CSP	OPC	TOTAL
[1]	Gross GPIS, December 31, 2000	$1,558,721,963	$2,739,392,759	$4,298,114,722
[2]	Accumulated Depreciation, December 31, 2000	$641,160,834	$1,526,498,824	$2,167,659,658
[3]	Net GPIS, December 31, 2000	$917,561,129	$1,212,893,935	$2,130,455,064
[4]	Generation Plant Depreciation Rate	3.2%	3.4%	3.33%
[5]	Annual Depreciation of 12/31/2000 GPIS	$49,879,103	$93,139,354	$143,018,457
[6]	Reduction in Net GPIS (12/31/2000 - 12/31/2010)	**$498,791,028**	**$931,393,538**	**$1,430,184,566**
[7]	**Remaining GPIS, 12/31/2010**	**$418,770,101**	**$281,500,397**	**$700,270,498**

Notes:
[1] Source: CSP, OPC 2000 FERC Form-1, pp.204-07.
[2] Source: CSP, OPC 2000 FERC Form-1, p. 219.
[3] Equals: [1] - [2]
[4] Source: ETP Proceeding, Landon Supplemental Direct, Revised Exhibit JHL-2.
[5] Equals: [1] x [4]
[6] Equals: - (10 x [5])
[7] Equals: [3] - [6]

Table 3 shows that, using the generation depreciation rates assumed by AEP witness Landon in the ETP proceeding for his calculation of stranded generation costs, an additional $498 million of CSP's GPIS on December 31, 2000 was depreciated through December 31, 2010. Similarly, an additional $931 million of OPC's GPIS on December 31, 2000 was depreciated through December 31, 2010. Thus, as shown on Line [6] of Table 3, over the 10-year period between December 31, 2000 and December 31, 2010, AEP Ohio accrued $1.43 billion of depreciation related to its GPIS as of December 31, 2000 (ignoring all subsequent capital additions that would further add to the overall depreciation accrual). Because stranded generation costs are defined as the difference between the market value of an asset (i.e., the net present value of future generation plant cash flows) and net undepreciated book value, these additional depreciation accruals represent a reduction in the initial estimates of CSP's and OPC's stranded generation costs. In other words, because the remaining undepreciated book value of pre-2001 generating plant investments necessarily decreases over time, so do stranded costs.

Q. HOW WERE THE STRANDED GENERATION COSTS FOR CSP AND OPC ESTIMATED IN THE ETP PROCEEDING?

A. CSP and OPC relied on a revenue-based approach, developed by AEP Ohio witness Landon, in which the net present value of each generating unit was estimated based on forecasts of future market prices and costs over the generating plant's remaining lifetime.[41] AEP Ohio also identified "regulatory assets" as costs that are distinct from stranded costs related to generation assets or the transition to competition. These "regulatory assets" are deferred expenses, including deferred taxes, from which

[41] ETP Proceeding, Direct Testimony of John Landon on behalf of Columbus Southern Power Company and Ohio Power Company, December 30, 1999 ("ETP Landon Direct"), p. 25-26.

ratepayers have already benefited but which had not been collected only because of past Commission orders and practices.[42]

Q. WHAT IS THE RELATIONSHIP BETWEEN THE EMBEDDED CAPACITY COSTS OF AEP OHIO'S GENERATING UNITS AND THE ESTIMATE OF ITS STRANDED COSTS?

A. The stranded generating cost estimates determined by AEP Ohio witness Landon in the ETP Proceeding for CSP and OPC were based on projections of future generation revenues, less future O&M costs (including fuel), taxes, and insurance, less the generating plants' overall net undepreciated book value as of December 31, 2000. In comparison, the embedded costs estimated by AEP Ohio in its capacity cost filing are a one-year snapshot of fixed costs that include a return on the undepreciated value of all of its generating plant, including all generating plant capital investment made on or after January 1, 2001, as of December 31, 2010.

Q. WHAT WERE THE STRANDED COST ESTIMATES DETERMINED BY MR. LANDON IN THE ETP PROCEEDING?

A. According to Exhibit JHL-2 of Mr. Landon's testimony, he estimated stranded costs of $517.5 million for CSP and $139.4 million for OPC under his "Base Environment, Low Gas" scenario.[43] Under his "High Gas, Alternative Environment" scenario, he estimated stranded costs of $476.7 million and $45.9 million for CSP and OPC, respectively. In Supplemental Direct testimony, Mr. Landon revised these estimates to $539.8 million and $558.7 million for CSP, and $353.8 million and $394.4

[42] *Id.*, p. 9.

[43] ETP Landon Direct, p. 44, lines 2-14.

million for OPC under Low and High gas price scenarios.[44] The aggregate stranded cost estimate derived by Mr. Landon for AEP Ohio was therefore between $893.6 million and $953.1 million.

Q. BASED ON MR. LANDON'S ESTIMATES, DO YOU CONCLUDE THAT AEP HAS RECOVERED ITS STRANDED GENERATION-RELATED COSTS?

A. Yes. Mr. Landon's highest estimate of stranded generation costs for AEP Ohio was $953.1 million. Because AEP Ohio recovered almost $1.43 billion in depreciation costs between December 31, 2000 and December 31, 2010 for GPIS, as shown in Table 4 above, it is reasonable to conclude that AEP Ohio has fully recovered all stranded generation costs. These depreciation accruals have eliminated from CSP's and OPC's books the stranded costs estimated by Mr. Landon, leaving only costs that are "un-stranded" and, thus, may be recovered through competitive markets at market pricing.

Q. WHAT IS THE SIGNIFICANCE OF YOUR CONCLUSION THAT AEP OHIO HAS RECOVERED ALL OF ITS STRANDED GENERATION COSTS?

A. In addition to the fact that AEP Ohio waived, and is not entitled to receive, any additional recovery of stranded costs, AEP Ohio has no basis for charging CRES customers an above-market price for capacity because AEP Ohio has recovered all of its stranded generation costs. Therefore, allowing AEP Ohio to recover these costs will allow AEP Ohio to double recover costs and be contrary to Ohio's policy towards creating a competitive electric market.

Q. DOES AEP OHIO ARGUE THAT THE PROVISIONS OF S.B. 3 CANNOT BE APPLIED IN DETERMINING AN ALLOWED CAPACITY CHARGE?

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[44] ETP Proceeding, Supplemental Direct Testimony of John Landon, April 18, 2000, p. 8. For his revised estimates, Mr. Landon assumed only one environmental regulation scenario.

A. Yes. In the Joint Initial Brief filed filed by AEP Ohio in the ESP II proceeding on November 10, 2011, regarding the proposed stipulation in Case No. 11-346-EL-SSO, et al., AEP Ohio argued:

> It would be extremely unfair and disingenuous for the Commission to currently find that AEP Ohio's cost-based capacity charge is barred by virtue of a 2000 era market analysis done under the previously effective provisions of SB 3 that were applied in a different factual and legal context. Not only is the 2000 vintage view of stranded generation investment inapplicable to the current situation, taking a short-term view cannot support any valid conclusions about whether generation investment is stranded in a competitive market. Non-Signatory Parties take the view that the relatively brief period during which the Stipulated blended capacity charges would apply (i.e., 2012- May 2015) should be used to judge whether a cost-based rate could be characterized as recovering costs stranded in a competitive market. <u>The fact that RPM prices for some recent years and some projected years are above the Stipulated blended capacity charge undermines a conclusion that AEP Ohio's generation assets are stranded in a competitive market</u>.[45]

AEP Ohio wrote this regarding the proposed $255/MW-day capacity charge for CRES providers in the now rejected ESP II Stipulation. It is clear from Table 1 that AEP Ohio's $355.72/MW-day capacity charge is far greater than RPM prices for the next three years. The 2014/15 planning year has the highest RPM delivered price over the next three years. Yet, that price, $153.89/MW-day, is still less than half of AEP Ohio's proposed capacity charge of $355.72/MW-day. Thus, applying AEP Ohio's own argument means that AEP Ohio's claimed capacity costs <u>are</u> stranded in a competitive market.

Q. IS IT YOUR UNDERSTANDING THAT S.B. 221 OVERTURNED THE LANGUAGE OF S.B. 3 REGARDING STRANDED COST RECOVERY?

[45] Joint Initial Brief, p. 122 (emphasis added).

A. No. Based on my understanding of S.B. 3, I find no language that overturns the language of S.B. 3 regarding stranded costs. AEP Ohio argues that S.B. 221 created a "hybrid" system of regulation, stating "The ESP option under SB 221 now involves several cost-based rate adjustments and amounts to a hybrid system of regulation and market-based pricing."[46] However, AEP Ohio's characterization of the ESP option under S.B. 221 as a "hybrid" system of regulation is irrelevant for purposes of setting a capacity price for CRES providers and their customers; those customers are, by definition, not selecting an ESP option.

Q. ARE YOU AWARE OF ANYTHING THAT ALLOWS AEP OHIO TO RECOVER STRANDED GENERATION COSTS?

A. No. Moreover, as I previously discuss, in its 2012 Corporate Separation Plan, filed on March 30, 2012, AEP Ohio admits that it is not allowed to recover stranded costs. I conclude that AEP Ohio is still prohibited from recovering stranded generation costs from its customers, whether directly or indirectly. Therefore, AEP Ohio should be required to charge CRES providers and, hence, its own non-SSO customers, the PJM RPM market price.

Q. IS AEP OHIO ENTITLED TO RECOVER ALL OF ITS POST-2011 ENVIRONMENTAL CAPITAL COSTS IN THE CAPACITY PRICE CHARGED TO CRES PROVIDERS?

A. No. AEP Ohio is not "entitled" to recover all of its embedded capacity costs from CRES providers whatsoever. Instead, AEP Ohio has an opportunity to recover those costs through the market price of capacity and through its off-system energy market sales.

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[46] Joint Initial Brief, p. 123.

Q. IS AEP OHIO GUARANTEED RECOVERY OF ALL OF ITS ENVIRONMENTAL CAPITAL INVESTMENT COSTS?

A. No. AEP Ohio is allowed to recover environmental carrying costs through the bypassable EICCR. In the Joint Initial Brief, AEP Ohio argued that the Commission supported specific recovery of environmental compliance investments that have allowed AEP Ohio's generation units to operate in many proceedings.[47]

AEP Ohio appears to be interpreting the PUCO's support for recovery of the carrying costs associated with environmental capital investments in a very different way than what the PUCO Orders have stated. Specifically, in its Order on Remand in the ESP I case, the PUCO cited to AEP Ohio witness Nelson's testimony, that environmental investments "[a]re necessary to keep the Companies' low cost coal-fired generating units running. The customers will benefit because the operating costs of these units remain <u>well below the cost of securing the power on the market</u>. The Companies are passing the lower-cost power through the FAC."[48] The PUCO then stated:

> We find that the environmental investment carrying charges have the effect of providing certainty to both the Companies and their customers regarding retail electric service, specifically generation service. With respect to AEP-Ohio, inclusion of the carrying charges in the ESP compensates the Companies for their investment in their generating plant.[49]

In other words, the PUCO was referring to SSO customers and inclusion of environmental carrying costs in the <u>bypassable</u> EICCR.

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[47] Joint Initial Brief, p. 119.

[48] *In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets*, Case No. 08-917-EL-SSO, et al., <u>Order on Remand</u>, October 11, 2011, p. 14 (emphasis added).

[49] *Id*.

Similarly, in its Order in Case No. 07-63-EL-UNC, which is one of the "4%" Cases, the PUCO discussed the types and amounts of costs AEP Ohio could recover under its rate stabilization plan ("RSP").[50] The PUCO quoted from Section 3 of AEP Ohio's RSP itself, which stated:

> During the RSP, the Companies may further adjust the generation rates and related riders of the <u>standard service tariff</u>, beyond those specified in Section 2 of the Plan, for increased expenditures (whether capitalized or expensed) incurred either directly, or indirectly through an affiliated pooling arrangement, for complying with changes in laws, rules or regulations related to environmental requirements …[51]

The PUCO is clearly referring to the standard service, i.e., SSO, tariff, not the price charged to CRES providers for capacity. Indeed, if AEP Ohio charged the market price for capacity, then it would recover some portion of those embedded environmental capital costs from CRES providers and, hence, its non-SSO customers. AEP Ohio recovers additional embedded environmental capital costs from the profits it earns on off-system energy sales. After corporate separation, this is exactly how AEP Generation Resources will recover those capital costs, and all other capital costs.

Nothing in any of the PUCO Orders refers to AEP Ohio being <u>guaranteed</u> recovery of its environmental capital costs by charging CRES providers for those in excess of the market price of capacity. Moreover, if AEP is recovering depreciation expenses and a return on environmental investments made between 2001 and 2008, then it cannot also recover these same costs in a separate capacity charge. That is double recovery of costs. Finally, the energy CRES providers secure for their retail customers

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[50] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of an Additional Generation Service Rate Increase Pursuant to Their Post-Market Development Period Rate Stabilization Plans,* Case No. 07-63-EL-UNC, Order, October 3, 2007.

[51] Case No. 07-63-EL-UNC, Order, p. 6 (emphasis added).

must comply with all environmental mandates. Thus, AEP Ohio argues that CRES providers, and their customers, should effectively be forced to pay twice to comply with environmental mandates: first through the energy they purchase on the retail market, and second by paying for AEP Ohio's environmental costs. That is discriminatory and anticompetitive.

C. <u>AEP Ohio's Proposed Formula Rate Must be Modified to Exclude all Post-Transition Capital Costs and to Account for the Profits AEP Ohio Makes on Off-System Energy Sales</u>

Q. HAVE YOU CORRECTED AEP OHIO'S CLAIMED COST-BASED CAPACITY PRICES USING AEP OHIO'S FORMULA RATE APPROACH?

A. Yes. Below, I present a revised embedded capacity cost estimate for AEP Ohio, based on 2010 data published in AEP Ohio's FERC Form-1 reports, that eliminates post-2001 transition capital expenditures and accounts for the profits AEP Ohio makes on off-system energy sales.

Q. PLEASE EXPLAIN WHY YOU SUBTRACTED FIXED COSTS RECOVERED FROM ENERGY-RELATED SALES FOR RESALE FROM AEP OHIO'S CAPACITY COST ESTIMATE?

A. In its formula rate estimates of 2010 capacity costs, AEP Ohio subtracts out only those revenues from capacity-specific sales for resale. AEP Ohio ignores the fact that it also recovers a portion of its fixed costs, including costs associated with its environmental capital investments, when it makes energy-related sales for resale because revenues received from those sales that exceed AEP Ohio's variable O&M plus fuel costs recover a portion of its embedded capacity costs. Thus, AEP Ohio has established a formula rate to recover all of its embedded costs. However, when AEP Ohio makes energy-related sales, the profits from those sales help recover those same embedded must comply with all environmental mandates. Thus, AEP Ohio argues that CRES providers, and their customers, should effectively be forced to pay twice to comply with environmental mandates: first through the energy they purchase on the retail market, and second by paying for AEP Ohio's environmental costs. That is discriminatory and anticompetitive.

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Q. HAVE YOU CORRECTED AEP OHIO'S CLAIMED COST-BASED CAPACITY PRICES USING AEP OHIO'S FORMULA RATE APPROACH?

A. Yes. Below, I present a revised embedded capacity cost estimate for AEP Ohio, based on 2010 data published in AEP Ohio's FERC Form-1 reports, that eliminates post-2001 transition capital expenditures and accounts for the profits AEP Ohio makes on off-system energy sales.

Q. PLEASE EXPLAIN WHY YOU SUBTRACTED FIXED COSTS RECOVERED FROM ENERGY-RELATED SALES FOR RESALE FROM AEP OHIO'S CAPACITY COST ESTIMATE?

A. In its formula rate estimates of 2010 capacity costs, AEP Ohio subtracts out only those revenues from capacity-specific sales for resale. AEP Ohio ignores the fact that it also recovers a portion of its fixed costs, including costs associated with its environmental capital investments, when it makes energy-related sales for resale because revenues received from those sales that exceed AEP Ohio's variable O&M plus fuel costs recover a portion of its embedded capacity costs. Thus, AEP Ohio has established a formula rate to recover all of its embedded costs. However, when AEP Ohio makes energy-related sales, the profits from those sales help recover those same embedded costs, and provide an additional return on embedded rate base. AEP Ohio recovers a portion of its embedded costs twice: first, through its embedded capacity cost and second through off-system energy sales. Regardless of whether AEP Ohio's assumption that it is entitled to recover its full embedded costs is valid, the company is clearly <u>not</u> allowed to double recover those costs. Such an outcome is incompatible with basic rate regulation. Thus, AEP Ohio is required to subtract all revenues from sales for resale that contribute to the recovery of embedded generation capacity costs.

Q. DO YOU AGREE WITH AEP OHIO THAT, BECAUSE IT SHARES PROFITS FROM OFF-SYSTEM ENERGY SALES UNDER THE POOL AGREEMENT, IT IS INCORRECT TO REMOVE THESE PROFITS FROM THE FORMULA-RATE CAPACITY CHARGE?[52]

A. No. First, AEP Ohio witness Pearce argues that the company should be allowed to keep 100% of the profits from off-system energy sales and that none of those profits should be credited against the embedded capacity cost.[53] Second, based on AEP Ohio's response to Interrogatory FES-2-12, attached as Exhibit JAL-2, the off-system sales revenues reported by AEP Ohio under FERC Account No. 447 (Sales for Resale) already reflect sharing under the Pool Agreement. Therefore, as I discuss below, my adjustments to AEP Ohio's embedded capacity cost reflects only AEP Ohio's share of off-system energy sales revenues. Third, AEP Ohio and the other Pool members gave notice long ago that the Pool would terminate as of January 1, 2014. AEP Ohio's profits will not be shared after termination. Regardless, my calculations use profits for AEP Ohio reflected

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[52] Pearce Direct, pp. 17-18.

[53] Pearce Direct, p. 13, lines 9-21.

on FERC Form 1, and these data reflect AEP Ohio margins after allocation under the Pool Agreement.

Q. WERE PROFITS FROM ENERGY OFF-SYSTEM SALES FOR RESALE TYPICALLY RETURNED TO CUSTOMERS?

A. Yes. Under a fully-regulated system, in which there was no retail competition, such an arrangement makes sense, because the combined system's generating units are dispatched in such a way that all members benefit. In other words, using the combined system of generating units allows the pool members to meet their customers' needs at a lower cost than if each operated separately. In that way, off-system sales profits were shared among the member companies and, importantly, the benefits were returned to customers. In essence, this was a *quid pro quo* of traditional utility regulation: customers guaranteed the utility's costs, and the utility returned any additional profits it made with off system sales to its customers.

With retail competition, however, this is no longer the case for AEP Ohio distribution customers. Instead, AEP Ohio proposes to recover a portion of its embedded capacity costs from CRES providers and recover the same portion from off-system energy sales. Thus, AEP Ohio wants captive CRES providers and, thus, its non-SSO distribution customers to guarantee recovery of all of its embedded capacity costs, and it wants to recover some of those same costs from off-system energy sales. Not only would this mean AEP Ohio would earn more than the 11.15% return on equity it proposes in its formula rate, it violates the basic *quid pro quo* associated with embedded cost pricing that AEP Ohio seeks.

Q. IS THE FACT THAT AEP OHIO SHARES PROFITS WITH OTHER POOL MEMBERS RELEVANT TO AEP OHIO'S PROPOSAL TO KEEP ALL OF THE PROFITS FROM OFF-SYSTEM ENERGY SALES FOR RESALE?

A. No. Whatever profits AEP Ohio earns from energy off-system sales offset its embedded capacity costs and, therefore, all of these profits should offset any embedded capacity cost charge. Furthermore, as shown in Exhibit JAL-2, AEP Ohio's reported off-system energy sales for resale revenues already account for revenue sharing under the Pool Agreement.

Q. HOW DO YOU ESTIMATE THE CONTRIBUTION TO EMBEDDED CAPACITY COSTS FROM ENERGY SALES FOR RESALE?

A. All of the revenues from energy sales for resale that exceed variable (or marginal) costs contribute to embedded costs by definition. For example, suppose that AEP Ohio's energy revenues from energy sales for resale total $200 million more than total fuel and variable O&M expenses recorded for these sales. In that case, AEP Ohio has now earned $200 million of profits that also recover its embedded capacity costs and contribute to its return on rate base. If AEP Ohio does not subtract this $200 million profits from energy-related sales from its formula rate capacity cost estimate, the company's "Annual Production Cost" estimates, which are what AEP Ohio uses to set the capacity prices that it proposes to use to charge customers for PJM-related capacity costs, will be overstated by $200 million. Thus, I have estimated the actual profits from energy-related sales for resale made by AEP Ohio in 2010, using the CSP and OPC 2010 FERC Form-1 Reports.

Q. WHAT REVENUES DID AEP OHIO EARN FROM ENERGY-RELATED SALES FOR RESALE IN 2010?

A. According to data published in CSP's and OPC's respective FERC Form-1 filings for 2010, the revenues from CSP's total non-requirements ("non-RQ") energy-related sales for resale were $295,218,916.[54] OPC's revenues from energy-related sales for resale were $778,113,468.[55] Based on AEP Ohio's response to Interrogatory FES-2-12, these reported revenues reflect AEP Ohio's share of total revenues under the Pool Agreement. The difference between these revenues and each utility's respective variable O&M and fuel costs associated with those off-system energy-related sales represents dollars that, by definition, recover embedded generating costs and provide AEP Ohio with an additional return on that capacity investment. Below, I present my estimate of the profits AEP Ohio earned in 2010 from these energy off-system sales.

Q DOES THE FORMULA RATE INCLUDE AN ALLOWED RETURN ON RATE BASE?

A. Yes. Thus, suppose AEP Ohio did not sell any of the energy generated by its generating resources, and only sold capacity. In that case, the $355.72/MW-day formula rate value estimated by Dr. Pearce would provide AEP with an allowed 11.15% return on equity and an overall 8.62% return on capital investment for OPC generating resources.[56] By retaining all or a portion of the profits from energy sales, AEP Ohio's realized return on equity and actual return on investment will be higher than the 11.15% allowed return in the formula rate.

Q. WHY IS EARNING A HIGHER RETURN PROBLEMATIC?

A. The 11.15% return on equity and 8.62% overall return on investment ("ROI") presumably are set on the basis of risk-comparability. For regulated firms, that is a long-

[54] Source: CSP FERC Form-1 2010, p. 311, and Exhibit KDP-3, page 4, line 6.

[55] Source: OPC FERC Form-1 2010, p. 311, and Exhibit KDP-4, page 4, line 6.

[56] *See* Exhibit KDP-2, page 11. For CSP, the return on investment is shown as 8.63% because of a slight difference in capital structure. *See* Exhibit KDP-1, page 11.

standing requirement.[57] What this means is that a regulated firm, such as an electric utility, is allowed to earn a return on its investment that is comparable to other firms facing the same level of business and financial risks. Under AEP Ohio's proposed formula rate, which allows for that comparable return plus additional revenues not counted by the formula, the company essentially has guaranteed itself an above-market return.

Q. CAN YOU EXPLAIN WHY AEP OHIO GUARANTEES ITSELF AN ABOVE-MARKET RETURN?

A. Yes. AEP Ohio witness Pearce's embedded capacity cost estimates include an overall 8.62% ROI and 11.15% ROE. The total after-tax return for both CSP and OPC is $440.4 million.[58] Mr. Pearce argues that AEP Ohio should be allowed to keep 100% of the returns from off-system energy sales. As shown in Table 6 below, I estimate those to be $178 million. On an after-tax basis, that amount would be about $108.6 million, based on an overall 39% tax rate. So, rather than earning an after tax return of $440.4 million, AEP Ohio proposes that it should earn $549 million. That implies an overall return on ratebase of 10.75% and, based on AEP Ohio's capital structure,[59] an overall ROE of 15.13%.[60] That return on equity is higher than the risk-comparable return of 11.15%. In fact, it would provide AEP Ohio with a 35% increase over its allowed return.

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[57] *Federal Power Comm'n. v Hope Natural Gas Co*., 323 U.S. 591 (1944).

[58] *See* Exhibits KDP-3 and KDP-4, p. 4, line 1. For CSP, the return is $129.1 million. For OPC, the return in $311.3 million.

[59] *See* Exhibits KDP-3 and KDP-4, p. 11, line 4.

[60] The calculation is as follows, using AEP Ohio's weighted average cost of debt of 2.67%, and weighted cost of preferred stock of 0.01%, and an overall equity percentage of 53.32%, based on the amounts shown in Exhibits KDP-3 and KDP-4, page 11, line 1. Then, 10.75% = 2.67% + 0.01% + (0.5332) *x* ROE, or ROE = [10.75% - 2.67% - 0.01%] / (0.5332) = 15.13%.

Q. HAVE YOU ESTIMATED THE REVENUES FROM ENERGY-RELATED SALES FOR RESALE THAT CONTRIBUTED TO AEP OHIO'S EMBEDDED GENERATION COSTS?

A. Yes. The details of my calculations for CSP and OPC are shown in Table 6, below. For each company, I began by determining the total variable costs associated with its power production expenses, using the FERC accounts shown in Table 4, which are the accounts AEP Ohio classifies as variable costs.[61]

Table 4: FERC Energy-Related Power Production Expense Accounts

FERC Account	Account Description
Steam Power Generation	
501	Fuel
502	Steam from Other Sources
504	Steam Transfers (Credit)
509	Emissions Allowances
510	Maintenance Supervision and Enginnering
512	Maintenance of Boiler Plant
513	Maintenance of Electric Plant
Hydraulic Power Generation	
544	Maintenance of Electric Plant
Other Power Generation	
547	Fuel

Q. HOW DID YOU ACCOUNT FOR DEFERRED FUEL COSTS?

A. Deferred fuel costs, as shown in Table 5, are reported in the FERC Form-1 reports under Account 182.3 "Other Regulatory Assets." Because AEP Ohio is no longer deferring fuel costs as of January 1, 2012, deferred fuel costs recorded under FERC Account No. 182.3 should be included when estimating energy off-system sales margins.

[61] *See* Exhibit KDP-1, p. 15.

Table 5: Deferred Fuel Costs, 2010

Company	2010 Debits	2010 Credits	Net Change
	[1]	[2]	[3]
CSP	$73,901,892	$95,694,224	($21,792,332)
OPC	$425,038,963	$271,396,141	$153,642,822
AEP Ohio Total	**$498,940,855**	**$367,090,365**	**$131,850,490**

Source: CSP, OPC 2010 FERC Form-1 Reports. P. 232.1, Line 12.

As Table 5 shows, total deferred fuel costs were just under $132 million for both companies. However, CSP's deferred fuel cost quantity actually decreased in 2010 by almost $22 million. I used the values in column [3] of Table 5 to adjust the fuel cost expenditures recorded in Account 501.

Using CSP's and OPC's FERC Form-1 filings for the year ended December 31, 2010, I determined total energy-related power production expenses. I then determined an average energy-related cost/MWh of generation for the year, based on reported total generation, as shown in the Electric Energy Accounts, page 401a of each company's FERC Form-1. Using this value as the energy-only cost per MWh, I then calculated total energy-related power production expenses associated with sales for resale, based on the total non-requirement energy-related sales for resale, as recorded in Account No. 447, which already reflect revenue sharing under the AEP Pool Agreement. I then subtracted this value from the off-system energy sales revenues reported by AEP Ohio for CSP and OPC in Exhibits KDP-3 and KDP-4. Because two of CSP's generating plants—Waterford and Darby—were constructed after the January 1, 2001 transition date, I adjusted the net contribution to embedded costs from energy sales from these plants. In that way, my revised capacity cost estimate is consistent with incorporating only pre-transition GPIS.

As shown in more detail in Table 6 below, I estimated that CSP's pre-2001 generating plants contributed $81,943,703 towards recovery of embedded costs, and that OPC's generating plants contributed $96,133,764 towards recovery of embedded costs, or $178,077,466 of embedded cost recovery in the aggregate, for which AEP Ohio would double-recover by charging its reported embedded cost capacity value. Because AEP Ohio is clearly not allowed to double-recover embedded costs, it is wrong to claim that ratepayers "benefit" if AEP Ohio does not do so.

Table 6: 2010 Contribution to Embedded Capacity Costs from Off-system Energy Sales

Line No.	Type	FERC Account	CSP	OPC	TOTAL
	Steam Power Generation				
[1]	501	Fuel	**$ 345,294,261**	**$ 1,146,205,314**	$ 1,491,499,575
[2]	503	Steam from Other Sources	$ -	$ -	$ -
[3]	504	Steam Transfers (credit)	$ -	$ -	$ -
[4]	509	Emissions Allowances	$ 5,727,736	$ 8,473,508	$ 14,201,244
[5]	510	Maintenance Supervision and Engineering	$ 2,327,198	$ 12,473,218	$ 14,800,416
[6]	512	Maintenance of Boiler Plant	$ 44,791,005	$ 107,219,065	$ 152,010,070
[7]	513	Maintenance of Electric Plant	$ 7,662,253	$ 22,984,446	$ 30,646,699
	Hydraulic Power Generation				
[8]	544	Maintenance of Electric Plant	$ -	$ 2,051,934	$ 2,051,934
	Other Power Generation				
[9]	547	Fuel	$ 2,928,243	$ -	$ 2,928,243
[10]	**Total Energy-related Production Costs**		**$ 408,730,696**	**$ 1,299,407,485**	**$ 1,708,138,181**
[11]	**Total Power Production (MWh)**		12,521,147	48,768,500	$ 61,289,647
[12]	*Power production - post-2001 GPIS (MWh)*		641,627	-	641,627
[13]	**Net pre-2001 GPIS power production (MWh)**		**11,879,520**	**48,768,500**	**60,648,020**
[14]	**Average energy-only production costs ($/ MWh)**		$ 32.6432	$ 26.6444	$ 27.8699
[15]	**Total Reported Energy Sales for Resale (MWh)**		6,397,937	25,595,610	31,993,547
[16]	**Estimated Variable Production Costs, Sales for Resale**		$ 208,849,336	$ 681,979,704	$ 890,829,041
[17]	**Total Reported Energy-related Revenues from Sales for Resale**		$ 295,218,916	$ 778,113,468	$ 1,073,332,384
[18]	**Net Contribution to Embedded Generation Costs**		**$ 86,369,580**	**$ 96,133,764**	**$ 182,503,343**
[19]	**Adjustment for post-2001 GPIS production**		**$ 4,425,877**	**$ -**	**$ 4,425,877**
[20]	**Net Contribution to Embedded Generation Costs, pre-2001 GPIS**		**$ 81,943,703**	**$ 96,133,764**	**$ 178,077,466**

Notes:

[1] Source: 2010 FERC Form-1 Report, pp. 320-21, plus deferred fuel costs reported in Acct. 182.3.
[2] Source: Table 5, line 20.
[3] Source: 2010 FERC Form-1 Report, pp. 320-21.
[4] Source: 2010 FERC Form-1 Report, pp. 320-21.
[5] Source: 2010 FERC Form-1 Report, pp. 320-21.
[6] Source: 2010 FERC Form-1 Report, pp. 320-21.
[7] Source: 2010 FERC Form-1 Report, pp. 320-21.
[8] Source: 2010 FERC Form-1 Report, pp. 320-21.
[9] Source: 2010 FERC Form-1 Report, pp. 320-21.
[10] Equals: [1] + [2] + ... + [9].
[11] Source: 2010 FERC Form-1 Report, p. 401a.
[12] Source: 2010 FERC Form-1 Report, p. 403.1.
[13] Equals: [11] - [12].
[14] Equals: [10] / [11].
[15] Source: 2010 FERC Form-1 Report, p. 311. (Non-requirements only)
[16] Equals: [14] x [15].
[17] Source: 2010 FERC Form-1 Report, p. 311. (Non-requirements only)
[18] Equals: [17] - [16].
[19] Equals: ([12] / [11]) x [18].
[20] Equals: [18] - [19].

Q. PLEASE DESCRIBE HOW YOU REVISED AEP OHIO'S FORMULA RATE ESTIMATE OF ITS CAPACITY COSTS TO ACCOUNT FOR PRE-2001 GENERATING PLANT.

A. In addition to correcting for double-recovery of embedded generation costs, I recalculated the capacity cost based on depreciation for pre-2001 GPIS only. I also accounted for the additional depreciation of existing generating plant that was in service on January 1, 2001 to determine the net undepreciated value of that generating plant as of December 31, 2010, because it is the undepreciated value that determines the "rate base," and return on that rate base. I then adjusted the income tax payments because, with a lower return on rate base, the income tax paid on that return would also decrease. Furthermore, to be conservative, I did not subtract out AEP Ohio's Allowance for Deferred Income Taxes ("ADIT"), as Mr. Pearce does in computing total rate base.[62]

Q. WHAT ARE YOUR REVISED CAPACITY COST ESTIMATES FOR CSP AND OPC?

A. My revised embedded capacity cost estimates are shown in Table 7. As can be seen, the overall average embedded capacity cost value for AEP Ohio is $77.53/MW-day, which is less than the $88.36/MW-day average of the PJM RPM market-clearing prices for the period June 2011 – May 2015. It is this $78.53/MW-day amount that AEP Ohio would be entitled to receive under an embedded cost formula rate, not $355.72/MW-day as Dr. Pearce estimates.

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[62] *See* Pearce Exhibits KDP-3 and KDP-4, p. 5, line 5. I also did not include an allowance for working capital. However, the $86.5 million total working capital shown by Pearce for materials and supplies (line 14), prepayments (line 15c) and cash working capital (line 16) is far less than the $352.8 million subtracted for ADIT. The reason I exclude both of these items is that it would be difficult to go back to January 1, 2001 and project what they would be ten years later absent AEP Ohio's post-2001 capital investments in generating plant.

Table 7: Revised Embedded Capacity Cost Estimates

Line No.	Item	CSP	OPC	TOTAL
[1]	Annual Production Fixed Cost, as Reported	$477,093,822	$660,504,310	**$1,137,598,132**
[2]	(Energy-only contribution to embedded costs adjustment)	($81,943,703)	($96,133,764)	($178,077,466)
	Depreciation Expense Adjustment			
[3]	*Depreciation Expense , as Reported*	$59,590,281	$256,957,852	**$316,548,133**
[4]	*Annual Depreciation Expense, GPIS 12/31/2000*	$49,879,103	$93,139,354	**$143,018,457**
[5]	***Calculated Depreciation Rate Adjustment***	***($9,711,178)***	***($163,818,498)***	***($173,529,676)***
	Return on Rate Base Adjustment			
[6]	*Return on Rate Base, as Reported*	$129,071,540	$311,327,830	**$440,399,370**
[7]	*Allowed Return*	8.63%	8.62%	
[8]	*Return on Net GPIS 12/31/2000, as of 12/31/2010*	$36,139,860	$24,265,334	**$60,405,194**
[9]	***Calculated Return on Rate Base Adjustment***	***($92,931,680)***	***($287,062,496)***	***($379,994,176)***
	Income Tax Adjustment			
[10]	*Income Tax Expense , as Reported*	$45,891,012	$123,339,938	**$169,230,950**
[11]	*ITC, as Reported*	($1,658,786)	($407,172)	**($2,065,958)**
[12]	*Income Tax Rate*	36.8399%	39.7482%	
[13]	*Income Tax on Adjusted Return on Rate Base*	$13,313,888	$9,645,034	**$22,958,922**
[14]	*ITC, Revised Based on 12/31/2000 GPIS*	($1,658,786)	($407,172)	($2,065,958)
[15]	***Calculated Income Tax Adjustment***	***($32,577,124)***	***($113,694,904)***	***($146,272,028)***
[16]	**Total Adjustments to Annual Production Cost, as Reported**	**($217,163,685)**	**($660,709,662)**	**($877,873,347)**
[17]	**Revised Annual Production Costs**	**$259,930,137**	**($205,352)**	**$259,724,785**
[18]	5 CP Coincident Peak Demand (MW)	4,126.2	4,934.6	9,060.8
[19]	**Revised Daily Capacity Cost ($/MW-day)**	**$172.59**	**($0.11)**	**$78.53**

Notes:

[1] Source: Exhibit KDP-3, p. 4 and KDP-4, p. 4.
[2] Source: Table 5, line 20.
[3] Source: Exhibit KDP-3, p. 4 and KDP-4, p. 4.
[4] Source: Table 3, line 5.
[5] Equals: [4] - [3].
[6] Source: Exhibit KDP-3, p. 4 and KDP-4, p. 4.
[7] Source: Exhibit KDP-3, p. 5 and KDP-4, p. 5.
[8] Equals: [Table 3, line 7] x [7].
[9] Equals: [8] - [6].
[10] Source: Exhibit KDP-3, p. 18 and KDP-4, p. 18.
[11] Source: Exhibit KDP-3, p. 18 and KDP-4, p. 18.
[12] Source: Exhibit KDP-3, p. 18 and KDP-4, p. 18.
[13] Equals: [12] x [8].
[14] No material change to ITC estimate.
[15] Equals: {[13] - [10] } + {[14] - [11]}.
[16] Equals: [2] + [5] + [9] + [15].
[17] Equals: [1] + [16]
[18] Source: Exhibit KDP-3, p. 2 and KDP-4, p. 2.
[19] Equals: [17] / [18] / 365.

Q. TABLE 7 SHOWS THAT THE EMBEDDED CAPACITY COST FOR OPC IS NEGATIVE $0.11/MW-DAY. HOW IS THAT POSSIBLE?

A. The reason is that OPC's generating assets are heavily depreciated. Therefore, the earnings from these units from both capacity and off-system energy sales more than cover pre-2001 embedded capacity costs. Clearly, no one is going to require OPC to pay

$0.11/MW-day to "give away" its capacity. This also illustrates another reason why market pricing of capacity it preferable. Charging the RPM market price for capacity allows OPC to earn far higher profits on its capacity units than based on its pre-2001 embedded costs would allow.

Q. ARE YOU ABLE TO ESTIMATE A REVISED EMBEDDED CAPACITY COST FOR 2011?

A. No. Because AEP Ohio is not scheduled to release its 2011 FERC Form 1 Report until April 18, 2012, it is not possible to perform this calculation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However I reserve the right to supplement my testimony as new information subsequently becomes available or in response to positions taken by other parties.

Exhibit JAL-5

AEP OHIO Fact Sheet

Information

Operating Information

Total customers:	1, 499,693		
* Residential	1, 308,552	* Commercial	177,408
* Industrial	10, 751	* Other	2,982

2010 electrical sales in megawatt-hours:	49,738,867
Average use per residential customer:	12,504 kwh per year (OP) 12,898 kwh per year (WP) 11,701 kwh per year (CSP)
Average cost per kilowatt-hour (residential):	9.70 cents (OP) 8.32 cents (WP) 11.32 cents (CSP)
Communities served:	1,126
Net plant in service:	$9.8 billion $0.106 billion (WP)
Size of distribution system:	47,540 miles
Size of transmission system:	9,248 circuit miles
Total number of AEP Ohio employees:	2,992

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A unit of American Electric Power

AEP Ohio Management Team

Joe Hamrock:	President & COO
Tom Kirkpatrick:	Vice President, Distribution Region Operations
Selwyn Dias:	Vice President, Finance & Regulatory
Tom Froehle:	Vice President, External Affairs
Karen Sloneker:	Director, Customer Services & Marketing
Matt Kyle:	Director, Business Operations Support
Terri Flora:	Director, Communications
Dan Boezio	Director Transmission Region Operations
Derek Carson:	Manager, Safety & Health

Top Customers (by revenue)*

Ormet Primary Aluminum Corporation

The Timken Company

Republic Engineered Products, LLC

Premcor Refining Group, LLC

The Ohio State University

Globe Metallurgical, Inc.

Consol Energy

PPG Industries, Inc.

Eramet Marietta, Inc.

Marathon Petroleum Company, LLC

* 12 month ending May 31, 2011

Exhibit JAL-5

AEP OHIO Fact Sheet

Financial Information

2010 Operating Revenue:	$ 5.6 billion
2010 Net Income:	$567.2 million
2010 Ohio Taxes Paid:	$164.4 million
2010 Local Taxes Paid:	$182.4 million
2010 West Virginia Taxes Paid:	$ 17.9 million

Generating Stations

Total Generating Capacity: 12,216 MW

Name	Location	Units	Capacity	Special Note
Gen. J.M. Gavin	Cheshire, Ohio	2	2,600 MW	SCR/FGD systems
Mitchell	Moundsville, W.Va	2	1,600 MW	SCR/FGD systems
Muskingum River	Beverly, Ohio	5	1,425 MW	SCR, Unit 5
Conesville	Conesville, Ohio	4	1,304 MW*	FDG units 4-6, SCR Unit 4 Unit 4 co-owned by DP&L/Duke
John E. Amos	St. Albans, W.Va	1	867 MW	FDG/SCR systems OP owns 2/3 of Unit 3 with APCO
Waterford	Waterford, Ohio	4	850 MW	Natural gas-fired combined cycle
Philip Sporn	New Haven, W.Va	3	750 MW	APCo owns 1 & 3
Kammer	Moundsville, W.Va	3	630 MW	
J.M. Stuart	Aberdeen, Ohio	4	624 MW	Co-owned by DP&L/Duke (OP 26%)
Cardinal	Brilliant, Ohio	1	580 MW	Two other units owned by Buckeye Power FDG/SCR systems
Darby	Mount Sterling, Ohio	6	480 MW	Natural gas-fired simple cycle
Wm. H. Zimmer	Moscow, Ohio	1	330 MW	Co-owned by DP&L/Duke (OP 25.4%)
Picway	Lockbourne, Ohio	1	100 MW	
Beckjord	New Richmond, Ohio	1	54 MW	Co-owned by DP&L/Duke (OP 12.5%)
Racine	Racine, Ohio	1	25 MW	Hydro plant

* Conesville Plant retired its units 1 and 2 in 2005, lowering the plant's active units to four and overall megawatt capacity to 1,745.

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A unit of American Electric Power

Introduction to the Input-Output Model Framework and how it is Used to Estimate the Economic Impacts of Increased Electric Costs in Ohio

1. Mathematics of the Input-Output Framework[1]

An input-output framework begins with observed transaction data for a particular region. For example, the IMPLAN model is constructed from data at the national, state, and county levels. The transactions are typically converted into dollar amounts, as that makes tracing economic flows much easier, since dollars are a uniform measure.

We assume that the economy is made of up of numerous sectors, e.g., manufacturing, mining, agriculture, services, government, and foreign trade. To construct an input-output table, we record how the output produced (supplied) by a given sector, such as steel, is purchased by (demanded) the other industry sectors (who then use those purchased inputs to manufacture other goods), plus external sales to government and consumers. Thus, if there the economy consists of N industries, the total output produced by an individual industry, X_k, will be purchased by the other N–1 industries, used by itself, and sold to final consumers. Thus,

$$X_k = z_{k,1} + z_{k,2} + z_{k,3} + \ldots + z_{k,N} + Y_k \tag{1}$$

where the $z_{i,n}$ are sales to each industry n, and Y_k equals sales for final demand (i.e., to consumers, the government, and for export). Since we have N industries, we can write the entire set of flows as

$$\begin{bmatrix} X_1 = z_{1,1} + z_{1,2} + \ldots + z_{1,k} + \ldots + z_{1,N} + Y_1 \\ X_2 = z_{2,1} + z_{2,2} + \ldots + z_{2,k} + \ldots + z_{2,N} + Y_2 \\ \vdots \\ X_k = z_{k,1} + z_{k,2} + \ldots + z_{k,k} + \ldots + z_{k,N} + Y_k \\ \vdots \\ X_N = z_{N,1} + z_{N,2} + \ldots + z_{N,k} + \ldots + z_{N,N} + Y_N \\ \end{bmatrix} \tag{2}$$

Each column of coefficients on the right-hand side of equation (2), i.e.,

[1] For a far more detailed discussion, see Leontief, *op. cit*. See also, R. Miller and P. Blair, *Input-Output Analysis: Foundations and Extensions*, (Englewood Cliffs, NJ: Prentice-Hall 1985), Chp. 2.

$$\begin{bmatrix} z_{1,k} \\ z_{2,k} \\ \vdots \\ z_{k,k} \\ \vdots \\ z_{N,k} \end{bmatrix}$$

represents the purchases from industry sector k to the N–1 other industry sectors, and to itself ($z_{k,k}$). In other words, industry k purchases inputs from all of the other industries to produce output X_k. When all of the N different columns are combined, they create an *input-output table*, with each selling sector a different row, and each purchasing sector a different column, as shown in Table 1.

Table 1: An Input-Output Table

		Purchasing industry sector					
		1	**2**	**…**	**K**	**…**	**N**
	1	$Z_{1,1}$	$Z_{1,2}$	…	$Z_{1,k}$		$Z_{1,N}$
Selling	**2**	$Z_{2,1}$	$Z_{2,2}$	…	$Z_{2,k}$		$Z_{2,N}$
Industry	⋮	⋮	⋮		⋮		⋮
Sector	**k**	$Z_{k,1}$	$Z_{2,k}$	…	$Z_{k,k}$		$Z_{N,k}$
	⋮	⋮	⋮		⋮		⋮
	N	$Z_{N,1}$	$Z_{N,2}$	…	$Z_{N,k}$		$Z_{N,N}$

Although the input-output table above incorporates all of the inter-industry sales and purchases, it does not account for the remainder of the economy. For example, final demand includes sales to consumers, state, local, and the federal government, investment, and exports. Moreover, in addition to buying outputs from other industries, each industry pays wages to its employees (W), pays for government services (in the form of taxes), pays for capital (in the form of interest payments, I), and profits. Together, these components are called *value-added*. On top of that, each sector imports goods and services from outside the economy. For example, if building a new high-voltage transmission line requires buying substation equipment from Germany, then the input-output model for the U.S. would consider that an import.

The input-output framework assumes that production coefficients are fixed. This means that there are specific quantities of inputs required to produce a given output. Thus, building a car—any car—is assumed to take (say) 2000 pounds of steel, 100 pounds of rubber, 200 pounds of glass, and so forth. Obviously, this assumption of fixed production coefficients does not hold true entirely—the amount of materials needed to build a large pick-up truck is greater than that needed to built a subcompact car—but for estimating short-run impacts, the overall assumption is reasonable: building more cars and trucks will clearly require more steel, producing more steel will require more iron ore, and so forth.

Because the input-output framework assumes fixed production coefficients (called a "Leontief production function"), the necessary inputs needed to produce a unit of output are all constant. If we divide the purchases made by industry k from every industry, i.e., the $z_{i,k}$, to produce output X_k, we derive the *technical coefficients, $a_{i,k}$*, for industry k. In other words,

$$a_{i,k} = \frac{Z_{i,k}}{X_k} \tag{3}$$

If we substitute equation (3) into equation (2), we obain:

$$\begin{bmatrix} X_1 = a_{1,1}X_1 + a_{1,2}X_2 + \ldots + a_{1,k}X_k + \ldots + a_{1,N}X_N + Y_1 \\ X_2 = a_{2,1}X_1 + a_{2,2}X_2 + \ldots + a_{2,k}X_k + \ldots + a_{2,N}X_N + Y_2 \\ \vdots \\ X_k = a_{k,1}X_1 + a_{k,2}X_2 + \ldots + a_{k,k}X_k + \ldots + a_{k,N}X_N + Y_n \\ \vdots \\ X_N = a_{N,1}X_1 + a_{N,2} + \ldots + a_{N,k}X_k + \ldots + a_{N,N}X_N + Y_N \end{bmatrix} \tag{4}$$

What equation (4) tells us is that some of the output produced by an industry is sold to all other industries and used in fixed quantities to produce those industries' outputs, and the remainder is sold as final demand to consumers, government, and as exports. As a final step, we isolate the final demands for the output from each industry, Y_k. Thus,

$$\begin{bmatrix} X_1 - a_{1,1}X_1 + a_{1,2}X_2 + \ldots + a_{1,k}X_k + \ldots + a_{1,N}X_N = Y_1 \\ X_2 - a_{2,1}X_1 + a_{2,2}X_2 + \ldots + a_{2,k}X_k + \ldots + a_{2,N}X_N = Y_2 \\ \vdots \\ X_k - a_{k,1}X_1 + a_{k,2}X_2 + \ldots + a_{k,k}X_k + \ldots + a_{k,N}X_N = Y_n \\ \vdots \\ X_N - a_{N,1}X_1 + a_{N,2} + \ldots + a_{N,k}X_k + \ldots + a_{N,N}X_N = Y_N \end{bmatrix} \tag{5}$$

Equation (5) lies at the heart of the economic impact analysis, because it allows us to answer the question, "If the demand for the output of industry k changes, by how much would the output of all of the other industries change?" For example, building a new high-voltage transmission line would increase the demand for concrete, steel, and so forth. How will these changes in demand ripple through the Ohio economy and what will be the final changes in output levels in all other industries, as well as the change in total labor (i.e., jobs) and income?

To answer this sort of question, we solve equation (5) for each of the X_i. This requires a bit of matrix algebra. It turns out that the solution can be written as

$$\mathbf{X} = (\mathbf{I} - \mathbf{A})^{-1}\mathbf{Y} \tag{6}$$

where

$$\mathbf{A} = \begin{bmatrix} a_{1,1} \cdots a_{1,N} \\ a_{2,1} \cdots a_{2,N} \\ \vdots \\ a_{k,1} \cdots a_{k,N} \\ \vdots \\ a_{N,1} \cdots a_{N,N} \end{bmatrix}, \qquad \mathbf{X} = \begin{bmatrix} X_1 \\ X_2 \\ \vdots \\ X_k \\ \vdots \\ X_N \end{bmatrix}, \qquad \mathbf{Y} = \begin{bmatrix} Y_1 \\ Y_2 \\ \vdots \\ Y_k \\ \vdots \\ Y_N \end{bmatrix}$$

The matrix $(\mathbf{I} - \mathbf{A})^{-1}$ is called the *Leontief inverse*. By changing the level of final demand in the output vector **Y** and knowing the technical coefficients $a_{i,k}$, we can determine the flows through the economy.

There are three types of economic impacts typically evaluated in an input-output study: *direct*, *indirect*, and *induced*. Direct effects are those that are a direct result of an increase in demand for good k. For example, building a new high-voltage transmission line will require concrete for the tower foundations. Thus, the demand for concrete will increase. That is a *direct* impact. Increasing the demand for concrete, however, will require concrete manufacturers to increased their purchases of all of the inputs used to manufacture concrete, including sand, gravel, electricity, and so forth, thus increasing the demand for all of those inputs. Thus, the *direct* increase in the demand for concrete *indirectly* increases the demand for all of these other products. Finally, all of these manufacturers pay wages to employees. Those employees, in turn spend a portion of their wages on food, electricity, new cars, and so forth. As a result, we say the resulting consumer spending from households *induces* further increases in demand, and thus additional economic impacts.

Because of the interconnections among industries and between industries and households, an increased demand for just one good or service is said to cause *ripple effects* throughout the economy. These ripple effects lead to additional jobs and increases disposable income as workers are hired, equipment and supplies are purchased from other local businesses, wages are paid to employees, and taxes are paid to government entities. These impacts are called *multiplier effects* or *multipliers*. For example, if the demand for concrete increases by $1 million and the overall impact on the Ohio economy is $2 million, then the output multiplier equals $2million/$1 million = 2.0. We can also calculate jobs and income multipliers. For example, if 100 workers are hired to construct a transmission line, and the overall ripple effects lead to 50 new jobs created as a result, the employment multiplier will equal 150/100 = 1.5.

2. Estimating economic impacts

Ripple effects act like waves bouncing off walls. Eventually, each subsequent round of impacts decreases in magnitude, just like a wave bouncing off walls eventually subsides. The speed at which these ripple effects diminish, and the overall magnitude of multipliers, depends on what are called *leakages* out of an economy. For example, not all of the materials needed to build the transmission line will be purchased from Ohio companies. Moreover, some of the workers hired to construct the project may be from outside the state. Furthermore, Ohio workers who are hired will not spend all of their wages within the state, but will instead buy goods and services from neighboring states, too. As we discuss in the sections that follow, assumptions about *leakage rates*, i.e., what fraction of spending occurs outside Ohio, are crucial in estimating the overall economic impacts to the state.

a. Calculating multipliers[2]

Multipliers are calculated from the Leontief inverse matrix defined previously. For example, suppose we have an economy with just two industries, industry **X** and industry **Y**, with the following technical coefficients matrix.

$$\mathbf{A} = \begin{bmatrix} 0.15 & 0.25 \\ 0.20 & 0.05 \end{bmatrix} \tag{7}$$

What this means is that to produce \$1 of additional output, industry **X** purchases \$0.15 from itself and \$0.20 from industry **Y**. The remaining \$0.65 is accounted for through valued added – wages and salaries paid to employees, taxes paid to federal, state, and local governments, and profits. Similarly, to produce \$1 of additional output, industry **Y** purchases \$0.25 from industry **X**, \$0.05 from itself, and the remaining \$0.70 is value added. It turns out the Leontief inverse matrix (ignoring the value added impacts) is

$$(\mathbf{I} - \mathbf{A})^{-1} = \begin{bmatrix} 1.254 & 0.33 \\ 0.264 & 1.122 \end{bmatrix} \tag{8}$$

The values in the Leontief inverse provide the output multipliers, by adding up each column. Specifically, if there is a \$1 increase in final demand for the output of industry **X**, then the total increase in demand for output of industry **X** is \$1.254 - \$1 for the increase in final demand, and \$0.254 for inter-industry and intra-industry use. There is also an *indirect* increase in demand of

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2 For a much more detailed discussion, see Miller and Blair, fn. 1, from which these examples are drawn.

\$0.264 of industry **Y** for inter-industry and intra-industry use. Thus, if we sum down the first column, a \$1 increase in demand for industry **X** leads to a total increase in output of \$1.254 + \$0.264 = \$1.518. The output multiplier for industry **X** is thus \$1.518/\$1 = 1.518. Because we are not considering households in this example, this output multiplier is called a *Type I* multiplier.

Next, we consider household impacts, such as from wages paid to households. Suppose that industry 1 **X** pays \$0.30 in wages per dollar of output and that industry 2 pays \$0.25 in wages per dollar of output. By incorporating these payments into the technical coefficients matrix, we can determine the direct, indirect, and *induced* impacts from increased output. So, we rewrite the technical coefficients matrix as follows:

$$\mathbf{A} = \begin{bmatrix} 0.15 & 0.25 & 0.05 \\ 0.20 & 0.05 & 0.40 \\ 0.30 & 0.25 & 0.05 \end{bmatrix} \qquad (\mathbf{I}-\mathbf{A})^{-1} = \begin{bmatrix} 1.365 & 0.425 & 0.251 \\ 0.527 & 1.348 & 0.595 \\ 0.570 & 0.489 & 1.289 \end{bmatrix} \tag{9}$$

The new technical coefficients matrix **A** now contains 3 rows and 3 columns. The 2x2 matrix of values in the top left hand corner is the original matrix shown in equation (7). The third column represents households. So, in the example, households spend \$0.05 per dollar buying items from industry **X**, \$0.40 per dollar buying items from industry **Y**, and \$0.05 buying items from within the household sector. (The remainder is spent paying taxes and for investment.). The third row shows that industry **X** spends \$0.30 per dollar on wages, while industry **Y** spends \$0.25 per dollar on wages.

When we calculate the new Leontief inverse $(\mathbf{I}-\mathbf{A})^{-1}$, the first thing to notice is that the previous coefficients (the top-left 2x2 matrix) are all larger than they were in equation (8). This is because we are now including household demand impacts. Now, the output multiplier for industry **X** is the sum of the first column [1.365, 0.527, 0.570], or 2.462. Thus, for every \$1 increase in demand in industry **X**, total output in the local economy increases by \$2.462. The output multiplier for industry **X** is therefore 2.4262. In matrix notation, the output multiplier for industry *i* in our N-industry economy is:

$$M_{output,i} = \mathbf{i}_i \bullet (\mathbf{I}-\mathbf{A})^{-1} \bullet \mathbf{i}_i', \tag{10}$$

where $\mathbf{i}_i = \begin{bmatrix} 0 & \cdots & 1_j & \cdots & 0 \end{bmatrix}$.[3]

In our 2-industry example, we can calculate the household income multiplier for industry **X** in several ways. The first is to treat household spending as outside our model and estimate impacts using the Type 1 multipliers. To do that, we go back to the initial Leontief inverse in equation (8)

3 In other words, $\mathbf{i}_j$ is a 1xN unit vector having value 1 for industry j. The term $\mathbf{i}_j'$is called the *transpose* of $\mathbf{i}_i$, and is a Nx1 column vector.

and multiply the household income coefficients in **A** for our two industries (the third row) by the first column in the Leontief inverse, and add the results, i.e.,

$$H_X = (0.30)(1.254) + (0.25)(0.264) = 0.442$$

What this means is that, for every $1 increase in demand for the output of industry **X**, total household income increase by $0.442 because of the direct and indirect economic impacts on output. Thus, the *Type 1 multiplier* is $0.442/$0.30 = 1.47.

If we include the economic impact caused by households also spending money in the economy, the result is called a *Type II multiplier*. To do this, we use the new **A** and $(\mathbf{I–A})^{-1}$ matrices shown above. For industry **X**, we calculate the total household income change, including the within-household sector impacts and divide by $0.30 that industry 1 pays directly to households in the form of wages. Thus, we have

$$H'_X = (0.30)(1.365) + (0.25)(0.527) + (0.05)(0.57) = 0.570$$

and the multiplier is $H'_X/0.30$ = $0.57/$0.30 = 1.9. Note also that the overall household impact, $0.57 is just the value in the last row of the Leontief inverse matrix for industry **X**.

Finally, we estimate *employment multipliers*, following the same approaches previously outlined. Only this time, the multipliers do not reflect dollar changes, but changes in employment. To do this, one determines the number of employees (in full-time equivalents) per dollar of output in each industry. For example, suppose for each million dollars of output produced in industry **X**, 300 employees are required, and that in industry 2, 400 employees are used per million dollars of output. This translates to values of 0.003 and 0.004 employees per dollar in industries **X** and **Y**, respectively. Similarly, assume the household sector requires 100 employees per million dollars of output, or 0.001 employees per dollar. Then, using the Leontief inverse matrix in equation (9), we calculate the total employment impact for industry **X** as

$$E'_X = (0.003)(1.365) + (0.004)(0.527) + (0.001)(0.570) = 0.000572$$

Then, using the same approach as for calculating the Type II income multipliers, we can calculate the Type II employment multiplier for industry 1 as $E'_X/0.0003$ = 1.907. Thus, for every job added in industry **X**, a total of 1.907 jobs are added in the entire economy.

3. The IMPLAN Model

IMPLAN was first developed in the 1970s by the U.S. Forest service to analyze the economic impacts of different forestry policies. The current version of IMPLAN is maintained by the University of Minnesota IMPLAN group. IMPLAN provides a detailed breakdown of the U.S. economy, with over 500 separate economic sectors. IMPLAN is widely used by numerous government agencies, including at the federal and state levels.

The IMPLAN model begins with the most current national transactions matrix developed by the current National Bureau of Economic Analysis Benchmark Input-Output Model. Next, the model creates state and county-level values by adjusting the national level data, such as removing industries that are not present in a particular state or economy. The model also estimates imports using what are called *regional purchase coefficients* (RPCs). RPCs measure the proportion of the total supply of a good or service required to meet a particular industry's intermediate demands and final demands that are produced locally. The larger the RPC value, the greater the percentage of total regional demand that is met through local supplies.

In addition to calculating standard Type I and Type II multipliers, IMPLAN can also calculate what are called "SAM multipliers." SAM stands for "Social Accounts Matrix," and is a more detailed breakdown of transactions within an economy. Specifically, whereas the typical input-output framework captures production and consumption, it leaves out some income transactions, such as taxes, savings, and transfer payments. IMPLAN allows users to capture these components as well, and thus derive what are called SAM multipliers.[4] SAM multipliers are a form of Type II multiplier. Thus, SAM multipliers incorporate direct, indirect, and induced impacts, while accounting for the effects of savings, taxes, and transfer payments.

4. Estimating the economic impacts of higher electric prices

To estimate the overall economic impacts of the higher wholesale electric prices and higher capacity market costs, we assumed a short-run elasticity of zero. That is, we assumed consumers would not, initially, reduce their electric consumption in response to the slightly higher electric prices they faced. Since consumer income is assumed to be fixed in the short run, this implies consumers must reduce their expenditures on all other goods and services (including savings and investment) by an equivalent amount.

Similarly, we assumed that in-state businesses would react to the increased price of electricity by reducing their total output such that their aggregate production expenses remained unchanged. This assumption is consistent with the assumption of fixed production coefficients in the Leontief model. It also assumes that businesses would not be able to pass on the increased production costs to consumers.

b. Estimating the total impacts on state output

With these assumptions, we estimate the overall change in output as follows. First, we calculate a weighted-average *regional purchase coefficient* for output in the Ohio economy, excluding

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4 For complete discussion of how SAM multipliers are derived, see G. Alward, "Deriving SAM multipliers using IMPLAN," paper presented at the 1996 National IMPLAN Users Conference, Minneapolis, MN, August 15–17, 1996, 1996. Available at: http://implan.com/v3/index.php?option=com_docman&task=doc_download&Itemid=138&gid=127.

electric power. A regional purchase coefficient (RPC) equals the fraction of local demand for a good or service that is satisfied from local production. For example, in Ohio, about 47% of all ready-mix concrete was purchased from in-state manufacturers, based on 2008 data. The weighted RPC, RPC_{OH}, equals the sales-weighted average of the individual sector RPCs, <u>excluding</u> the electric generation sector (assumed to be sector k). Thus,

$$RPC_{OH} = \frac{\sum_{i=1, i\neq k}^{N} Q_i \cdot RPC_i}{\sum_{i=1, i\neq k}^{N} Q_i} \tag{11}$$

Similarly, we calculate the weighted-average SAM output multiplier, $\bar{M}_{OH}^{output}$, using the output from each industry as the individual industry weights. Thus, using equation (10) for the output multiplier for industry i, we have

$$\bar{M}_{OH}^{output} = \sum_{i=1, j\neq k}^{N} Q_i \cdot \{\mathbf{i_i} \bullet (\mathbf{I} - \mathbf{A})^{-1} \bullet \mathbf{i_i}'\} / \Delta Q_{OH}^{TOT} = \sum_{i=1, j\neq k}^{N} Q_i \cdot M_{output,i} / \Delta Q_{OH}^{TOT}, \tag{12}$$

The total impact on output in the state, ΔQ_{OH}^{TOT}, will equal the weighted RPC times the weighted output multiplier, times the estimated increase in total electric expenditures. Thus, if the total change in electric expenditures is ΔQ_{ELEC}, we have:

$$\Delta Q_{OH}^{TOT} = \Delta Q_{ELEC} \cdot RPC_{OH} \cdot \bar{M}_{OH}^{output} \tag{13}$$

c. Estimating the total impact on state employment

We can follow a similar procedure to estimate the total impacts on state employment arising from the higher electric expenditures, with the additional step of estimating the weighted average employment per million dollars of output, using the employment multipliers calculated by IMPLAN. Thus, the weighted jobs per million dollars of output can be written as:

$$\bar{J}_{OH} = \sum_{i=1, i\neq k}^{N} Q_i \cdot J_i / \Delta Q_{OH}^{TOT}, \tag{14}$$

where J_i is jobs per million dollars of output in industry i. Therefore, the overall weighted jobs multiplier is:[5]

[5] The jobs multiplier is just the output multiplier weighted by jobs per million dollars of output.

$$\bar{M}_{OH}^{jobs} = \sum_{i=1, i \neq k}^{N} Q_i \cdot J_i \{\mathbf{i_i} \bullet (\mathbf{I} - \mathbf{A})^{-1} \bullet \mathbf{i_i}'\}, \tag{15}$$

And so, the total impact on jobs in the state from the increased expenditures on electricity will equal:

$$\Delta J_{OH}^{TOT} = (\Delta Q_{ELEC} \cdot RPC_{OH}) \cdot (\bar{J}_{OH} \cdot \bar{M}_{OH}^{jobs}) \tag{16}$$

OHIO POWER COMPANY'S RESPONSES
TO THE OFFICE OF THEOHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUESTS
PUCO CASE 11-346-EL-SSO and 11-348-EL-SSO - Modified ESP
SECOND SET

INTERROGATORY

OCC-INT-2-036 Referring to Company Witness Powers testimony at 19, he testifies to the Company's proposal to conduct "energy auctions for 100% of the SSO load, with delivery beginning January 2015":

a. Please identify the Company's rationale for proposing an interim energy auction prior to implementing full-requirement auctions with delivery beginning on June 1, 2015. Please describe the benefits to SSO customers from such an interim energy auction.

b. Please identify the basis for the proposed capacity price of $255/MW-day for auctioned SSO load.

c. Please explain how the Company would recover the proposed price of $255/MW-day for capacity support of auctioned SSO load. Is the Company proposing to recover the cost of capacity support from winning bidders in the interim energy auction or SSO customers?

d. Has the Company developed a forecast of the expected auction clearing price from its proposed interim energy auction?

e. Under the Company's proposal, would the Genco be allowed to participate in the interim energy auction? Please explain.

RESPONSE

a. Refer to the Company's response to OCC- Set 2- INT 34 b. i.
b. The proposed capacity price of $255/MW-day for auction SSO load was developed as part of the overall package proposed in the modified ESP, which is a discount from the Company's full cost of capacity of $355.72 as presented in Case No. 10-2929-EL-UNC.
c. Please refer to the testimony of Company witness Roush, page 13 lines 13 through page 14 line 12.
d. No, the Company has not developed a forecast of expected auction clearing prices for energy auctions with delivery beginning January 2015.
e. Yes.

Prepared by: Philip Nelson

OHIO POWER COMPANY'S RESPONSES
TO THE OFFICE OF THEOHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUESTS
PUCO CASE 11-346-EL-SSO and 11-348-EL-SSO - Modified ESP
SECOND SET

INTERROGATORY

OCC-INT-2-037 Referring to Company Witness Powers testimony at 20, he testifies that from January to May of 2015 a "CBP will determine the price of energy for AEP-Ohio":

a. Please explain how the price of capacity will be determined. Will the price of capacity be set at the proposed rate of $255/MW-day for capacity support of auctioned load?

b. Please identify the Company's estimate of the price of capacity for the period January through May of 2015.

c. Please identify the expected prices for capacity and energy for 2014 as well as those expected for the period January through May of 2015.

RESPONSE

a. Please refer to the testimony of Company witness Powers' page 19, line 22.
b. The price for capacity for the period January through May of 2015 is currently estimated to be $355.72 as supported in Case No. 10-2929-EL-UNC.
c. See the testimony of Company witness Thomas for the development of Competitive Benchmark prices which reflect market pricing of energy and three capacity scenarios as reflected in the Company's ESP proposal. Those include pricing for the 2014/2015 planning year.

Prepared by: Philip Nelson / Laura Thomas

OHIO POWER COMPANY'S RESPONSES
TO THE OFFICE OF THEOHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUESTS
PUCO CASE 11-346-EL-SSO and 11-348-EL-SSO - Modified ESP
SECOND SET

INTERROGATORY

OCC-INT-2-038 Referring to Company Witness Powers testimony at 20-21, he refers to the Company's proposal for a "partial SSO auction prior to 2015":

a. Please explain how the auction-clearing prices from a partial SSO auction would be reflected in generation rates charged to SSO customers.

b. Is the Company proposing to charge for capacity support for the auctioned load? If so, what is the proposed capacity price and who would be charged for capacity support?

c. Please explain how the auction-clearing prices and capacity support charges from a partial SSO auction would be reflected in SSO generation rates while ensuring "no net changes to overall generation base prices for SSO customers," as discussed on page 16.

d. Under the Company's proposal, would the Genco be allowed to participate in the partial SSO auction? Please explain.

RESPONSE

a. Please see the Company's response to OCC-INT-2-36 c.
b. Please see the Company's response to OCC-INT-2-37 a.
c. Please see the Company's response to OCC-INT-2-36 c.
d. Please see the Company's response to OCC-INT-2-36 e.

Prepared by: Philip Nelson

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO FIRST SET

INTERROGATORY

INT-007. Prior to entering into the Memorandum of Understanding ("MOU") with Turning Point Solar did AEP seek any competitive bids for this project?

RESPONSE

The selection of the project Developer was not competitively bid.

News Release

<< Back

FirstEnergy's Ohio Utilities Meet 2012 Benchmarks for In-State Solar Renewable Energy

AKRON, Ohio, April 26, 2012 /PRNewswire via COMTEX/ --FirstEnergy Corp. (NYSE: FE) today announced that its Ohio utilities - Ohio Edison, Cleveland Electric Illuminating Company and Toledo Edison - have met the 2012 benchmarks for in-state solar renewable energy that were established under Ohio's energy law. The benchmarks were met through a successful Request for Proposal (RFP) to secure 10 -year Solar Renewable Energy Credits (SRECs).

In Ohio, FirstEnergy supports the development of solar energy resources by purchasing SRECs, which represent the environmental attributes of solar renewable electricity generation. For every megawatt hour of solar renewable electricity generated, an equivalent amount of SRECs are produced.

The RFP sought and procured the delivery of 1,000 SRECs produced by generating facilities throughout Ohio for each calendar year beginning in 2012 and continuing through 2021. There were 38 qualified bids received offering over 15 times the required SRECs being sought under the RFP.

FirstEnergy is a diversified energy company dedicated to safety, reliability and operational excellence. Its 10 electric distribution companies comprise one of the nation's largest investor-owned electric systems. Its diverse generating fleet features non-emitting nuclear, scrubbed baseload coal, natural gas, hydro, and pumped-storage hydro and other renewables, and has a total generating capacity of approximately 23,000 megawatts.

Forward-Looking Statement: This news release includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Actual results may differ materially due to: the speed and nature of increased competition in the electric utility industry, the impact of the regulatory process on the pending matters before FERC and in the various states in which we do business including, but not limited to, matters related to rates, the status of the PATH project in light of the PJM Interconnection, L.L.C., (PJM) direction to suspend work on the project pending review of its planning process, its re-evaluation of the need for the project and the uncertainty of the timing and amounts of any related capital expenditures, business and regulatory impacts from ATSI's realignment into PJM, economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices and availability, financial derivative reforms that could increase our liquidity needs and collateral costs, the continued ability of FirstEnergy's regulated utilities to collect transition and other costs, operation and maintenance costs being higher than anticipated, other legislative and regulatory changes, and revised environmental requirements, including possible GHG emission, water intake and coal combustion residual regulations, the potential impacts of any laws, rules or regulations that ultimately replace CAIR, including CSAPR which was stayed by the courts on December 30, 2011, and the effects of the EPA's MATS rules, the uncertainty of the timing and amounts of the capital expenditures that may arise in connection with any litigation including NSR litigation or potential regulatory initiatives or rulemakings (including that such expenditures could result in our decision to shut down or idle certain generating units), the uncertainty associated with the company's plan to retire its older unscrubbed regulated and competitive fossil units, including the impact on vendor commitments and PJM's review of the company's plans, adverse regulatory or legal decisions and outcomes with respect to our nuclear operations (including, but not limited to the revocation or non-renewal of necessary licenses, approvals or operating permits by the NRC including as a result of the incident at Japan's Fukushima Daiichi Nuclear Plant), issues that could result from our continuing investigation and analysis of the indications of cracking in the plant shield building at Davis-Besse, adverse legal decisions and outcomes related to Met-Ed's and Penelec's ability to recover certain transmission costs through their transmission service charge riders, the continuing availability of generating units and changes in their ability to operate at or near full capacity, replacement power costs being higher than anticipated or inadequately hedged, the ability to comply with applicable state and federal reliability standards and energy efficiency mandates, changes in customers' demand for power, including but not limited to, changes resulting from the implementation of state and federal energy efficiency mandates, the ability to accomplish or realize anticipated benefits from strategic goals, FirstEnergy's ability to improve electric commodity margins and the impact of, among other factors, the increased cost of fuel and fuel transportation on such margins, the ability to experience growth in the distribution business, the changing market conditions that could affect the value of assets held in FirstEnergy's NDTs, pension trusts and other trust funds, and cause FirstEnergy and its subsidiaries to make additional contributions sooner, or in amounts that are larger than currently anticipated, the impact of changes to material accounting policies, the ability to access the public securities and other capital and credit markets in accordance with FirstEnergy's financing plan, the cost of such capital and overall condition of the capital and credit markets affecting FirstEnergy and its subsidiaries, changes in general economic conditions affecting FirstEnergy and its subsidiaries, interest rates and any actions taken by credit rating agencies that could negatively affect FirstEnergy's and its subsidiaries' access to financing or their costs and increase requirements to post additional collateral to support outstanding commodity positions, LOCs and other financial guarantees, the continuing uncertainty of the national and regional economy and its impact on major industrial and commercial customers of FirstEnergy and its subsidiaries, issues concerning the soundness of financial institutions and counterparties with which FirstEnergy and its subsidiaries do business, issues arising from the completed merger of FirstEnergy and Allegheny Energy and the ongoing coordination of their combined operations including FirstEnergy's ability to maintain relationships with customers, employees and suppliers, as well as the ability to continue to successfully integrate the businesses and realize cost savings and other synergies, the risks and other factors discussed from time to time in FirstEnergy's and its applicable subsidiaries' SEC filings, and other similar factors. The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor assess the impact of any such factor on FirstEnergy's business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. FirstEnergy expressly disclaims any current intention to update, except as required by law, any forward-looking statements contained herein as a result of new information, future events or otherwise.

www.firstenergycorp.com

SOURCE FirstEnergy Corp.

Exhibit JAL-10

Notice: Undefined index: extract_pricing in **/home/srectrad/public_html/srec_prices.php** on line **4**

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  - Ohio
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  - All Other States »

SREC Market Prices

SREC Prices	Feb-12	Mar-12	Apr-12
Delaware			
2009-10	--	--	--
2010-11	--	--	--
2011-12	$60.00	$40.00	--
Maryland			
2010	$180.00	--	--
2011	$205.00	$218.00	--
2012	--	--	--
Massachusetts			
2011	--	--	$540.00
New Jersey			
2010	--	--	--
2011	--	--	--
2012	$205.00	$145.00	$135.00
Ohio			
In-State			
2010	--	--	--
2011	$285.00	$199.99	$234.99
2012	--	$190.00	$185.00
Out-of-State			
2010	--	--	--
2011	$40.00	$30.00	$17.50
2012	--	$35.00	$30.00
Pennsylvania			
2010	$9.99	--	--
2011	$30.00	$10.00	$20.00
2012	$35.00	$20.50	$20.00
Washington, D.C.			
2010	--	$275.00	$250.00
2011	$275.00	$275.00	$277.50
2012	--	$284.00	$290.00

Note: "--" means that bids and/or offers were not placed for SRECs of that vintage period or the market was unable to determine a clearing price because of the value of bid and offer prices.

Ohio Power Company
Case No. 10-2929
FES Set 1 RPD 1-005 Attachment 1

Exhibit JAL-11

Physical Off System Sales & Trading Margin
2011
($1,000s)

	Ohio Power
Physical Off System Sales by Region:	
East (ECAR)	166,756
	-
Total Physical Off System Sales	166,756
	-
Total Trading	37,331
	-
Total for Off System Sales Line - Gross Margin	204,087

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S
DISCOVERY RESPONSES TO FIRSTENERGY SOLUTIONS CORP.'S
DISCOVERY REQUEST IN
PUCO CASE NO. 10-2929-EL-UNC
FIRST SET**

INTERROGATORY

INT-1-001 Please identify the revenue received by AEP Ohio from net sales (sales less purchases) of capacity to non-affiliates of AEP Ohio during 2011. Please provide the information separately for each AEP Ohio operating company.

RESPONSE

Objection to the extent the question seeks individual operating company data for a company that was effectively merged in 2011. Without waiving this objection, the Company states as follows: the 2011 capacity revenues for the merged Ohio Power Company were $71,216,148. This amount represents revenues from CRES providers and other non-affiliated revenues.

Prepared by Counsel/Kelly Pearce

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Direct Testimony of Jonathan A. Lesser on Behalf of FirstEnergy Solutions Corp.* was served this 4th day of May, 2012, via e-mail upon the parties below.

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One of the Attorneys for FirstEnergy Solutions Corp.

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