BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission Review of	**)**	
the Capacity Charges of Ohio Power	**)**	**Case No. 10-2929-EL-UNC**
Company and Columbus Southern Power	**)**	
Company	**)**	

DIRECT TESTIMONY

OF

JONATHAN A. LESSER

ON BEHALF OF

FIRSTENERGY SOLUTIONS CORP.

April 4, 2012

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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 *Principles of Utility Corporate Finance* (2011), as well as numerous academic and trade press publications. 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").

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, and most recently in Case Nos. 11-501-EL-FOR and 11-502-EL-FOR.

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

A. My testimony addresses the proposed capacity charges that AEP Ohio wishes to charge to Competitive Retail Electric Service ("CRES") providers. I also rebut the testimony of AEP Ohio witnesses Munczinski and Pearce.

Q. CAN YOU SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS PROCEEDING?

A. Yes. My conclusions and recommendations are as follows:

1. AEP Ohio's proposed embedded cost capacity charge of $355.72/MW-day, based on 2010 FERC Form-1 data, is over **400**% higher than the average PJM delivered market price for capacity of $69.22/MW-day for the next three years, beginning on June 1, 2012. This means that AEP Ohio is proposing to collect from all of its distribution customers—both SSO and non-SSO alike—an additional **$2.8 billion** in above-market charges for capacity. If the PUCO approves AEP Ohio's embedded capacity cost charge, that $2.8 billion will not be available to Ohio businesses to compete in the marketplace, invest and expand, and create new jobs. Nor will it be available to residential customers to lower their electric bills.

2. AEP Ohio has no legitimate claim to recover all of the embedded costs of its capacity resources from CRES providers and, hence, AEP Ohio's shopping distribution customers through an above-market capacity charge. All such costs arising from investments made after the January 1, 2001 date on which electric competition began in Ohio were to be recovered solely from the market. AEP Ohio's argument that it is only prevented from recovering stranded costs from retail customers, but not from wholesale CRES providers fails basic standards of price comparability, is blatantly discriminatory, and contradicts its own statements in the

Corporate Separation Plan it filed on March 30, 2012.[1] In setting its proposed capacity charge to CRES providers, AEP Ohio is attempting to collect indirectly the same costs that it admits it cannot recover directly. As an FRR entity, AEP Ohio is required to provide capacity for all of its retail customers, whether those customers purchase electricity from CRES providers or they are Standard Service Offer ("SSO") customers. Therefore, AEP Ohio cannot charge these customers different prices for the same capacity. If AEP Ohio is prohibited from collecting stranded generation costs directly from its SSO retail customers, it cannot recover those same costs indirectly from non-SSO customers, merely because AEP uses CRES providers as a "middleman."

3. The capacity price AEP Ohio proposes to charge to CRES providers to serve non-SSO customers exceeds what AEP Ohio is charging through its Base Generation Rate ("BGR") and, thus, is discriminatory. Because CRES providers are currently obligated to obtain all of their capacity requirements from AEP Ohio while the company remains an FRR entity through May 31, 2015, the PUCO must ensure that AEP Ohio charges the same capacity price to SSO customers and CRES providers who provide service to AEP Ohio's non-SSO customers. To do otherwise would violate comparability standards and be price discriminatory. The easiest way to ensure the prices charged are the same is by separating (or unbundling) the capacity price from AEP Ohio's overall BGR it charges SSO customers. In this way, all customers, as well as CRES providers, will know that they face a "level playing field"

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

on which to compete, and AEP Ohio customers will be provided with more transparent pricing options. This will allow customers to choose the energy supplier of their choice more effectively, whether that supplier is AEP Ohio or a CRES provider.

4. The capacity price AEP Ohio charges CRES providers is what economists call a "transfer price." Transfer prices are prices that one part of a firm charges another part. AEP Ohio's capacity price can be thought of as an internal transfer price of capacity that is sold to SSO customers and CRES providers. Rather than purchasing capacity from the market, which in this case is the PJM Reliability Pricing Model ("RPM"), CRES providers must purchase all of their required capacity from AEP Ohio. A well-known economic result is that the economically efficient transfer price is always the market price. In this case, the market price for capacity is the price established in PJM's capacity market: RPM. Thus, AEP Ohio should charge all customers, both its SSO customers through the base generation rate and CRES providers, the RPM price.

5. AEP Ohio's argument that a cost-based capacity price will provide all customers greater stability is undercut by the fact that it will no longer be an FRR entity as of June 1, 2015. What AEP Ohio means by "stability" is that it will charge customers a "stable" rate—although AEP Ohio proposes to update that rate each year—that is more than five times the average market price between June 1, 2012 and May 31, 2015, and then charge the market price thereafter. AEP Ohio witness Munczinski states that the company wishes to charge a cost-based rate because, "At this time in the market cycle, adjusted RPM-based capacity prices are below AEP Ohio's

embedded costs."[2] This is an admission by AEP Ohio that it simply seeks to charge CRES providers the higher of cost-based or market prices. Moreover, as Mr. Stoddard's testimony discusses,[3] it directly conflicts with the testimony of Mr. Graves: if AEP Ohio believes that charging the RPM price is a form of economic bypass when the market price is below AEP Ohio's embedded costs, then charging the RPM price as of June 1, 2015 will also be "uneconomic bypass" if the RPM price is below AEP Ohio's embedded cost, or excessive enrichment by AEP Ohio if the RPM price is above AEP Ohio's embedded costs. AEP Ohio's argument is that the RPM market price is economically efficient <u>only if</u> that price happens to be exactly equal to AEP Ohio's embedded cost. AEP Ohio's argument is wrong.

6. RPM-based capacity pricing is most economically efficient, and a cost-based price based on an Avoided Cost Rate as discussed by FES witness Stoddard is a reasonable substitute for market pricing. AEP Ohio's reliance on a formula-based full embedded cost is neither reasonable nor justified. As calculated by AEP Ohio, the formula rate improperly allows it to double recover certain costs, including off-system energy (not capacity) sales and carrying costs associated with environmental capital investments. Standard regulatory practice is that a utility receiving an embedded cost rate for its generation is required to return 100% of off-system sales profits to its customers. Furthermore, the margins that AEP Ohio earns from off-

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[2] *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 Richard Munczinski, March 23, 2012 ("Munczinski Direct"), p. 12, lines 9-11.

[3] *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 Robert Stoddard, April 4, 2012.

system energy sales, as reported in FERC Account 447 already account for revenue sharing under the AEP East Pool Agreement ("Pool Agreement").

7. After necessary adjustments, the formula rate results in a price of $78.53/MW-day. This price is separate and distinct from the "avoided cost rate" ("ACR"), which represents the maximum allowable price at which generators can offer their capacity into the PJM RPM capacity market. As Mr. Stoddard explains, the purpose of ACR values is to replicate the bidding behavior that would be expected in a competitive environment.

II. AEP OHIO'S PROPOSED CAPACITY CHARGE IS DISCRIMINATORY AND CONTRARY TO STATE POLICY PROMOTING RETAIL ELECTRIC COMPETITION

A. <u>The Role Capacity plays in Ohio's Competitive Retail Electric Market</u>

Q. WHY DOES AEP OHIO PROVIDE CAPACITY?

A. Every entity that sells electricity to retail customers (load serving entities, "LSEs"), whether an electric distribution utility ("EDU") like AEP Ohio or a CRES provider, must have, at a minimum, capacity reserves set by PJM each year, called the installed reserve margin ("IRM"), based on the entity's forecast peak load for the planning year.[4] The capacity reserve ensures that there is always enough reserve capacity to meet forecast peak demand for power at all times, plus accounts for unplanned events, such as forced generator outages or loss of a transmission line. The capacity reserve for the current PJM 2011-2012 planning year, which ends May 31, 2012, is 15.5%.[5]

[4] PJM planning years run from June 1 to May 31.

[5] PJM, "Planning Period Parameters," December 2, 2009. http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2011-2012-rpm-bra-planning-parameters.ashx

Q. HOW IS CAPACITY PROVIDED?

A. Providing reserve capacity can be done in one of two ways. Some LSEs purchase capacity through the PJM RPM, which is a competitive wholesale market for buyers and sellers of capacity. Others purchase capacity through bilateral agreements with generators. There is also one other alternative, called the Fixed Resource Requirement ("FRR") option. Under the PJM Reliability Assurance Agreement ("RAA"), any LSE that meets the eligibility requirements can declare itself to be an FRR entity.[6]

As Mr. Stoddard's testimony discusses, AEP Ohio has elected to be an FRR entity through May 31, 2015, after which it will obtain capacity through the PJM RPM. As an FRR entity, AEP Ohio is obligated to provide capacity for <u>all</u> of its distribution customers' load for the period of its FRR election, including the load of customers who purchase retail electric service from CRES providers.[7] Thus, AEP Ohio requires that all CRES providers who wish to sell electricity to AEP Ohio retail customers purchase their PJM-mandated capacity requirements from AEP Ohio for the next three PJM planning years, i.e., between June 1, 2012 and May 31, 2015. CRES providers cannot obtain capacity from the PJM RPM or any other market participants until June 1, 2015.[8] CRES providers in AEP Ohio's service territory are captive to AEP Ohio, meaning that AEP Ohio is a monopoly supplier of capacity until May 31, 2015.

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[6] *See* PJM RAA, Schedule 8.1.B.

[7] *See* PJM RAA, Schedule 8.1(D)(8). "In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs."

[8] CRES providers can also declare themselves FRR entities beginning June 1, 2015. However, as Mr. Stoddard explains, the issue is moot, because at that time, they can purchase capacity from the PJM market at the RPM price.

Q. HOW IS THE PRICE OF CAPACITY THAT AEP OHIO CHARGES DETERMINED?

A. Under the RAA, AEP Ohio is not allowed to charge whatever price it wants for capacity, which obviously would be unreasonable. Instead, Schedule 8.1, Section D.8 of the RAA establishes what price an FRR entity may charge:

> In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

So, if the state of Ohio does <u>not</u> establish a state compensation mechanism, the price defaults to the "capacity price in the PJM Region." That price is the PJM RPM capacity price. For the 2011-2012 planning year, the RPM capacity clearing price is \$116.15/MW-day. The final cost to capacity purchasers also includes as adjustments the "scaling factor," the "forecast pool requirement," and transmission system losses.[9] With these adjustments, the final RPM price is \$145.78/MW-day for the current 2011-2012 planning year. If the state does establish the state compensation mechanism, it should do so consistent with market principles reflected in the RAA and in state policy.

Q. HOW DOES THE WHOLESALE CAPACITY PRICE TO CRES PROVIDERS AFFECT RETAIL COMPETITION?

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[9] The scaling factor and forecast pool requirement are defined in the PJM RAA in Schedule 8.1(F) and Schedule 4(C), respectively. The loss factor is set forth in AEP Ohio's tariff.

A. Because CRES providers are captive to AEP Ohio for capacity needs for the next three PJM planning years, the wholesale capacity price AEP Ohio charges CRES providers can affect the competitive retail market. For example, suppose AEP Ohio charged its SSO customers $100/MW-day for capacity, but charged CRES providers $1,000/MW-day for the same capacity. Suppose both charged the wholesale market price for energy, say, $50/MWh. In that case, CRES providers could not match AEP Ohio's price without losing money because capacity is an unavoidable cost to CRES providers from AEP Ohio. Thus, in addition to the capacity price differential being unduly discriminatory, it would make it impossible for CRES providers to compete for retail load against AEP Ohio's SSO price. And that is contrary to state policy, which seeks to encourage retail electric competition.

B. <u>AEP Ohio's Retail v. Wholesale Transition Cost Argument Lacks Credibility</u>

Q. WHAT IMPACT DID S.B. 3 HAVE ON THE ABILITY OF ELECTRIC UTILITIES TO IMPOSE ABOVE-MARKET PRICES IN ORDER TO RECOVER THEIR FULL EMBEDDED COSTS FOR THEIR GENERATING CAPACITY RESOURCES?

A. Under S.B. 3, which unbundled retail electric generation service from distribution and transmission service beginning January 1, 2001, all generation plant investment after that date, except for transition costs, was to be recovered solely in the market.[10] Under S.B. 3, each electric utility was given an opportunity during a transition period to recover any previously-sunk costs in their generating facilities (*i.e.*, costs incurred prior to the transition date of January 1, 2001) that would be uneconomic or "stranded" in

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

competitive markets.[11] Because S.B. 3 provided a clear demarcation date between pre-transition and post-transition generation costs, any cost-based capacity charges levied by AEP Ohio can apply only to generating plant that was in-service on or before December 31, 2000, the day before the transition date of January 1, 2001, and only then if AEP Ohio had not waived recovery and/or already fully recovered these costs during the transition period, which for AEP Ohio ended as of December 31, 2008.[12]

Q. WHAT ARE STRANDED COSTS AND WHY ARE THEY RELEVANT TO AEP OHIO'S CAPACITY COST ESTIMATE?

A. Stranded costs are defined as the difference between the market value of an asset and its net book value. (Net book value is just an asset's original cost less accumulated depreciation.) For example, if a generating unit's market value is estimated at $500 million and its net book value is $600 million, then the unit has stranded costs of $100 million.

Stranded costs are relevant to the capacity charge AEP Ohio proposes to charge all customers for three reasons. First, stranded costs hinge on the net undepreciated book value of generating plant-in-service ("GPIS"). If the market value of a generating asset is greater than its net GPIS, then there are no stranded costs associated with that asset.

Second, because Revised Code Section 4928.01(A)(28) defined the starting date of competitive retail electric service as January 1, 2001, all generating plant investment subsequent to that date must be recovered from the market, rather than in cost-based

[11] R.C. § 4928.38-.40; *see In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues*, Case Nos. 99-1730-EL-ETP and 99-1731-EL-ETP (the "ETP Proceeding").

[12] ETP Proceeding, Stipulation, Attachment 1 (May 8, 2000). Under the Stipulation, CSP could recover its RTCs through December 31, 2008, while OPC could recover its RTCs through December 31, 2007.

rates. Thus, the only legitimate embedded capacity costs AEP Ohio could have recovered as stranded costs were those costs related to generating plant that was in service prior to the start of competitive retail service.

Third, under AEP Ohio's proposed corporate separation agreement, AEP Ohio will transfer all of its existing generating assets to an unregulated generation company, AEP Generation Resources, Inc. The expected date of this transfer of generating assets is December 31, 2013 "or other such date as ordered by the FERC."[13] After the transfer, AEP Generation Resources cannot charge AEP Ohio an above-market price for capacity because charging customers an above-market price from an affiliate would constitute a prohibited cross-subsidy.[14]

Q. HOW WERE STRANDED COSTS TO BE RECOVERED UNDER S.B. 3?

A. Under S.B. 3, stranded cost recovery took two forms, which became known as Generation Transition Costs ("GTCs") and Regulatory Transition Costs ("RTCs"). An electric utility could recover GTCs through a transition charge during the transition period, provided the costs satisfied statutory requirements.[15] At the end of the transition period, which was December 31, 2005, unless modified by the Commission as part of a

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[13] 2012 Corporate Separation Plan, p. 3, fn. 2.

[14] *See* 2012 Corporate Separation Plan, Attachment A, Item 1(3) "Cross-subsidies between an electric utility and its affiliates are prohibited. An electric utility's operating employees and those of its affiliates shall function independently of each other."

[15] R.C. 4928.39 provided for recovery of "just and reasonable transition costs of the utility, which costs the commission finds meet all of the following criteria:

(A) The costs were prudently incurred.

(B) The costs are legitimate, net, verifiable, and directly assignable or allocable to retail electric generation service provided to electric consumers in this state.

(C) The costs are unrecoverable in a competitive market.

(D) The utility would otherwise be entitled an opportunity to recover the costs."

utility's transition plan, S.B. 3 stated that, "the utility shall be fully on its own in the competitive market."[16] Similarly, an electric utility could recover its RTCs both during the transition period and for several years thereafter, but in any case no later than December 31, 2010.[17] AEP Ohio's ability to recover stranded costs of its generating facilities—meaning, any costs that would not be fully recovered through the competitive market after the transition period—ended more than six years ago for GTCs and more than three years ago for RTCs (pursuant to the ETP Stipulation). Moreover, an electric utility is barred from including any transition costs in an ESP or MRO.[18] Yet AEP Ohio wishes to recover these above-market costs until June 1, 2015.

Q. HAS AEP OHIO RECOGNIZED THAT THE TRANSITION PERIOD HAS ENDED AND THAT IT CAN NO LONGER RECOVER STRANDED COSTS?

A. Yes. In its 2012 Corporate Separation Plan, AEP states,

> [OPCo] seeks to transfer its generating assets to an affiliate within the same parent corporation, in compliance with the mandate of R.C. 4928.17. 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. 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.[19]

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16 R.C. 4928.38.

17 R.C 4928.40.

18 R.C. 4928.141 ("A standard service offer under section 4928.142 or 4928.143 of the Revised Code shall exclude any previously authorized allowances for transition costs, with such exclusion being effective on and after the date that the allowance is scheduled to end under the utility's rate plan.").

19 2012 Corporate Separation Plan, p. 7 (emphasis added).

Q. DOES THE 2012 CORPORATE SEPARATION PLAN STATE THAT STRANDED COSTS CAN BE RECOVERED INDIRECTLY FROM NON-SSO CUSTOMERS THROUGH CRES PROVIDERS?

A. No.

Q. DO THE STRANDED COST RECOVERY PROVISIONS OF S.B. 3 PERTAIN ONLY TO RETAIL SERVICE?

A. No. Following the transition period, Ohio policy is clear that "the utility shall be on its own in the competitive market."[20] Although Ohio law was modified in 2008 to allow limited cost-based charges as part of an ESP, this statute continues to mandate that generation costs, in whatever form, be recovered through the competitive market. The prohibition on collection of transition charges after the transition period is not limited to retail sales. Ohio does not say that a utility is on its own in the competitive market *except that the Commission can authorize above-market charges to CRES providers*. A utility is simply prohibited from collecting stranded costs from any source.

Q. HOW DO YOU RESPOND TO THE ARGUMENT THAT ABOVE-MARKET CHARGES TO CRES PROVIDERS DO NOT FALL WITHIN THE SCOPE OF THE STRANDED COST PROVISIONS OF S.B. 3?

A. It makes no economic sense that AEP Ohio is prohibited from recovering stranded capacity costs directly from its retail distribution customers, but is somehow allowed to recover these same stranded costs, from these same retail customers, as long as the costs are first charged to CRES providers, who act as "middlemen." In fact, AEP Ohio itself states that "CRES providers who choose not to self-supply act merely as a middle-man

[20] R.C. § 4928.38.

[sic] on capacity flowing from AEP Ohio to support retail generation service."[21] If the Commission directed that the state compensation mechanism be charged to retail customers,[22] AEP Ohio would have no argument. The mere fact that the state compensation mechanism is collected from CRES providers should not alter the analysis. Second, AEP Ohio's logic implies that it is reasonable to charge discriminatory prices to identical customers for the same service, which is economically inefficient and contrary to state policy.

Q. IN LIGHT OF AEP OHIO'S 2012 CORPORATE SEPARATION PLAN, CAN AEP OHIO OR AEP GENERATION RESOURCES RECOVER STRANDED COSTS FROM CRES PROVIDERS?

A. No. First, AEP Ohio itself admits it can no longer recover stranded costs. Instead, all such costs must be recovered in the market and there is no regulatory basis for AEP Ohio charging an embedded capacity cost to any of its customers. Second, AEP Generation Resources will only be able to charge AEP Ohio the market price of capacity. Because AEP Generation Resources will operate independently of AEP Ohio, there is no rational economic basis as to why AEP Ohio would agree to purchase capacity from AEP Generation Resources at an above-market price if it can purchase that capacity at a lower price in the market. In other words, buying capacity from AEP Generation Resources at an above-market price would be a cross-subsidy and a form of price discrimination.

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[21] *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 Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case No. 11-346-SSO, et al., Joint Initial Brief of the Undersigned Signatory Parties, November 10, 2011 ("Joint Initial Brief"), p. 90.

[22] *See* RAA Schedule 8.1, Section D.8 ("where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail." (emphasis added)).

Q. DO YOU AGREE WITH AEP OHIO'S ARGUMENT THAT CRES PROVIDERS HAVE CHOSEN NOT TO SELF-SUPPLY CAPACITY AND THEREFORE SHOULD NOT BE SUBSIDIZED BY AEP OHIO?

A. No. AEP Ohio witness Munczinski states, "CRES providers who serve shopping customers, and who choose not to self-supply capacity, are currently required to pay only the PJM RPM-based auction price."[23] Suggesting that CRES providers have a choice is a clear distortion of the facts. CRES providers are captive customers of AEP Ohio for capacity until May 31, 2015, and AEP Ohio will not allow them to self-supply capacity before then.

Q. COULD CRES PROVIDERS HAVE PREVIOUSLY ELECTED TO SELF-SUPPLY CAPACITY?

A. Yes. This is discussed in Mr. Stoddard's testimony. Of course, because AEP Ohio had originally charged the PJM RPM market price to CRES providers, they had no reason to self-supply. The price they would expect to pay in the market was no different than what AEP Ohio charged. With AEP Ohio's attempt to charge an above-market embedded capacity cost, however, CRES providers are effectively the victims of "bait and switch" tactics.

Q. ARE CRES PROVIDERS NOW CAPTIVE CUSTOMERS OF AEP OHIO FOR CAPACITY?

A. Yes. Under Schedule 8.1 of the PJM RAA, CRES providers can give three years' notice to themselves become FRR entities. Thus, the earliest CRES providers could supply their own capacity is now June 1, 2015. Until then, AEP Ohio requires that they <u>must</u> purchase capacity from AEP Ohio. CRES providers, therefore, are captive

[23] Munczinski Direct, p. 11, lines 2-4.

customers of AEP Ohio until May 31, 2015, when AEP Ohio's current FRR designation expires. Although CRES providers can choose to self-supply if given advance notice of AEP Ohio's switch away from market pricing, they would have needed to do so prior to the applicable PJM planning years. For the upcoming 2012-2013 and 2013-2014 planning years, CRES providers would have had to have provided notice by March 2009 and March 2010, respectively. Since AEP Ohio's position at that time – during its ESP I – was that capacity would be priced based on RPM, there was no reason for CRES providers to give notice.

Q. WHY DOES IT NOT MAKE ECONOMIC OR REGULATORY SENSE TO ALLOW AEP OHIO TO RECOVER COSTS INDIRECTLY THAT IT IS PROHIBITED FROM RECOVERING DIRECTLY?

A. Because AEP Ohio is an FRR entity, CRES providers are <u>required</u> to purchase capacity from AEP Ohio if they wish to sell electricity to AEP Ohio retail customers. AEP Ohio's argument amounts to a justification that it can charge <u>indirectly</u>—recovering stranded costs from its non-SSO distribution customers—what it is not allowed to recover <u>directly</u> from SSO customers. The result is capacity prices that are not comparable and are unduly discriminatory: one capacity price for AEP Ohio's SSO customers and another price for CRES providers who provide electricity to AEP Ohio's remaining non-SSO distribution customers.

Q. SHOULD SSO CUSTOMERS BE CHARGED A LOWER CAPACITY PRICE THROUGH THE BASE GENERATION RATES THAN WHAT AEP OHIO PROPOSES TO CHARGE CRES PROVIDERS?

A. No. Although the Base Generation Rate ("BGR") is not required to be cost-based, the BGR rate must satisfy two conditions. First, under the ESP/MRO test, AEP

Ohio must show that its BGR, plus all other terms and conditions of its ESP, is no greater than the equivalent market rate, including both energy and capacity. Second, because AEP Ohio is an FRR entity and therefore is the monopoly provider of capacity to <u>all</u> of its distribution customers, the capacity portion of the BGR rate <u>must</u> be the same for both SSO and non-SSO customers (through the capacity price charged to CRES providers) alike. To do otherwise violates comparability requirements and is price discriminatory.

AEP Ohio admits that its embedded capacity costs are greater than the PJM RPM market price of capacity, and will be through May 31, 2015. Therefore, if the BGR rate incorporates an above-market cost of capacity, which it must to ensure comparability and avoid price discrimination, then AEP Ohio is providing its SSO customers energy at a below-market price. Otherwise, the combination of an above-market price of capacity and a market price of energy would mean an above-market BGR rate, which would fail the ESP/MRO comparison test.

Q. WHY IS CHARGING ONE CAPACITY PRICE TO AEP OHIO SSO CUSTOMERS AND ANOTHER PRICE INDIRECTLY TO NON-SSO CUSTOMERS "DISCRIMINATORY?"

A. Charging one price for capacity to SSO customers and another to CRES providers is discriminatory for two reasons. First, as was just discussed, AEP is seeking to collect stranded costs indirectly from non-SSO customers that it cannot collect directly from SSO customers, and which its 2012 Corporate Separation Plan states can no longer be collected. Second, AEP Ohio is the monopoly provider of capacity to all of its distribution customers, both shopping and non-shopping. Because there is no difference in the cost to provide the same capacity to SSO customers and to provide it to CRES providers, charging those customers different prices is unduly discriminatory. In other words, the price difference cannot be justified based on different costs to serve the two groups.

For example, suppose we look at the cost to provide electric service to two residential apartments, A and B, located in the same building. The average cost (per kWh) to serve those two apartments is the same. There is no difference in the cost of reading each apartment's electric meter or sending out a bill. There is no difference in the cost of maintaining the distribution line that serves the entire apartment building. If both apartments take SSO service, then clearly there is no difference in the costs to provide service to each apartment and, as such, AEP Ohio cannot charge each a different price for capacity and energy.

Suppose, however, that apartment A is an SSO customer but that apartment B purchases electricity, including capacity, from a CRES provider. In this case, AEP Ohio sells energy to apartment A, whereas the CRES provider sells energy to apartment B. However, because AEP Ohio is an FRR entity, it provides the physical capacity associated with the energy sales to both apartments. The <u>only</u> difference is that, for apartment B, AEP Ohio first sells that capacity to a CRES provider, who then sells it, along with energy, to apartment B.

Clearly, there is no physical difference whatsoever in the cost AEP Ohio incurs to provide capacity to both apartments. Thus, there is no economic basis for AEP Ohio to charge a different capacity price for each apartment, and charging apartment B a higher price for capacity than apartment A is clearly discriminatory.

Q. HAVE YOU COMPARED AEP OHIO'S EMBEDDED COST OF CAPACITY RATES WITH ITS BGR RATES?

A. Yes. Table 1 compares the BGR rates under ESP I, which is currently in effect, and AEP Ohio's embedded capacity and ancillary service costs. As Table 1 shows, AEP Ohio's embedded capacity costs, when converted to a per-MWh basis, plus its estimated ancillary service costs, are significantly greater than what it charges residential customers of CSP and OPC, and are greater than what CSP industrial customers are charged.

The capacity rates in Table 1 are based on the $355.72/MW-day value of AEP Ohio witness Pearce, which was converted to a per-MWh value for each customer class by ESP II witness Thomas.[24] Similarly, the ancillary services cost of $0.60/MWh is taken directly from Ms. Thomas's testimony in the ESP II Stipulation case.

[24] AEP Ohio witness Horton wrongly estimates capacity charges on a per-MWh basis in his testimony, as he simply divides the per 2012/13 RPM delivered price of $20/MW-day by 24 to derive a per-MWh price of $0.83. Mr. Horton's calculation fails to account for the load factor of different customers, as Ms. Thomas did in her Stipulation testimony.

Table 1: Comparison of BGR and Capacity/Ancillary Services Rates

	BGR Rates - ESP I ($/MWh)		
Company	R	C	I
CSP	$20.13	$25.98	$14.43
OP	$24.21	$26.54	$18.05
AEP Ohio	$22.15	$26.27	$17.07

Source: Roush Workpapers, ESP II

	Capacity Rates ($/MWh)		
Company	R	C	I
CSP	$28.17	$22.77	$16.09
OP	$28.17	$22.77	$16.09
AEP Ohio	$28.17	$22.77	$16.09

Source: Thomas - ESP II, Exhibit LJT-1

	Ancillary Service Rates ($/MWh)		
Company	R	C	I
CSP	$0.60	$0.60	$0.60
OP	$0.60	$0.60	$0.60
AEP Ohio	$0.60	$0.60	$0.60

Source: Thomas - ESP II, Exhibit LJT-1

	Capacity + Ancillary Service Rates ($/MWh)		
Company	R	C	I
CSP	$28.77	$23.37	$16.69
OP	$28.77	$23.37	$16.69
AEP Ohio	$28.77	$23.37	$16.69

	Difference from BGR Rates ($/MWh)		
Company	R	C	I
CSP	($8.64)	$2.61	($2.26)
OP	($4.56)	$3.17	$1.36
AEP Ohio	**($6.62)**	**$2.90**	**$0.38**

Q. WHY IS THIS SIGNIFICANT?

A. AEP Ohio cannot charge a lower price for capacity to its SSO customers than it charges CRES providers, because doing so violates comparability and is price discriminatory. However, because some of the BGR rates, which include energy, capacity, and ancillary service charges, are below AEP Ohio's own estimates of embedded capacity and ancillary service costs, AEP Ohio's BGR charged to SSO customers includes a capacity component that is less than the $355.72/MW-day AEP Ohio wants to charge shopping customers. This is price discrimination.

Q. UNDER AEP OHIO'S APPROVED ESP, ISN'T IT ALLOWED TO SET A BASE GENERATION RATE FOR SSO SERVICE THAT IS NOT COST-BASED?

A. Yes. But the BGR consists of an energy component and a capacity component. The capacity component of AEP Ohio's SSO price cannot be different than what AEP Ohio charges CRES providers for capacity. Thus, if AEP Ohio wishes to charge CRES providers $355.72/MW-day for capacity, as it has proposed, then AEP Ohio must also charge the exact same price to SSO customers. To do otherwise would violate comparability requirements and mean that AEP Ohio is price discriminating against non-SSO customers.

Q. HOW CAN THE PUCO ENSURE THAT SSO CUSTOMERS AND RETAIL CUSTOMERS WHO BUY ELECTRICITY FROM CRES PROVIDERS PAY THE SAME CAPACITY PRICE?

A. The easiest way to ensure comparable pricing is to unbundle the BGR into its energy and capacity components, and ensure that AEP Ohio is charging the same price for capacity to its SSO customers as it charges CRES providers. In addition to eliminating discriminatory pricing, unbundling the capacity and energy prices in the BGR will improve price transparency, which will promote economically efficient retail competition. Thus, even if AEP Ohio is ultimately allowed to charge a price for capacity other than the PJM RPM market-clearing price, which it should not be authorized to do, the price charged should be transparent and nondiscriminatory. As such, it will enhance retail electric competition, consistent with the state's policy goals.

Q. ARE YOU TESTIFYING THAT AEP OHIO CAN CHARGE $355.72/MW-DAY TO ALL CUSTOMERS WITHOUT HARMING RETAIL COMPETITION?

A. No. Artificially high capacity rates for all customers will provide an anti-competitive advantage to the AEP affiliate CRES provider. An above-market capacity rate will discourage competition and keep customers from saving the money they should. In other words, AEP Ohio customers will have a choice: pay the SSO rate, which must be better than the corresponding market price, or purchase power from CRES providers, who will be paying an above-market price for capacity and the market price for energy. Although CRES providers can sell at a loss, unlike AEP Ohio's retail affiliate, those losses will not be cross-subsidized by AEP Ohio's profits from selling capacity at an above-market price. Thus, AEP Ohio's affiliate CRES provider will gain an anticompetitive advantage in the retail market. That cannot possibly be consistent with the state's policy goal of enhancing retail competition.

C. <u>The Only Economically Efficient Capacity Price is the PJM RPM Price.</u>

Q. YOU HAVE PREVIOUSLY DISCUSSED WHY THE CAPACITY PRICE CHARGED TO BOTH SSO CUSTOMERS AND CRES PROVIDERS SHOULD BE THE SAME. WHAT SHOULD THAT PRICE BE SET TO?

A. The most economically efficient capacity price is the PJM RPM market price. Moreover, under the 2012 Corporate Separation Plan, this 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, through May 31, 2015, the PJM RPM prices are already known. Therefore, the logical bilateral sales price would be based on the known PJM RPM market prices. If AEP Ohio agreed to pay a higher capacity price, that would represent a cross-subsidy.

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 to SSO customers and CRES providers. For the former, the capacity price is embedded within the 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. Moreover, as discussed previously, once AEP Ohio's generation is transferred to its unregulated affiliate AEP Generation Resources, AEP Ohio should not cross-subsidize AEP Generation Resources by paying an above-market price for capacity.

Q. IS THE PROPOSED $355.72/MW-DAY CAPACITY PRICE THAT CUSTOMERS WILL BE CHARGED 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.

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

A. No. In Case No. 11-346-SSO, AEP Ohio argued that:

> An FRR Entity like AEP Ohio, unlike participants in the RPM market, must sell all of the capacity that the CRES provider requires at the specified price. As a result, the cost-based pricing option of Schedule 8.1, Section D.8, is a reasonable option for FRR entities because it provides a guard against situations, like the instant one, where precipitous declines in RPM prices leave the FRR entity unable to recover anywhere near its actual costs of providing capacity to CRES providers. Contrary to FES's mantra-like position, in the case of an FRR Entity, there is not one right price for capacity in all circumstances. Under current circumstances, RPM–priced capacity for all of AEP Ohio's load is not the right price.[25]

In other words, AEP Ohio's argument is that it should be allowed to charge the <u>higher</u> of the RPM market price or its full embedded costs.

[25] *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 Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case No. 11-346-SSO, et al., Joint Reply Brief of the Undersigned Signatory Parties, November 18, 2011 ("Joint Reply Brief"), p. 67.

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

A. No. AEP Ohio's argument is just as illegitimate as arguments that retail customers should be charged the lower of market price or a utility's embedded cost. Both are "heads I win, tails you lose" arguments that are completely incompatible with market competition. 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, nor 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. To suggest that it is economically efficient to charge an above-market price until AEP Ohio transfers all of its generating capacity to AEP Generation Resources, at which time the efficient price will be the market price, contradicts basic economics.

D. <u>Arguments that CRES Providers are Being Subsidized by AEP Ohio Are Incorrect</u>

Q. HAS AEP OHIO ARGUED THAT CRES PROVIDERS ARE SUBSIDIZED IF THEY PAY THE MARKET PRICE FOR AEP OHIO CAPACITY?

A. Yes. On November 24, 2010, AEP Ohio filed an application with the Federal Energy Regulatory Commission ("FERC") arguing that, by paying a market price, CRES providers were receiving below-cost capacity from AEP Ohio, constituting a subsidy to those providers.[26] AEP Ohio has also argued that "CRES providers take advantage of the capacity supplied by AEP Ohio as opposed to supplying their own capacity."[27] AEP Ohio is making the same argument in this case.[28]

Q. IF AEP OHIO WERE NOT AN FRR ENTITY, WOULD IT PARTICIPATE IN THE PJM RPM?

A. Yes. As Mr. Stoddard's testimony discusses, if AEP Ohio were not an FRR entity, it would be required to participate in the PJM RPM. It would offer capacity into the market and be paid the market-clearing price for all of the capacity offered that cleared the auction, just like every other capacity market participant. As AEP Ohio witness Munczinski states, the company will begin participating in the RPM as of June 1, 2015.[29]

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

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[26] *American Electric Power Service Corporation*, Docket No. ER11-2183-000, November 24, 2010, p. 6. "[t]he AEP Ohio Companies have not been fully recovering from Ohio CRES Providers a fully-allocated share of their respective capacity costs."

[27] Joint Initial Brief, p. 93.

[28] Munczinski Direct, p. 8, lines 7-15.

[29] Munczinski Direct, p. 7, lines 18-19.

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.

In its Reply Brief in Case No. 11-346-EL-SSO, et al., AEP Ohio attempted to rebut the argument that the RPM market-clearing price was the economically efficient price to charge CRES providers, stating

> The primary error in this argument is that Schedule 8.1, Section D.8 to PJM's RAA explicitly provides otherwise. That provision allows an FRR entity, such as AEP Ohio, the option of a cost-based capacity price. An FRR Entity like AEP Ohio, unlike participants in the RPM market, must sell all of the capacity that the CRES provider requires at the specified price. As a result, the cost-based pricing option of Schedule 8.1, Section D.8, is a reasonable option for FRR entities *because it provides a guard against situations, like the instant one, where precipitous declines in RPM prices leave the FRR entity unable to recover anywhere near its actual costs of providing capacity to CRES providers*.[30]

In essence, AEP Ohio argued that, because it has been forced, as an FRR entity, to provide capacity to CRES providers it has the right to recover its full embedded capacity costs, or the market price, whichever is higher. AEP Ohio's argument ignores both facts and logic.

Q. WHAT PRICE HAD AEP OHIO BEEN CHARGING CRES PROVIDERS FOR CAPACITY UNDER ESP I?

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[30] Joint Reply Brief, p. 68 (emphasis added).

A. AEP Ohio had been charging the PJM RPM price. Under the ESP II Stipulation, AEP proposed to charge CRES providers the market price for a portion of shopping load, and $255/MW-day for any additional load. The Stipulation was approved, then later rejected by the PUCO. Pursuant to a March 7, 2012 Entry, AEP Ohio is once again charging these capacity rates, but only through May 31, 2012.

Q. AFTER AEP OHIO IS NO LONGER AN FRR ENTITY, WHAT PRICE WILL CRES PROVIDERS PAY FOR CAPACITY THEY NEED?

A. They would pay the RPM market-clearing price if they bid for capacity resources in the RPM. Alternatively, CRES providers could voluntarily enter into bilateral purchase agreements with capacity suppliers. In that case, however, the bilateral price would reflect the RPM market-clearing price. Buyers will be unwilling to pay a price that is much higher than the RPM market price and sellers will be unwilling to sell at a price much below it.

Q. ARE CRES PROVIDERS "TAKING ADVANTAGE" OF AEP OHIO?

A. No. AEP Ohio ignores several salient facts. First, AEP Ohio previously sold capacity to CRES providers at the PJM RPM price. 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. That capacity, in turn, would presumably have been obtained from the market, at the RPM market price. Because AEP Ohio was initially selling capacity at the PJM RPM market price, CRES providers would be indifferent to relying on AEP Ohio for their capacity requirements. Now, however, 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 "bait and switch."

Q. WILL AEP OHIO BE GUARANTEED RECOVERY OF ITS EMBEDDED CAPACITY COSTS AFTER IT JOINS THE PJM RPM BEGINNING JUNE 1, 2015?

A. No. AEP Ohio will be one of hundreds of RPM market participants that will be paid the market-clearing RPM price for capacity that they successfully offer into the RPM auction.

Q. WHAT PRICE WILL CRES PROVIDERS WHO SERVE AEP DISTRIBUTION CUSTOMERS PAY FOR CAPACITY STARTING JUNE 1, 2015?

A. CRES providers will pay the market price, either directly from the PJM RPM or through voluntary bilateral contracts with capacity suppliers.

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 to recover its embedded capacity costs in the market. In fact, AEP Ohio (or, after corporate separation, AEP Generation Resources) may recover 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. 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.

Q. HOW DO YOU RESPOND TO MR. MUNCZINSKI'S ARGUMENT THAT THE VOLATILITY OF PJM RPM MARKET PRICES WILL PREVENT NEW INVESTMENT?

A. Besides being irrelevant for the purposes of this proceeding, since we are only addressing capacity pricing for June 1, 2012 through May 31, 2015, when RPM market prices are already known, Mr. Munczinski is wrong. In 2011, the Brattle Group, which is the firm AEP Ohio witness Graves co-founded, prepared its second assessment of the PJM Capacity market.[31] The Brattle Report stated that:

> Stakeholders expressed particular concerns about the volatility and unpredictability of RPM prices. Some of the observed price changes are

[31] J. Pfeiffenberger, et al., "Second Performance Assessment of PJM's Reliability Pricing Model," August 26, 2011 ("2011 Brattle Report").

> consistent with changes in market fundamentals, which necessarily must be reflected in prices for the market to be efficient. Others are caused by the one-time implementation of various improvements to the initial RPM design, such as modeling more LDAs or elimination of Interruptible Load for Reliability ("ILR"). These impacts on prices reflect a non-recurring one-time adjustment, which is not a concern going forward.[32]

The Brattle PJM Report further stated that:

> One of the key benefits of competitive power markets, including the PJM's capacity market, is that market prices can move with market fundamentals and create incentives to respond. Unexpectedly high prices will create a strong incentive for suppliers to quickly develop more demand response and speed the completion of generation under construction. Similarly, unexpectedly low prices will signal that expensive existing generation should be retired and new generation projects should be delayed. Ensuring that these incentives are delivered accurately to marginal resources through capacity prices will allow reserve margins to remain near the target levels, preventing both severe shortages and costly excess of supply.[33]

Thus, even though market prices may be volatile, that volatility, in part, is necessary to provide the correct signals to capacity suppliers.

Moreover, AEP Ohio witness Pearce states that the embedded capacity costs would be updated each year to reflect the most recent FERC Form-1 data.[34] Thus, AEP Ohio's embedded capacity costs may be volatile. And, unlike the PJM RPM prices, AEP Ohio's future costs are not known.

III. AEP OHIO'S PROPOSED CAPACITY CHARGE IS EXCESSIVE BECAUSE IT DOUBLE RECOVERS COSTS, INCLUDING STRANDED GENERATION COSTS

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[32] 2011 Brattle Report, p. i.

[33] *Id.*, p. 55.

[34] Pearce Direct, p. 21, lines 21-23.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING AEP OHIO'S PROPOSED CAPACITY CHARGE OF $355.72/MW-DAY.

First, as I have previously discussed, AEP Ohio's proposed capacity price of $355.72/MW-day to be charged to CRES providers is anticompetitive, unduly discriminatory, and clearly contrary to state policy promoting retail electric competition. AEP Ohio is attempting to double recover costs that it had previously agreed to forgo as part of the "transition to competition" that began on January 1, 2001. Because Ohio policy requires that AEP Ohio's generating assets be on their own in the competitive market, the correct capacity price is the RPM price. Moreover, the proposed capacity price of $355.72/MW-day is inconsistent with AEP Ohio's own statements in its 2012 Corporate Separation Plan.[35]

Second, even if AEP Ohio is correct that the PUCO is not prohibited from selecting a cost-based capacity charge as the state compensation mechanism, AEP Ohio wrongly equates "cost-based" with "full embedded cost." They are not the same. Mr. Stoddard explains that "cost based" for purposes of the RAA means the Avoided Cost Rate.

Third, AEP Ohio's formula rate analysis is incorrect. In Section III.C, below, I show that the corrected formula rate should not exceed $78.53/MW-day, based on data published in CSP's and OPC's 2010 FERC Form-1 filings.

Among the many failings of AEP Ohio's formula rate is AEP Ohio witness Pearce's inclusion in his capacity cost ratebase of the capital costs of the Darby Electric Generating Station and Waterford Energy Center generating facilities. These were

[35] This proposed capacity price also is not what AEP Ohio has proposed to charge under its revised ESP II proposal filed March 31, 2012 in Case Nos. 11-346-EL-SSO, et al., which is a two-tier proposal of $146/MW-day for a limited amount of shopping customers and $255/MW-day for the rest.

purchased by AEP Ohio after the January 1, 2001 transition date as merchant generating plants. Therefore, AEP Ohio has no basis for including the capital costs of these plants, over $400 million, in its capacity cost calculations. Indeed, in an Entry on Rehearing in Case No. 08-917-EL-SSO et al., the PUCO rejected inclusion of these units' costs in AEP Ohio's SSO rates.[36] Therefore, their costs are properly excluded from any capacity charge estimate.

Fourth, AEP Ohio wrongly argues that it should be allowed to keep <u>all</u> of the profits it earns from off-system energy sales.[37] AEP Ohio witness Pearce reasons that AEP Ohio is entitled to all of the profits it earns from off-system energy sales because "[o]btaining capacity through PJM's RPM market or through a FRR plan does not provide any rights or a call option on energy at any price. Energy must be separately procured by all PJM load-serving entities."[38] However, the fact that PJM has separate energy and capacity markets is irrelevant. If a regulated utility's customers are paying the utility for all of its generating costs, 100% of the profits from off-system sales should be returned to those customers.

Fifth, AEP Ohio wrongly argues that the PUCO has supported AEP Ohio recovering $2.5 billion in environmental compliance costs from capacity cost charges. In fact, the PUCO has supported recovery of the carrying costs of environmental capital investments as part of the SSO rate, including the bypassable Environmental Incremental

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[36] *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>Entry on Rehearing</u>, July 23, 2009, par. 100.

[37] *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 ("Pearce Direct"), p. 14, lines 11-23.

[38] Pearce Direct, p. 13, lines 20-22.

Carrying Cost Charge Rider ("EICCR"). The PUCO was not referring to including those same costs in the price charged to CRES providers for capacity.

A. <u>AEP Ohio's Rationale for Charging a Full Embedded-Cost Rate for Capacity is Unsupported</u>

Q. DOES AEP OHIO OFFER ANY OTHER ARGUMENTS AS TO WHY CHARGING A FULL-EMBEDDED COST RATE IS JUSTIFIED?

A. Yes. In its arguments for stranded cost recovery and that the PUCO could approve a cost-based capacity charge, AEP Ohio argues that it has avoided the "volatile and uncertain" RPM market by virtue of its status as an FRR entity. This argument rings hollow when one compares the price AEP Ohio proposes it be allowed to charge for capacity and the PJM RPM market prices in the current and next three planning years, June 1, 2011 through May 31, 2015, as shown in Table 2.

Table 2: RPM Billed Capacity Rate and AEP Ohio Proposed Charge

PJM Planning Year	RPM BRA Clearing Price ($/MW-day)	Final Zonal Capacity Price ($/MW-day)	Scaling Factor	Forecast Pool Requirement	Loss Factor	Billed RPM Capacity Rate ($/MW-day)	AEP Ohio Proposed Capacity Charge ($/MW-Day)	Percentage that AEP Ohio Proposed Exceeds Billed RPM
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
2011/12	$110.04	$116.15	1.1204	1.0833	1.03413	$145.78	$355.72	144%
2012/13	$16.46	$16.73	1.0572	1.0872	1.03413	$19.89	$355.72	1689%
2013/14	$27.73	$27.86	1.0881	1.0804	1.03413	$33.87	$355.72	950%
2014/15	$125.99	TBD	1.0928	1.0809	1.03413	$153.89	$355.72	131%
2011-2015 Average	**$70.06**					**$88.36**	**$355.72**	**303%**
2012-2015 Average	**$56.73**					**$69.22**	**$355.72**	**414%**

<u>Notes:</u>
[1]: Source - PJM RPM Auction User Information, http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item08
[2]: Price based on incremental auctions to-date. (No incremental auctions have been held for 2014/15.)
[3]: Source: RPM auction results spreadsheets
[4]: Source: RPM auction results spreadsheets
[5]: Source: PJM
[6]: Equals [2] x [3] x [4] x 5].
[7]: Source Pearce Direct
[8]: Equals { [7] / [8] } - 1.

Table 2 clarifies the importance of the issues in this case. It shows that the average delivered RPM capacity price for the current and next three planning years is \$88.36/MW-day. Over the next three planning years, the average billed RPM capacity rate will be just \$69.22/MW-day. Although these prices change each year, they are known with certainty.[39] AEP Ohio's proposed capacity charge, which AEP Ohio witness Pearce estimates to be \$355.72/MW-day based on 2010 FERC Form-1 data, is over **300%** higher than the average RPM billed capacity market rate over this four-year period, and over 400% higher for the next three planning years, beginning on June 1, 2012. For the next three planning years, the proposed capacity charge is over 400% higher than the average PJM RPM delivered price. For the 2012 planning year, which begins June 1, 2012, AEP Ohio's proposed capacity charge is almost **1,700%** higher than what CRES providers and thus AEP Ohio's non-SSO customers would otherwise pay. Over the next three years, this means that AEP Ohio distribution customers—both SSO and non-SSO alike—will pay an additional **\$2.8 billion**[40] premium for the privilege of avoiding these "volatile" RPM prices. Paying a 400% markup over market as "insurance" against volatile prices, when the volatile prices are already known, makes no economic sense.

[39] The exception is the final capacity price for the 2014/15 will not be established until after the three incremental auctions are completed. However, as the initial and final prices for planning years 2012/13 and 2013/14 show, the price change can be expected to be small.

[40] This is based on AEP Ohio's 5 coincident peak load ("5CP") in 2010 as reported in the Exhibits KDP-3 and KDP-4, p. 2. Calculated as follows: (9060.8 MW) x (\$355.72/MW-day - \$69.22/MW-day) x 365 days x 3 years ~ \$2.8 billion.

B. <u>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</u>

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?

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[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, <u>not</u> 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 standard service tariff, 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 guaranteed 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

[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. 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

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

[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 <u>after</u> 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 <u>customers</u>. 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.

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[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.

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.
- Lesser, J., "Renewable Energy and the Fallacy of 'Green' Jobs," *The Electricity Journal* (August 2010):45-53.
- Lesser, J., "Let the Tough Choices Begin: Affordable or Green?," *Natural Gas & Electricity* (June 2010): 27-29.
- Lesser, J., "Will Shale Gas Production be Damaged by Too Many Fraccing Complaints?," *Natural Gas & Electricity* (April 2010): 31-32.
- Lesser, J., "As the Climate Turns: The Saga Continues," *Natural Gas & Electricity* (February 2010): 29-32.
- Lesser, J. and N. Puga, "Public Policy and Private Interests: Why Transmission Planning and Cost-Allocation Methods Continue to Stifle Renewable Energy Policy Goals," *The Electricity Journal* (December 2009): 7-19.

- Lesser, J, "Short Circuit: Will Electric Cars Provide Energy and Environmental Salvation?" *Natural Gas & Electricity* (November 2009): 27-28.
- Lesser, J., "Green is the New Red: The High Cost of Green Jobs," *Natural Gas & Electricity* (August 2009): 31-32.
- Lesser, J., "Regulating Greenhouse Gas Emissions: EPA Gets Down," *Natural Gas & Electricity* (June 2009): 31-32.
- Lesser, J., "Being Reasonable While Regulating Greenhouse Gas Emissions under the Clean Air Act," *Natural Gas & Electricity* (April 2009): 30-32.
- Lesser, J., "Renewables, Becoming Cheaper, Are Suddenly Passé," *Natural Gas & Electricity* (February 2009): 30-32.
- Lesser, J., "Measuring the Costs and the Benefits of Energy Development," *Natural Gas & Electricity* (December 2008): 30-32.
- Lesser, J., "Comparing the Benefits and the Costs of Energy Development," *Natural Gas & Electricity* (October 2008): 31-32.
- Lesser, J., "New Source Review Is Still Anything but Routine," *Natural Gas & Electricity* (August 2008): 31-32.
- Lesser, J., and N. Puga, "PV versus Solar Thermal," *Public Utilities Fortnightly* 146 (July 2008), pp. 16-20, 27.
- Lesser, J., "Cap-and-Trade for Gasoline?," *Wall Street Journal*, June 14, 2008, A14.
- Lesser, J., "Kansas Secretary Unilaterally Bans Coal Plants," *Natural Gas & Electricity* (June 2008): 30-32.
- Lesser, J., "Seeing Through a Glass, Darkly, Banks Approach Coal-Fired Power Financing," *Natural Gas & Electricity* (April 2008): 29-31.
- Lesser, J., "The Energy Independence and Security Act of 2007: No Subsidy Left Behind," *Natural Gas & Electricity* (February 2008): 29-31.
- Lesser, J., "Control of Greenhouse Gases: Difficult with Either Cap-and-Trade or Tax-and-Spend." *Natural Gas & Electricity* (December 2007): 28-31.
- Lesser, J., "Déjà vu All Over Again: The Grass was not Greener Under Utility Regulation." *The Electricity Journal* 20 (December 2007): 35–39.

- Lesser, J., "Blowin' in the Wind: Renewable Energy Mandates, Electric Rates, and Environmental Quality." *Natural Gas & Electricity* (October 2007): 26-28.
- Lesser, J., "No Leg to Stand On." *Natural Gas & Electricity* (August 2007): 28–31.
- Lesser, J., "Goldilocks Chills Out." *Natural Gas & Electricity* (July 2007): 26–28.
- Lesser, J., "Goldilocks and the Three Climates." *Natural Gas & Electricity* (April 2007): 22–24.
- Lesser, J., "Command-and-Control Still Lurks in Every Legislature." *Natural Gas & Electricity* (February 2007): 8–12.
- Lesser, J., and G. Israilevich, "The Capacity Market Enigma." *Public Utilities Fortnightly* 143 (December 2005): 38-42.
- Lesser, J., "Overblown Promises: The Hidden Costs of Symbolic Environmentalism." *Livin' Vermont* 1 (January/February 2005): 7, 27.
- Lesser, J., "Regulation by Litigation." *Public Utilities Fortnightly* 142 (October 2004): 24–29.
- Lesser, J., "ROE: The Gorilla is Still at the Door." *Public Utilities Fortnightly* 144 (July 2004): 19–23.
- Lesser, J., and S. Chapel, "Keys to Transmission and Distribution Reliability." *Public Utilities Fortnightly* 142 (April 2004): 58–62.
- Lesser, J. ,"DCF Utility Valuation: Still the Gold Standard?" *Public Utilities Fortnightly* 141 (February 15, 2003): 14–21.
- Lesser, J., "Welcome to the New Era of Resource Planning: Why Restructuring May Lead to More Complex Regulation, Not Less." *The Electricity Journal* 15 (July 2002): 20–28.
- Lesser, J., and C. Feinstein, "Identifying Applications for Distributed Generation: Hype vs. Hope." *Public Utilities Fortnightly* 140 (June 1, 2002): 20–28.
- Lesser, J., et al., "Utility Resource Planning: The Need for a New Approach." *Public Utilities Fortnightly* 140 (January 15, 2002): 24–27.
- Lesser, J., "Distribution Utilities: Forgotten Orphans of Electric Restructuring?" *Public Utilities Fortnightly* 137 (March 1, 1999): 50–55.

- Lesser, J., "Regulating Distribution Utilities in a Restructured World." *The Electricity Journal* 12 (January/February 1999): 40–48.
- Lesser, J., "Is it How Much or Who Pays? A Response to Rothkopf." *The Electricity Journal* 10 (December 1997): 17–22.
- Lesser, J., and M. Ainspan, "Using Markets to Value Stranded Costs." *The Electricity Journal* (October 1996): 66–74.
- Lesser, J., "Economic Analysis of Distributed Resources: An Introduction." *Proceedings*, First Annual Conference on Distributed Resources, Electric Power Research Institute, Kansas City, MO, July 1995.
- Lesser, J., "Distributed Resources as a Competitive Opportunity: The Small Utility Perspective." *Proceedings*, First Annual Conference on Distributed Resources, Electric Power Research Institute, Kansas City, MO, July 1995.
- Lesser, J., and M. Ainspan, "Retail Wheeling: Deja vu All Over Again?" *The Electricity Journal* 7 (April 1994): 33–49.
- Lesser, J., "An Economically Rational Approach to Least-Cost Planning: Comment." *The Electricity Journal* 4 (October 1991).
- Lesser, J., "Long-Term Utility Planning Under Uncertainty: A New Approach." Paper presented for the Electric Power Research Institute: *Innovations in Pricing and Planning*, May 1990.
- Lesser, J., "Centralized vs. Decentralized Resource Acquisition: Implications for Bidding Strategies." *Public Utilities Fortnightly* (June 1990).
- Lesser, J., "Most Value—The Right Measure for the Wrong Market?" *The Electricity Journal* 2 (December 1989): 47–51.

Selected speaking engagements

- "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.

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S DISCOVERY RESPONSES TO FIRSTENERGY SOLUTIONS, CORP. DISCOVERY REQUEST IN PUCO CASE NO. 10-2929-EL-UNC SECOND SET

INTERROGATORY NO. 2-12:

a. Do the off-system sales revenues reported by CSP and OPC in FERC Account 447 (Sales for Resale) on page 311 of CSP's and OPC's respective 2010 FERC Form -1 Reports represent gross sales revenues from their owned generating assets?

b. Or do those off-system sales revenues reflect CSP's and OPC's respective shares under Article 7.5, "Settlement for Power Sales to Foreign Companies" of the Pool Agreement?

c. If the answer is gross sales revenues, please explain whether the amounts shown on p. 262 of CSP's and OPC's respective 2010 FERC Form 1 filings for taxes paid have been adjusted for net revenues received under the Pool Agreement and, if not, why not.

d. Please identify each individual tax that was adjusted for net revenues received under the Pool Agreement.

RESPONSE:

A. No.

B. CSP and OPCo receive their respective MLR shares of resulting off system sales (OSS) margins from AEP East Pool OSS activity per article 7.5 of the IA.

C. Not applicable.

D. Net revenues received under the Pool Agreement effect taxable income, which impacts state and federal income taxes. The PUCO, OUCC and CAT taxes are not included in the formula rate. The pool capacity charge also includes a component for taxes.

Prepared by Kelly Pearce.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Direct Testimony of Jonathan A. Lesser* was served this 4th day of April, 2012, via e-mail upon the parties below.

/s/ *Laura McBride*
One of the Attorneys for FirstEnergy Solutions Corp.

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