BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals	))))	Case No. 10-2376-EL-UNC
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan	))))))	Case No. 11-346-EL-SSO Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority	))))	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM
In the Matter of the Application of Columbus Southern Power Company to Amend its Emergency Curtailment Service Riders	))))	Case No. 10-343-EL-ATA
In the Matter of the Application of Ohio Power Company to Amend its Emergency Curtailment Service Riders	))))	Case No. 10-344-EL-ATA
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
In the Matter of the Application of Columbus Southern Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Ordered Under Ohio Revised Code 4928.144	)))))	Case No. 11-4920-EL-RDR

TESTIMONY OF
MICHAEL M. SCHNITZER
ON BEHALF OF
FIRSTENERGY SOLUTIONS CORP.

PUBLIC VERSION

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I. BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME.

A. Michael M. Schnitzer.

Q. WHAT IS YOUR BUSINESS ADDRESS?

A. My business address is 30 Monument Square, Concord MA 01742.

Q. MR. SCHNITZER, BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a Director of The NorthBridge Group, Inc. ("NorthBridge"). NorthBridge is a consulting firm that provides economic and strategic advice to the electric and natural gas industries.

Q. MR. SCHNITZER, PLEASE SUMMARIZE YOUR RELEVANT EXPERIENCE IN THE ELECTRIC ENERGY INDUSTRY.

A. In 1992, I co-founded NorthBridge. Before that, I was a Managing Director of Putnam, Hayes & Bartlett, which I joined in 1979. I have focused throughout this time on advising energy companies about strategic issues, particularly those relating to finance and market structure issues. In so doing, I have experience working with private sector clients in the electric utility, natural gas, private power, and steel industries, as well as with public and nonprofit agencies.

I have testified before the Federal Energy Regulatory Commission ("FERC") and a number of state commissions and departments on issues relating to competitive restructuring and wholesale market design, including Locational Marginal Pricing ("LMP") and Financial Transmission Rights, Regional Transmission Organizations ("RTO"), standard market design, resource adequacy, and transmission expansion pricing. On several occasions I have been invited by FERC staff to participate as a panelist in technical conferences on these subjects. I have also testified before several state commissions and departments on the subject of provision of default service to retail customers, including evaluation of competitive procurement proposals.

Q. MR. SCHNITZER, PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Master of Science degree in Management from the Sloan School of Management, of the Massachusetts Institute of Technology, which I received in 1979. My concentration was in finance. I also received a Bachelor of Arts degree in chemistry, with honors, from Harvard College in 1975. My resume is attached as Exhibit MMS-1 to this testimony.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY TO THE PUBLIC UTILITIES COMMISSION OF OHIO ("COMMISSION" OR "PUCO")?

A. Yes. I testified on behalf of Ohio Edison Company, the Cleveland Electric Illuminating Company, and the Toledo Edison Company, in Case No. 09-906-EL-SSO, on behalf of Constellation New Energy and Constellation Energy Commodities Group, Inc. in Case No. 08-0935-EL-SSO, and on behalf of Cinergy Gas & Electric in Docket No. 95-656-GA-AIR.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

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

II. PURPOSE OF TESTIMONY AND CONCLUSIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. AEP Ohio[1] filed a Stipulation and Recommendation ("Stipulation") with certain parties ("Signatory Parties") regarding its Electric Security Plan ("ESP"), the establishment of capacity charges, and other issues. The proposed ESP under the Stipulation would establish Standard Service Offer ("SSO") rates from January 1, 2012 through May 31, 2016. The Stipulation includes significant changes from AEP Ohio's initial ESP proposal filed on January 27, 2011 ("Initial ESP Proposal"). The principal purpose of my testimony is to provide an assessment of the Stipulation and in particular to assess whether the Stipulation ESP Price is more favorable than the expected price under a Market Rate Offer ("MRO") plan. I also assess whether, in a broader perspective, the Stipulation ESP would benefit customers and the development of competitive markets.

Q. COULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS?

A. I have three main conclusions:

1. AEP Ohio's 2012 to May 2015 price analysis contains significant omissions and speculative assumptions that overstate the price benefits of the Stipulation:

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[1] Columbus Southern Power Company ("CSP") and Ohio Power Company ("OPCo") are the AEP Ohio Companies, and also comprise "AEP Ohio" or the "Company" as referenced in this testimony.

a) AEP Ohio understates the Stipulation ESP Price by underestimating fuel costs and ignoring potential costs associated with the Generation Resource Rider ("GRR") and the Pool Modification Rider ("PMR").

b) AEP Ohio overstates the Competitive Benchmark Price component of the MRO Price by assuming the Commission would resolve the capacity pricing issue in the same manner as the negotiated capacity prices in the Stipulation.[2]

c) Under more reasonable alternative assumptions with respect to these items, the Stipulation ESP Price would not be more favorable than the price result under an MRO.[3]

d) The Stipulation would result in excess costs to the AEP Ohio zone as compared to an MRO – ranging from $100 million to as much as $800 million.[4] In addition, a modified ESP that relies fully on competitive solicitations for SSO supply could save customers $1.0 billion over the January 2012 through May 2015 period, as compared to the prices under the Stipulation.

2. During the period through May 2015, the above-market capacity price ($255 per MW-day) for CRES suppliers above the RPM set-aside caps effectively precludes

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[2] In other words, AEP Ohio's price analysis assumes that under an MRO the Commission would have approved above-market capacity prices at the levels established in the Stipulation.

[3] This is especially true if the Commission under an MRO would have continued its current policy of AEP Ohio charging competitive retail electric service ("CRES") suppliers for capacity at RPM prices.

[4] These estimates do not take into account other elements identified by Witness Lesser which, as he describes, would make the ESP even less favorable.

retail competition for the majority of customers and exposes them to above-market Stipulation ESP Prices.

3. The GRR could harm customers because it would likely result in costly generation investments even when no generation is needed and cheaper resource alternatives exist in the market.

My conclusions are described further in the pages that follow after a brief description of the key terms of the Stipulation.

III. KEY TERMS OF THE STIPULATION

Q. WHAT ARE THE KEY TERMS OF THE STIPULATION?

A. The Stipulation includes significant changes from AEP Ohio's Initial ESP Proposal filed in January. Several important terms of the Stipulation include:

1. AEP Ohio agreed to transition to a competitive procurement process to meet its SSO obligation, but not until the June 1, 2015 through May 31, 2016 period.

2. AEP Ohio agreed to participate in the RPM capacity market effective June 1, 2015.[5] In the interim, the Signatory Parties recommended that the Commission set the capacity charge in Case No. 10-2929-EL-UNC to be the PJM RPM-based rate except that an interim rate of $255 per MW-day, effective starting in January 2012, will be charged to CRES providers for all shopping above specific thresholds. According to the Stipulation, there will be a set-aside of RPM-priced capacity available as follows: 21% of AEP Ohio's total retail load in 2012 (based on total

[5] Stipulation, IV.1.r., at 11.

kWh retail sales), 29% in 2013 until securitization is completed when it will become 31% for the remaining portion of 2013,[6] and 41% in 2014 continuing through the first half of 2015.[7]

3. AEP Ohio dropped its proposals to impose non-bypassable charges for generation-related costs, including the Facilities Closure Cost Recovery Rider, the NERC Compliance Cost Recovery Rider, the Carbon Capture and Sequestration Rider, the Provider of Last Resort Rider, the Environmental Investment Carrying Charge Rider ("EICCR"), and the Rate Security Rider.[8]

4. AEP Ohio will be able to seek approval of the Turning Point Solar Project and a new 500 MW combined-cycle generating plant at Muskingum River ("MR6") in the GRR during the term of the ESP. In addition, the Signatory Parties agreed that any non-bypassable surcharge approved by the Commission for inclusion in the GRR shall reflect the net cost of the facility, including fuel and operating and maintenance costs, associated with the facility.[9] AEP Ohio also agreed to pursue development of up to 350 MW of customer-sited combined heat and power, waste energy recovery and distributed generation resources in its service territory, with costs to be recovered under an appropriate rider.[10]

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[6] If securitization is completed prior to January 1, 2013, then the applicable set aside for the entirety of 2013 will be 31%.

[7] Stipulation, IV.2.b.3., at 21.

[8] Stipulation, IV.1.a., at 4.

[9] Stipulation, IV.1.d., at 6.

[10] Stipulation, IV.2.c., at 23.

5. The Signatory Parties agreed to annual increases to the (non-fuel) bypassable base generation rate.[11]

6. AEP Ohio agreed to certain retail market enhancements (*e.g.*, to add capacity and transmission information to master customers lists, to eliminate the 90-day customer notice requirement before switching to a CRES provider, to discuss reducing the $10 switching fee, and to eliminate the current minimum stay rules by June 1, 2015).[12]

Q. MR. SCHNITZER, WHAT ARE YOUR PRIMARY CONCERNS RELATED TO THE STIPULATION?

A. My primary concerns are that the Stipulation delays the implementation of competitive procurement of SSO supply in AEP Ohio's territory and, in the interim, effectively limits retail competition for the majority of customers. As a policy matter, I support the move to competitive procurement of SSO supply and AEP Ohio's participation in the RPM capacity market. I also support the elimination of non-bypassable generation charges funded by ratepayers and other efforts to promote effective wholesale and retail competition. However, the Stipulation contains terms that continue to raise concerns. My primary concerns related to the Stipulation include:

- Under reasonable assumptions, the Stipulation ESP Price is not more favorable than the price under an MRO through May 2015 and would result in excess costs to the

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[11] The Stipulation includes negotiated (non-fuel) average base generation rates of $0.0245 per kWh starting in January of 2012, $0.0257 per kWh in January of 2013 and $0.0272 per kWh in January of 2014 to be in effect through May 31, 2015. Stipulation, IV.1.f., at 7.

[12] Stipulation, IV.1.s., at 14-15.

AEP Ohio zone as compared to an MRO ranging from $100 million to as much as $800 million;[13]

- During the period through May 2015, the above-market capacity price ($255 per MW-day) for CRES suppliers above the RPM set-aside caps effectively precludes retail competition for the majority of customers and exposes them to above-market Stipulation ESP Prices; and

- Customers would be required to pay new above-market costs through a non-bypassable generation charge for investments if they were included in the GRR.

These concerns are described in more detail below.

IV. AEP OHIO'S 2012 TO MAY 2015 PRICE ANALYSIS CONTAINS SIGNIFICANT OMISSIONS AND SPECULATIVE ASSUMPTIONS THAT OVERSTATE THE PRICE BENEFITS OF THE STIPULATION

Q. DOES AEP OHIO ATTEMPT TO SHOW THAT THE PROPOSED ESP UNDER THE STIPULATION SATISFIES THE STATUTORY TEST THAT IT BE MORE FAVORABLE IN THE AGGREGATE THAN THE EXPECTED RESULTS OF AN MRO?

A. AEP Ohio witness Hamrock offers testimony that concludes "in conjunction with Company witnesses Allen and Thomas that AEP Ohio's proposed ESP, as modified by the Stipulation, including its pricing and other terms and conditions, is more favorable in the aggregate than the expected results that would otherwise apply under a market rate offer

[13] These estimates do not take into account other elements identified by Witness Lesser which, as he describes, would make the ESP even less favorable.

(MRO)."[14] Mr. Hamrock's conclusion appears to be based on the price comparison presented by Company witness Thomas, other quantifiable benefits presented by Company witness Allen, and other less-quantifiable benefits that he presents. Comparing the price under the Stipulation ESP and under an MRO is a key component of the "more favorable in the aggregate" test, so I address this issue first.

Q. WHAT IS THE BASIS OF AEP OHIO'S CLAIM THAT THE STIPULATION PRICE IS MORE FAVORABLE THAN THE EXPECTED PRICE IN AN MRO?

A. AEP Ohio presents the testimony of Ms. Thomas, which purports to compare the Stipulation ESP Price to the price that she expects would be realized under an MRO.[15] Specifically, her Exhibit LJT-2 compares an "MRO Annual Price" (or "MRO Price") that she calculates to the Company's "Stipulation ESP Price." The MRO Price that Ms. Thomas calculates is a blended price consisting partly of a "Competitive Benchmark Price" and partly of a legacy ESP "Total Generation Service Price."[16] The Total Generation Service Price is a function of generation pricing from AEP Ohio's 2009-2011 ESP adjusted for certain generation-related items.[17] The MRO Price calculated for the ESP period is a blend of these two prices because the Ohio Revised Code requires that an MRO offered by an EDU that owns generation phase in an increasing percentage of the necessary default service supply from the market over time.[18]

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[14] Stipulation Testimony of Joseph Hamrock on Behalf of CSP and OPCo, at 4.

[15] Stipulation Testimony of Laura Thomas on Behalf of CSP and OPCo, Exhibit LJT-2.

[16] In Ms. Thomas' Exhibit LJT-2, the Competitive Benchmark Price is also referred to as the Expected Bid Price.

[17] Stipulation Testimony of Laura Thomas on Behalf of CSP and OPCo, at 12, lines 1-15.

[18] Ohio Revised Code Section 4928.142(D).

Q. WHAT DOES MS. THOMAS' ANALYSIS IN EXHIBIT LJT-2 SHOW?

A. Ms. Thomas concludes that, between January 2012 and May 2015, the average MRO Price would be $62.82 and that the average Stipulation ESP Price would be $61.15, so the net benefit of the Stipulation ESP is $1.67 per MWH. Using this price comparison, Ms. Thomas claims that the Stipulation ESP Price is more favorable than the expected price under an MRO.

Q. DO YOU AGREE WITH MS. THOMAS' CONCLUSION?

A. No. Ms. Thomas' conclusion should be disregarded because her analysis contains material flaws and the price benefits claimed by AEP Ohio are overstated – potentially significantly so. There are four major flaws in the analysis:

- **AEP Ohio understates the Stipulation ESP Price by as much as $[redacted] per MWH:** The Stipulation ESP Price understates fuel costs and omits important rider costs (*i.e.*, the GRR and PMR) that are expected to be incurred during the ESP period.

- **AEP Ohio overstates the Competitive Benchmark Price by up to $9 per MWH:** The MRO case assumes very aggressive "but for" treatment by the Commission with respect to capacity costs.[19] Ms. Thomas' analysis in effect assumes that the Commission, under the MRO option, would approve above-market capacity rates for CRES suppliers equal to those established in the Stipulation – capacity rates that are higher than those approved by the Commission and in effect today.

[19] The term "but for" refers to what would be in place absent Commission approval of either the Stipulation or a new Company ESP proposal. In other words, what would happen if the Company continued its business under the current ESP plan or under an MRO. This has implications for expected CRES capacity costs as well as for other costs (*e.g.*, fuel, environmental compliance, POLR charge, etc.) that could otherwise be recovered absent a new ESP. I have considered this "but for" world in my assessment of the price under an MRO.

- **AEP Ohio understates the Legacy ESP Total Generation Service Price by $[redacted] to $[redacted] per MWH:** The Total Generation Service Price used in AEP Ohio's analysis does not reflect increasing fuel costs and environmental compliance costs that are expected over the ESP period.

- **AEP Ohio incorrectly assumes the same level of customer shopping under both the Stipulation ESP and an MRO**: Ms. Thomas uses estimated retained load to weight the annual Stipulation ESP and MRO prices to develop her weighted average prices shown in Exhibit LJT-2.[20] There are two problems. First, the retained load in MWH is too high and does not reflect the higher levels of customers currently shopping. Second, Ms. Thomas assumes the same retained load (*i.e.*, the same level of shopping) under the Stipulation ESP as under an MRO, even though the "savings opportunity" (*i.e.*, the difference between the bypassable generation charges and the CRES market cost of service) is likely to be higher under the Stipulation ESP (for switching levels up to the cap) than under an MRO.

After making these corrections and considering reasonable assumptions with respect to these items, the Stipulation ESP Price would not be more favorable than the price result under an MRO.

Q. PLEASE SUMMARIZE YOUR CORRECTIONS TO MS. THOMAS' ANALYSIS.

A. I have made the following corrections to the Stipulation ESP Price, the Competitive Benchmark Price, and the Total Generation Service Price:

[20] LJT Workpaper, "Final Exhibit – MRO Price Test with Input Data.xls."

Stipulation ESP Price

- **Fuel** – I forecasted the Company's FAC rider recovery through May 2015 based on data provided by the Company in discovery.[21]

- **Generation Resource Rider** – I relied on the Company's forecast of the Turning Point Solar Project revenue requirements.[22]

- **Pool Modification Rider** – I developed a high and low estimate of the financial impact of the PMR beginning on September 1, 2013.[23]

My corrections to the Stipulation ESP Price are shown in Exhibit MMS-2.

Competitive Benchmark Price

- **Capacity** – I replaced the negotiated Stipulation capacity prices assumed in Ms. Thomas' analysis with RPM market prices. The basis for this change is described later in my testimony and in the testimony of Dr. Lesser and Dr. Shanker.

- **Other** – I calculated the other costs in Ms. Thomas' Competitive Benchmark Price model, taking into account the "ripple" effects of the capacity assumption above on the other cost components.[24]

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[21] Both Ms. Thomas (LJT-2) and Staff witness Fortney (Attachment A) rely on fuel prices that are $33 per MWH with slight differences. Meanwhile, AEP Ohio's fuel cost forecast is much higher – ranging from $[redacted] per MWH in 2012 to $[redacted] per MWH in 2014 (AEP Ohio Interrogatory Response, FES-1-1 RESTRICTED ACCESS CONFIDENTIAL).

[22] I assume that the MR6 project will not be in service until on or after June 1, 2015. Therefore, it does not affect the calculations that I show later. If the MR6 project were placed in service before and GRR cost recovery commenced prior to June 2015, then the Stipulation ESP Price would increase relative to the MRO Price.

[23] Staff witness Fortney lists in Attachment A the Pool Termination Modification Provision under "Things that are part of the ESP but would not be in an MRO," but describes these costs as "Unknown." Therefore, the costs associated with this rider are not included in the Staff's price comparison.

My corrections to the Competitive Benchmark Price are shown in Exhibit MMS-3.

Total Generation Service Price (Legacy ESP)[25]

- **Fuel** – I forecasted the Company's FAC rider recovery through May 2015 based on data provided by the Company in discovery.

- **Environmental** – Assuming the EICCR mechanism currently in place is used to recover costs incurred to comply with environmental compliance consistent with R.C. 4928.142(D), I estimated low and high scenarios based on the Company's June 9, 2011 forecast range of environmental capital costs.[26]

- **Other Sensitivity Analyses** – I considered the impact of including or not including the POLR charge[27] and Sporn 5 closure costs.

Retained Load Forecasts

- **Retained Load Forecasts** – Under the Stipulation ESP, I adjusted the retained load forecast to be consistent with shopping at the RPM caps in each year.[28] Under the MRO, I assume that shopping remains at current levels.

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[24] I used the same energy forwards as Ms. Thomas and Staff. I reviewed more recent forwards as of September and observed that the differences were immaterial for purposes of comparison.

[25] These corrections, all else equal, increase the MRO Price, and present a more accurate depiction of future prices under an MRO.

[26] AEP Ohio witness Hamrock discusses the Stipulation benefit of eliminating the EICCR. My analysis, unlike AEP Ohio's, quantifies this benefit by including these costs in the Total Generation Service Price. Stipulation Testimony of Joseph Hamrock on Behalf of CSP and OPCo, at 14-15.

[27] It is my understanding that the Commission has not yet reached a determination on AEP Ohio's Remand Proceeding (Case No. 08-917-EL-SSO) and, therefore, the existence and size of any POLR charge that would be incorporated into a continuing SSO is in question. It also is my understanding that numerous parties argued that there should be no POLR charge at all and that the Commission Staff argued that AEP Ohio's calculation was significantly overstated. Therefore, it is possible that AEP Ohio's generation service rate would not include the full $3.07 POLR charge, and my sensitivity analysis was intended to depict the high and low range of possible outcomes.

The corrected MRO Price Test (*i.e.*, the corrected LJT-2) results from the above adjustments are shown in Exhibit MMS-4.

A. AEP OHIO UNDERSTATES THE STIPULATION ESP PRICE BY UNDERESTIMATING FUEL COSTS AND IGNORING POTENTIAL COSTS ASSOCIATED WITH THE GRR AND THE PMR

Q. TURNING NOW TO THE STIPULATION ESP PRICE, PLEASE EXPLAIN FURTHER MS. THOMAS' UNDERESTIMATION OF THE STIPULATION ESP PRICE.

A. Ms. Thomas' Stipulation ESP Price is too low because it significantly understates the fuel costs and omits the likely costs and risks that customers would face related to the GRR and PMR under the Stipulation. Including the Company's higher fuel costs and the costs associated with these proposed generation-related riders increases the Stipulation ESP Price by as much as $[redacted] per MWH. My adjustments are summarized in Exhibit MMS-2.

Q. HOW DID MS. THOMAS DEVELOP THE STIPULATION ESP PRICE?

A. The Stipulation ESP Price shown on line 15 of Exhibit LJT-2 consists of the Tariff Generation Price or Proposed Base G rate, plus "2011 Full Fuel" and 2010/11 transmission-related expenses.[29] These 2011 costs are held constant throughout the ESP period from January 2012 through May 2015.

Q. WHAT ARE THE MAIN PROBLEMS WITH MS. THOMAS' ESTIMATE OF THE STIPULATION ESP PRICE?

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[28] This correction, all else equal, lowers the load-weighted average Stipulation ESP Price.

[29] These include PJM administrative, scheduling, and certain ancillary service charges for a 12 month 2010/11 period that represent the types of charges that a competitive supplier would also incur.

A. There are two main errors in the calculation. First, Ms. Thomas underestimates the fuel cost component of the Stipulation ESP Price. Because fuel cost recovery under the FAC is expected to increase, according to AEP Ohio's own forecast, the 2011 cost is not a reliable proxy for future costs. Holding fuel costs constant, while increasing the energy costs in the Competitive Benchmark Price in the MRO, as Ms. Thomas does, creates a systemic bias in AEP Ohio's calculations.

The second serious error is that the Stipulation ESP Price does not include the costs that would be imposed on customers by the GRR and the PMR. In effect, these costs are assumed to be zero in her analysis since they are not included in the Stipulation ESP Price. It is modeled as if AEP Ohio expects the Commission not to approve these costs. The failure to include any consideration of these costs renders AEP Ohio's estimate of the Stipulation ESP Price inaccurate and misleading.

Q. DID THE COMPANY PROVIDE ANY INFORMATION ABOUT HOW THE FAC OR AVERAGE FUEL COSTS MAY CHANGE DURING THE PROPOSED ESP PERIOD?

A. Yes. In discovery, the Company provided projected fuel revenues, sales and an average rate for the years 2012, 2013 and 2014. These figures are higher than the 2011 fuel charge embedded in the Stipulation ESP Price that Ms. Thomas relies on when performing her MRO price comparison.[30]

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[30] Both Ms. Thomas (LJT-2) and Staff witness Fortney (Attachment A) rely on fuel prices that are $33 per MWH with slight differences. Meanwhile, AEP's fuel cost forecasts are much higher – ranging from $[redacted] per MWH in 2012 to $[redacted] per MWH in 2014 (AEP Ohio Interrogatory Response, FES-1-1 RESTRICTED ACCESS CONFIDENTIAL).

Q. WHAT ADJUSTMENT SHOULD BE MADE TO THE STIPULATION ESP PRICE FOR FUEL COSTS?

A. To more accurately compare AEP Ohio's Stipulation ESP to an MRO, I replaced the 2011 fuel cost used by Ms. Thomas with the Company's projected average fuel costs on a $/MWH basis for 2012-2014 provided in discovery. To estimate the FAC for the first five months of 2015, I applied the same average growth found in the Company's estimates of FAC rates for the 2012 through 2014 period.

Q. MR. SCHNITZER, IS IT APPROPRIATE TO ASSUME THE COSTS OF THE GRR AND THE POOL MODIFICATION RIDER ARE ZERO IN THE MRO PRICE COMPARISON?

A. No. By ignoring these costs, AEP Ohio unfairly biases the comparison in favor of the Stipulation ESP.

Q. DO YOU AGREE WITH MS. THOMAS' ASSERTION THAT SINCE THE GRR IS A NON-BYPASSABLE RIDER, IT HAS NO IMPACT ON THE MRO TEST WHETHER OR NOT IT IS INCLUDED?[31]

A. No. The GRR is a new generation-related rider specific to the Company's Initial ESP Proposal and Stipulation ESP. It is not a rider that would be an element of an MRO. Therefore, it should be included in the Stipulation ESP Price but not the MRO Price. Staff

[31] Stipulation Testimony of Laura Thomas on Behalf of CSP and OPCo, at 16, lines 1-2.

witness Fortney also includes the GRR in the Stipulation ESP Price, but excludes it from the expected MRO price.[32]

Q. DOES MS. THOMAS EVEN MENTION THE BYPASSABLE[33] POOL MODIFICATION RIDER IN HER ANALYSIS?

A. No. She simply dismisses it stating that "[a]ll other riders are not for generation-related service and are not includable in the MRO Price Test for generation-related service."[34] I find it interesting that a rider intended to recover the Company's lost capacity revenues is not considered generation-related. As I describe further below, the PMR could result in large financial impacts of more than $[redacted] million, and should not be ignored.

Q. WHAT CORRECTIONS DID YOU MAKE TO THE STIPULATION ESP PRICE FOR THE GRR AND THE PMR?

A. Rather than assume that the GRR and PMR costs are zero in the MRO Price Test, I included the estimated costs for these riders. I prepared cost estimates based, for the most part, on information provided by the Company and publicly available information. Each correction is described below.

1. Generation Resource Rider

Q. HOW DID YOU ESTIMATE THE GRR?

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[32] Stipulation Testimony of Robert B. Fortney on Behalf of Staff, at 4, lines 7-8, Attachment A.

[33] In the Application, the PMR was proposed as bypassable. However, in response to interrogatory STIP-FES-INT-17-042 regarding the Stipulation, AEP Ohio stated it did not know if the PMR will be bypassable or not.

[34] Stipulation Testimony of Laura Thomas on Behalf of CSP and OPCo, at 16, lines 21-22.

A. In order to estimate the GRR, I relied upon AEP Ohio's forecast of the Turning Point Solar Project's revenue requirement, and netted out an estimate of the energy and capacity revenues that will be available to the facility.[35] For the purposes of comparing the Stipulation ESP to the expected results under an MRO, I assumed that the MR6 project is not in service until on or after June 1, 2015. If the MR6 project were placed in service and GRR cost recovery commenced prior to June 2015, then the Stipulation ESP Price would increase relative to the MRO Price. For purposes of comparison to an MRO, I have included in the Stipulation ESP Price a GRR of $[redacted] per MWH in 2013, $[redacted] per MWH in 2014, and $[redacted] per MWH in 2015.

Q. DOES THIS ESTIMATE OF THE GRR INCLUDE THE COSTS ASSOCIATED WITH AEP OHIO'S AGREEMENT TO PURSUE DEVELOPMENT OF UP TO 350 MW OF CUSTOMER-SITED COMBINED HEAT AND POWER, WASTE ENERGY RECOVERY AND DISTRIBUTED GENERATION RESOURCES, WITH THE COSTS TO BE RECOVERED UNDER AN "APPROPRIATE RIDER"?[36]

A. No. The details of this effort will be resolved in a separate proceeding before the Commission. I do not have sufficient information at this time to estimate these costs. Any additional costs associated this effort would be included in the Stipulation ESP Price, but not the MRO Price. Thus, the Stipulation ESP Price would increase relative to the MRO Price.

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[35] Supplemental Direct Testimony of Philip Nelson, PUCO Case No. 11-346-EL-SSO et al., 7/1/2011, Exhibit PJN-4, at 2.

[36] Stipulation, IV.2.c., at 23.

2. Pool Modification Provision

Q. HOW DID YOU ESTIMATE THE FINANCIAL IMPACT OF THE PMR?

A. I developed a high and low estimate of the financial impact of the PMR beginning on September 1, 2013 with calculation of the impact extending through May 31, 2015 and recovery of any losses occurring from the termination/modification date through May 31, 2016.[37] The PMR estimates are based on lost capacity revenues due to the termination of the AEP Pool.[38] For the high estimate, the capacity revenue losses were calculated as the difference between the AEP Ohio capacity transfer price[39] and the RPM capacity price.[40] In addition, I assumed that AEP Ohio would offset the lost capacity revenues with the associated incremental energy revenues as a result of pool termination.[41] Based on my analysis, the total potential impact of pool termination, net of offsetting increases in energy revenue, is more than $[redacted] million or $[redacted] per MWH. For the low estimate, rather than sell excess capacity and energy at market, I assume that AEP Ohio is able to

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[37] Pool termination/modification is assumed to occur by September 1, 2013, in line with the expectations of the Stipulation, IV.1.t, at 15 ("AEP Ohio agrees to collaborate with Staff and make all diligent efforts in order to achieve FERC approval of corporate separation and Pool dissolution or amendment such that full legal corporate separation of AEP Ohio can be implemented prior to the first scheduled auction under Paragraph 1.r above (i.e., before September of 2013)." The losses were assumed to be calculated through May 31, 2015 and collection was assumed to occur through May 31, 2016 based on AEP Ohio Interrogatory Response, FES 17th Set, STIP-FES-INT-17-17-043(A).

[38] To the extent that AEP Ohio would seek to recover other costs associated with pool termination besides lost capacity revenues, the PMR costs could be even higher than what I include in my analysis.

[39] Forecasted pool transfer prices for 2012-2014 were provided by AEP Ohio in AEP Ohio Interrogatory Response, PUCO Case No. 11-346-EL-SSO et al., FES 6th Set, INT-6-9 Attachment 1, "FES 6-009 Attachment 1." The average transfer price and monthly volumes from 2014 were extended through the first five months of 2015.

[40] When AEP modeled the costs associated with the termination of the AEP Pool for a study conducted in Indiana, it assumed that replacement capacity prices were those available from PJM's RPM market. (Study Report of AEP Interconnection Agreement submitted by Indiana Michigan Power to the Indiana Utility Regulatory Commission, IURC Cause No. 43306, 12/11/2009, at 25-30.)

[41] AEP Ohio Interrogatory Response, FES 17th Set, STIP-FES-INT-17-17-043(G).

negotiate prices with its affiliates that split the price difference between market and the forecasted transfer prices, thereby reducing the costs to be recovered in the rider by half.

B. AEP OHIO OVERSTATES THE COMPETITIVE BENCHMARK PRICE COMPONENT OF THE MRO PRICE BY ASSUMING THE COMMISSION WOULD RESOLVE THE CAPACITY PRICING ISSUE IN THE SAME MANNER AS THE STIPULATION

Q. TURNING NOW TO THE COMPETITIVE BENCHMARK PRICE, HOW DID YOU MAKE THE CORRECTIONS THAT YOU DESCRIBED EARLIER FOR CAPACITY AND OTHER COSTS?

A. I used the model that Ms. Thomas provided.[42] I replaced the Stipulation capacity prices with RPM capacity prices. The other costs were calculated by the model.[43]

Q. WHAT CAPACITY PRICE IS USED IN AEP OHIO'S ANALYSIS FOR THE MRO?

A. AEP Ohio's MRO analysis, as shown in Exhibit LJT-2, is based on a blending of the negotiated capacity prices in the Stipulation of $255 per MW-day and RPM.[44]

Q. HOW DOES AEP OHIO'S ASSUMED CAPACITY PRICE COMPARE WITH THE CAPACITY VALUES APPROVED BY THE COMMISSION?

A. The Commission has expressly adopted the capacity prices established by PJM's RPM forward capacity auction as the prices that AEP Ohio may charge CRES suppliers for

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[42] Workpapers provided 9/13/2011, "Ohio model to LT 3 scenarios 90811.xls."

[43] I also updated the retained load forecast used to calculate the weighted average Competitive Benchmark Price to be consistent with current levels of shopping. AEP Ohio's Interrogatory Response, Staff, DR-49, Attachment 1, COMPETITIVELY-SENSITIVE CONFIDENTIAL.

[44] Stipulation Testimony of Laura Thomas on Behalf of CSP and OPCo, at 9, lines 10-12.

capacity.[45] These RPM prices are $116.16 per MW-day for June 2011 – May 2012, $16.52 per MW-day for June 2012 – May 2013, $27.73 per MW-day for June 2013 – May 2014, and $125.94 for June 2014 – May 2015. In comparison, Ms. Thomas' assumed capacity price of $255 per MW-day is substantially higher than the capacity price approved by the Commission. Ms. Thomas blends the $255 per MW-day price with RPM prices using the RPM set-aside caps described in the Stipulation, resulting in a capacity price for each year that is higher than the appropriate RPM prices.

In Exhibit LJT-2, Ms. Thomas calculates the Competitive Benchmark Price with a $255 per MW-day capacity cost (line 4) and at RPM market capacity prices (line 6). According to her calculations, the $255 per MW-day assumption increases the Competitive Benchmark Price over the ESP period by $12.74 per MWH ($74.95-$62.21) above the Competitive Benchmark Price level at RPM market prices. Thus, the negotiated $255 per MW-day capacity price used in Ms. Thomas' MRO Price analysis is significantly higher than the RPM capacity prices that the Commission approved for CRES providers serving retail customers. Neither the $255 figure nor the blended capacity price in the Stipulation has been approved by the Commission or FERC.

Q. DOES MS. THOMAS ADMIT THAT THE CAPACITY COST COMPONENT IN HER ESTIMATE OF THE COMPETITIVE BENCHMARK PRICE SHOULD BE BASED ON THE CAPACITY COST THAT A CRES SUPPLIER WOULD INCUR TO SERVE A RETAIL CUSTOMER?

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[45] Dr. Shanker also describes the PJM Capacity Market design in his Testimony.

A. Yes, when describing the capacity cost component on page 7 of her direct testimony in the Initial ESP Proposal, she states that the capacity item "includes the capacity cost that a CRES (competitive electric retail service) provider would incur to serve a retail customer in AEP Ohio's service territory."[46] Again on page 4 of her direct testimony, Ms. Thomas states that the "Competitive Benchmark price is based on market data and includes the items that would be included by a supplier providing retail electric service to AEP Ohio customers." Despite these statements, Ms. Thomas' price comparison is <u>not</u>, in fact, based on the capacity cost that a CRES supplier would have to pay. The costs that a CRES supplier would pay under an MRO are the Commission-approved RPM clearing prices, not the negotiated Stipulation AEP Ohio capacity price or the capacity price filed in Case No. 10-2929-EL-UNC.[47]

Q. IN A PRIOR ESP FILING MADE BY THE COMPANY, DID AEP OHIO RELY ON PJM RPM PRICES TO DETERMINE THE CAPACITY COST COMPONENT OF THE COMPETITIVE BENCHMARK PRICE?

A. Yes. Contrary to Ms. Thomas's Stipulation analysis, AEP Ohio used PJM's RPM prices for capacity cost in its filing for its 2009-2011 ESP. In this prior ESP proceeding, Company witness Baker described the capacity cost component as follows:

> "PJM Capacity Obligations - This component reflects the cost of PJM's required capacity obligations for load serving entities <u>and was derived</u>

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[46] Direct Testimony of Laura Thomas on Behalf of CSP and OPCo, at 7, lines 12-14. Also see Stipulation Testimony of Laura Thomas on Behalf of CSP and OPCo, at 9, lines 6-8.

[47] Even if we assume that the Commission will not adopt the RPM clearing prices for AEP Ohio in that proceeding, I will demonstrate later that the capacity price used in Ms. Thomas' analysis is still far too high.

from the PJM Reliability Pricing Model (PJM Capacity Auction) results for the relevant time period."[48]

Thus, AEP Ohio clearly relied on PJM's RPM capacity price to derive the capacity cost component of the Competitive Benchmark Price under an MRO.

Q. HAS PUCO ADOPTED THE CAPACITY PRICE IN THE STIPULATION OR THE CAPACITY PRICE PROPOSED BY THE COMPANY IN CASE NO. 10-2929-EL-UNC?

A. No. The Commission's review of the Stipulation and the proposed changes to AEP Ohio's capacity price is currently ongoing. On December 8, 2010, the Commission issued an order finding it necessary to review the proposed changes,[49] and expressly adopted the RPM clearing prices as AEP Ohio's allowed compensation mechanism during the review.[50] In PUCO Case No. 10-2929-EL-UNC, the Commission confirmed that AEP Ohio's compensation level in retail rates was "[b]ased upon the continuation of the current capacity charges established by the three-year capacity auction conducted by PJM, Inc., under the current fixed resource requirement (FRR) mechanism."[51] AEP Ohio's proposed change to its capacity price also remains pending at FERC in Docket No. ER11-2183,

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[48] Direct Testimony of Craig Baker on Behalf of CSP and OPCo, Case No. 08-918-EL-SSO, at 11, lines 11-14, (emphasis added).

[49] As stated on page 2 of the Order, "As an initial step, the Commission seeks public comment regarding the following issues: (1) what changes to the current state mechanism are appropriate to determine the Companies' FRR capacity charges to Ohio competitive retail electric service (CRES) providers; (2) the degree to which AEP-Ohio's capacity charges are currently being recovered through retail rates approved by the Commission or other capacity charges; and (3) the impact of AEP-Ohio's capacity charges upon CRES providers and retail competition in Ohio."

[50] The Public Utilities Commission of Ohio Order, Case No. 10-2929-EL-UNC, December 8, 2010, at 2.

[51] The Public Utilities Commission of Ohio Order, Case No. 10-2929-EL-UNC, December 8, 2010, at 4.

after FERC initially "rejected [AEP Ohio's] rate schedules as unauthorized under the RAA."[52]

Q. IS THERE OTHER EVIDENCE TO SUGGEST THAT AEP OHIO'S PROPOSED CAPACITY PRICE IS WELL ABOVE MARKET?

A. Yes. Even if the Commission does not continue to adopt the RPM prices at the termination of Case No. 10-2929-EL-UNC, other evidence shows that the capacity price Ms. Thomas uses in her analysis is significantly above market. AEP Ohio's proposed capacity price is well above the capacity prices obtained in recent capacity auctions for FirstEnergy's Ohio service areas, which were necessary due to the integration of these areas into PJM. These auctions, held in March 2010,[53] solicited capacity for the ATSI Load Zone, which is comprised of the service areas of The Toledo Edison Company, The Cleveland Electric Illuminating Company, Ohio Edison Company, and Pennsylvania Power Company. The first three of these four service areas are in Ohio, and these Ohio service areas represent the overwhelming majority of the load in the ATSI Load Zone. The clearing prices in these auctions were $108.89 per MW-day for June 2011 – May 2012 and $20.46 per MW-day for June 2012 – May 2013.[54,55] These capacity prices are almost identical to the RPM auction clearing prices discussed earlier, and are significantly below Ms. Thomas' assumed $255 per MW-day capacity price.

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[52] Request for Rehearing of American Electric Power Service Corporation, FERC Docket ER11-2183, 2/22/2011 at 1, quoting *American Electric Power Service Corp.*, 134 FERC ¶ 61,039 (2011) at 1.

[53] ATSI Integration RPM Auction Dates.

[54] 2011/2012 & 2012/2013 ATSI FRR Integration Auction Results, at 1.

[55] A special integration auction was not required for June 2013 – May 2014, and the PJM RPM capacity prices are applicable to the ATSI Load Zone for this period.

Q. HOW DOES MS. THOMAS' ESTIMATE OF THE COMPETITIVE BENCHMARK PRICE CHANGE WHEN YOU CORRECT THE FLAWS THAT YOU HAVE IDENTIFIED?

A. Correcting for the capacity and other related cost components results in a significantly lower Competitive Benchmark Price. Using the Commission-approved RPM capacity price, as opposed to the capacity prices in the Stipulation, the Competitive Benchmark Price would be about $9 per MWH lower than Ms. Thomas' estimate. The results are summarized in Exhibit MMS-3.

C. <u>AEP OHIO UNDERSTATES THE LEGACY ESP TOTAL GENERATION SERVICE PRICE</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO THE TOTAL GENERATION SERVICE PRICE.

A. For purposes of comparison, the Total Generation Service Price (based on current ESP rates) that is used to calculate the blended MRO Price was adjusted upward for projected increases in fuel (FAC) and environmental investment (EICCR) costs under the riders currently in place over the ESP period.[56]

Q. WHAT ADJUSTMENT DID YOU MAKE TO THE TOTAL GENERATION SERVICE PRICE FOR FUEL COSTS?

A. To more accurately compare AEP Ohio's Stipulation ESP to an MRO, I replaced the 2011 fuel cost used by Ms. Thomas with the Company's projected annual fuel costs. I used the

[56] These adjustments present a more accurate depiction of the MRO Price absent Commission approval of the Stipulation.

same fuel costs as I did in the Stipulation ESP Price that I described earlier in my testimony. These fuel costs are higher than those shown in Ms. Thomas' Exhibit LJT-2.

Q. HOW DID YOU TREAT THE CURRENT EICCR IN THE LEGACY ESP WHEN DETERMINING THE TOTAL GENERATION SERVICE PRICE?

A. For the environmental compliance costs, I adjusted the 2011 EICCR figure ($0.90 per MWH) that Ms. Thomas assumes and holds constant throughout the ESP period upward to reflect known and measurable changes in environmental costs in the future consistent with R.C. 4928.142(D).

Q. WITH RESPECT TO THE EICCR, WHY DO YOU BELIEVE THAT FUTURE COSTS WILL BE HIGHER THAN THE 2011 COSTS INCLUDED IN EXHIBIT LJT-2?

A. AEP Ohio is expected to incur very large capital and O&M costs in order to comply with the consent decree signed by AEP and the Environmental Protection Agency ("EPA"),[57] and to meet the requirements of several new EPA rules.[58]

Q. WHAT IMPACT WILL THE COSTS RESULTING FROM THE CONSENT DECREE AND NEW EPA RULES HAVE ON THE EICCR?

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[57] The consent decree, which was signed on October 9, 2007, resolved a number of complaints filed against AEP and its affiliates related to compliance with the Clean Air Act. The consent decree obligates AEP to achieve specified sulfur, nitrous oxide and particulate emission reductions and install emission controls or otherwise achieve compliance at units. (AEP Press Release, "AEP Reaches Settlement Agreement in NSR Case," 10/9/2007. *See also*, Consent Decree, *United States et al. v. American Electric Power Service Corp*, 10/7/2007.)

[58] The EPA rules include but are not limited to the Cross-State Air Pollution Rule ("CSAPR"), the Toxics rule (also known as the "Hazardous Air Pollutants" or "MACT" rule), and the Coal Combustion Residuals ("CCR") rule. These rules are expected to cause AEP Ohio to install additional air emission controls and ash and water management systems at generating facilities.

A. AEP Ohio has estimated that compliance with the EPA's proposed environmental regulations may require expenditures of $2.1 billion to $2.8 billion by AEP Ohio between 2012 and 2020.[59] In discovery, AEP Ohio provided a high and low estimate of the annual capital expenditures necessary to comply with environmental regulations consistent with AEP's June 9, 2011 "Plan for Compliance with Proposed EPA Regulations."[60,61] Using AEP Ohio's annual estimates, it is possible to forecast the EICCR through 2020.

Q. WHAT IMPACT WOULD THESE ADDITIONAL COSTS HAVE ON THE EICCR?

A. To estimate the EICCR under the MRO, I used the current EICCR calculation methodology, which provides for investment recovery over a 25-year period. Using AEP's low forecast of annual costs to comply with proposed EPA regulations,[62] the 2015 EICCR would rise to $[redacted] per MWH. Alternately, assuming AEP Ohio is forced to accelerate its planned expenditures to meet the EPA's proposed deadlines and that AEP Ohio's compliance costs do not exceed its high forecast of costs to comply with proposed EPA regulations,[63] the 2015 EICCR would rise to $[redacted] per MWH. As can be seen, these

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[59] AEP Ohio's Interrogatory Response, FES, Set 10, INT-10-2.

[60] Based on AEP Ohio's Interrogatory Response, FES, Set 10, INT-10-2, Attachments 1 and 2.

[61] On June 9, 2011 AEP announced its plan for complying with a series of regulations proposed by the EPA that would impact coal-fueled power plants. Based on the regulations as proposed, AEP's compliance plan would retire nearly 6,000 MW of coal-fueled power generation; upgrade or install new advanced emissions reduction equipment on another 10,100 MW; refuel 1,070 MW of coal generation as 932 MW of natural gas capacity; and build 1,220 MW of natural gas-fueled generation. The cost of AEP's compliance plan could range from $6 billion to $8 billion in capital investment across its entire system through the end of the decade. According to their press release, they state that high demand for labor and materials due to a constrained compliance time frame could drive actual costs higher than these estimates and that the plan, including retirements, could change significantly depending on the final form of the EPA regulations and regulatory approvals from state commissions. "AEP Shares Plan For Compliance With Proposed EPA Regulations," 6/9/2011, (http://www.aep.com/newsroom/newsreleases/?id=1697).

[62] AEP Ohio's Interrogatory Response, FES, Set 10, INT-10-2, Attachment 1.

[63] AEP Ohio's Interrogatory Response, FES, Set 10, INT-10-2, Attachment 2.

figures are significantly higher than the $0.90 per MWH figure assumed by Ms. Thomas in her MRO price comparison.

Q. WHAT OTHER COSTS DID YOU CONSIDER IN YOUR EVALUATION OF THE LEGACY ESP TOTAL GENERATION SERVICE PRICE?

A. I calculated the Total Generation Service Price with and without the POLR charge. As discussed above, the POLR charge as an element of the 2009-2011 ESP is currently under review and subject to remand. Given all of this uncertainty, I estimated the MRO Price with and without the POLR charge included in the Total Generation Service Price.[64]

Similarly, in the "but-for" world of continuation of the legacy ESP during the MRO period, the ability of AEP Ohio to recover the facility closure costs associated with the Sporn 5 generating unit and the magnitude of those costs is still in question. Therefore, my analysis of MRO pricing considered the impact of not including or including the costs associated with the Sporn 5 generating unit facility closure costs.[65]

D. UNDER REASONABLE ASSUMPTIONS, THE STIPULATION ESP PRICE WOULD NOT BE MORE FAVORABLE THAN THE MRO PRICE RESULTING IN EXCESS COSTS TO THE AEP OHIO ZONE RANGING FROM $100 MILLION TO AS MUCH AS $800 MILLION

Q. DID YOU CORRECT THE PRICE COMPARISON SHOWN IN EXHIBIT LJT-2?

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[64] In her direct testimony supporting AEP Ohio's Initial ESP Proposal, Ms. Thomas performed the MRO Price Test without the POLR charge (LJT-2) and with the POLR charge (LJT-4) included. This time Ms. Thomas only shows her analysis with a POLR charge of $3.07 per MWH. Additionally, in the Initial ESP Proposal the Company supported in its testimony a $2.84 per MWH POLR charge, while Staff and other parties claimed that this charge was overstated. In my analysis, I considered both a $3.07 POLR charge and no POLR charge to reflect a wide range of potential outcomes. As can be seen in Exhibit MMS-4, whether or not the POLR charge is assumed to continue at current levels in the Total Generation Service Price is material to the outcome of the MRO Price Test.

[65] Neither Ms. Thomas nor Staff Witness Fortney includes the Sporn 5 closure costs in their analyses. Including Sporn 5 facility closure costs in the Total Generation Service Price raises the blended price of the MRO.

A. Yes. I used a similar methodology as Ms. Thomas to blend the corrected Competitive Benchmark Price and the Total Generation Service Price to derive a corrected MRO Price.[66] The corrected MRO Price was then compared with the corrected Stipulation ESP Price, taking into account total charges to the AEP Ohio zone.[67] Based on my analysis, the Stipulation would result in excess costs to the AEP Ohio zone as compared to an MRO under a wide range of reasonable assumptions – ranging from $100 million to as much as $800 million. The corrected MRO Price Test results are summarized in Exhibit MMS-4. Thus, correcting Ms. Thomas' errors leads to the opposite conclusion: the Stipulation ESP Price is not more favorable than the expected price under an MRO. This remains true under a wide range of assumptions.[68]

Q. HAS AEP OHIO SHOWN THAT THE STIPULATION ESP IS SUPERIOR TO A MARKET-BASED APPROACH INVOLVING FIXED-PRICE FULL REQUIREMENTS SSO SUPPLY PRODUCT SOLICITATIONS?

A. No, it has not. As described earlier in this testimony, AEP Ohio's analysis contains serious errors. Correcting these errors, I show that a modified ESP that relies on fixed-price full requirements solicitations could result in an SSO price that is substantially less than the Stipulation ESP Price.[69] The Competitive Benchmark Price (using RPM capacity

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[66] As discussed previously, I adjusted the retained load forecast under the Stipulation ESP to reflect shopping at the RPM set-aside caps. Under the MRO, I have assumed that current shopping levels are maintained.

[67] In order to compare costs between the Stipulation ESP and an MRO, I have evaluated the total generation costs for the AEP Ohio zone. Shopping customers were assumed to pay the Competitive Benchmark Price plus any generation-related non-bypassable riders while retained load paid the MRO Price or the Stipulation ESP Price.

[68] I have not included the impact of the Distribution Investment Rider in my analysis. To the extent that this rider would result in additional costs beyond what would be recovered in an MRO, this would increase the costs of the Stipulation ESP. This is discussed further by FES witness Lesser.

[69] It should be noted that a modified ESP based on procurement of SSO supply through competitive solicitations of fixed-price full requirements products, is different from an MRO. For example, the SSO price under an MRO

without any blending with the 2011 Total Generation Service Price) is about $8 per MWH lower over the period than the Stipulation ESP Price (including the PMR). This suggests that a modified ESP that relies fully on competitive solicitations for SSO supply could save customers $1.0 billion over the January 2012 through May 2015 period, as compared to the prices under the Stipulation. An immediate transition to an ESP with competitive SSO supply procurement would allow customers to benefit from lower competitive market prices during the interim period – benefits that are not afforded to AEP Ohio's customers until June 2015 under the proposed Stipulation.[70] This type of default service plan has been approved by the Commission for the FirstEnergy Ohio Utilities. Alternatively, these benefits could be made available to AEP Ohio's customers during the period prior to June 2015 if the Commission were to eliminate the RPM set-aside caps in the Stipulation, thereby allowing more customers to shop and access lower RPM market capacity prices.

Q. MR. SCHNITZER, THE ANALYSIS DESCRIBED ABOVE ASSUMES THAT THE CURRENTLY APPROVED RPM CAPACITY PRICES THAT APPLY TO CRES SUPPLIERS REMAINS IN EFFECT FOR THE MRO. WOULD IT BE APPROPRIATE TO USE THE STIPULATION CAPACITY PRICE OR THE EVEN HIGHER CAPACITY PRICE PROPOSED IN CASE NO. 10-2929-EL-UNC IN THE MRO ANALYSIS?

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represents a blend of the Competitive Benchmark Price and the Total Generation Service Price, while a modified ESP would not incorporate a blending with the Total Generation Service Price.

[70] Mr. Hamrock does not attempt to dispute that an auction-based SSO would be less expensive for customers. He states that he has been "advised by counsel that implementing an auction-based SSO is not something the Commission can require of an EDU within an ESP," even if it would be cheaper for customers. Stipulation Testimony of Joseph Hamrock on Behalf of CSP and OPCo, at 6, lines 10-11.

A. No. Even if the Commission were to determine that there is both a legal and a policy basis for allowing the recovery of above-market capacity costs, there is no valid economic basis for supporting either the Stipulation capacity price of $255 per MW-day or the $347.97 per MW-day capacity price that AEP Ohio proposed in Case No. 10-2929-EL-UNC.[71,72] Both these above-market capacity prices, from an economic standpoint, exceed a "maximum above-market" rate that would result taking into account the appropriate revenue offsets. This "maximum above-market" rate is described further in Exhibit MMS-5. This rate would cover AEP Ohio's total generation costs, but would only include costs that the utility could not otherwise recover (*i.e.*, market and other sources of revenue available to the Company would be netted from total generation costs). Both the Stipulation capacity price of $255 per MW-day and the $347.97 per MW-day capacity price that AEP Ohio proposed in Case No. 10-2929-EL-UNC overcompensate AEP Ohio through double recovery of costs that it recoups elsewhere.

Q. WHY DO YOU CONSIDER THIS THE MAXIMUM RATE FOR CAPACITY?

A. Let me first be clear that I am not recommending that the Commission adopt this maximum above-market rate. The capacity price that best supports both wholesale and

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[71] I take no position as to whether, as a legal matter, AEP Ohio is entitled to an above-market capacity price, which would allow it to recover some of its above-market sunk costs. See the Testimony of FES witness Dr. Lesser for a discussion of this issue and his conclusions that: 1) because AEP Ohio agreed to forego recovery of its stranded generation costs, it should reflect a market price for capacity; 2) AEP Ohio has, in any case, recovered all of its stranded generation costs prior to December 31, 2009; and, 3) even if AEP Ohio could charge a cost-based rate for capacity, such rate should not include double-counting and should only reflect costs associated with pre-transition generating resources (*i.e.*, those in service prior to January 2, 2001).

[72] The $347.97 figure was based on 2009 costs and was applicable to retail load (including line losses). AEP Ohio witness Pearce shows in Exhibit KDP-4 the corresponding figure for 2010 of $343.98 per MW-day. In some cases, the capacity price is cited as the price applicable to generation output (excluding line losses) for 2009 ($359.84) and for 2010 ($355.72).

retail competition is the RPM price.[73] The point I am making here is that even if the Commission were to determine that it is appropriate and permissible to approve an above-market capacity price (which I am not recommending), there would be a maximum level that could be economically justified that would allow AEP Ohio to recover its above-market capacity costs. The reason for this is that, if a customer shops with a CRES supplier, AEP Ohio no longer has to supply energy or ancillary services to that customer. This would then allow AEP Ohio to sell the "freed up" energy and ancillary services in the market, and retain the margin from the market sale. However, failure to credit the energy and ancillary services revenue (and other sources of revenue available to the Company) against the all-in costs of the generation plant output would result in a windfall or double recovery to AEP Ohio, and force its customers to pay more than is necessary. It is important to recognize that a "maximum above-market" rate is not the same as the competitive market price of capacity. Rather, it is based on AEP Ohio's total generation costs (including its sunk costs), even if these costs are not competitive with the costs of other generators. Failure to consider all of the revenues that the Company could otherwise recover would overcompensate AEP Ohio and force its customers to pay more than is necessary.

This concept of netting other revenues is similar to the calculation of transition costs identified in Section 4928.39 of the Ohio Revised Code, which costs utilities were previously authorized to recover from customers. Under that section, transition costs must have been prudently incurred and include costs that the utility could not recover in a

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[73] Because the RPM price is the price that best supports wholesale and retail competition and as in fact the market price for capacity, I have been advised by counsel that it should be the price used in the comparison of whether the revised ESP is better than the MRO and that an above market regulatory-determined price for capacity is not consistent with the competitive procurement of capacity. As contemplated under 4928.142(c).

competitive market. While I am not an attorney, it is clear from an economic perspective that if a customer shops with an alternative supplier, the utility would be able to recover the market value of the "freed up" energy and ancillary services in the competitive market. Therefore, if the Commission does allow AEP Ohio to recover all or some portion of its above-market capacity costs from customers, which again, I do not recommend or endorse, these market revenues along with other sources of revenue available to the Company should be credited against its total generation costs.

V. A SUBSTANTIAL PORTION OF THE OTHER BENEFITS THAT AEP OHIO QUANTIFIES ARE ILLUSORY

Q. DOES AEP OHIO CLAIM THAT THERE ARE SIGNIFICANT QUANTIFIABLE BENEFITS THAT THE STIPULATION PROVIDES TO CUSTOMERS AND STAKEHOLDERS?

A. Yes. Mr. Hamrock summarize these on pages 11 and 12 of his testimony stating that, "[i]n the aggregate, Mr. Allen estimates that the net present value of these quantifiable benefits that result from the Stipulation are in excess of $1.1 billion."[74]

Q. WHAT IS YOUR RESPONSE?

A. This so-called benefit is illusory because it assumes that, absent the Stipulation, the Company would have charged its above-market capacity request of approximately $345 per MW-day[75] that has not been approved by either this Commission or the FERC. As I

[74] Stipulation Testimony of Joseph Hamrock on Behalf of CSP and OPCo, at 12, lines 11-12.

[75] The Company proposed a $347.97 per MW-day figure in Case No. 10-2929-EL-UNC. This figure was based on 2009 costs and was applicable to retail load (including line losses). AEP Ohio witness Pearce shows in Exhibit KDP-

described earlier, the Company's initial above-market capacity request would significantly overcompensate AEP Ohio for its capacity. AEP Ohio's requested above-market compensation is not the appropriate benchmark on which to measure "savings." Indeed, if, absent the Stipulation, the Commission would have maintained its current policy of pricing capacity at the RPM prices, the capacity prices in the Stipulation would be a net cost rather than a benefit. FES witness Lesser estimates the excess costs of the Stipulation capacity prices to be $1.3 billion relative to RPM market prices, not a benefit at all.[76] In fact, whether the Stipulation capacity price represents a savings or a cost depends on what you believe would have been in place absent the Stipulation. AEP Ohio assumes very aggressive "but for" treatment by the Commission with respect to capacity costs, namely that the Commission would have approved the excessive capacity price that the Company requested. I believe it is more appropriate to conclude that the Stipulation represents an incremental cost since it assumes above-market capacity charges to CRES suppliers in excess of those approved by the Commission and in effect today.

Q. WHAT ABOUT THE SECOND LARGEST BENEFIT QUANTIFIED BY MR. ALLEN?

A. Mr. Allen relies on Ms. Thomas' price comparison to calculate the "ESP Price Benefit for Non-Shopping Customers." As I have described in detail, Ms. Thomas' price comparison contains material flaws, which when corrected, dramatically alters her conclusion. Rather

4 the corresponding figure for 2010 of $343.98 per MW-day. In some cases, the capacity price is cited as the price applicable to generation output (excluding line losses) for 2009 ($359.84) and for 2010 ($355.72).

[76] Stipulation Testimony of Jonathan Lesser on behalf of FES, Table 1.

than a price benefit, the Stipulation ESP represents a potentially significant cost under a wide range of assumptions, as shown in Exhibit MMS-4.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING MR. ALLEN'S CLAIM THAT THE STIPULATION ESP REPRESENTS A BENEFIT OF $1.1 BILLION VERSUS THE EXPECTED RESULTS UNDER AN MRO.

A. Mr. Allen's calculation of the alleged capacity and Stipulation ESP pricing benefits, which represent almost 90% of the claimed benefits that he calculates, are not valid. And in fact, the alleged benefits that he attributes to these areas should more appropriately be viewed as a cost of the Stipulation.

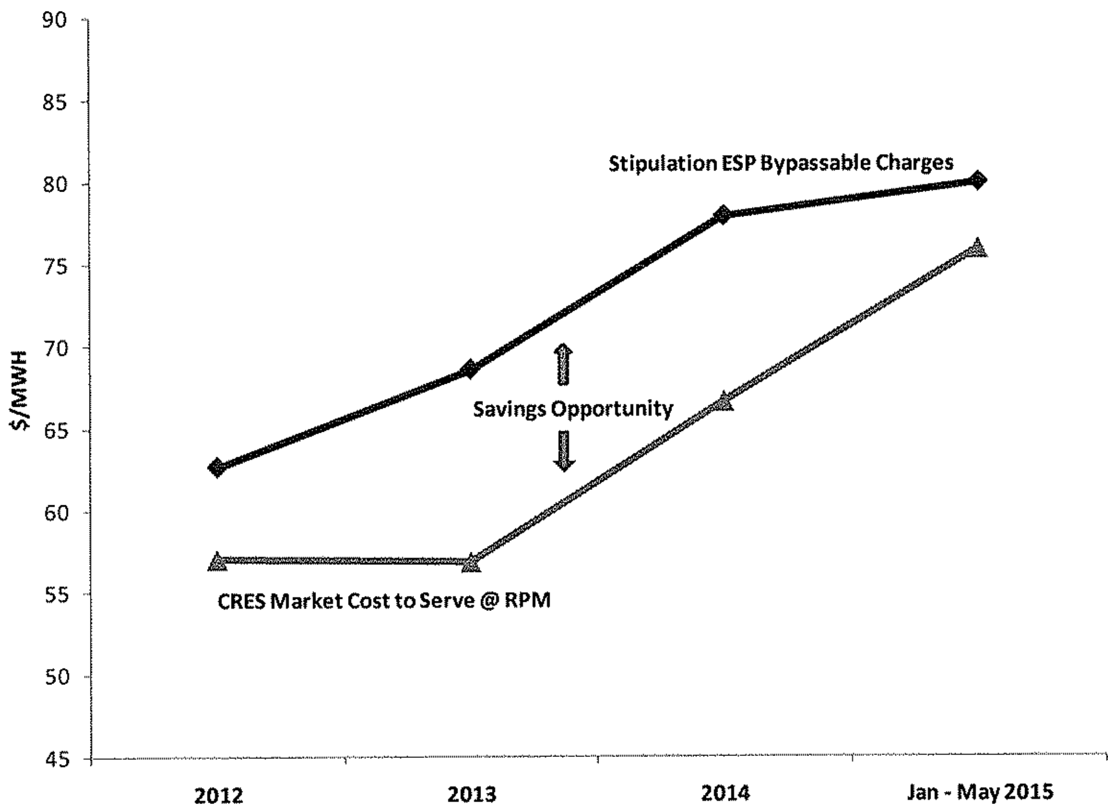
VI. <u>DURING THE PERIOD THROUGH MAY 2015, THE ABOVE-MARKET CAPACITY PRICE ($255 PER MW-DAY) FOR CRES SUPPLIERS ABOVE THE RPM SET-ASIDE CAPS EFFECTIVELY PRECLUDES RETAIL COMPETITION FOR THE MAJORITY OF CUSTOMERS AND EXPOSES THEM TO ABOVE-MARKET STIPULATION ESP PRICES</u>

Q. WHAT IS LIKELY TO BE THE IMPACT OF THE PROPOSED CHANGES IN THE STIPULATION ON RETAIL COMPETITION?

A. The Stipulation would limit retail competition during the interim period prior to June 2015 in the AEP Ohio service area. The Stipulation in essence would allow AEP Ohio to impose specific limits on the amount of customer load that can take advantage of competitive market prices.

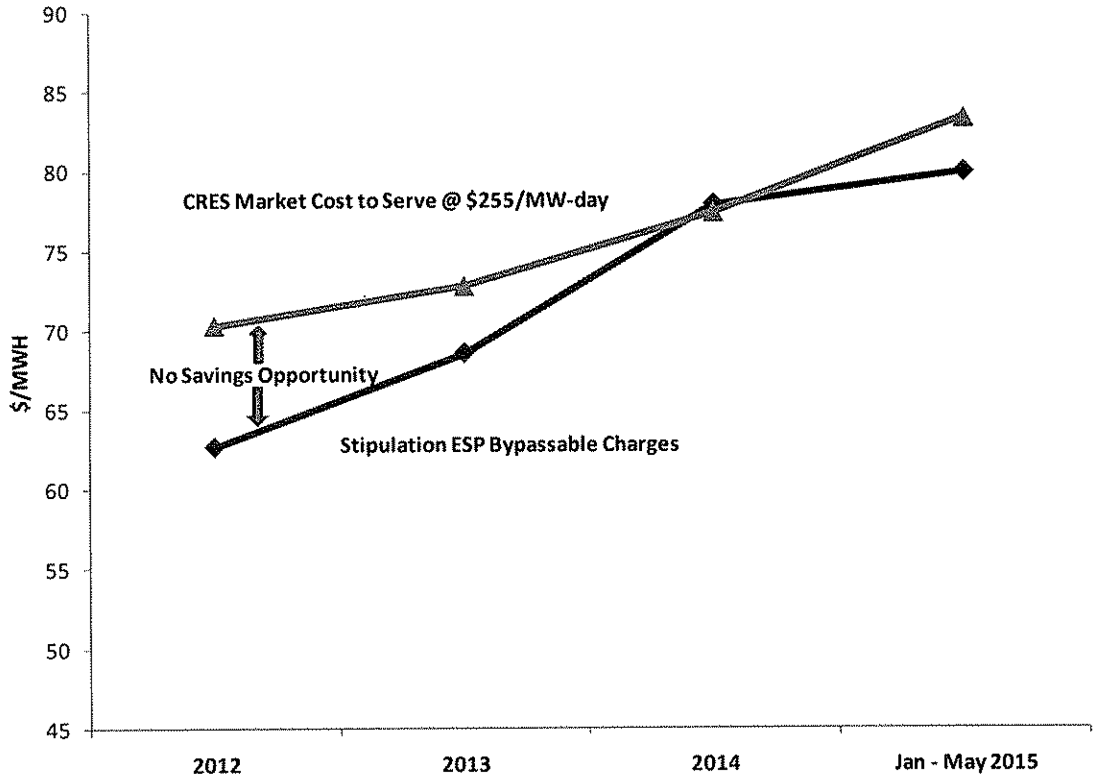
The chart below compares the generation-related bypassable charges in the Stipulation with the market costs to serve customers when RPM capacity prices are available to CRES providers. As can be seen from the chart, the Stipulation ESP bypassable charges exceed the CRES market costs to serve when RPM capacity prices are available to CRES providers. This represents a savings opportunity for customers who switch to CRES providers.

Customers Can Benefit from Retail Shopping When Capacity is Available to CRES Providers at RPM Prices



However, once the thresholds in the Stipulation are reached and AEP Ohio no longer has to provide capacity to CRES providers at RPM market prices, the Stipulation would allow AEP Ohio to charge an interim above-market capacity charge of $255 per MW-day. Once this occurs, there is little opportunity for customers to shop with a CRES supplier. The bypassable generation charges in the Stipulation are below the costs that a CRES supplier would have to incur when faced with paying AEP Ohio's above-market $255 per MW-day capacity charge.

The Stipulation Would Limit Retail Choice When CRES Suppliers Have to Pay AEP Ohio's Above-Market $255 per MW-Day Capacity Charge



As a result, under the Stipulation, once AEP Ohio no longer has to provide capacity to CRES providers at RPM market prices, the Stipulation effectively shuts down the opportunity for customers to shop by making it very difficult for customers to shop for price savings. Thus, the higher base generation rates and the other "bypassable charges" included in the Stipulation become non-bypassable in practical terms.

My concern is that the above-market capacity price of $255 per MW-day for shopping above the RPM set-aside cap effectively precludes retail competition for the majority of customers. Therefore, there is little to protect customers from the above-market Stipulation ESP Prices.

VII. THE GRR IN THE STIPULATION COULD HARM CUSTOMERS BECAUSE IT WOULD LIKELY RESULT IN COSTLY GENERATION INVESTMENTS EVEN WHEN CHEAPER RESOURCE ALTERNATIVES EXIST IN THE MARKET

Q. WHAT ARE YOUR CONCERNS ABOUT THE GRR INCLUDED IN THE STIPULATION?

A. I am concerned that customers would be required to pay new above-market costs through a non-bypassable generation charge for investments eligible for inclusion in the GRR. The Stipulation would allow non-bypassable recovery of above-market costs for the life of the Turning Point and MR6 facilities. This rider would likely result in uneconomic generation investments, and AEP Ohio's customers would bear the costs of these uneconomic investments. Finally, under the Stipulation, this rider would be collected from all shopping and non-shopping customers regardless of their supplier.

Q. WHY WOULD THE GRR LIKELY RESULT IN UNECONOMIC GENERATION INVESTMENTS, THEREBY HARMING CUSTOMERS?

A. The GRR would allow for recovery of the costs of investment in new generating facilities, even when cheaper resource alternatives exist in the market. Since the rider would require customers to bear the costs of the investments, customers would be responsible for paying for the uneconomic investment and operating decisions made by AEP Ohio under the rider.

The electricity supply business is inherently risky, because the future is uncertain with respect to those things that will determine the future market price of electricity: load growth, fuel prices, environmental costs, new technology, and so forth. The proposed GRR would improperly allocate risk (including the risk associated with technological choices, excess supply problems, and cost overruns) to consumers rather than to investors. Not surprisingly, the regulatory process significantly underestimates these risks when making long-term resource commitments because customers, and not investors, largely bear these risks. In these risky electricity markets, unfavorable and unforeseen investment outcomes are common. Unfortunately, in regulated markets, retail customers bear the responsibility of paying for those mistakes.

In competitive markets (and when the costs of generation investment are not passed on to customers through a rider such as the proposed GRR), price signals, rather than administrative determinations, guide generation investment. This encourages the right amount of generating capacity with the appropriate levels of reliability, as well as the right mix of generating technologies in the right locations. Competition makes investors, rather than consumers, responsible for investment decisions with no assured recovery of the investment. All of this works to the benefit of customers. In a properly functioning competitive market, AEP Ohio's proposed GRR is unnecessary and is potentially harmful.

Q. WOULD THE HARM TO CUSTOMERS BE LIMITED TO THE TERM OF THE ESP?

A. No. In fact, if the proposed GRR is adopted, it could expose AEP Ohio's retail customers to costs and risks for many years into the future. The costs of uneconomic investments in generation, once made by AEP Ohio, would need to be recovered from its customers for many years into the future (*i.e.*, creating a new round of "stranded generation costs" that otherwise would not be recoverable in competitive markets). For example, I estimate that the above-market costs associated with a full year of the GRR could be about $60 million in the first year.[77] Additionally, the financial impact on customers of the decision in this case could extend well beyond the proposed ESP period. These costs would also be incurred by Ohio businesses that are struggling to compete with out-of-state competitors.

VIII. THE COMMISSION SHOULD ELIMINATE THE SHOPPING CAPS AND RECOGNIZE THERE IS NO NEED TO BUILD NEW GENERATION

Q. IF THE COMMISSION DOES NOT REJECT THE STIPULATION IN ITS ENTIRETY, WHAT MODIFICATIONS SHOULD BE MADE TO THE STIPULATION?

A. The Commission should consider the following modifications to the Stipulation:

1. Mitigate barriers to retail competition prior to June 2015 by making AEP Ohio's capacity available to CRES suppliers at RPM market prices (*i.e.*, eliminate the caps) to allow more customers to benefit from Ohio's competitive electricity market; and

2. Before allowing recovery through a cost-based *GRR*, subject any otherwise eligible investment in generation to an open and transparent market test.

Q. WHY DO YOU RECOMMEND THAT THE COMMISSION MITIGATE BARRIERS TO RETAIL COMPETITION?

A. As described earlier, AEP Ohio should make its capacity available to CRES suppliers at RPM market prices by eliminating the caps in the Stipulation. The Stipulation limits retail choice by allowing AEP Ohio to charge an above-market $255 per MW-day capacity

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[77] Currently, it is not known when the planned MR6 facility will be in-service, and the associated GRR costs are not included in my analysis.

price. This is detrimental to customers and harms retail competition. Eliminating or increasing the RPM set-aside caps in the Stipulation would allow customers to benefit from competitive markets. As discussed earlier, the above-market capacity price will make it difficult for AEP Ohio's customers to find savings and to avoid the above-market Stipulation ESP Price.

Q. PLEASE EXPLAIN YOUR RECOMMENDATION THAT BEFORE ALLOWING RECOVERY THROUGH A COST-BASED GRR, THE COMMISSION SUBJECT ANY OTHERWISE ELIGIBLE INVESTMENT IN GENERATION TO AN OPEN AND TRANSPARENT MARKET TEST.

A. First, let me be clear that I take no position as a matter of law as to whether AEP Ohio's proposed GRR has satisfied all of the statutory criteria under either Revised Code sections 4928.143(B)(2)(b) or 4928.143(B)(2)(c). That issue is specifically addressed by other Witnesses Banks and Lesser. My point is that any such investments that AEP Ohio seeks to recover in a cost-based GRR should be subject to an open and transparent market test.

Q. WHAT DO YOU MEAN BY AN OPEN AND TRANSPARENT MARKET TEST?

A. If AEP Ohio was planning to make a certain investment in generation, it should be required to solicit competitive bids for an equivalent number of MW and/or MWH for a specified period of time in order to determine whether its proposed investment is least cost. The competitive bid should be for a similar product (in terms of energy output, capacity, etc.) for a similar term, similar strike price, and location as the investment being proposed by the utility. AEP Ohio then should compare the costs of its proposed utility investment to the market alternative. I would include in this analysis all "to go" or nonsunk costs – both capital and O&M costs. In business, this is the classic "make" vs. "buy" decision.

Q. WHY IS AN OPEN AND TRANSPARENT MARKET TEST IMPORTANT?

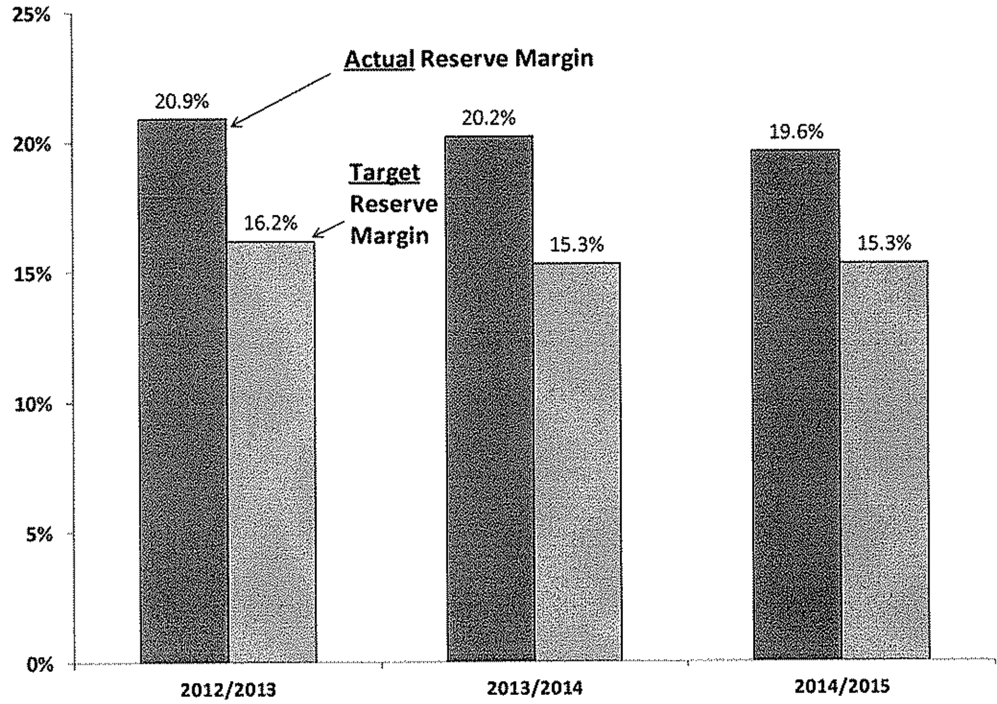
A. A transparent market test is appropriate from an economic perspective to ensure that the least-cost resource options are employed at the time of the investment decision, so that Ohio residential and business customers are not burdened with high-cost (*i.e.*, above market) generation for many years into the future. This will help avoid situations in which customers must incur stranded costs associated with future investments or long-term contracts.

Without testing the market in order to determine whether the "build" option is cheaper than the "buy" option or vice versa, the Commission cannot make a decisional prudence determination. The "best evidence" that a proposed investment in new generation is prudent is that no market competitor will offer equivalent capacity and energy for a lower price.

Q. IS THERE ANY EVIDENCE TO SUGGEST THAT MORE GENERATION CAPACITY IS PHYSICALLY NEEDED IN AEP OHIO'S REGION OF PJM?

A. No. The results of PJM's RPM auctions suggest that there is a substantial amount of excess capacity in the region. PJM acquires all the necessary capacity needed for the load-serving entities participating in the RPM. Eligible resources can be generation, demand response, energy efficiency and qualified transmission enhancements. PJM's RPM auctions solicit commitments from capacity resources to ensure resource adequacy, which will enhance the long-term reliability of service within the RTO. As the graph below shows, while AEP Ohio load is not part of the RPM auction, PJM has already procured more than enough capacity for all of the load-serving entities in PJM, including AEP Ohio, for the entire ESP period and has a reserve margin that exceeds its target.[78]

PJM Has Sufficient Capacity



Q. IS THERE ANY EVIDENCE TO DEMONSTRATE THAT THERE IS A NEED FOR AEP OHIO TO BUILD MORE GENERATION CAPACITY TO SERVE ITS CUSTOMERS?

A. No. According to AEP Ohio's own figures, the Company's net capability of its generating assets well exceeds its peak load both now and in the foreseeable future.[79] AEP Ohio's reserve margin was about 55% in 2009, 37% in 2010, and is expected to gradually decline

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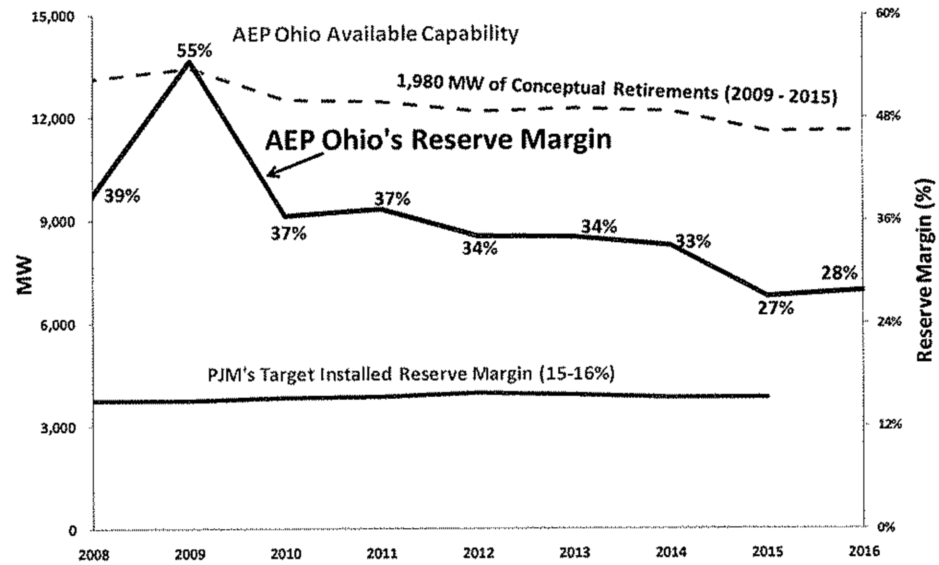
[78] The actual reserve margin shown in the graph is understated since it only includes capacity that cleared in the PJM base residual auctions. Other capacity in PJM that did not clear in the auction and has not been retired, if included, would increase the size of the reserve margin.

[79] AEP Ohio Filing, PUCO Case Nos. 11-2501-EL-FOR and 11-2502-EL-FOR, 4/15/2011, at 140-141.

to about 28% by 2016, even after assuming 2.0 GW in plant retirements.[80] These numbers are well above PJM's target installed reserve margin of 15-16%.

AEP Ohio's Reserve Margin is Well Above PJM's Target Reserve Margin



Source: AEP Filing, PUCO Case Nos. 11-2501-EL-FOR and 11-2502-EL-FOR, 4/15/2011, pp. 140-141. Retirements include Phil Sporn 5 (440 MW, 2010), Conesville 3 (165 MW, 2012), Muskingum River 2&4 (395 MW, 2012), Muskingum River 1&3 (380 MW, 2014), Muskingum River 5 (600 MW, 2015). OPCo and CSP's Non-Coincident Peak Loads have been scaled to reflect AEP Ohio's expected share of PJM 1CP, based upon AEP Ohio's 5CP contribution to PJM's 5CP in 2009. Available Capability is net of an average of 1.0 GW in annual net sales over the 2008-2016 period. PJM's Target IRM is known through PY14/15.

As a result, AEP Ohio has significant reserve margins and does not need new generation dedicated to serve its AEP Ohio load.[81]

Q. HAS AEP OHIO DEMONSTRATED THAT THE PROPOSED GENERATION INVESTMENTS MADE BY THE COMPANY ARE THE LOWEST COST ALTERNATIVE?

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[80] According to internal planning documents associated with AEP's 2010 IRP for AEP Ohio, AEP Ohio is projected to have a reserve margin of over [redacted]% through PJM Planning Year 2028-2029, even after accounting for [redacted] MW of retirements during the period 2010-2030. AEP Ohio's Interrogatory Response, Exelon Generation Company, Set 3, RPD-3-012, Attachment 1, Appendix at 12, COMPETITIVELY-SENSITIVE CONFIDENTIAL. Furthermore, AEP acknowledges, "[redacted]" AEP Ohio's Interrogatory Response, Exelon Generation Company, Set 3, RPD-3-014, Attachment 4, p. 25, COMPETITIVELY-SENSITIVE CONFIDENTIAL, emphasis retained from the original.

[81] The available capability and reserve margin shown in the chart is net of an average of 970 MW in annual net sales of capacity over the period 2008-2016.

A. No, it has not. And as discussed above, the Company should be required to conduct a competitive market test to demonstrate that these generation investments are the lowest cost alternative.

Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO ADD AT THIS TIME?

A. Yes. I would like to mention that the discovery responses that I relied on in my testimony are attached as Exhibit MMS-6.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

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

Michael M. Schnitzer, Director

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Concord, MA 017742

Michael Schnitzer is a Director of The NorthBridge Group. He has over 25 years of experience in management consulting to clients in energy industries, with a primary focus on the electricity industry. Working with utility and non-utility clients, he has developed initiatives in strategy, marketing, pricing, regulatory relations, and generation investment. He also has broad experience in the transition to competitive wholesale and retail electricity markets and has developed and evaluated numerous electricity restructuring proposals.

Mr. Schnitzer has been an expert witness in a number of regulatory proceedings involving electric industry restructuring, utility supply planning, and environmental issues. He has testified before the Federal Energy Regulatory Commission on issues relating to competitive restructuring and wholesale market design, including Locational Marginal Pricing and Financial Transmission Rights, Regional Transmission Organizations, standard market design, resource adequacy, and transmission expansion pricing policy. On several occasions he has been invited by FERC staff to participate as a panelist in technical conferences on market design issues. Mr. Schnitzer has also testified before several state commissions and departments on the subject of provision of default service to retail customers, including evaluation of competitive procurement proposals.

He is a former adjunct research fellow at the Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University. Before joining NorthBridge, Mr. Schnitzer was a Managing Director at Putnam, Hayes & Bartlett, Inc., where he co-directed the firm's regulated industry practice.

Mr. Schnitzer received an A.B. in chemistry, with honors, from Harvard University, and an M.S. in management from the Sloan School, Massachusetts Institute of Technology.

Exhibit MMS-2: Corrections to Stipulation ESP Price

($/MWh)	2012	2013	2014	Jan - May 2015	Load-Wtd Average	Source
Stipulation ESP Price Estimate Used by AEP Ohio						
Base Generation Rate	24.50	25.70	27.20	27.20		Stipulation at IV(f)
Transmission Adjustment	2.14	2.14	2.14	2.14		Roush Workpapers
Market Comparable Base 'g' Rate	26.64	27.84	29.34	29.34		
AEP Ohio Estimate of 2011 Full Fuel	33.08	33.08	33.00	33.00		Roush Workpapers
AEP Ohio Estimated Stipulation ESP Price	59.71	60.91	62.34	62.34	61.15	LJT-2 and Roush Workpapers
Stipulation ESP Price Estimate Used by MMS - High Case Pool Modification Rider						
Base Generation Rate	24.50	25.70	27.20	27.20		Stipulation at IV(f)
Transmission Adjustment	2.14	2.14	2.14	2.14		Roush Workpapers
Market Comparable Base 'g' Rate	26.64	27.84	29.34	29.34		
Full Fuel Forecast	[redacted]					INT-FES-1-1, RESTRICTED ACCESS CONFIDENTIAL
Estimate of GRR						Based on Supplemental Direct Testimony of Philip J. Nelson, 7/1/2011, Exhibit PJN-4, at p. 2.
Estimate of High Case Pool Modification Rider						
MMS Estimated Stipulation ESP Price						
MMS Total Adjustments to Stipulation ESP Price - High PMR	[redacted]					
Stipulation ESP Price Estimate Used by MMS - Low Case Pool Modification Rider						
Base Generation Rate	24.50	25.70	27.20	27.20		Stipulation at IV(f)
Transmission Adjustment	2.14	2.14	2.14	2.14		Roush Workpapers
Market Comparable Base 'g' Rate	26.64	27.84	29.34	29.34		
Full Fuel Forecast	[redacted]					INT-FES-1-1, RESTRICTED ACCESS CONFIDENTIAL
Estimate of GRR						Based on Supplemental Direct Testimony of Philip J. Nelson, 7/1/2011, Exhibit PJN-4, at p. 2.
Estimate of Low Case Pool Modification Rider						
MMS Estimated Stipulation ESP Price						
MMS Total Adjustments to Stipulation ESP Price - Low PMR	[redacted]					

Exhibit MMS-3: Corrections to Competitive Benchmark Price (Expected Bid Price)

($/MWh)	Thomas RPM CBP	Thomas $255 CBP	Thomas Blended CBP	MMS CBP (RPM)	Total Corrections	Corrections
Simple Swap	43.88	43.88	43.88	43.90	0.02	
Basis Adjustment	0.58	0.58	0.58	0.58	0.00	
Load Following/Shaping Adjustment	2.87	3.69	3.44	2.79	-0.65	A "ripple effect" due to the change in capacity prices
Capacity	4.79	16.08	12.55	4.76	-7.79	MMS uses solely RPM capacity, LJT blends RPM and $255/MW-Day capacity
Ancillary Services	0.60	0.60	0.60	0.60	0.00	
Alternative Energy Requirement	0.79	0.79	0.79	0.79	0.00	
ARR Credit	-1.12	-1.12	-1.12	-1.10	0.01	
Losses	1.85	1.89	1.88	1.81	-0.07	A "ripple effect" due to the change in capacity prices
Transaction Risk Adder	2.96	3.57	3.38	2.96	-0.42	A "ripple effect" due to the change in capacity prices
Retail Administration	5.00	5.00	5.00	5.00	0.00	
Total	**62.20**	**74.95**	**70.98**	**62.08**	**-8.90**	

Note: Ms. Thomas' CBP prices are weighted using a forecast of retained load based on 9.5% shopping while the MMS CBP is weighted using a retained load forecast based on current levels of shopping ([redacted] based on COMPETITIVELY SENSITIVE CONFIDENTIAL, Staff DR-49, Attachment 1).

Exhibit MMS-4: Summary Table and Corrected LJT-2

			AEP Ohio Zone ESP Price Benefit ($/MWh)	AEP Ohio Zone Excess Costs under ESP ($MM)
			January 2012 - May 2015	January 2012 - May 2015
RPM Capacity	No POLR, No FCCR	**Scenario 1: No POLR, No FCCR, Low EICCR**		
		a. High Case Pool Modification Rider	-4.93	804
		b. Low Case Pool Modification Rider	-3.57	582
		Scenario 2: No POLR, No FCCR, High EICCR		
		a. High Case Pool Modification Rider	-3.56	580
		b. Low Case Pool Modification Rider	-2.19	357
	$3.07 POLR, Sporn 5 FCCR	**Scenario 3: $3.07 POLR, Sporn 5 FCCR, Low EICCR**		
		a. High Case Pool Modification Rider	-2.04	333
		b. Low Case Pool Modification Rider	-0.68	111
		Scenario 4: $3.07 POLR, Sporn 5 FCCR, High EICCR		
		a. High Case Pool Modification Rider	-0.67	109
		b. Low Case Pool Modification Rider	0.70	-114

Note: After accounting for the $220 million in incremental Distribution Investment Rider costs related to the Stipulation ESP quantified by Dr. Lesser, the Stipulation ESP Price would not be more favorable than the MRO Price in all cases.

Exhibit MMS-4: Summary Table and Corrected LJT-2

Scenario 1(a): No POLR, No FCCR, Low EICCR, High PMR

	2012	2013	2014	Jan - May 2015	Load-Wtd Avg
MRO Pricing					
Total Generation Service Price					
Tariff Generation Price	21.02	21.02	21.02	21.02	21.02
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	23.16	23.16	23.16	23.16	23.16
Full Fuel	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Low EICCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
FCCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
POLR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Generation Service Price	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Generation Service Price Weight	90%	80%	70%	60%	
Competitive Benchmark Price					
Simple Swap	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Competitive Benchmark Price	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CBP Weight	10%	20%	30%	40%	
Estimate of MRO Price	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Stipulation ESP Price					
Stipulation ESP					
Tariff Generation Price	24.50	25.70	27.20	27.20	25.83
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	26.64	27.84	29.34	29.34	27.97
Full Fuel	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GRR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
High Pool Modification Rider ("PMR")	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Estimate of Stipulation ESP Price	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MRO - ESP Rate Comparison to AEP Ohio Zone					
Average AEP Ohio Zone Price Under MRO	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average AEP Ohio Zone Price Under ESP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
AEP Zone ESP Price Benefit	[redacted]	[redacted]	[redacted]	[redacted]	-4.93
Total Charges to the AEP Ohio Zone					**Total Charges**
Estimate of Total Charges Under ESP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Estimate of Total Charges Under MRO	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Excess Costs Charged Under ESP	[redacted]	[redacted]	[redacted]	[redacted]	804

Exhibit MMS-4: Summary Table and Corrected LJT-2

Scenario 1(b): No POLR, No FCCR, Low EICCR, Low PMR

	2012	2013	2014	Jan - May 2015	Load-Wtd Avg
MRO Pricing					
Total Generation Service Price					
Tariff Generation Price	21.02	21.02	21.02	21.02	21.02
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	23.16	23.16	23.16	23.16	23.16
Full Fuel	[redacted]				
Low EICCR					
FCCR					
POLR					
Total Generation Service Price					
Generation Service Price Weight	90%	80%	70%	60%	
Competitive Benchmark Price					
Simple Swap	[redacted]				
Capacity					
Other					
Competitive Benchmark Price					
CBP Weight	10%	20%	30%	40%	
Estimate of MRO Price	[redacted]				
Stipulation ESP Price					
Stipulation ESP					
Tariff Generation Price	24.50	25.70	27.20	27.20	25.83
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	26.64	27.84	29.34	29.34	27.97
Full Fuel	[redacted]				
GRR					
Low Pool Modification Rider ("PMR")					
Estimate of *Stipulation* ESP Price					
MRO - ESP Rate Comparison to AEP Ohio Zone					
Average AEP Ohio Zone Price Under MRO	[redacted]				
Average AEP Ohio Zone Price Under ESP					
AEP Zone ESP Price Benefit					-3.57
Total Charges to the AEP Ohio Zone					Total Charges
Estimate of Total Charges Under ESP	[redacted]				
Estimate of Total Charges Under MRO					
Excess Costs Charged Under ESP					582

Exhibit MMS-4: Summary Table and Corrected LJT-2

Scenario 2(a): No POLR, No FCCR, High EICCR, High PMR

	2012	2013	2014	Jan - May 2015	Load-Wtd Avg
MRO Pricing					
Total Generation Service Price					
Tariff Generation Price	21.02	21.02	21.02	21.02	21.02
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	23.16	23.16	23.16	23.16	23.16
Full Fuel	[redacted]				
High EICCR					
FCCR					
POLR					
Total Generation Service Price					
Generation Service Price Weight	90%	80%	70%	60%	
Competitive Benchmark Price					
Simple Swap	[redacted]				
Capacity					
Other					
Competitive Benchmark Price					
CBP Weight	10%	20%	30%	40%	
Estimate of MRO Price	[redacted]				
Stipulation ESP Price					
Stipulation ESP					
Tariff Generation Price	24.50	25.70	27.20	27.20	25.83
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	26.64	27.84	29.34	29.34	27.97
Full Fuel	[redacted]				
GRR					
High Pool Modification Rider ("PMR")					
Estimate of Stipulation ESP Price					
MRO - ESP Rate Comparison to AEP Ohio Zone					
Average AEP Ohio Zone Price Under MRO	[redacted]				
Average AEP Ohio Zone Price Under ESP					
AEP Zone ESP Price Benefit					-3.56
Total Charges to the AEP Ohio Zone					**Total Charges**
Estimate of Total Charges Under ESP	[redacted]				
Estimate of Total Charges Under MRO					
Excess Costs Charged Under ESP					580

Exhibit MMS-4: Summary Table and Corrected LJT-2

Scenario 2(b): No POLR, No FCCR, High EICCR, Low PMR

	2012	2013	2014	Jan - May 2015	Load-Wtd Avg
MRO Pricing					
Total Generation Service Price					
Tariff Generation Price	21.02	21.02	21.02	21.02	21.02
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	23.16	23.16	23.16	23.16	23.16
Full Fuel	[redacted]				
High EICCR					
FCCR					
POLR					
Total Generation Service Price					
Generation Service Price Weight	90%	80%	70%	60%	
Competitive Benchmark Price					
Simple Swap	[redacted]				
Capacity					
Other					
Competitive Benchmark Price					
CBP Weight	10%	20%	30%	40%	
Estimate of MRO Price	[redacted]				
Stipulation ESP Price					
Stipulation ESP					
Tariff Generation Price	24.50	25.70	27.20	27.20	25.83
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	26.64	27.84	29.34	29.34	27.97
Full Fuel	[redacted]				
GRR					
Low Pool Modification Rider ("PMR")					
Estimate of Stipulation ESP Price					
MRO - ESP Rate Comparison to AEP Ohio Zone					
Average AEP Ohio Zone Price Under MRO	[redacted]				
Average AEP Ohio Zone Price Under ESP					
AEP Zone ESP Price Benefit					-2.19
Total Charges to the AEP Ohio Zone					**Total Charges**
Estimate of Total Charges Under ESP	[redacted]				
Estimate of Total Charges Under MRO					
Excess Costs Charged Under ESP					357

Exhibit MMS-4: Summary Table and Corrected LJT-2

Scenario 3(a): $3.07 POLR, Sporn 5 FCCR, Low EICCR, High PMR

	2012	2013	2014	Jan - May 2015	Load-Wtd Avg
MRO Pricing					
Total Generation Service Price					
Tariff Generation Price	21.02	21.02	21.02	21.02	21.02
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	23.16	23.16	23.16	23.16	23.16
Full Fuel	[redacted]				
Low EICCR					
FCCR					
POLR					
Total Generation Service Price					
Generation Service Price Weight	90%	80%	70%	60%	
Competitive Benchmark Price					
Simple Swap	[redacted]				
Capacity					
Other					
Competitive Benchmark Price					
CBP Weight	10%	20%	30%	40%	
Estimate of MRO Price	[redacted]				
Stipulation ESP Price					
Stipulation ESP					
Tariff Generation Price	24.50	25.70	27.20	27.20	25.83
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	26.64	27.84	29.34	29.34	27.97
Full Fuel	[redacted]				
GRR					
High Pool Modification Rider ("PMR")					
Estimate of Stipulation ESP Price					
MRO - ESP Rate Comparison to AEP Ohio Zone					
Average AEP Ohio Zone Price Under MRO	[redacted]				
Average AEP Ohio Zone Price Under ESP					
AEP Zone ESP Price Benefit					-2.04
Total Charges to the AEP Ohio Zone					**Total Charges**
Estimate of Total Charges Under ESP	[redacted]				
Estimate of Total Charges Under MRO					
Excess Costs Charged Under ESP					333

Exhibit MMS-4: Summary Table and Corrected LJT-2

Scenario 3(b): $3.07 POLR, Sporn 5 FCCR, Low EICCR, Low PMR

	2012	2013	2014	Jan - May 2015	Load-Wtd Avg
MRO Pricing					
Total Generation Service Price					
Tariff Generation Price	21.02	21.02	21.02	21.02	21.02
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	23.16	23.16	23.16	23.16	23.16
Full Fuel	[redacted]				
Low EICCR					
FCCR					
POLR					
Total Generation Service Price					
Generation Service Price Weight	90%	80%	70%	60%	
Competitive Benchmark Price					
Simple Swap	[redacted]				
Capacity					
Other					
Competitive Benchmark Price					
CBP Weight	10%	20%	30%	40%	
Estimate of MRO Price	[redacted]				
Stipulation ESP Price					
Stipulation ESP					
Tariff Generation Price	24.50	25.70	27.20	27.20	25.83
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	26.64	27.84	29.34	29.34	27.97
Full Fuel	[redacted]				
GRR					
Low Pool Modification Rider ("PMR")					
Estimate of Stipulation ESP Price					
MRO - ESP Rate Comparison to AEP Ohio Zone					
Average AEP Ohio Zone Price Under MRO	[redacted]				
Average AEP Ohio Zone Price Under ESP					
AEP Zone ESP Price Benefit					-0.68
Total Charges to the AEP Ohio Zone					Total Charges
Estimate of Total Charges Under ESP	[redacted]				
Estimate of Total Charges Under MRO					
Excess Costs Charged Under ESP					111

Exhibit MMS-4: Summary Table and Corrected LJT-2

Scenario 4(a): $3.07 POLR, Sporn 5 FCCR, High EICCR, High PMR

	2012	2013	2014	Jan - May 2015	Load-Wtd Avg
MRO Pricing					
Total Generation Service Price					
Tariff Generation Price	21.02	21.02	21.02	21.02	21.02
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	23.16	23.16	23.16	23.16	23.16
Full Fuel	[redacted]				
High EICCR					
FCCR					
POLR					
Total Generation Service Price					
Generation Service Price Weight	90%	80%	70%	60%	
Competitive Benchmark Price					
Simple Swap	[redacted]				
Capacity					
Other					
Competitive Benchmark Price					
CBP Weight	10%	20%	30%	40%	
Estimate of MRO Price	[redacted]				
Stipulation ESP Price					
Stipulation ESP					
Tariff Generation Price	24.50	25.70	27.20	27.20	25.83
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	26.64	27.84	29.34	29.34	27.97
Full Fuel	[redacted]				
GRR					
High Pool Modification Rider ("PMR")					
Estimate of Stipulation ESP Price					
MRO - ESP Rate Comparison to AEP Ohio Zone					
Average AEP Ohio Zone Price Under MRO	[redacted]				
Average AEP Ohio Zone Price Under ESP					
AEP Zone ESP Price Benefit					-0.67
Total Charges to the AEP Ohio Zone					**Total Charges**
Estimate of Total Charges Under ESP	[redacted]				
Estimate of Total Charges Under MRO					
Excess Costs Charged Under ESP					109

Exhibit MMS-4: Summary Table and Corrected LJT-2

Scenario 4(b): $3.07 POLR, Sporn 5 FCCR, High EICCR, Low PMR

	2012	2013	2014	Jan - May 2015	Load-Wtd Avg
MRO Pricing					
Total Generation Service Price					
Tariff Generation Price	21.02	21.02	21.02	21.02	21.02
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	23.16	23.16	23.16	23.16	23.16
Full Fuel	[redacted]				
High EICCR					
FCCR					
POLR					
Total Generation Service Price					
Generation Service Price Weight	90%	80%	70%	60%	
Competitive Benchmark Price					
Simple Swap	[redacted]				
Capacity					
Other					
Competitive Benchmark Price					
CBP Weight	10%	20%	30%	40%	
Estimate of MRO Price	[redacted]				
Stipulation ESP Price					
Stipulation ESP					
Tariff Generation Price	24.50	25.70	27.20	27.20	25.83
Transmission Adjustment	2.14	2.14	2.14	2.14	2.14
Market Comparable Base 'g' Rate	26.64	27.84	29.34	29.34	27.97
Full Fuel	[redacted]				
GRR					
Low Pool Modification Rider ("PMR")					
Estimate of Stipulation ESP Price					
MRO - ESP Rate Comparison to AEP Ohio Zone					
Average AEP Ohio Zone Price Under MRO	[redacted]				
Average AEP Ohio Zone Price Under ESP					
AEP Zone ESP Price Benefit					0.70
Total Charges to the AEP Ohio Zone					**Total Charges**
Estimate of Total Charges Under ESP	[redacted]				
Estimate of Total Charges Under MRO					
Excess Costs Charged Under ESP					-114

Methodology Used to Calculate Maximum Above-Market Capacity Rate

The analysis shown below establishes the annual capacity revenues that would allow AEP Ohio's generating fleet to recover its total generation costs (including a return on its investment) if customers shopped with CRES suppliers in 2010. I first included all costs associated with owning and operating the generating fleet, based on data provided by AEP Ohio, and then subtracted the revenues available to AEP Ohio.[1] The components of the analysis are described below:

Total Generation Costs (Additions)

1. **Fixed Production Costs:** Annual fixed production costs are the costs associated with AEP Ohio's generating fleet that are independent of the level of production.
2. **Variable Production Costs:** Variable production costs are the costs associated with AEP Ohio's generating fleet that are dependent on the level of production. This includes annual fuel costs for OPCo and CSP.

The sum of the fixed and variable productions costs result in AEP Ohio's total costs for its generating fleet.

Available Revenues (Subtractions)

3. **Non-AEP Pool Sales Revenues:** The largest source of revenue available to AEP Ohio's generating fleet when customers shop comes from the sale of energy and ancillary services in the wholesale market. Energy revenues are calculated by multiplying each generating unit's hourly output by the applicable Day-Ahead LMP in 2010.[2] Ancillary revenues are available to AEP Ohio as a member of PJM. Revenues associated with net sales of capacity outside of the AEP East Power Pool ("AEP Pool") were also included.[3]

[1] For purposes of this analysis, the Lawrenceburg plant is included in AEP Ohio's generating fleet. CSP has contracted through 2017 for all energy, capacity and ancillary services associated with the facility. CSP schedules and dispatches the facility and pays fuel, O&M, and other costs. (AEP, 2010 10-K, at 16.)

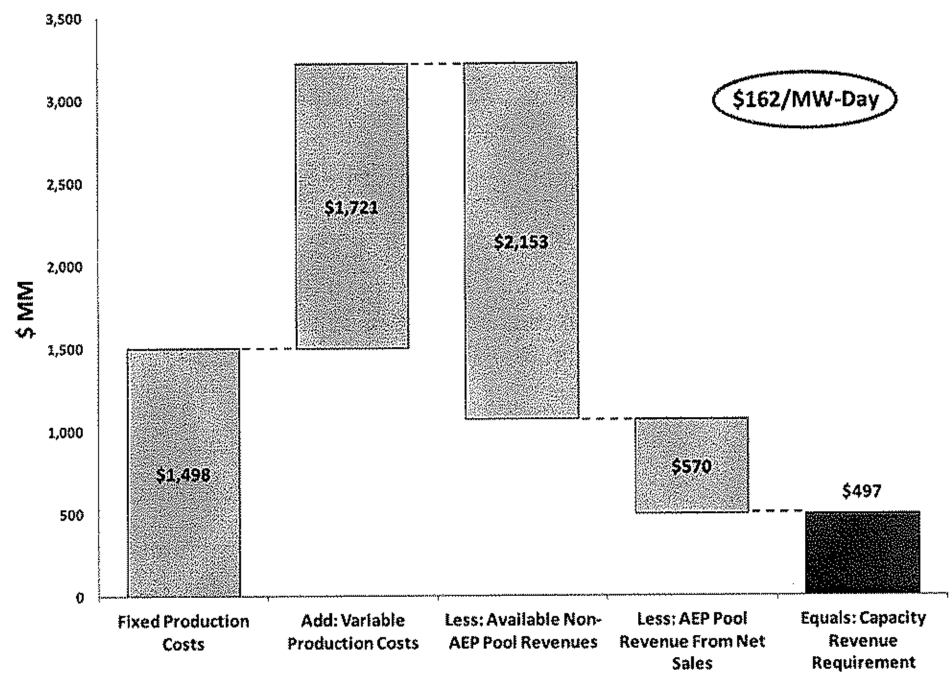
[2] Hourly generation was available from the EPA's Continuous Emission Monitoring System. Day-Ahead LMPs were reported by Ventyx's Energy Velocity.

[3] These transactions are reported on FERC Form 1, p. 311, col. (h) and p. 327, col. (j).

4. **AEP Pool Net Sales Revenues:** The final revenue stream available to AEP Ohio's generating fleet results from its membership in the AEP Pool. As a member of the AEP Pool, AEP Ohio is assigned a capacity reservation requirement based upon its Member Load Ratio. Although CSP is a deficit-capacity member of the AEP Pool, AEP Ohio has surplus capacity and has made net sales of capacity to the AEP Pool in 2010.[4] AEP Ohio also makes net sales of energy to other pool members. These net capacity and energy revenues are available to AEP Ohio as a member of the AEP Pool.

The result of subtracting these revenues from AEP Ohio's total generation costs yields a capacity revenue requirement of $497 million in 2010, or a "maximum above-market" capacity rate of $162 per MW-Day in 2010 for generating capacity not sold into the AEP Pool. These calculations are illustrated in the chart below:

Method Used to Calculate the "Maximum Above-Market" Capacity Rate



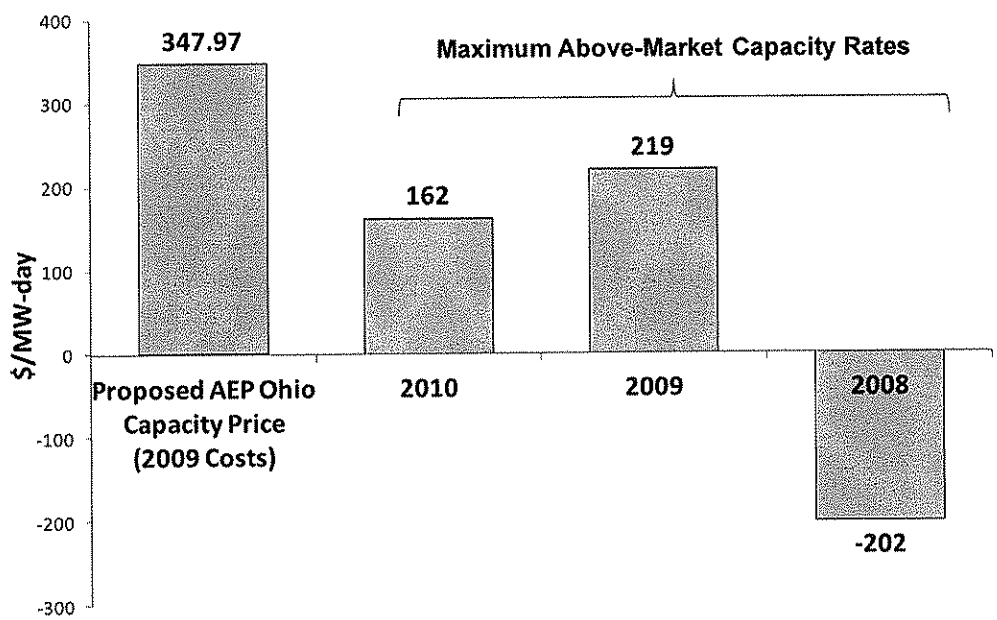
Sensitivity Analysis

[4] In 2010 AEP Ohio had revenues of $398 million from net sales of an average 2,493 MW in capacity to the AEP Pool. This equates to a capacity transfer price of $437 per MW-Day (AEP Ohio Interrogatory Response, OEG, Set 3, INT-3-003, at 3 and FES, Set 6, INT-6-8).

The above analysis is based on a 2010 test year, while AEP Ohio uses a test year of 2009 to calculate its proposed capacity price. Therefore, I have performed a sensitivity analysis using market energy, fuel and generation output from other years to support the use of the 2010 test year. The "maximum above-market" capacity rate is dependent largely on the net generation revenues – the difference between the market energy revenues less the fuel costs multiplied by the generation output of the AEP Ohio plants. As market prices increase, the difference between market prices and fuel costs tend to increase, as does the generation output from the plants. Therefore, the resulting "maximum above-market" capacity rate would be lower as market prices increase.

As a sensitivity analysis, I have calculated this "maximum above-market" capacity rate for 2008, 2009 and 2010, using the formula rates provided by AEP Ohio to estimate total production costs in 2008 and 2010.[5] The results are shown below:

Sensitivity Analyses of "Maximum Above-Market" Capacity Rates Confirm that the Capacity Price Used by AEP Ohio Is Far Too High

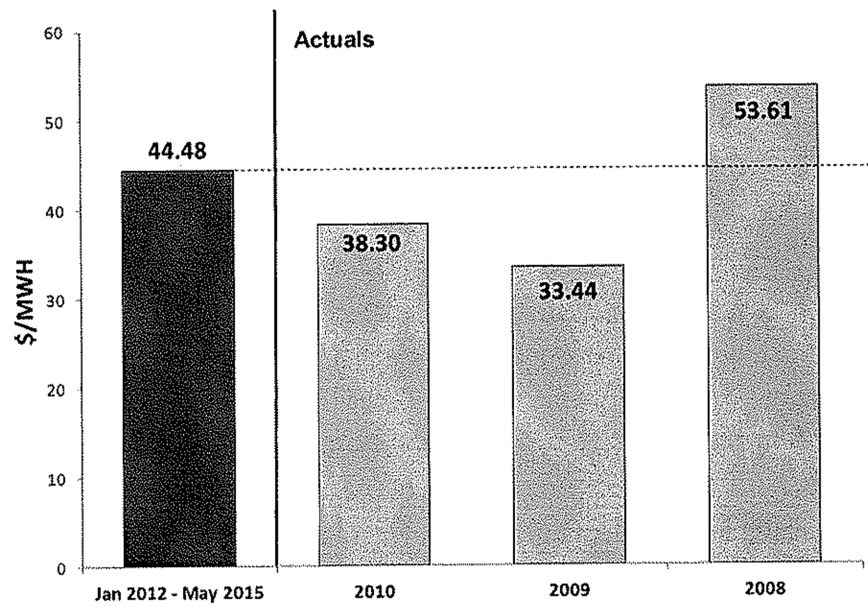


[5] Initial Comments of OPCo and CSP, PUCO Case No. 10-2929-EL-UNC, 1/7/2011. *See also*, Initial Filing of American Electric Power Service Corporation, FERC Docket ER11-2183, 11/24/2010. The calculations for 2008 and 2010 were based on 2009 data when data for 2008 and 2010 was not available.

In 2009, the test year AEP Ohio used in its analysis, the "maximum above-market" capacity rate would have been higher ($219 per MW-Day) due to lower market energy prices, while in 2008, when market energy prices were significantly higher, the "maximum above-market" capacity rate would have been negative (-$202 per MW-day). This suggests that AEP Ohio actually would have been able to exceed its total generation revenue requirement in 2008 if it had received market energy revenues.

There is reason to believe that the "maximum above-market" capacity rate for the proposed ESP period would be lower than the rate for 2009, the test year used by AEP Ohio. The average forward energy prices suggest that market energy prices during the SSO delivery period are expected to be higher than in 2009, the test year used by AEP Ohio, and also higher than those experienced in 2010, so the "maximum above market" capacity rate would be expected to be no higher than the 2010 rate, or $162 per MW-day. As shown below, the around-the-clock energy prices averaged $53.61 per MWH in 2008, $33.44 in 2009, and $38.30 in 2010. Meanwhile, the around-the-clock forward energy price during the January 2012 through May 2015 delivery period of the SSO was $44.48 per MWH, higher than both the 2009 and 2010 around-the-clock energy price.[6]

Energy Futures for the ESP Delivery Period Are Higher Than Actual Energy Levels Experienced in 2010



As shown above, the ESP delivery period futures energy price is closest to the levels experienced in 2010, which is the test year that I used for calculating the "maximum above-market" capacity rate.

[6] Based on the "Simple Swap" and "Basis Adjustment" using energy forwards from July 7-13, 2011.

Exhibit MMS-6: Discovery Responses and Other Sources

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO DISCOVERY REQUEST PUCO CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO THIRD SET

INTERROGATORY

INT-129. What is the estimated level of weighted average cost of capital to be used for the Facility Closure Cost Recovery Rider?

RESPONSE

The Facility Closure Recovery Rider will use a pre-tax WACC, estimated to be 11 77% as described in Company witness Hawkins' testimony.

Prepared By: Andrea E Moore

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSES TO
FIRSTENERGY SOLUTIONS CORPORATION'S
DISCOVERY REQUEST
CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO
SIXTH SET**

INTERROGATORY

INT-6-9. Referring to OCC INT-097, please identify the forecast of the monthly power pool capacity revenues (or expenses) for Ohio Power and CSP for each of 2012, 2013, and 2014, and the associated MWs sold (or purchased) to AEP pool members.

RESPONSE:

See FES INT-6-009 Attachment 1.

Prepared by: Philip J Nelson

AEP EAST SYSTEM
CAPACITY EQUALIZATION SETTLEMENT

	Jan 2012	Feb 2012	Mar 2012	Apr 2012	May 2012	Jun 2012	Jul 2012	Aug 2012	Sep 2012	Oct 2012	Nov 2012	Dec 2012	Jan 2013
MEMBER CAPACITY SURPLUS (MW)													
APCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CSP	337.13	337.13	341.16	341.16	341.16	341.16	341.16	344.65	521.90	521.90	521.90	383.64	383.52
I&M	70.21	70.21	75.04	75.04	75.04	75.04	75.04	0.00	0.00	0.00	0.00	0.00	0.00
KPCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OPCO	2,236.74	2,236.74	2,241.84	2,241.84	2,241.84	2,241.84	2,241.84	2,323.75	2,278.36	2,278.36	2,278.36	2,313.89	2,314.47
Sum:	2,644.07	2,644.07	2,658.03	2,658.03	2,658.03	2,658.03	2,658.03	2,668.39	2,800.25	2,800.25	2,800.25	2,697.52	2,697.99
MEMBER CAPACITY DEFICIT (MW)													
APCO	2,222.85	2,222.85	2,244.34	2,244.34	2,244.34	2,244.34	2,244.34	2,237.36	2,310.41	2,310.41	2,310.41	2,253.50	2,253.76
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.69	62.73	62.73	62.73	28.55	28.71
KPCO	421.22	421.22	413.70	413.70	413.70	413.70	413.70	412.35	427.12	427.12	427.12	415.47	415.52
OPCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sum:	2,644.07	2,644.07	2,658.04	2,658.04	2,658.04	2,658.04	2,658.04	2,668.40	2,800.26	2,800.26	2,800.26	2,697.52	2,697.99
SYSTEM (PAYMENTS)/ RECEIPTS ($000)													
APCO	(31,381.735)	(31,381.735)	(31,686.121)	(31,686.121)	(31,686.121)	(31,686.121)	(31,686.121)	(31,491.100)	(32,214.028)	(32,214.028)	(32,214.028)	(31,650.432)	(32,206.043)
CSP	4,067.174	4,067.174	4,115.793	4,115.793	4,115.793	4,115.793	4,115.793	4,157.897	6,296.271	6,296.271	6,296.271	4,628.279	4,782.741
I&M	1,111.746	1,111.746	1,188.227	1,188.227	1,188.227	1,188.227	1,188.227	(263.064)	(874.644)	(874.644)	(874.644)	(400.985)	(410.264)
KPCO	(5,946.696)	(5,946.696)	(5,840.714)	(5,840.714)	(5,840.714)	(5,840.714)	(5,840.714)	(5,803.874)	(5,955.331)	(5,955.331)	(5,955.331)	(5,835.281)	(5,937.746)
OPCO	32,149.511	32,149.511	32,222.816	32,222.816	32,222.816	32,222.816	32,222.816	33,400.141	32,747.732	32,747.732	32,747.732	33,258.419	33,771.311
Sum:	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

AEP EAST SYSTEM
CAPACITY EQUALIZATION SETTLEMENT

	Feb 2013	Mar 2013	Apr 2013	May 2013	Jun 2013	Jul 2013	Aug 2013	Sep 2013	Oct 2013	Nov 2013	Dec 2013	Jan 2014	Feb 2014
MEMBER CAPACITY SURPLUS (MW)													
APCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CSP	383.52	395.53	395.53	395.53	395.53	395.53	400.34	403.27	403.27	396.01	396.01	396.77	396.77
I&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
KPCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OPCO	2,314.47	2,330.21	2,330.21	2,330.21	2,330.21	2,330.21	2,373.46	2,372.65	2,372.65	2,363.06	2,363.06	2,364.27	2,364.27
Sum:	2,697.99	2,725.74	2,725.74	2,725.74	2,725.74	2,725.74	2,773.80	2,775.92	2,775.92	2,759.07	2,759.07	2,761.04	2,761.04
MEMBER CAPACITY DEFICIT (MW)													
APCO	2,253.76	2,302.07	2,302.07	2,302.07	2,302.07	2,302.07	2,292.46	2,293.53	2,293.53	2,309.12	2,309.12	2,310.21	2,310.21
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I&M	28.71	13.23	13.23	13.23	13.23	13.23	73.02	73.82	73.82	38.21	38.21	38.87	38.87
KPCO	415.52	410.45	410.45	410.45	410.45	410.45	408.31	408.58	408.58	411.75	411.75	411.97	411.97
OPCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sum:	2,697.99	2,725.75	2,725.75	2,725.75	2,725.75	2,725.75	2,773.79	2,775.93	2,775.93	2,759.08	2,759.08	2,761.05	2,761.05
SYSTEM (PAYMENTS)/ RECEIPTS ($000)													
APCO	(32,206.043)	(32,881.822)	(32,881.822)	(32,881.822)	(32,881.822)	(32,881.822)	(32,748.588)	(32,759.040)	(32,759.040)	(32,990.255)	(32,990.255)	(33,562.588)	(33,562.588)
CSP	4,782.741	4,932.514	4,932.514	4,932.514	4,932.514	4,932.514	4,992.498	5,029.037	5,029.037	4,938.500	4,938.500	5,037.631	5,037.631
I&M	(410.264)	(188.972)	(188.972)	(188.972)	(188.972)	(188.972)	(1,043.116)	(1,054.389)	(1,054.389)	(545.904)	(545.904)	(564.701)	(564.701)
KPCO	(5,937.746)	(5,862.699)	(5,862.699)	(5,862.699)	(5,862.699)	(5,862.699)	(5,832.850)	(5,835.846)	(5,835.846)	(5,882.647)	(5,882.647)	(5,985.075)	(5,985.075)
OPCO	33,771.311	34,000.979	34,000.979	34,000.979	34,000.979	34,000.979	34,632.057	34,620.237	34,620.237	34,480.306	34,480.306	35,074.732	35,074.732
Sum:	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

AEP EAST SYSTEM
CAPACITY EQUALIZATION SETTLEMENT

	Mar 2014	Apr 2014	May 2014	Jun 2014	Jul 2014	Aug 2014	Sep 2014	Oct 2014	Nov 2014	Dec 2014
MEMBER CAPACITY SURPLUS (MW)										
APCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CSP	401.85	401.85	401.85	401.85	401.85	399.71	405.59	389.33	389.33	389.33
I&M	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.61	56.61	56.61
KPCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OPCO	2,371.23	2,371.23	2,371.23	2,371.23	2,371.23	2,369.36	2,367.75	2,346.24	2,346.24	2,346.24
Sum:	2,773.08	2,773.08	2,773.08	2,773.08	2,773.08	2,769.07	2,773.34	2,792.18	2,792.18	2,792.18
MEMBER CAPACITY DEFICIT (MW)										
APCO	2,338.55	2,338.55	2,338.55	2,338.55	2,338.55	2,343.36	2,346.04	2,381.15	2,381.15	2,381.15
CSP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I&M	31.92	31.92	31.92	31.92	31.92	22.02	23.36	0.00	0.00	0.00
KPCO	402.61	402.61	402.61	402.61	402.61	403.68	403.95	411.03	411.03	411.03
OPCO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sum:	2,773.08	2,773.08	2,773.08	2,773.08	2,773.08	2,769.06	2,773.35	2,792.18	2,792.18	2,792.18
SYSTEM (PAYMENTS)/ RECEIPTS ($000)										
APCO	(33,968.391)	(33,968.391)	(33,968.391)	(33,968.391)	(33,968.391)	(34,041.202)	(34,070.365)	(34,760.226)	(34,760.226)	(34,760.226)
CSP	5,102.130	5,102.130	5,102.130	5,102.130	5,102.130	5,074.959	5,149.615	4,943.168	4,943.168	4,943.168
I&M	(463.651)	(463.651)	(463.651)	(463.651)	(463.651)	(319.877)	(339.246)	1,010.057	1,010.057	1,010.057
KPCO	(5,848.074)	(5,848.074)	(5,848.074)	(5,848.074)	(5,848.074)	(5,864.124)	(5,866.364)	(6,000.250)	(6,000.250)	(6,000.250)
OPCO	35,177.986	35,177.986	35,177.986	35,177.986	35,177.986	35,150.244	35,126.359	34,807.252	34,807.252	34,807.252
Sum:	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO FIRSTENERGY SOLUTIONS DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO TENTH SET

INTERROGATORY

INT-10-2. In a press release issued June 9, 2011, AEP issued a "Plan for Compliance With Proposed EPA Regulations," which stated, in part, that "The cost of AEP's compliance plan could range from $6 billion to $8 billion in capital investment through the end of the decade."

a. Please provide a detailed description of what portion of the $6 billion in capital investment referenced above pertains to Ohio Power Company and the Columbus Southern Power Company.

b. Please provide a detailed description of what portion of the $8 billion in capital investment referenced above pertains to Ohio Power Company and the Columbus Southern Power Company.

c. Please provide the specific amount of capital investment applicable to each of Ohio Power Company and the Columbus Southern Power Company, by year from 2011 to 2020 under the $6 billion capital investment scenario referenced above.

d. Please provide the specific amount of capital investment applicable to each of Ohio Power Company and the Columbus Southern Power Company, by year from 2011 to 2020 under the $8 billion capital investment scenario referenced above.

e. Please provide by generation plant, the plant name, the expected timing, and the specific milestones relating to each environmental investment under the $6 billion capital investment scenario referenced above, for each of Ohio Power Company and the Columbus Southern Power Company.

INT-10-2 (CONTINUED)

f. Please provide by generation plant, the plant name, the expected timing, and the specific milestones relating to any environmental investment under the $8 billion capital investment scenario referenced above, for each of Ohio Power Company and the Columbus Southern Power Company.

RESPONSE

a. and b. The $6 billion to $8 billion range AEP provided in its June 9, 2011 press release was based on setting bounds around a single base plan point estimate. The point estimates for Columbus Southern Power and Ohio Power Company are $671.8 million and $1.89 billion, respectively (total of $2.56 billion for AEP Ohio Companies). The lower bounds are approximately $550 million for Columbus Southern Power and $1.55 billion for Ohio Power Company (total $2.1 billion for AEP Ohio Companies). The upper bounds are approximately $740 million for Columbus Southern Power and $2.06 billion for Ohio Power Company (total $2.8 billion for AEP Ohio Companies)

c. Please see FES INT 10-2 Attachment 1 for capital investment by year from 2012 through 2020; capital for these projects was not forecasted for 2011.

d. Please see FES INT 10-2 Attachment 2 for capital investment by year from 2012 through 2020; capital for these projects was not forecasted for 2011.

e. Please see FES INT 10-2 CONFIDENTIAL Attachment 3

f. Please see FES INT 10-2 CONFIDENTIAL Attachment 4

Please note that these estimates provided in parts a through f. were prepared based on the best available information at the time without the benefit of detailed engineering. In addition, high demand for labor and materials due to a constrained compliance timeframe could result in actual costs different than these estimates. Finally, the comliance plan could change significantly depending on the final form of the proposed EPA regulations and regulatory approvals from state commissions.

Prepared By: Philip J. Nelson

2012-2020 AEP Ohio Generation Capital
(post-allocated, capital, owned-view, $000's, less AFUDC)
(data as of May 27, 2011)
Environmental Capital only

Operating Co	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
144 Columbus Southern Power	63,406	107,103	138,354	123,551	52,085	14,617	32,370	13,797	4,718	550,000
181 Ohio Power Co	80,409	331,262	346,729	216,029	241,895	167,455	102,109	33,725	26,756	1,546,370
Total	**143,815**	**438,365**	**485,083**	**339,580**	**293,980**	**182,072**	**134,479**	**47,522**	**31,474**	**2,096,370**

2012-2020 AEP Ohio Generation Capital
(post-allocated, capital, owned-view, $000's, less AFUDC)
(data as of May 27, 2011)
Environmental Capital only

Operating Co	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
144 Columbus Southern Power	85,310	144,102	186,150	166,233	70,078	19,666	43,552	18,563	6,348	740,000
181 Ohio Power Co	106,867	440,258	460,814	287,109	321,487	222,553	135,706	44,822	35,560	2,055,175
Total	**192,176**	**584,361**	**646,963**	**453,342**	**391,564**	**242,219**	**179,258**	**63,385**	**41,908**	**2,795,176**

COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S
RESPONSE TO
FIRST ENERGY SOLUTIONS'S DISCOVERY REQUEST
IN PUCO CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO
SEVENTEENTH SET

INTERROGATORY

STIP-FES-INT-17-17-043 Referring to Section IV.5 of the Stipulation, which states that "if the impact of the Pool termination/modification on AEP Ohio during the ESP term is greater than $50 million prior to May 31, 2015, the company may pursue cost recovery of the entire impact during the ESP term and obtain approval by the Ohio commission . . . .":

(a) Under the Stipulation, would AEP Ohio be permitted to recover lost capacity revenues attributable to months after May 31, 2015? If so, what is the last possible date that lost capacity revenues could be calculated?

(b) Under the Stipulation, would AEP Ohio be permitted to begin recovery of lost capacity revenues as of January 1, 2013? September 1, 2013?

(c) What is the estimated date of termination of the pool? If You do not have an estimate, what is the earliest feasible date for termination of the pool? What is the latest possible date for termination of the pool?

(d) For the collection period of the proposed Pool Modification Rider, what is Your estimate of the initial date upon which the proposed Pool Modification Rider is expected to be collected from customers?

(e) For the collection period of the proposed Pool Modification Rider, what is the date through which the proposed Pool Modification Rider will be collected from customers?

(f) Assuming pool termination occurs January 1, 2014:

i. When would the Pool Modification Rider begin to be collected from SSO customers?
ii. What time period of lost capacity revenues would be collected through the rider?
iii. Would there be a time lag between when the capacity revenues are lost versus collected in the rider?

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S
RESPONSE TO
FIRST ENERGY SOLUTIONS'S DISCOVERY REQUEST
IN PUCO CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO
SEVENTEENTH SET**

STIP-FES-INT-17-17-043

(g) If AEP Ohio is able to increase energy revenues as a result of pool termination (i.e., by selling energy at a higher rate than under the existing Pool Agreement), will AEP Ohio offset lost capacity revenues with these increased energy revenues?

RESPONSE

A. No, however recovery of the impacts of the pool termination/modification on AEP Ohio incurred prior to May 31, 2015 could occur through May 31, 2016.

B. The calculation of the impact of the pool termination/modification would begin upon the effective date of the modification/termination of the pool. Once the calculation of the impact is completed, a recovery request could be filed with the Commission for approval.

C. See the testimony of Company witness Munczinski and Appendix B of the Joint Stipulation and Recommendation.

D. See B. above

E. See A. and B. above

F. See A. and B. above

G. The impact of the modification/termination of the pool is a net impact on AEP Ohio.

Prepared By: Richard E. Munczinski

COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S
RESPONSE TO
FIRST ENERGY SOLUTIONS'S DISCOVERY REQUEST
IN PUCO CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO
EIGHTEENTH SET

INTERROGATORY

STIP-FES-18-001: For the Proposed ESP under the Stipulation, please provide a forecast of total system load and total SSO retained load for the calendar years for 2012, 2013, 2014, 2015, 2016, the first five months of 2015, and the first five months of 2016.

RESPONSE

AEP Ohio objects to this interrogatory on the grounds that it is vague and ambiguous. Without waiving its objection, AEP Ohio states that the forecasted AEP Ohio total system load is included in the workpapers of Company witness Allen For the purposes of developing the pro forma financial information, AEP Ohio has assumed 21%, 31%, 41% and 41% shopping for 2012, 2013, 2014 and Jan-May 2015, respectively For June 2015 - May 2016, the Company assumed 80% shopping.

Prepared By: William A Allen

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO OHIO ENERGY GROUP DISCOVERY REQUEST PUCO CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO THIRD SET

INTERROGATORY

INT-3-003. Please provide monthly, for the most recently available 12 month period, the AEP East Interchange Power Statement showing Interconnection Agreement monthly billing/credit statements for each of the AEP East Companies Also, provide all supporting schedules showing the basis for monthly billings and credits to each Company.

RESPONSE

See OEG 3-3 Attachment 1 for the most recently available 12 months AEP East Interchange Power Statements. The Company objects to this request for all supporting schedules as being overbroad and unduly burdensome. Without waiving these objections or any general objection the Company may have, the Company states as follows. The supporting schedules are voluminous and may be inspected at the Company's offices at a mutually agreed date and time.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY *		(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	595,810	680,800	24,069,945	29,112,930
RECOVERY AND MLR	KPCO	119,858	76,828	5,033,685	3,241,785
ALLOCATION FOR ALL	I&M	341,746	268,940	13,733,544	12,249,257
AEP SYSTEM	OPCO	386,214	463,548	15,671,574	16,465,348
DELIVERIES TO	CSP	333,619	287,131	13,617,421	11,056,849
NON-AFFILIATED COS.	AEP	1,777,247	1,777,247	72,126,169	72,126,169
ADJUSTMENT TO	APCO	(436,825)	(436,825)	(18,796,465)	(18,796,465)
PREVENT RECOGNITION	KPCO	(63,702)	(63,702)	(2,877,571)	(2,877,571)
OF SALES BY POOL	I&M	(198,371)	(198,371)	(8,628,085)	(8,628,085)
MEMBERS TO	OPCO	(260,933)	(260,933)	(10,523,276)	(10,523,276)
THEMSELVES	CSP	(196,190)	(196,190)	(8,342,424)	(8,342,424)
(PAGE 7)	AEP	(1,156,021)	(1,156,021)	(49,167,821)	(49,167,821)
SUBTOTAL	APCO	158,985	243,975	5,273,480	10,316,465
AEP EXTERNAL	KPCO	56,156	13,126	2,156,114	364,214
ENERGY	I&M	143,375	70,569	5,105,459	3,621,172
	OPCO	125,281	202,615	5,148,298	5,942,072
	CSP	137,429	90,941	5,274,997	2,714,425
	AEP	621,226	621,226	22,958,348	22,958,348
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,130,045	0	28,109,640	0
ENERGY	KPCO	20,201	54,276	505,453	1,460,674
(PAGE 8)	I&M	89,530	144,676	2,265,076	2,857,929
	OPCO	0	1,765,296	0	44,594,908
	CSP	724,472	0	18,033,342	0
	AEP	1,964,248	1,964,248	48,913,511	48,913,511
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	1,289,030	244,557	33,383,120	10,357,487
	KPCO	76,357	67,507	2,661,567	1,832,944
	I&M	232,905	216,866	7,370,535	6,590,456
	OPCO	127,896	1,967,911	5,330,526	50,536,980
	CSP	861,901	91,249	23,308,339	2,736,220
	AEP	2,588,089	2,588,090	72,054,087	72,054,087

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL (MLR SHARE)	DELIVERED TO POOL (AS SUPPLIED)	CHARGE MEMBER A/C 555 (MLR SHARE)	CREDIT MEMBER A/C 447 (AS SUPPLIED)
I. AEP EXTERNAL ENERGY *					
ENERGY COST	APCO	526,269	615,966	20,646,790	25,922,632
RECOVERY AND MLR	KPCO	105,606	73,979	4,281,835	2,733,253
ALLOCATION FOR ALL	I&M	302,194	240,536	11,780,146	10,894,169
AEP SYSTEM	OPCO	342,285	383,483	13,442,178	12,960,126
DELIVERIES TO	CSP	295,085	257,475	11,680,597	9,321,366
NON-AFFILIATED COS.	AEP	1,571,439	1,571,439	61,831,546	61,831,546
ADJUSTMENT TO	APCO	(354,610)	(354,610)	(14,955,109)	(14,955,109)
PREVENT RECOGNITION	KPCO	(47,394)	(47,394)	(2,014,676)	(2,014,676)
OF SALES BY POOL	I&M	(150,076)	(150,076)	(6,443,246)	(6,443,246)
MEMBERS TO	OPCO	(196,910)	(196,910)	(7,635,924)	(7,635,924)
THEMSELVES	CSP	(149,788)	(149,788)	(6,100,284)	(6,100,284)
(PAGE 7)	AEP	(898,778)	(898,778)	(37,149,239)	(37,149,239)
SUBTOTAL	APCO	171,659	261,356	5,691,681	10,967,523
AEP EXTERNAL	KPCO	58,212	26,585	2,267,159	718,577
ENERGY	I&M	152,118	90,460	5,336,900	4,450,923
	OPCO	145,375	186,573	5,806,254	5,324,202
	CSP	145,297	107,687	5,580,313	3,221,082
	AEP	672,661	672,661	24,682,307	24,682,307
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	540,961	1,657	12,534,665	45,177
ENERGY	KPCO	45,542	96,905	1,092,737	2,608,199
(PAGE 8)	I&M	3,803	551,518	105,086	10,511,386
	OPCO	5,361	530,993	108,358	14,688,328
	CSP	585,406	0	14,012,244	0
	AEP	1,181,073	1,181,073	27,853,090	27,853,090
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	712,620	263,305	18,226,346	11,038,553
	KPCO	103,754	123,531	3,359,896	3,330,483
	I&M	155,921	645,160	5,441,986	15,230,686
	OPCO	154,367	717,566	6,222,663	20,012,530
	CSP	730,703	107,803	19,592,557	3,231,196
	AEP	1,857,365	1,857,365	52,843,448	52,843,448

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL (MLR SHARE)	DELIVERED TO POOL (AS SUPPLIED)	CHARGE MEMBER A/C 555 (MLR SHARE)	CREDIT MEMBER A/C 447 (AS SUPPLIED)
I. AEP EXTERNAL ENERGY '					
ENERGY COST	APCO	469,419	533,868	19,679,521	23,912,708
RECOVERY AND MLR	KPCO	92,991	56,655	4,081,238	2,409,994
ALLOCATION FOR ALL	I&M	270,104	227,162	11,228,265	10,782,152
AEP SYSTEM	OPCO	304,630	335,776	12,812,434	12,187,509
DELIVERIES TO	CSP	263,361	247,044	11,133,380	9,642,475
NON-AFFILIATED COS.	AEP	1,400,505	1,400,505	58,934,838	58,934,838
ADJUSTMENT TO	APCO	(334,575)	(334,575)	(14,957,985)	(14,957,985)
PREVENT RECOGNITION	KPCO	(48,482)	(48,482)	(2,187,618)	(2,187,618)
OF SALES BY POOL	I&M	(152,483)	(152,483)	(6,889,264)	(6,889,264)
MEMBERS TO	OPCO	(192,575)	(192,575)	(7,983,570)	(7,983,570)
THEMSELVES	CSP	(153,713)	(153,713)	(6,625,283)	(6,625,283)
(PAGE 7)	AEP	(881,828)	(881,828)	(38,643,720)	(38,643,720)
SUBTOTAL	APCO	134,844	199,293	4,721,536	8,954,723
AEP EXTERNAL	KPCO	44,509	8,173	1,893,620	222,376
ENERGY	I&M	117,621	74,679	4,339,001	3,892,888
	OPCO	112,055	143,201	4,828,864	4,203,939
	CSP	109,648	93,331	4,508,097	3,017,192
	AEP	518,677	518,677	20,291,118	20,291,118
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	524,037	746	11,894,364	21,421
ENERGY	KPCO	228,804	33,684	5,561,875	1,021,062
(PAGE 8)	I&M	2,429	545,190	65,634	9,643,322
	OPCO	350	651,823	6,645	17,541,211
	CSP	481,618	5,795	10,868,945	170,447
	AEP	1,237,238	1,237,238	28,397,463	28,397,463
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	658,881	200,362	16,615,900	9,013,421
	KPCO	273,313	41,885	7,455,495	1,247,970
	I&M	120,567	619,869	4,473,036	13,536,210
	OPCO	112,405	795,113	4,835,509	21,759,378
	CSP	591,266	99,203	15,377,042	3,200,003
	AEP	1,756,432	1,756,432	48,756,982	48,756,982

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT

SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY		*(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	860,934	901,142	32,956,634	36,833,425
RECOVERY AND MLR	KPCO	175,367	217,749	6,834,712	8,201,691
ALLOCATION FOR ALL	I&M	493,935	384,476	18,803,600	15,716,520
AEP SYSTEM	OPCO	560,456	643,531	21,456,553	21,523,570
DELIVERIES TO	CSP	485,552	429,346	18,644,699	16,420,992
NON-AFFILIATED COS.	AEP	2,576,244	2,576,244	98,696,198	98,696,198
ADJUSTMENT TO	APCO	(479,176)	(479,176)	(20,875,845)	(20,875,845)
PREVENT RECOGNITION	KPCO	(64,789)	(64,789)	(3,053,334)	(3,053,334)
OF SALES BY POOL	I&M	(198,186)	(198,186)	(8,941,124)	(8,941,124)
MEMBERS TO	OPCO	(275,987)	(275,987)	(11,239,739)	(11,239,739)
THEMSELVES	CSP	(202,235)	(202,235)	(9,010,380)	(9,010,380)
(PAGE 7)	AEP	(1,220,373)	(1,220,373)	(53,120,422)	(53,120,422)
SUBTOTAL	APCO	381,758	421,966	12,080,789	15,957,580
AEP EXTERNAL	KPCO	110,578	152,960	3,781,378	5,148,357
ENERGY	I&M	295,749	186,290	9,862,476	6,775,396
	OPCO	284,469	367,544	10,216,814	10,283,831
	CSP	283,317	227,111	9,634,319	7,410,612
	AEP	1,355,871	1,355,871	45,575,776	45,575,776
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,342,611	0	29,453,015	0
ENERGY	KPCO	33,950	50,037	749,023	1,365,759
(PAGE 8)	I&M	1,948	756,221	45,246	14,338,711
	OPCO	0	1,343,267	0	31,200,066
	CSP	778,700	7,684	16,920,385	263,133
	AEP	2,157,209	2,157,209	47,167,669	47,167,669
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	1,724,369	422,684	41,604,067	15,957,580
	KPCO	144,528	203,146	4,544,281	6,514,116
	I&M	298,317	943,124	9,956,093	21,179,616
	OPCO	285,842	1,710,962	10,233,412	41,604,855
	CSP	1,062,017	235,157	26,592,059	7,673,745
	AEP	3,515,073	3,515,073	92,929,912	92,929,912

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY		*(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	1,273,204	1,407,507	47,130,739	54,006,402
RECOVERY AND MLR	KPCO	264,358	135,026	9,774,995	5,147,368
ALLOCATION FOR ALL	I&M	698,778	508,850	25,819,740	20,837,845
AEP SYSTEM	OPCO	827,578	1,045,374	30,684,876	33,854,813
DELIVERIES TO	CSP	712,620	679,781	26,352,236	25,916,159
NON-AFFILIATED COS.	AEP	3,776,538	3,776,538	139,762,586	139,762,586
ADJUSTMENT TO	APCO	(671,133)	(671,133)	(29,159,087)	(29,159,087)
PREVENT RECOGNITION	KPCO	(68,772)	(68,772)	(3,546,042)	(3,546,042)
OF SALES BY POOL	I&M	(225,295)	(225,295)	(11,226,440)	(11,226,440)
MEMBERS TO	OPCO	(380,444)	(380,444)	(15,825,356)	(15,825,356)
THEMSELVES	CSP	(261,637)	(261,637)	(12,380,303)	(12,380,303)
(PAGE 7)	AEP	(1,607,281)	(1,607,281)	(72,137,228)	(72,137,228)
SUBTOTAL	APCO	602,071	736,374	17,971,652	24,847,315
AEP EXTERNAL	KPCO	195,586	66,254	6,228,953	1,601,326
ENERGY	I&M	473,483	283,555	14,593,300	9,611,404
	OPCO	447,134	664,930	14,859,520	18,029,457
	CSP	450,983	418,144	13,971,933	13,535,856
	AEP	2,169,257	2,169,257	67,625,358	67,625,358
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,339,003	0	30,451,648	0
ENERGY	KPCO	91	239,101	2,023	5,727,902
(PAGE 8)	I&M	4,501	811,032	109,081	16,303,369
	OPCO	0	1,210,382	0	29,356,608
	CSP	916,920	0	20,825,127	0
	AEP	2,260,515	2,260,515	51,387,879	51,387,879
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	1,941,074	737,291	48,423,300	24,918,981
	KPCO	195,677	305,477	6,230,976	7,340,352
	I&M	478,174	1,095,116	14,724,649	25,957,155
	OPCO	449,381	1,875,358	15,035,618	47,391,772
	CSP	1,367,903	418,967	34,797,060	13,603,344
	AEP	4,432,209	4,432,209	119,211,604	119,211,605

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL (MLR SHARE)	DELIVERED TO POOL (AS SUPPLIED)	CHARGE MEMBER A/C 555 (MLR SHARE)	CREDIT MEMBER A/C 447 (AS SUPPLIED)
I. AEP EXTERNAL ENERGY '					
ENERGY COST	APCO	995,065	1,134,653	37,981,066	44,721,765
RECOVERY AND MLR	KPCO	204,450	122,761	7,876,598	4,923,160
ALLOCATION FOR ALL	I&M	599,386	455,258	22,839,085	19,420,264
AEP SYSTEM	OPCO	701,856	774,011	26,724,592	26,314,468
DELIVERIES TO	CSP	568,612	582,686	21,894,691	21,936,376
NON-AFFILIATED COS.	AEP	3,069,369	3,069,369	117,316,032	117,316,033
ADJUSTMENT TO	APCO	(548,371)	(548,371)	(24,391,308)	(24,391,308)
PREVENT RECOGNITION	KPCO	(58,718)	(58,718)	(3,166,303)	(3,166,303)
OF SALES BY POOL	I&M	(219,777)	(219,777)	(10,879,158)	(10,879,158)
MEMBERS TO	OPCO	(324,489)	(324,489)	(13,958,880)	(13,958,880)
THEMSELVES	CSP	(233,311)	(233,311)	(10,966,909)	(10,966,909)
(PAGE 7)	AEP	(1,384,666)	(1,384,666)	(63,362,558)	(63,362,558)
SUBTOTAL	APCO	446,694	586,282	13,589,758	20,330,457
AEP EXTERNAL	KPCO	145,732	64,043	4,710,295	1,756,856
ENERGY	I&M	379,609	235,481	11,959,927	8,541,106
	OPCO	377,367	449,522	12,765,712	12,355,589
	CSP	335,301	349,375	10,927,782	10,969,467
	AEP	1,684,703	1,684,703	53,953,474	53,953,475
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,621,120	1,120	37,754,638	34,189
ENERGY	KPCO	313	235,268	7,195	5,687,133
(PAGE 8)	I&M	0	824,443	0	16,905,203
	OPCO	0	1,273,114	0	31,638,156
	CSP	714,467	1,955	16,563,509	60,661
	AEP	2,335,900	2,335,900	54,325,342	54,325,342
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	2,067,814	588,317	51,344,396	20,471,155
	KPCO	146,045	299,462	4,717,490	7,463,898
	I&M	379,894	1,060,342	12,001,351	25,495,529
	OPCO	379,124	1,722,716	12,968,539	44,005,311
	CSP	1,049,768	351,808	27,491,291	11,087,175
	AEP	4,022,645	4,022,645	108,523,067	108,523,068

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL (MLR SHARE)	DELIVERED TO POOL (AS SUPPLIED)	CHARGE MEMBER A/C 555 (MLR SHARE)	CREDIT MEMBER A/C 447 (AS SUPPLIED)
I. AEP EXTERNAL ENERGY *					
ENERGY COST	APCO	526,076	567,214	20,215,391	23,863,968
RECOVERY AND MLR	KPCO	107,673	96,462	4,192,313	3,429,451
ALLOCATION FOR ALL	I&M	316,785	231,756	12,156,084	10,050,152
AEP SYSTEM	OPCO	370,578	503,952	14,224,142	16,573,433
DELIVERIES TO	CSP	298,344	220,072	11,653,431	8,524,357
NON-AFFILIATED COS.	AEP	1,619,456	1,619,456	62,441,361	62,441,360
ADJUSTMENT TO	APCO	(299,315)	(299,315)	(13,459,597)	(13,459,597)
PREVENT RECOGNITION	KPCO	(39,069)	(39,069)	(1,870,507)	(1,870,507)
OF SALES BY POOL	I&M	(128,495)	(128,495)	(6,062,418)	(6,062,418)
MEMBERS TO	OPCO	(208,361)	(208,361)	(8,382,191)	(8,382,191)
THEMSELVES	CSP	(120,434)	(120,434)	(5,566,321)	(5,566,321)
(PAGE 7)	AEP	(795,674)	(795,674)	(35,341,034)	(35,341,034)
SUBTOTAL	APCO	226,761	267,899	6,755,794	10,404,371
AEP EXTERNAL	KPCO	68,604	57,393	2,321,806	1,558,944
ENERGY	I&M	188,290	103,261	6,093,666	3,987,734
	OPCO	162,217	295,591	5,841,951	8,191,242
	CSP	177,910	99,638	6,087,110	2,958,036
	AEP	823,782	823,782	27,100,327	27,100,326
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,569,349	6,228	35,540,578	199,095
ENERGY	KPCO	3,071	167,378	74,917	4,696,626
(PAGE 8)	I&M	2,389	1,030,984	67,226	20,653,702
	OPCO	1,350	1,069,982	43,081	25,890,356
	CSP	708,686	10,273	16,027,015	313,038
	AEP	2,284,845	2,284,845	51,752,817	51,752,817
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	1,796,110	274,127	42,296,372	10,603,466
	KPCO	71,675	224,771	2,396,723	6,255,570
	I&M	190,679	1,134,245	6,160,892	24,641,436
	OPCO	163,567	1,365,573	5,885,032	34,081,598
	CSP	886,596	109,911	22,114,125	3,271,074
	AEP	3,108,627	3,108,627	78,853,144	78,853,143

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY *		(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	428,785	429,462	16,548,563	18,620,000
RECOVERY AND MLR	KPCO	86,672	77,187	3,431,878	2,724,689
ALLOCATION FOR ALL	I&M	258,842	222,573	9,951,117	9,687,756
AEP SYSTEM	OPCO	302,699	413,665	11,644,054	13,443,105
DELIVERIES TO	CSP	243,161	177,272	9,539,639	6,639,702
NON-AFFILIATED COS.	AEP	1,320,159	1,320,159	51,115,251	51,115,252
ADJUSTMENT TO	APCO	(294,698)	(294,698)	(12,207,427)	(12,207,427)
PREVENT RECOGNITION	KPCO	(49,494)	(49,494)	(1,950,664)	(1,950,664)
OF SALES BY POOL	I&M	(155,519)	(155,519)	(6,310,919)	(6,310,919)
MEMBERS TO	OPCO	(220,252)	(220,252)	(8,027,096)	(8,027,096)
THEMSELVES	CSP	(140,399)	(140,399)	(5,523,517)	(5,523,517)
(PAGE 7)	AEP	(860,362)	(860,362)	(34,019,624)	(34,019,624)
SUBTOTAL	APCO	134,087	134,764	4,341,136	6,412,573
AEP EXTERNAL	KPCO	37,178	27,693	1,481,214	774,025
ENERGY	I&M	103,323	67,054	3,640,198	3,376,837
	OPCO	82,447	193,413	3,616,958	5,416,008
	CSP	102,762	36,873	4,016,122	1,116,184
	AEP	459,797	459,797	17,095,627	17,095,628
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,866,883	0	43,576,856	0
ENERGY	KPCO	293	220,957	6,722	6,009,370
(PAGE 8)	I&M	0	857,039	0	19,309,092
	OPCO	0	1,484,399	0	34,467,744
	CSP	695,651	432	16,217,023	14,395
	AEP	2,562,827	2,562,827	59,800,601	59,800,601
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	2,000,970	134,764	47,917,992	6,412,573
	KPCO	37,471	248,650	1,487,936	6,783,395
	I&M	103,323	924,093	3,640,198	22,685,929
	OPCO	82,447	1,677,812	3,616,958	39,883,752
	CSP	798,413	37,305	20,233,145	1,130,579
	AEP	3,022,624	3,022,624	76,896,228	76,896,229

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
I. AEP EXTERNAL ENERGY		RECEIVED FROM POOL (MLR SHARE)	DELIVERED TO POOL (AS SUPPLIED)	CHARGE MEMBER A/C 555 (MLR SHARE)	CREDIT MEMBER A/C 447 (AS SUPPLIED)
ENERGY COST	APCO	402,152	447,213	15,386,134	18,485,403
RECOVERY AND MLR	KPCO	81,732	59,942	3,190,811	2,163,628
ALLOCATION FOR ALL	I&M	242,406	198,590	9,252,116	8,572,650
AEP SYSTEM	OPCO	283,358	370,335	10,826,135	12,327,173
DELIVERIES TO	CSP	228,311	161,879	8,869,542	5,975,882
NON-AFFILIATED COS.	AEP	1,237,959	1,237,959	47,524,738	47,524,737
ADJUSTMENT TO	APCO	(245,166)	(245,166)	(10,275,596)	(10,275,596)
PREVENT RECOGNITION	KPCO	(32,601)	(32,601)	(1,372,803)	(1,372,803)
OF SALES BY POOL	I&M	(110,969)	(110,969)	(4,741,673)	(4,741,673)
MEMBERS TO	OPCO	(165,557)	(165,557)	(6,255,747)	(6,255,747)
THEMSELVES	CSP	(99,292)	(99,292)	(4,090,418)	(4,090,418)
(PAGE 7)	AEP	(653,585)	(653,585)	(26,736,237)	(26,736,237)
SUBTOTAL	APCO	156,986	202,047	5,110,538	8,209,806
AEP EXTERNAL	KPCO	49,131	27,341	1,818,008	790,825
ENERGY	I&M	131,437	87,621	4,510,443	3,830,978
	OPCO	117,801	204,778	4,570,388	6,071,426
	CSP	129,019	62,587	4,779,124	1,885,463
	AEP	584,374	584,374	20,788,501	20,788,499
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,609,191	0	38,004,429	0
ENERGY	KPCO	2,925	138,057	70,083	3,704,621
(PAGE 8)	I&M	669	667,542	17,811	15,342,117
	OPCO	0	1,318,114	0	30,979,633
	CSP	521,499	10,571	12,287,445	353,397
	AEP	2,134,284	2,134,284	50,379,768	50,379,768
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	1,766,177	202,047	43,114,967	8,209,806
	KPCO	52,056	165,398	1,888,091	4,495,446
	I&M	132,106	755,163	4,528,254	19,173,095
	OPCO	117,801	1,522,892	4,570,388	37,051,059
	CSP	650,518	73,158	17,066,569	2,238,860
	AEP	2,718,658	2,718,658	71,168,269	71,168,267

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL (MLR SHARE)	DELIVERED TO POOL (AS SUPPLIED)	CHARGE MEMBER A/C 555 (MLR SHARE)	CREDIT MEMBER A/C 447 (AS SUPPLIED)
I. AEP EXTERNAL ENERGY *					
ENERGY COST	APCO	488,686	665,857	23,510,322	31,000,525
RECOVERY AND MLR	KPCO	98,834	63,527	4,875,623	3,338,341
ALLOCATION FOR ALL	I&M	294,565	218,001	14,137,419	12,457,738
AEP SYSTEM	OPCO	344,264	293,831	16,542,552	13,707,914
DELIVERIES TO	CSP	278,149	263,282	13,552,838	12,114,237
NON-AFFILIATED COS.	AEP	1,504,498	1,504,498	72,618,754	72,618,755
ADJUSTMENT TO	APCO	(369,432)	(369,432)	(19,293,535)	(19,293,535)
PREVENT RECOGNITION	KPCO	(48,049)	(48,049)	(2,872,370)	(2,872,370)
OF SALES BY POOL	I&M	(153,212)	(153,212)	(9,054,280)	(9,054,280)
MEMBERS TO	OPCO	(191,343)	(191,343)	(10,560,431)	(10,560,431)
THEMSELVES	CSP	(155,117)	(155,117)	(8,679,300)	(8,679,300)
(PAGE 7)	AEP	(917,153)	(917,153)	(50,459,916)	(50,459,916)
SUBTOTAL	APCO	119,254	296,425	4,216,787	11,706,990
AEP EXTERNAL	KPCO	50,785	15,478	2,003,253	465,971
ENERGY	I&M	141,353	64,789	5,083,139	3,403,458
	OPCO	152,921	102,488	5,982,121	3,147,483
	CSP	123,032	108,165	4,873,538	3,434,937
	AEP	587,345	587,345	22,158,838	22,158,839
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,867,523	0	43,936,261	0
ENERGY	KPCO	137,868	76,484	3,281,185	2,206,181
(PAGE 8)	I&M	0	1,319,744	0	27,884,869
	OPCO	94	840,388	2,335	21,719,827
	CSP	312,801	81,670	7,259,091	2,667,995
	AEP	2,318,286	2,318,286	54,478,872	54,478,872
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	1,986,777	297,504	48,153,048	11,822,272
	KPCO	188,653	92,172	5,284,438	2,695,567
	I&M	141,827	1,385,496	5,110,538	31,377,797
	OPCO	155,511	942,997	6,257,463	24,874,461
	CSP	435,833	190,432	12,132,629	6,168,020
	AEP	2,908,601	2,908,601	76,938,116	76,938,117

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6.

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
I. AEP EXTERNAL ENERGY		RECEIVED FROM POOL (MLR SHARE)	DELIVERED TO POOL (AS SUPPLIED)	CHARGE MEMBER A/C 555 (MLR SHARE)	CREDIT MEMBER A/C 447 (AS SUPPLIED)
ENERGY COST	APCO	614,985	745,915	22,776,475	28,086,552
RECOVERY AND MLR	KPCO	129,406	97,241	4,768,529	3,424,124
ALLOCATION FOR ALL	I&M	360,412	199,539	13,367,469	8,929,518
AEP SYSTEM	OPCO	416,601	417,550	15,641,776	14,260,397
DELIVERIES TO	CSP	350,620	411,779	13,038,989	14,892,646
NON-AFFILIATED COS.	AEP	1,872,024	1,872,024	69,593,238	69,593,237
ADJUSTMENT TO	APCO	(319,544)	(319,544)	(13,229,841)	(13,229,841)
PREVENT RECOGNITION	KPCO	(29,029)	(29,029)	(1,405,114)	(1,405,114)
OF SALES BY POOL	I&M	(91,565)	(91,565)	(4,561,137)	(4,561,137)
MEMBERS TO	OPCO	(153,336)	(153,336)	(6,400,620)	(6,400,620)
THEMSELVES	CSP	(129,361)	(129,361)	(5,582,524)	(5,582,524)
(PAGE 7)	AEP	(722,835)	(722,835)	(31,179,235)	(31,179,235)
SUBTOTAL	APCO	295,441	426,371	9,546,634	14,856,711
AEP EXTERNAL	KPCO	100,377	68,212	3,363,415	2,019,010
ENERGY	I&M	268,847	107,974	8,806,332	4,368,381
	OPCO	263,265	264,214	9,241,156	7,859,777
	CSP	221,259	282,418	7,456,465	9,310,122
	AEP	1,149,189	1,149,189	38,414,003	38,414,002
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	2,062,275	0	43,472,366	0
ENERGY	KPCO	11,957	91,198	272,426	2,417,659
(PAGE 8)	I&M	2,503	1,281,103	67,942	22,419,303
	OPCO	0	1,039,576	0	25,155,663
	CSP	383,891	48,749	7,837,989	1,658,098
	AEP	2,460,626	2,460,626	51,650,723	51,650,723
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	2,357,716	428,473	53,019,000	15,015,038
	KPCO	112,334	159,673	3,635,841	4,459,353
	I&M	272,268	1,389,889	8,967,708	26,845,455
	OPCO	266,547	1,303,920	9,475,495	33,034,700
	CSP	605,150	332,060	15,294,454	11,037,950
	AEP	3,614,015	3,614,015	90,392,498	90,392,497

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL (MLR SHARE)	DELIVERED TO POOL (AS SUPPLIED)	CHARGE MEMBER A/C 555 (MLR SHARE)	CREDIT MEMBER A/C 447 (AS SUPPLIED)
I. AEP EXTERNAL ENERGY *					
ENERGY COST	APCO	516,642	596,561	18,301,306	22,092,437
RECOVERY AND MLR	KPCO	108,981	146,896	3,831,598	4,792,648
ALLOCATION FOR ALL	I&M	303,508	148,519	10,741,001	6,630,494
AEP SYSTEM	OPCO	350,232	364,456	12,568,448	11,489,582
DELIVERIES TO	CSP	295,292	318,223	10,477,062	10,914,255
NON-AFFILIATED COS.	AEP	1,574,655	1,574,655	55,919,415	55,919,416
ADJUSTMENT TO	APCO	(248,397)	(248,397)	(9,572,419)	(9,572,419)
PREVENT RECOGNITION	KPCO	(26,082)	(26,082)	(1,007,322)	(1,007,322)
OF SALES BY POOL	I&M	(65,960)	(65,960)	(2,924,348)	(2,924,348)
MEMBERS TO	OPCO	(123,816)	(123,816)	(4,435,885)	(4,435,885)
THEMSELVES	CSP	(96,359)	(96,359)	(3,664,501)	(3,664,501)
(PAGE 7)	AEP	(560,614)	(560,614)	(21,604,475)	(21,604,475)
SUBTOTAL	APCO	268,245	348,164	8,728,887	12,520,018
AEP EXTERNAL	KPCO	82,899	120,814	2,824,276	3,785,326
ENERGY	I&M	237,548	82,559	7,816,653	3,706,146
	OPCO	226,416	240,640	8,132,563	7,053,697
	CSP	198,933	221,864	6,812,561	7,249,754
	AEP	1,014,041	1,014,041	34,314,940	34,314,941
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,227,342	0	26,627,297	0
ENERGY	KPCO	30,825	68,315	680,750	1,906,331
(PAGE 8)	I&M	0	663,570	0	11,166,555
	OPCO	0	993,705	0	24,067,538
	CSP	480,642	13,219	10,239,798	407,421
	AEP	1,738,809	1,738,809	37,547,845	37,547,845
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	1,495,587	348,533	35,356,184	12,558,833
	KPCO	113,724	189,212	3,505,026	5,699,783
	I&M	237,548	746,638	7,816,653	14,912,674
	OPCO	227,587	1,234,345	8,241,698	31,121,235
	CSP	679,575	235,293	17,052,359	7,679,396
	AEP	2,754,021	2,754,021	71,971,920	71,971,921

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the ECR#MLR report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Total All Source Allocation". The MWh and $ CHARGE AMOUNTS labelec "MLR SHARE" correspond to the MWh and COST columns associated with the "Total All MLR Allocation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6

EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

DIRECT TESTIMONY
OF
ANDREA E. MOORE
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: January 27, 2011

Estimate of 2012 Environmental Investment Carrying Charge Rider

In Thousands

Line No.	Description	CSP	OPCo	AEP Ohio	
1	2009 Actual	$ 73,838	$ 148,928	$ 222,766	
2	2010 Estimate	$ 76,620	$ 67,463	$ 144,083	
3	2011 Estimate	$ 20,614	$ 49,443	$ 70,057	
4	2012 Estimate	$ 18,841	$ 30,115	$ 24,478	*
5	Total Capital Expenditures	$ 189,913	$ 295,949	$ 461,384	
6	Levelized Carrying Cost Rate			14.11%	
7	Total Capital Carrying Cost			$ 65,101	
8	Estimated Annual O&M Expense			$ 28,000	
9	Total Annual Revenue Requirement			$ 93,101	
10	Capacity Allocation (Estimated)			80.00%	
11	Retail & Firm Wholesale Annual Revenue Requirement			$ 74,481	
12	Retail Allocation Factor			95.60%	
13	Retail Annual Revenue Requirement			$ 71,204	

* Represents a half-year convention

1 Actual Environmental Capital Expenditures from Case No. 10-0155
2 Estimated Environmental Capital Expenditures for 2010
3 Estimated Environmental Capital Expenditures for 2011
4 Estimated Environmental Capital Expenditures for 2012
5 Sum of Lines 1 through 4
6 25 Yr rate from PJN-2, Adjusted to Remove Property Taxes
7 Line 5 Times Line 6
8 Estimated O&M Associated with Post 2008 Environmental Equipment Excluding FAC Expenses
9 Line 7 Plus Line 8
10 Estimated Pool Capacity Allocation to Other Pool Members
11 Line 9 Times Line 10
12 Estimated Retail Allocation Factor
13 Line 11 Times Line 12

EXHIBIT NO.__________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

DIRECT TESTIMONY OF
LAURA J. THOMAS
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed January 27, 2011

2. Basis Adjustment – this adjustment is based on the historic relationship between pricing points. Applying such an adjustment to the AEP-Dayton Hub SS prices results in prices at the AEP load zone which is where PJM settles all AEP Ohio loads. Such an adjustment would not be required if market quotes were readily available for the AEP load zone.
3. Load Following/Shaping Adjustment – this adjustment, applied to the SS component, accounts for the fact that customers do not use a constant amount of energy across all hours of the day and that customers will deviate from their historic load profile. The calculations are the result of modeling that uses CSP and OPCo hourly class historical load shapes, publicly available PJM market prices and historic volatility.
4. Capacity – this item includes the capacity cost that a CRES (competitive electric retail service) provider would incur to serve a retail customer in AEP Ohio's service territory. The cost reflected in the capacity component is based on the rates provided in AEP Ohio's Initial Comments filed in Case No. 10-2929-EL-UNC on January 7, 2011.
5. Ancillary Services - this component prices the cost of ancillary services required by PJM to serve load in the Company's service territory.
6. Alternative Energy Requirement – Section 4928.64, Ohio Revised Code requires that all suppliers meet certain requirements for the mix of alternative energy resources that must be used to serve load in Ohio. This component reflects the anticipated incremental market cost of meeting that requirement.

AEP Ohio
Electric Security Plan
Market Rate Option Test

		2012	Jan 2013 - May 2014	Wtd Average (3) = weighted (1) and (2)
	Generation Service Price	(1)	(2)	
1	2011 Base ESP 'g' Rate	23.15	23.07	23.10
2	2011 Full Fuel*	32.86	32.86	32.86
3	2011 Environmental Compliance Costs **	0.90	0.90	0.90
4	Total Generation Service Price	56.91	56.82	56.86
	Expected Bid Price			
5	Competitive Benchmark	77.91	82.90	80.83
	MRO Pricing			
6	Generation Service Price	56.91	56.82	56.86
7	Generation Service Weight	90%	77%	
8	Expected Bid Price	77.91	82.90	80.83
9	Expected Bid Weight	10%	23%	
10	MRO Annual Price	59.01	62.82	61.23
	MRO - ESP Price Comparison			
11	MRO Annual Price	59.01	62.82	61.23
12	Proposed ESP Price	58.42	60.82	59.82
13	ESP Price Benefit	0.59	2.00	1.41

* Includes "Renewable and Energy Efficiency Adjustment"
** Assumes no lag in recovery or 2009-2011 carrying costs

AEP-Ohio
Forecasted Non-Shopping Load (MWH)

CSP	2012	2013	2014	Total 2012 2014		2013	Jan-May 2014	Total Jan 2013-May 2014
Residential	7,482,100	7,504,000	7,510,000	22,496,100		7,504,000	3,138,200	10,642,200
Commercial	5,056,500	4,931,000	4,908,000	14,895,500		4,931,000	1,891,200	6,822,200
Industrial	4,935,400	4,950,000	4,888,000	14,773,400		4,950,000	2,020,900	6,970,900
Total	17,474,000	17,385,000	17,306,000	52,165,000		17,385,000	7,050,300	24,435,300

29 Month Proposed ESP Period		
2012	Jan 2013-May 2014	Total Jan 2012-May 2014
7,482,100	10,642,200	18,124,300
5,056,500	6,822,200	11,878,700
4,935,400	6,970,900	11,906,300
17,474,000	24,435,300	41,909,300

OPCo	2012	2013	2014	Total 2012 2014		2013	Jan-May 2014	Total Jan 2013-May 2014
Residential	7,349,400	7,267,000	7,187,000	21,803,400		7,267,000	3,070,700	10,337,700
Commercial	5,416,200	5,114,000	5,101,000	15,631,200		5,114,000	2,057,400	7,171,400
Industrial	13,263,900	13,431,000	13,503,000	40,197,900		13,431,000	5,625,900	19,056,900
Total	26,029,500	25,812,000	25,791,000	77,632,500		25,812,000	10,754,000	36,566,000

2012	Jan 2013-May 2014	Total Jan 2012-May 2014
7,349,400	10,337,700	17,687,100
5,416,200	7,171,400	12,587,600
13,263,900	19,056,900	32,320,800
26,029,500	36,566,000	62,595,500

AEP-Ohio	2012	2013	2014	Total 2012 2014		2013	Jan-May 2014	Total Jan 2013-May 2014
Residential	14,831,500	14,771,000	14,697,000	44,299,500		14,771,000	6,208,900	20,979,900
Commercial	10,472,700	10,045,000	10,009,000	30,526,700		10,045,000	3,948,600	13,993,600
Industrial	18,199,300	18,381,000	18,391,000	54,971,300		18,381,000	7,646,800	26,027,800
Total	43,503,500	43,197,000	43,097,000	129,797,500		43,197,000	17,804,300	61,001,300

2012	Jan 2013-May 2014	Total Jan 2012-May 2014
14,831,500	20,979,900	35,811,400
10,472,700	13,993,600	24,466,300
18,199,300	26,027,800	44,227,100
43,503,500	61,001,300	104,504,800

AEP-Ohio
Forecasted Connected Load (MWH)

									29 Month Proposed ESP Period		
CSP	2012	2013	2014	Total 2012 2014		2013	Jan-May 2014	Total Jan 2013-May 2014	2012	Jan 2013-May 2014	Total Jan 2012-May 2014
Residential	7,482,000	7,504,000	7,510,000	22,496,000		7,504,000	3,138,200	10,642,200	7,482,000	10,642,200	18,124,200
Commercial	8,790,000	8,878,000	8,895,000	26,563,000		8,878,000	1,891,200	10,769,200	8,790,000	10,769,200	19,559,200
Industrial	4,935,000	4,950,000	4,888,000	14,773,000		4,950,000	2,020,900	6,970,900	4,935,000	6,970,900	11,905,900
Total	21,207,000	21,332,000	21,293,000	63,832,000		21,332,000	7,050,300	28,382,300	21,207,000	28,382,300	49,589,300

OPCo	2012	2013	2014	Total 2012 2014		2013	Jan-May 2014	Total Jan 2013-May 2014	2012	Jan 2013-May 2014	Total Jan 2012-May 2014
Residential	7,349,000	7,267,000	7,187,000	21,803,000		7,267,000	3,070,700	10,337,700	7,349,000	10,337,700	17,686,700
Commercial	5,856,000	5,866,000	5,860,000	17,582,000		5,866,000	2,057,400	7,923,400	5,856,000	7,923,400	13,779,400
Industrial	13,264,000	13,431,000	13,503,000	40,198,000		13,431,000	5,625,900	19,056,900	13,264,000	19,056,900	32,320,900
Total	26,469,000	26,564,000	26,550,000	79,583,000		26,564,000	10,754,000	37,318,000	26,469,000	37,318,000	63,787,000

AEP-Ohio	2012	2013	2014	Total 2012 2014		2013	Jan-May 2014	Total Jan 2013-May 2014	2012	Jan 2013-May 2014	Total Jan 2012-May 2014
Residential	14,831,000	14,771,000	14,697,000	44,299,000		14,771,000	6,208,900	20,979,900	14,831,000	20,979,900	35,810,900
Commercial	14,646,000	14,744,000	14,755,000	44,145,000		14,744,000	3,948,600	18,692,600	14,646,000	18,692,600	33,338,600
Industrial	18,199,000	18,381,000	18,391,000	54,971,000		18,381,000	7,646,800	26,027,800	18,199,000	26,027,800	44,226,800
Total	47,676,000	47,896,000	47,843,000	143,415,000		47,896,000	17,804,300	65,700,300	47,676,000	65,700,300	113,376,300

FILE

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EXHIBIT NO.________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

SUPPLEMENTAL DIRECT TESTIMONY OF
LAURA J. THOMAS
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed July 6, 2011

AEP Ohio
Electric Security Plan
Market Rate Option Test

		2012	Jan 2013 - May 2014	Wtd Average (3) = weighted (1) and (2)
	Generation Service Price	(1)	(2)	
1	2011 Base ESP 'g' Rate	23.15	23.07	23.10
2	2011 Full Fuel*	32.86	32.86	32.86
3	2011 Environmental Compliance Costs **	0.90	0.90	0.90
4	Total Generation Service Price	56.91	56.82	56.86
5	2011 POLR Cost	3.07	3.07	3.07
6	Total Generation Service Price + POLR	59.98	59.89	59.93
	Expected Bid Price			
7	Competitive Benchmark	77.91	82.90	80.83
	MRO Pricing			
8	Generation Service Price	59.98	59.89	59.93
9	Generation Service Weight	90%	77%	
10	Expected Bid Price	77.91	82.90	80.83
11	Expected Bid Weight	10%	23%	
12	MRO Annual Price	61.77	65.18	63.76
	MRO - ESP Price Comparison			
13	MRO Annual Price	61.77	65.18	63.76
14	Proposed ESP Price	58.42	60.82	59.82
15	Proposed POLR Cost	2.84	2.84	2.84
16	Proposed ESP Price + POLR Cost	61.26	63.66	62.66
17	ESP Price Benefit	0.51	1.52	1.10

* Includes "Renewable and Energy Efficiency Adjustment"
** Assumes no lag in recovery or 2009-2011 carrying costs

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EXHIBIT NO.__________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

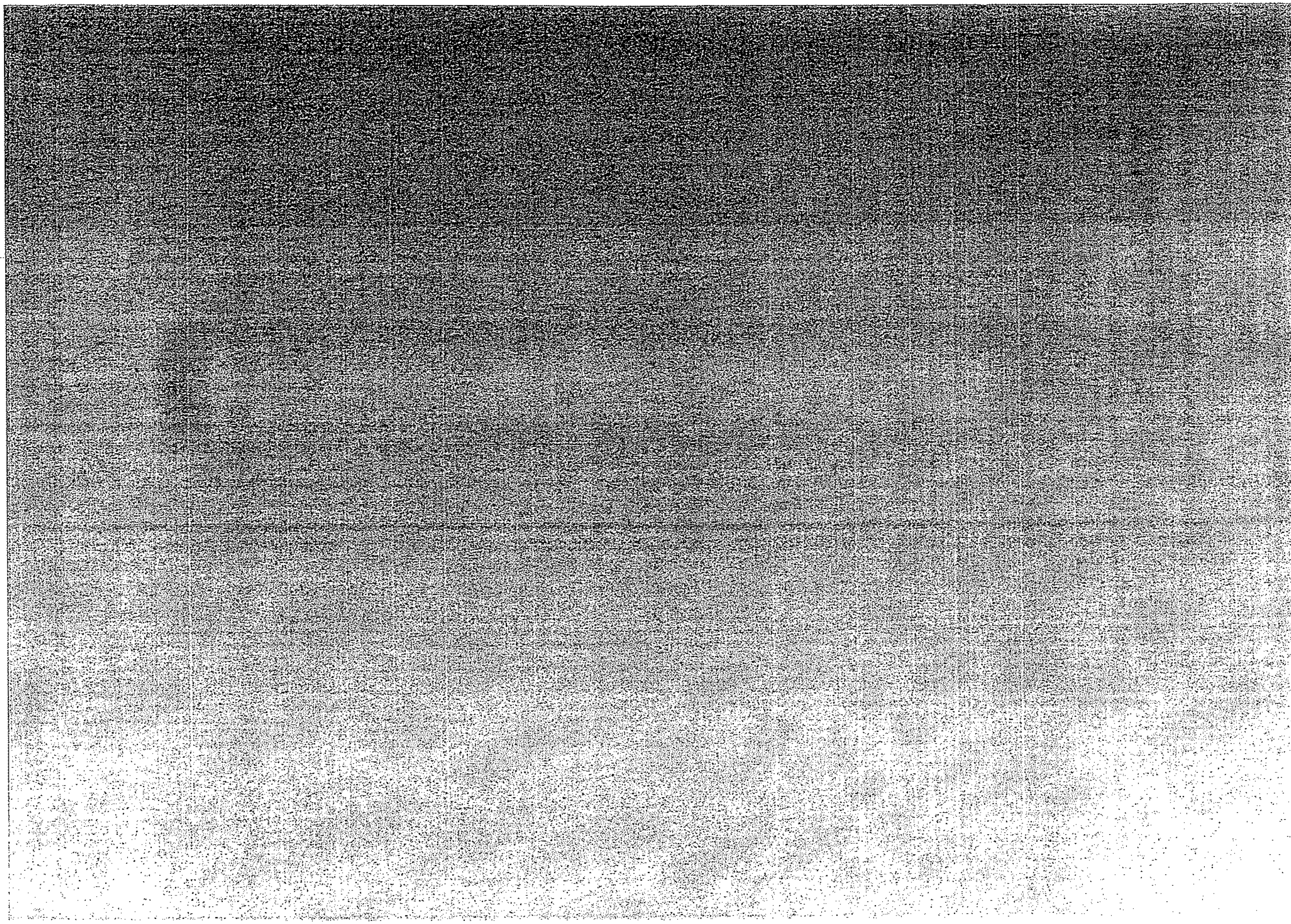
PUBLIC VERSION OF
SUPPLEMENTAL DIRECT TESTIMONY OF
PHILIP J. NELSON
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: July 1, 2011

TPS PROJECT
ESTIMATED REVENUE REQUIREMENT ($000)
BASED ON 25 YEAR PROJECT LIFE AND KEY ASSUMPTIONS

	Revenue Requirement					
Year	Lease Expense	O&M Expense*	Tax Benefits	Property Tax	Additional Capital Carrying Costs	Annual Revenue Requirement
Ref.	Pgs. 3	Pg. 8	Page 9		Pg. 11	
2013	$ 9,081	$ 900	$ (1,583)	$ 180	$ -	$ 8,579
2014	$ 14,540	$ 1,079	$ (3,366)	$ 315	$ -	$ 12,569
2015	$ 19,597	$ 1,264	$ (5,556)	$ 449	$ -	$ 15,755
2016	$ 19,603	$ 1,290	$ (6,828)	$ 449	$ -	$ 14,514
2017	$ 19,610	$ 1,315	$ (7,720)	$ 449	$ -	$ 13,655
2018	$ 19,616	$ 1,342	$ (8,207)	$ 449	$ 9	$ 13,210
2019	$ 19,623	$ 1,368	$ (8,336)	$ 449	$ 26	$ 13,130
2020	$ 19,630	$ 1,396	$ (8,168)	$ 449	$ 48	$ 13,355
2021	$ 19,637	$ 1,424	$ (7,811)	$ 449	$ 70	$ 13,769
2022	$ 19,644	$ 1,452	$ (7,388)	$ 449	$ 102	$ 14,260
2023	$ 19,651	$ 1,481	$ (6,959)	$ 449	$ 263	$ 14,885
2024	$ 19,658	$ 1,511	$ (6,524)	$ 449	$ 519	$ 15,613
2025	$ 19,666	$ 1,541	$ (6,082)	$ 449	$ 862	$ 16,437
2026	$ 19,674	$ 1,572	$ (5,631)	$ 449	$ 1,198	$ 17,261
2027	$ 19,681	$ 1,603	$ (5,174)	$ 449	$ 1,529	$ 18,089
2028	$ 19,689	$ 1,635	$ (4,709)	$ 828	$ 1,862	$ 19,305
2029	$ 19,698	$ 1,668	$ (4,234)	$ 1,043	$ 2,200	$ 20,375
2030	$ 19,706	$ 1,702	$ (3,750)	$ 1,209	$ 2,549	$ 21,415
2031	$ 19,714	$ 1,736	$ (3,257)	$ 1,140	$ 2,913	$ 22,245
2032	$ 19,723	$ 1,770	$ (2,752)	$ 1,071	$ 3,279	$ 23,090
2033	$ 19,732	$ 1,806	$ (2,237)	$ 1,002	$ 3,448	$ 23,751
2034	$ 19,741	$ 1,842	$ (1,711)	$ 946	$ 3,464	$ 24,282
2035	$ 19,750	$ 1,879	$ (1,171)	$ 899	$ 3,321	$ 24,678
2036	$ 19,759	$ 1,916	$ (620)	$ 861	$ 3,202	$ 25,118
2037	$ 19,769	$ 1,955	$ (54)	$ 823	$ 3,073	$ 25,566
2038	$ 11,001	$ 1,648	$ 68	$ 458	$ 2,934	$ 16,110
2039	$ 5,515	$ 1,417	$ 107	$ 215	$ 2,764	$ 10,017

Phase 1 Starts 01/01/2013
Phase 2 Starts 01/01/2014
Phase 3 Starts 01/01/2015



AEP Ohio's Interrogatory Response, PUCO Case No. 11-346-EL-SSO et al., FES, Set 1, FES-1-1 is **RESTRICTED ACCESS CONFIDENTIAL.**

COMPETITIVELY-SENSITIVE CONFIDENTIAL INFORMATION

AEP OHIO SHOPPING DATA AS OF AUGUST 23, 2011

[redacted]

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

CONFIDENTIAL EXCERPT OF
EXHIBIT PJN-4 FOR
SUPPLEMENTAL DIRECT TESTIMONY OF
PHILIP J. NELSON
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Key Assumptions to Develop Estimated Revenue Requirement

1. AEP Ohio receives a favorable private letter ruling from the IRS.
2. Cost of solar panels – assumes a panel cost of $[redacted]W (dc) for phase one, $[redacted]W for phase two and $[redacted]W for phase three
3. Cost of AEP Ohio equity– assumes AEP Ohio's cost of equity is 11.15%, based on expert testimony in AEP Ohio 2011 Distribution rate case.
4. Third party equity - is assumed to be brought into the project at an after-tax cost of[redacted]%.
5. Cost of RUS debt – is based on the long-term financing rates currently being offered by the RUS.
6. OAQDA Loan - is available for the Phase 1 investment, but not the available for Phase 2 and 3. No debt forgiveness is included in estimated revenue requirement
7. Tax Benefits - AEP Ohio makes a Tax Loan to TPS Generation to facilitate providing tax benefits to the ratepayer (see assumption 1) as a rate of 5.80%. The loan life of the AEP Tax Loan is approximately 25 years,
8. Cost of construction debt – uses the 1-month LIBOR plus a spread of 200 bps as the cost of the construction financing. The model also assumes a 1% up-front fee and a 0.60% commitment fee.
9. Property tax abatement/PILOT – assumes the TPS Project would qualify for an Enterprise Zone abatement of $9,000/MW for the first 15 years of each phase, at which point the property tax payments will revert back to the normal personal property rate.
10. O&M Expenses - AEP Ohio will pay all operating and maintenance costs associated with the project The annual O&M expense consists of charges for labor, contract services, material and supplies, insurance.
11. O&M inflation rate – assumes a 2% annual increase in O&M expenses.
12. Energy Production – The long-term production forecast for the project is derived from a Black & Veatch Production Estimate Report dated 5/12/11 and assumes an initial capacity factor for each phase at[redacted]%. B&V estimates that the annual degradation in efficiency is[redacted]% per year.

Annual MWh Production

Year	Phase I MW	Phase II MW	Phase III MW	Phase I MWh	Phase II MWh	Phase III MWh	Total MWh
2013	20.0	0.0	0.0	[illegible]	[illegible]	[illegible]	[illegible]
2014	20.0	15.0	0.0	[illegible]	[illegible]	[illegible]	[illegible]
2015	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2016	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2017	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2018	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2019	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2020	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2021	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2022	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2023	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2024	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2025	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2026	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2027	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2028	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2029	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2030	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2031	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2032	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2033	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2034	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2035	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2036	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2037	20.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2038	0.0	15.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]
2039	0.0	0.0	14.9	[illegible]	[illegible]	[illegible]	[illegible]