BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

DIRECT TESTIMONY OF J. EDWARD HESS ON BEHALF OF INDUSTRIAL ENERGY USERS-OHIO

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Attorneys for Industrial Energy Users-Ohio

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INDEX

Page No.

I. INTRODUCTION.....1

II. PURPOSE OF THE TESTIMONY.....3

III. TRANSITION REVENUES.....4

IV. AEP-OHIO'S ETP 8

V. CONCLUSIONS.....18

EXHIBITS

CERTIFICATE OF SERVICE

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I. INTRODUCTION

Q1. Please state your name and business address.

A1. J. Edward Hess, 21 East State Street, 17th Floor, Columbus, Ohio 43215.

Q2. By whom are you employed and in what position?

A2. I am a Technical Specialist for McNees Wallace & Nurick LLC ("McNees") providing testimony on behalf of Industrial Energy Users-Ohio ("IEU-Ohio"). IEU-Ohio is an association of commercial and industrial customers and functions to address issues that affect the price and availability of energy they need to operate their Ohio plants and facilities.

Q3. Please describe your educational background.

A3. I received a Bachelors of Business Administration degree from Ohio University in 1975 majoring in accounting. I completed the majority of Capital University's Master of Business Administration program and I have completed many regulatory training programs. I am a certified public accountant.

Q4. Please describe your professional experience.

A4. I have been employed by McNees since October 2009. In March 2009, I retired from the Public Utilities Commission of Ohio ("Commission") after 30 years of employment. My last position with the Commission was as the Chief of the Accounting and Electricity Division of the Utilities Department. My duties included ensuring statutory compliance with state and federal laws, rules, regulations, and procedures governing utility regulation with the majority of that responsibility in the electric industry. I was also responsible for the operating income and rate base portions of base rates and general accounting matters in all of the utility industries.

Q5. Have you previously testified before the Commission?

A5. As part of my responsibilities as a Commission employee, I have provided expert testimony in numerous Commission proceedings. I began testifying in the early 1980's. More recently I testified in Case Nos. 09-872-EL-FAC and 09-873-EL-FAC and provided written testimony in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR on behalf of IEU-Ohio.

Q6. What documents did you review before your recommendation?

A6. I reviewed the majority of the documents in Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP (the electric transition plan or "ETP" proceedings) shortly after the cases were filed. Also, with regard to the ETP, I revisited the testimonies of Dr. John Landon, Dr. Edward P. Kahn, Section F of the Application, the Stipulation filed on May 5, 2000, the Staff Report filed on March 28, 2000, sections of the ETP Opinion and Order filed on September 28, 2000, and

sections of the Entry on Rehearing filed on November 21, 2000. I also reviewed other documents specifically noted in my testimony and the testimony of William A. Allen, Dana E. Horton, Richard E. Munczinski, Kelly D. Pearce and Frank C. Graves filed in this case**.**

II. PURPOSE OF THE TESTIMONY

Q7. What is the purpose of your testimony?

A7. My testimony addresses Columbus Southern Power Company's ("CSP") and Ohio Power Company's ("OP") (collectively "AEP-Ohio") proposal to establish a "cost-based" formula for purposes of setting the generation capacity price paid by a competitive retail electric services ("CRES") supplier. Based on the advice of counsel and my reasoning from that advice, it is my opinion that this AEP-Ohio proposal would, if approved, allow AEP-Ohio to receive additional generation transition revenue well beyond the time when the receipt of such revenue is precluded by Ohio law and well after the amount and type of transition revenue eligible for recovery from customers was addressed and resolved in prior Commission cases associated with AEP-Ohio's implementation of Ohio's electric restructuring legislation enacted by the 123rd General Assembly (Amended Substitute Senate Bill 3 or "SB 3"). AEP-Ohio's opportunity to collect transition revenue was determined as a part of AEP-Ohio's ETPs filed with the Commission in December 1999 as a result of the enactment of SB 3. I therefore conclude that AEP-Ohio's proposal for establishing the generation service capacity price paid by a CRES supplier is unreasonable.

III. TRANSITION REVENUES

Q8. Were you involved in AEP-Ohio's ETP filings?

A8. Yes. As my testimony above states, I was employed by the Commission as a staff member when the plan was filed and I supervised the review of AEP-Ohio's transition cost request.

Q9. What is your understanding of how and when SB 3 permitted collection of transition revenue?

A9. Like many states that enacted electric restructuring legislation in the late 1990's, Ohio addressed the subject that was typically referred to as "stranded costs" for those services for which a customer could select a competitive supplier. This subject provoked most of the debate about how to move to a customer choice structure while being fair to utilities that may have been negatively impacted if they were subjected to competition on day one of customer choice. SB 3 implemented customer choice on January 1, 2001. SB 3 also provided an opportunity for an electric distribution utility ("EDU") to seek transition revenue associated with the electricity generation function for a period of years but not after December 31, 2010. The period for recovering stranded generation plant cost ended by no later than December 31, 2005.

SB 3 contains the criteria that the Commission applied to determine how much, if any, of the transition revenue claim was eligible for recovery. When the Commission approved a transition revenue claim, it also approved transition charges that the EDU could then charge shopping customers for the period

specified by the Commission. For non-shopping customers, the transition charges were embedded in the default generation supply price and were equal to the portion of the applicable default generation supply price that was not avoidable by shopping customers.

Q10. What is your understanding of the SB 3 criteria that were applied to determine how much, if any, transition revenue could be approved by the Commission and collected through transition charges?

A10. It is my understanding that Section 4928.39, Revised Code, specified these criteria. These criteria were applied to determine the total amount of transition revenue that was eligible for collection through transition charges **if** an EDU submitted a claim for transition revenue. SB 3 did not require transition revenue to be addressed unless the EDU submitted a claim for transition revenue.

Q11. Which EDUs submitted a claim for transition revenues?

A11. All of the EDUs, including CSP and OP, submitted a claim with their ETP applications.

Q12. More specifically, what is your understanding of the criteria that were used to determine how much, if any, of a transmission revenue claim was eligible for collection through transition charges?

A12. As indicated previously, it is my understanding that Section 4928.39, Revised Code, contains the criteria used to determine the total allowable transition revenue claim. A transition revenue claim was eligible for collection through transition charges if the revenue claim was limited to:

(1) Costs that were prudently incurred;

(2) Costs that were legitimate, net verifiable, and directly assignable or allocable to retail electric generation service provided to electric consumers in this state;

(3) Costs that were unrecoverable in a competitive market;

(4) Costs that the utility would otherwise have been entitled an opportunity to recover.

All four of the criteria had to be satisfied for the transition revenue claim to be recoverable through transition charges approved by the Commission.

Q13. Was the amount of a total transition revenue claim potentially separated into different components?

A13. Yes. The total allowable amount of any transition revenue claim was separated if a portion of that total claim involved generation-related regulatory assets. The total transition charge resulting from any allowable transition revenue claim was also separated to show a separate regulatory asset charge. It is my understanding that SB 3 limited the Commission's ability to make adjustments to the regulatory asset portion of an allowed transition charge and also required the regulatory asset portion of a transition charge to end no later than December 31, 2010. As stated previously, it is also my understanding that under SB 3, the non-regulatory asset portion of any transition charge which was associated with above-market generating plants had to end by no later than December 31, 2005 or the end of the market development period ("MDP"), whichever occurred first. Based on advice of counsel, I also understand that Section 4928.141, Revised

Code, which was added after SB 3, excluded any previously authorized allowances for transition costs with the exclusion becoming effective on and after the date the allowance was scheduled to end under the prior rate plan.

Q14. Generally, how was the amount of transition revenue associated with above-market generating plants measured?

A14. If an EDU wanted to make a claim for transition revenue, it had to include the claim in its proposed ETP. A proposed ETP had to be filed 90 days after the effective date of SB 3. The statutory criteria discussed above were then used to determine how much of the transition revenue claim was eligible for collection through transition charges. For the generation plant-related portion of the transition revenue claim, the net book value of generating assets at December 31, 2000 was used as the baseline to determine how much, if any, of the net, verifiable, prudently incurred book value was not recoverable in the market and in this context the market included the entire market, including the wholesale and retail segments.

Various methods were used by EDUs to forecast how much transition cost they would experience as a result of customers being able to select their generation service supplier. The most popular approach was a revenue-based approach. Generally, the revenue-based approach projected revenue streams for the various generating plants and computed a present value of the future estimated revenue streams. The present value of the estimated future revenue streams was then compared to the net book value of the generating plants at December 31, 2000. Generation plant-related transition costs were deemed to

be positive (and potentially eligible for recovery through transition charges) if the present value of the projected revenue streams was, in the aggregate, less than the net book value of the generating plants at December 31, 2000. Again, the generation plant-related transition revenue had to be recovered during the period beginning January 1, 2001 through either the end of the MDP or December 31, 2005, whichever occurred first.

IV. AEP-OHIO'S ETP

Q15. Please describe the generation plant-related transition revenue claim made by CSP and OP in their proposed ETPs.

A15. CSP and OP filed their proposed ETPs on December 30, 1999. As a part of these proposed ETPs, OP and CSP submitted a claim for transition revenue which included both above-market generation plant costs and a regulatory asset component. CSP and OP relied upon Dr. John Landon to estimate the extent to which they had a basis for claiming generation plant-related transition revenue. Dr. Landon used a revenue-based approach described earlier in my testimony. Dr. Landon projected market-based generation revenue, expenses and capital expenditures for the period 2001 through 2030 using multiple scenarios reflecting different assumptions about natural gas prices and environmental regulations. He discounted these projections to December 31, 2000 to develop his net present value revenue stream and then compared this net present value to net generation plant and associated asset book values as of the same date, December 31, 2000. From this comparison, he rendered an opinion on the amount of generation plant-related transition revenue that the Commission

should approve for CSP and OP (the present value revenue delta or difference between a cost-based ratemaking revenue stream and a competitive market revenue stream). The results of CSP and OP's witness Landon's analysis are summarized on his Exhibit JHL-2 filed as a part of his direct testimony which was filed on December 30, 1999 in the AEP-Ohio ETP proceedings.[1] His Exhibit JHL-2 is attached to my testimony as Exhibit JEH-1.

Q16. Did Dr. Landon's methodology for determining generation plant-related transition revenue cover the generating plants and the time period that are included in AEP-Ohio's proposed "cost-based" formula for setting the capacity price paid by a CRES supplier?

A16. Yes. His methodology included all of the components of cost-based ratemaking including a rate base, return on rate base, operation and maintenance expenses, depreciation expense, taxes other than income taxes, and income taxes associated with the **total** generation service (both wholesale and retail market segments). His analysis covered the period from 2001 through 2030.

Q17. What were the results of his analysis?

A17. Dr. Landon's testimony concluded that AEP-Ohio would be unable to recover a significant amount of generating plant-related cost in the competitive market.

Q18. Did the Commission's Staff perform an analysis to evaluate AEP-Ohio's transition revenue claim?

[1] *In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Transition Plan and Application for Receipt of Transition Revenues*, Case Nos. 99-1729-EL-ETP, *et al.*, Direct Testimony of Dr. John Landon, Ex. JHL-2 at 1-4 (December 30, 1999) (hereinafter "*AEP-Ohio ETP Cases*").

A18. Yes. As indicated in the Staff Report that was filed in the AEP-Ohio ETP proceedings, the Staff retained Resource Data International to assist with the evaluation of AEP-Ohio's generation plant-related transition revenue claim.

Q19. Did the Staff agree with the results of AEP-Ohio's and Dr. Landon's conclusions about the potential form of generation plant-related transition revenue?

A19. According to the Staff Report, the Staff took exception to AEP-Ohio's calculations and claims of above-market generation costs contained in the ETPs. Other parties to the ETP cases contested AEP-Ohio's claim as well.

Q20. How was the dispute over AEP-Ohio's generation plant-related transition revenue claim ultimately resolved?

A20. As part of a settlement package that was approved by the Commission, CSP and OP agreed to drop their generation plant-related transition revenue claim.[2] The same Commission-approved settlement provided CSP and OP with the opportunity to collect a significant amount of transition charges for regulatory assets with the regulatory asset transition charges ending on December 31, 2007 for OP and December 31, 2008 for CSP. As part of this Commission-approved settlement, AEP-Ohio also committed to not "… impose any lost revenue charges

[2] *AEP-Ohio ETP Cases*, Entry on Rehearing at 4 (November 21, 2000). "The primary stipulation also addresses the netting of GTCs since AEP agreed to withdraw its claim for recovery of any GTCs set forth in its transition plans. To the extent that there may be stranded generation plant benefits, the signatory parties to the primary stipulation have agreed that AEP's withdrawal of the GTCs reasonably offsets any possible stranded benefits. The Commission finds this compromise to be a reasonable resolution of the netting issue raised by the language in Section 4928.39(B), Revised Code." *Id.*

(generation transition charges (GTC)) on any switching customer," an outcome that was designed to encourage shopping.[3]

Q21. Earlier, you indicated that your testimony focused on the "cost-based" formula that AEP-Ohio has proposed be used in this proceeding to set the capacity price that is paid by a CRES supplier serving retail customers in AEP-Ohio's service area. How does the transition revenue claim opportunity presented by SB 3 relate to the "cost-based" formula that AEP-Ohio is now proposing be approved in this proceeding to set the capacity price that is paid by a CRES supplier serving retail customers in AEP-Ohio's service area?

A21 While the form of AEP-Ohio's "cost-based" formula proposed in this proceeding may be different than the transition revenue claim previously advanced by AEP-Ohio in the ETP proceedings, the "cost-based" formula proposal in this proceeding is, in substance, another claim for generation plant-related transition revenue. The proposal which AEP-Ohio has put forward in this proceeding is designed to provide AEP-Ohio with revenue it says it will lose if customers shop and CRES suppliers pay a market-based capacity price. It is a proposal to recover lost revenue based on a cost to market comparison.

AEP-Ohio has characterized its proposals to set capacity rates above market as a transition mechanism. On February 27, 2012, OP filed a motion seeking authorization to implement the two-tiered generation service capacity charges until the Commission resolves this case. In response to the Commission's Entry

[3] *AEP-Ohio ETP Cases,* Stipulation and Recommendation at 3 (May 8, 2000).

on Rehearing rejecting the Stipulation on February 23, 2012, AEP-Ohio explained that it believed it had the ability to establish cost-based rates, but complained that it was being forced to move to Reliability Priced Model ("RPM")-priced capacity "without a reasonable transition mechanism" for "a transition period."[4] In a press release on the same day, the Chief Executive Officer of American Electric Power Service Corporation ("AEP") stated, "The settlement agreement allowed AEP-Ohio a reasonable transition to market over a period of time."[5]

AEP-Ohio previously relied upon PJM Interconnect LLC's ("PJM") RPM to establish the market-based price for generation service capacity and which was approved by the Commission. In this proceeding, AEP-Ohio is proposing to change to a capacity pricing methodology that, if approved, would provide AEP-Ohio with revenue for generation capacity service that is significantly in excess of the revenue that AEP-Ohio would be able to collect if a PJM-determined market-based price were used to determine the revenue AEP-Ohio collects for generation capacity service provided to a CRES supplier.

Regardless of whether you agree with the results of AEP-Ohio's "cost-based" formula, AEP-Ohio is essentially asserting that the Commission must permit AEP-Ohio to collect a significantly above-market revenue stream for generation capacity service because the market-based price revenue stream it would

[4] Ohio Power Company's Motion for Relief and Request for Expedited Ruling at 5 (February 27, 2012).

[5] AEP-Ohio Press Release (February 27, 2012) (viewed at https://www.aepohio.com/info/news/viewRelease.aspx?releaseID=1203). A copy of the press release is attached as Exhibit JEH-2.

otherwise collect is not high enough. AEP-Ohio labels its "cost-based" capacity pricing proposal as it chooses but, in substance, the proposal is a transition revenue claim for generation plant-related transition costs. And, this new transition revenue claim comes well after the time period specified by SB 3 for bringing a transition revenue claim.

Q22. Has AEP-Ohio acknowledged that it was given an opportunity to recover above-market generation investments during the transition period created by SB 3, that the period for doing so is over and that it gave up whatever opportunity it had to seek transition revenue?

A22. Yes. AEP-Ohio recently (March 30, 2012) filed an application with the Commission to secure approval of changes to its corporation separation plan in Commission Case No. 12-1126-EL-UNC. As part of that application, AEP-Ohio is proposing to transfer generating assets and the application seeks a waiver from the Commission's rule [Rule 4901:1-37-09(C)(4), Ohio Administrative Code] that AEP-Ohio says would otherwise require the submission of an analysis of the market value of the plants to be transferred. At page 7 of the corporate separation application, AEP-Ohio states:

> The request to waive Admin. Code Rule 4901:1-37-09(C)(4) is reasonable because OPCo seeks to transfer its generating assets to an affiliate within the same parent corporation, in compliance with the mandate of R.C. 4928.17. Under SB 3, all of these generation assets were subjected to market and EDUs therefore were given a temporary opportunity to recover stranded generation investments during a transition period. That transition period is over. EDUs can no longer recover stranded generation investments, and transferring the generation assets based on an

> arbitrary determination of their current fair market value rather than net book value would be inappropriate.[6]

In addition to the period for obtaining transition revenue or "stranded costs" being over, AEP-Ohio agreed, as I identify in my testimony, to give up that opportunity as part of the Commission-approved ETP settlement discussed in my testimony. That ETP settlement was contested by one party because the party believed that AEP-Ohio had negative transition costs or "stranded benefits" and argued that the "stranded benefits" (generation plant net book values below market) should have been netted against the regulatory asset transition costs authorized for AEP-Ohio to increase the shopping credits that were used to encourage shopping.

On November 6, 2000, AEP-Ohio filed a memorandum contra to the party's application for rehearing on the settlement's treatment of transition revenue. Beginning at page 6 of that memorandum, AEP-Ohio stated:

> Under the Stipulation, neither Company will impose any generation transition charge on any switching customer. Stipulation, Section IV. The Companies original transition plan filings included GTCs calculated on the basis of a lost revenues approach. The Commission in its Opinion and Order estimated that the claims that the Companies had foregone as a result of their agreement not to impose GTCs amounted to several hundred million dollars. Nonetheless, Shell argues on rehearing that the Commission erred in adopting the Stipulation's resolution of the Companies' GTCs.
>
> This argument illustrates perfectly the bankrupt nature of Shell's advocacy. Shell is relegated to arguing that the Stipulation is unreasonable because it contains a provision that eliminates all

[6] *In the Matter of the Application of Ohio Power Company for Approval of Full Legal Corporate Separation and Amendment to Its Corporate Separation Plan*, Case No. 12-1126-EL-UNC, Application at 7 (March 30, 2012).

> generation transition charges for both Companies. (emphasis removed)[7]

In the Commission's November 21, 2000 Entry on Rehearing addressing and rejecting this party's protest of the Commission-approved settlement, the Commission said:

> The primary stipulation also addresses the netting of GTCs since AEP agreed to withdraw its claim for recovery of any GTCs set forth in its transition plans. To the extent that there may be stranded generation plant benefits, the signatory parties to the primary stipulation have agreed that AEP's withdrawal of GTCs reasonably offsets any possible stranded benefits. The Commission finds this compromise to be a reasonable resolution of the netting issue raised by the language in Section 4928.39(B), Revised Code.[8]

Q23. If approved, would the proposed "cost-based" formula for setting the generation service capacity price for CRES suppliers' rates allow AEP-Ohio to recover above-market generation costs?

A23. Yes. As discussed above, the market-based prices for capacity are based upon PJM's RPM. RPM relies on an auction process to secure adequate capacity resources to meet projected demand for all load serving entities ("LSEs") that do not elect the fixed resource requirement ("FRR") option under RPM. According to IEU-Ohio witness Kevin Murray, the clearing prices in the most recent base residual auctions for the balance of RTO zone were $110.00 per megawatt-day ("MW-day") for the 2011-2012 delivery year, $16.46 per MW-day for the 2012-2013 delivery year, $27.73 per MW-day for the 2013-2014 delivery year and

[7] *AEP-Ohio ETP Cases*, Columbus Southern Power Company's and Ohio Power Company's Memorandum Contra Shell Energy Services Company, L.L.C.'s Application for Rehearing at 6-7 (November 6, 2000).

[8] *AEP-Ohio ETP Cases*, Entry on Rehearing at 4 (November 21, 2000).

$125.94 per MW-day for the 2014-2015 delivery year.[9] AEP-Ohio's proposed formula rate would set the charge for capacity provided to CRES suppliers at $327.59 per MW-day for CSP and $379.23 per MW-day for OP.[10] These charges are significantly above prevailing market prices as determined by the PJM RPM process.

Q24. Are capacity prices paid by CRES suppliers reflected in prices paid by retail customers obtaining generation supply from a CRES supplier?

A24. To analyze this from a regulatory perspective, it is reasonable, if not mandatory, to assume that they are included. Common sense dictates that CRES suppliers will pass through known changes in the prices of the products and services they sell to retail customers unless there is competitive pressure blocking such pass-through. Since there would not be any competitive pressure under AEP-Ohio's FRR structure which, as I understand the FRR structure, makes CRES suppliers captive to AEP-Ohio, it is unreasonable to assume that CRES suppliers will choose to forego passing through the significantly above-market capacity prices to retail consumers. Additionally, when administratively estimating market prices for purposes of conducting the MRO v. ESP test, AEP-Ohio witnesses J. Craig Baker and Laura Thomas have both included capacity prices as a necessary component of a competitive retail market price.[11]

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[9] PJM conducts incremental auctions subsequent to the base residual auction for each delivery that typically result in a small adjustment to the final capacity price for a delivery year.

[10] Direct Testimony of Kelly D. Pearce, Ex. KDP-3 at 1, KDP-4 at 1 (March 23, 2012).

[11] *In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets*, Case Nos. 08-917-EL-SSO, *et al.*, Direct Testimony of J. Craig Baker at 13 (July 31, 2008) (hereinafter, "*AEP-Ohio ESP Cases*"); *In the Matter of the Application of Columbus*

Q25. Assuming the Commission granted AEP-Ohio another chance to collect transition revenue, do you agree with AEP-Ohio's methodology for establishing a cost-based capacity price?

A25. No. Irrespective of whether AEP-Ohio should be authorized to collect additional transition revenue, AEP-Ohio's methodology to establish a cost-based price should be rejected because it is unreasonable. OP's proposed cost-based formula in this proceeding violates established legal and regulatory principles and policies associated with traditional cost-based ratemaking under Chapter 4909, Revised Code. A non-exhaustive list of some of the problems with AEP-Ohio's cost-based methodology includes:

(1) The improper inclusion of construction work in progress ("CWIP"), which has not been demonstrated to be 75% complete;

(2) Omission of the mirroring component of a CWIP allowance where mirroring is supposed to provide customers with a benefit in exchange for giving the utility accelerated cash flow;

(3) Prepayments are improperly added to rate base;

(4) The working capital component of rate base is not supported by a lead lag study;

(5) The federal income tax ("FIT") expense calculation assumes full normalization of reconciling items;

(6) The improper inclusion of property held for future use;

Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Case Nos. 11-346-EL-SSO, *et al.*, Direct Testimony of Laura J. Thomas, Ex. LJT-1 (January 27, 2011).

(7) Selective application of a cost-based methodology to one unbundled service element without looking at whether total revenue is providing adequate compensation; and,

(8) A return on equity that is overstated because it ignores the business and financial risk that AEP-Ohio would effectively transfer to CRES suppliers and customers of CRES suppliers through a periodically adjusted formula rate that protects AEP-Ohio against revenue lost because AEP-Ohio's prices exceed market prices.

V. CONCLUSIONS

Q26. Should the Commission authorize recovery of above-market generation plant-related costs through the "cost-based" formula that AEP-Ohio is now proposing be approved to set the generation service capacity price that is paid by a CRES supplier serving retail customers in AEP-Ohio's service area?

A26. No. AEP-Ohio's proposal for setting capacity prices for CRES suppliers is strategically asymmetrical, unbalanced, unjust and unreasonable. These costs were analyzed and accounted for as a part of the transition from cost-based regulation to market-based regulation in AEP-Ohio's ETP as required by SB 3. The amount of above-market generation plant costs recoverable by AEP-Ohio was resolved in the ETP cases by AEP-Ohio agreeing to drop its right to seek any transition revenue for above-market generation plant costs. The time for bringing a transition revenue claim to the Commission has passed. And, AEP-Ohio also committed, in the ETP settlement, to not impose "… any lost

revenue charges (generation related transition charges (GTC)) on any switching customer."[12] AEP-Ohio passed on the opportunity for a transition to "customer choice" unencumbered by the legacy of cost-based ratemaking as applied to generation plant and it did so as part of the settlement package approved by the Commission.

I also believe it would be unreasonable, regardless of what the law may say, to permit AEP-Ohio to selectively and strategically revise the methods used to establish generation service capacity prices based on AEP-Ohio's desire to use the method that produces the best revenue and earnings outcome for AEP-Ohio in a context where the method that AEP-Ohio and the Commission previously favored is now beneficial to consumers.

Accordingly, I recommend that AEP-Ohio's application in this proceeding be rejected.

Q27. Do you have any additional recommendations?

A27. I recommend that the actual amount of above-market capacity charge revenue that AEP-Ohio has collected as a result of the December 14, 2011 Opinion and Order in Case Nos. 11-346-EL-SSO, *et al*. and the March 7, 2012 decision in this proceeding be applied as an offset to regulatory asset balances that are eligible for recovery from retail consumers. The amount of the offset should include interest at the rate of interest or the carrying charge rate that AEP-Ohio is using to accumulate the regulatory asset balances. Unless this offset is made,

[12] *AEP-Ohio ETP Cases,* Stipulation and Recommendation at 3 (May 8, 2000).

consumers are unlikely to receive timely credit for the excessive rates that AEP-Ohio has been allowed to collect for service provided in Ohio.

Q28. Does this conclude your testimony?

A28. Yes.

Projected Generation Related Net Stranded Costs
Columbus and Southern Company
Low Gas + Base Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$377,541
NPV of Cash Flow 2016 - 2030	$79,210
Total NPV Cash Flow	$456,751
Book	$974,329
Net Stranded Costs	$517,578

Income Statement		Source	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Present Value @ 10.75%
Revenue																			
1) Total GWH Generation		Input	16,308	16,308	16,308	16,461	16,541	16,631	16,403	16,179	16,057	16,739	16,524	15,602	14,672	14,264	13,968	13,462	
2) AEP Price		Input	$23.52	$23.76	$24.01	$24.26	$25.53	$26.79	$27.58	$28.39	$29.22	$30.06	$30.94	$31.81	$32.69	$33.60	$34.53	$35.48	
3) Total Revenue			$386,780	$404,636	$412,448	$420,612	$446,263	$470,053	$478,663	$488,261	$484,558	$503,009	$511,000	$511,972	$512,348	$512,719	$513,093	$513,467	
Expense																			
4) Production Expense excl fuel		Input	$59,059	$61,133	$63,279	$66,501	$68,799	$72,030	$74,546	$77,772	$80,612	$83,571	$87,254	$87,167	$86,961	$86,815	$86,669	$86,523	$636,374
5) Fuel Expense		Input	$179,510	$180,578	$181,248	$181,921	$186,411	$190,901	$194,245	$197,648	$201,110	$204,633	$208,218	$204,307	$200,463	$197,283	$193,767	$190,314	$1,963,673
6) Decommissioning/Dismantling		Input	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,953	$18,402	$0	$3,725	$18,920
7) SO2 allowance costs		Input	$11,527	$16,798	$18,967	$18,218	$19,543	$21,168	$18,248	$16,300	$12,812	$8,879	$8,205	$8,468	$4,869	$2,804	$996	$0	$101,546
8) A&G Expense		Input	$61,361	$88,843	$85,998	$90,905	$76,870	$73,034	$71,300	$75,600	$82,796	$75,900	$76,724	$77,874	$79,043	$80,228	$81,432	$82,653	$692,615
9) Depreciation - Steam Gen	3.20%	Calculated	$49,864	$51,003	$52,718	$54,966	$56,477	$57,241	$58,025	$58,829	$59,652	$60,496	$61,361	$62,176	$62,771	$63,383	$64,176	$64,942	
10) - Hydro		Calculated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
11) Retirements			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,958	$0	$0	$1,829	
12) Taxes - NOx and Scrubber	0.16%	Calculated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13) Taxes Other - Other		Input	$11,198	$12,797	$13,063	$14,163	$14,679	$15,216	$15,774	$16,351	$16,950	$17,573	$18,219	$18,886	$19,576	$20,293	$21,035	$21,805	$143,429
14) Total Expenses		Calculated	$403,469	$418,058	$435,873	$464,675	$418,448	$429,591	$432,529	$441,898	$453,922	$452,142	$456,981	$457,920	$452,855	$460,270	$448,875	$451,792	$3,142,713
15) Operating Income		Calculated	($6,689)	($13,520)	$18,575	$15,937	$28,037	$40,462	$46,555	$44,585	$40,636	$50,864	$51,519	$54,052	$59,491	$52,449	$66,918	$61,674	$287,954
16) Interest Expense	7.00%	Calculated	$31,504	$30,810	$30,063	$31,300	$31,905	$30,000	$28,300	$27,825	$26,361	$25,773	$24,888	$23,530	$22,864	$20,637	$19,360	$18,006	$203,068
17) Income Before Taxes		Calculated	($38,193)	($44,330)	($11,488)	($15,543)	($2,868)	$10,412	$18,255	$16,861	$13,764	$25,091	$26,630	$31,423	$7,407	$22,811	$46,558	$43,580	$84,786
18) Schedule M		Input	($2,866)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($3,370)
19) Taxable Income		Calculated	($41,979)	($44,793)	($12,751)	($16,006)	($2,731)	$9,949	$18,105	$16,198	$13,321	$24,628	$26,167	$30,960	$6,944	$22,348	$46,195	$43,127	$81,396
20) Current Federal Tax	40.55%	Calculated	($16,982)	($18,148)	($5,172)	($6,482)	($1,108)	$4,034	$6,531	$6,570	$5,401	$9,989	$10,736	$12,557	$2,817	$9,064	$18,719	$17,482	$4,879
21) Deferred FIT/ITC	36.00%	Input	$1,940	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	
22) Total Income Taxes		Calculated	($15,041)	($18,000)	($5,010)	($6,300)	($948)	$4,196	$6,993	$6,722	$5,586	$10,151	$10,937	$12,719	$2,979	$9,228	$18,901	$17,664	$4,858
23) Net Income Before Preferred		Calculated	($22,541)	($26,324)	($7,276)	($9,213)	($1,322)	$6,216	$9,973	$9,929	$8,219	$14,940	$15,833	$18,703	$4,429	$13,586	$27,147	$25,936	$14,908
Cash Flow																			
24) Net Income Before Preferred		From above	($22,541)	($26,324)	($7,276)	($9,213)	($1,322)	$6,216	$9,973	$9,929	$8,219	$14,940	$15,833	$18,703	$4,429	$13,586	$27,147	$25,936	$14,908
25) Plus Interest Expense		From above	$31,504	$30,810	$30,063	$31,300	$31,905	$30,000	$28,300	$27,825	$26,361	$25,773	$24,888	$23,530	$22,864	$20,637	$19,360	$18,006	$203,068
26) Plus Deferred Taxes		From above	$1,940	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	
27) Plus Depreciation		From above	$49,864	$51,003	$52,718	$54,966	$56,477	$57,241	$58,025	$58,829	$59,652	$60,496	$61,361	$62,176	$62,771	$63,383	$64,176	$64,942	
28) Plus Retirements		From above	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,958	$0	$0	$1,829	
29) Less Construction		External File	$31,943	$37,796	$35,232	$36,503	$23,698	$24,188	$24,793	$25,413	$26,048	$26,699	$27,367	$23,723	$24,316	$24,924	$24,579	$25,193	$293,698
30) Less NOx (SNCR)		External File	$0	$0	$44,239	$32,940	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$89,573
31) Less NOx (SCR) and Scrubber		External File	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
32) Total		Calculated	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$377,541
Capitalization																			
33) Debt		Input	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	
34) Equity		Input	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	
Investment																			
35) Gross Plant in Service - Steam Gen		Input	$1,574,841	$1,612,656	$1,662,209	$1,753,102	$1,776,700	$1,800,888	$1,825,681	$1,851,084	$1,877,142	$1,903,842	$1,931,208	$1,954,951	$1,966,848	$1,983,672	$2,017,750	$2,041,114	
36) - Hydro		Input	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
37) Accum. Depreciation - Steam Gen		Calculated	$629,812	$680,812	$733,529	$788,494	$844,971	$902,212	$960,236	$1,019,065	$1,078,718	$1,139,214	$1,200,574	$1,262,750	$1,325,521	$1,388,904	$1,453,081	$1,518,023	
38) - Hydro		Input	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
39) Net Plant		Calculated	$945,029	$931,844	$928,680	$964,608	$931,729	$898,676	$865,444	$832,020	$798,425	$764,628	$730,634	$692,179	$642,326	$594,768	$564,669	$523,091	
40) Plus Fuel Inventory		Input	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$19,532	$19,532	$19,532	$19,057	
41) Plus M&S & Prepayments		Input	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	
42) Less Accum DFIT		Calculated	$10,840	$11,022	$11,204	$11,386	$11,568	$11,750	$11,932	$12,114	$12,296	$12,478	$12,661	$12,843	$12,786	$12,947	$13,109	$13,271	
43) Net Investment		Calculated	$974,329	$960,964	$957,616	$993,422	$960,301	$927,164	$893,772	$860,194	$826,268	$792,276	$758,314	$719,896	$667,472	$620,851	$589,093	$548,878	
44) Net Investment		Calculated	$974,329																

45) NPV of Cash Flow 2016 - 2030 $79,210

Projected Generation Related Net Stranded Costs
Ohio Power Company
Low Gas + Base Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$906,821
NPV of Cash Flow 2016 - 2030	$263,210
Total NPV Cash Flow	$1,170,032
Plus	$1,209,382
Net Stranded Costs	$139,350

Income Statement	Source	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Present Value @ 10.72%
Revenues																		
1) Total GWH Generation	Input	48,624	48,812	49,001	49,189	49,037	50,085	48,182	46,316	44,538	42,830	41,187	49,919	49,061	48,266	48,122	50,968	
2) AEP Price	Input	$23.52	$23.76	$24.01	$24.26	$25.53	$26.79	$27.58	$28.39	$29.22	$30.08	$30.96	$31.81	$32.88	$33.89	$34.53	$35.48	
3) Total Revenues		$1,209,139	$1,248,884	$1,296,506	$1,296,200	$1,298,890	$1,482,091	$1,458,267	$1,424,772	$1,411,207	$1,307,906	$1,264,764	$1,499,979	$1,435,852	$1,463,812	$1,456,530	$1,515,560	
Expenses																		
4) Production Expense and fuel	Input	$245,453	$255,161	$265,294	$275,906	$286,521	$302,930	$304,582	$310,376	$314,218	$318,197	$322,045	$334,496	$347,632	$360,887	$374,321	$388,315	$2,541,415
5) Fuel Expense	Input	$543,929	$515,624	$488,183	$582,149	$578,654	$591,119	$583,976	$576,142	$567,517	$559,598	$551,364	$555,512	$558,881	$562,629	$565,418	$568,827	$4,274,786
6) Decommissioning/Dismantling	Input	$0	$0	$0	$0	$0	$0	$0	$0	$34,000	$35,731	$24,441	$25,011	$0	$0	$0	$0	
7) SO2 allowance costs	Input	$0	$21,706	$29,964	$28,468	$25,964	$25,326	$18,676	$12,009	$6,208	$0	$0	$0	$0	$0	$0	$0	$114,573
8) A&G Expense	Input	$83,279	$84,879	$101,464	$102,737	$103,708	$104,995	$105,907	$108,667	$106,984	$109,114	$110,205	$111,307	$112,620	$113,544	$114,680	$116,026	$760,769
9) Depreciation - Steam Gen 3.40%	Calculated	$90,998	$97,186	$106,159	$108,772	$112,008	$116,097	$119,423	$122,468	$124,279	$126,107	$128,029	$131,222	$134,091	$137,254	$140,263	$143,589	
10) - Hydro 2.70%	Calculated	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	$2,956	
11) Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$58,750	$0	$18,413	$0	$0	$0	$0	$0	
12) Taxes - NOx and Scrubber 0.15%	Calculated	$0	$41	$71	$80	$86	$103	$103	$103	$105	$103	$103	$105	$103	$105	$103	$103	$660
13) Taxes Other - Other	Input	$78,147	$78,929	$42,538	$42,861	$43,172	$43,500	$43,835	$44,177	$44,527	$44,884	$45,248	$45,619	$46,000	$46,387	$46,783	$47,186	$364,578
14) Total Expenses	Calculated	$1,154,781	$1,166,082	$1,134,757	$1,122,819	$1,154,617	$1,186,737	$1,184,548	$1,178,948	$1,296,385	$1,194,800	$1,253,084	$1,208,029	$1,251,772	$1,223,140	$1,245,143	$1,267,865	$8,744,404
15) Operating Income	Calculated	$73,378	$80,832	$161,199	$182,440	$214,163	$295,354	$257,819	$246,823	$164,823	$201,268	$189,772	$292,950	$233,890	$236,672	$213,298	$247,747	$1,410,528
16) Interest Expense 7.18%	Calculated	$38,150	$38,982	$43,790	$44,549	$45,748	$46,312	$42,869	$41,730	$38,485	$37,211	$35,801	$33,977	$32,831	$31,292	$29,898	$28,450	$294,849
17) Income Before Taxes	Calculated	$35,229	$40,849	$97,410	$117,901	$179,414	$222,042	$215,121	$208,193	$111,439	$164,157	$145,171	$189,973	$201,059	$207,419	$213,429	$219,297	$1,116,679
18) Schedule M	Input	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$25,830
19) Taxable Income	Calculated	$38,694	$44,304	$100,876	$121,367	$173,980	$225,508	$218,587	$212,659	$114,896	$167,623	$148,637	$193,439	$204,524	$210,879	$216,894	$222,763	$1,141,349
20) Current Federal Tax 40.68%	Calculated	$15,884	$17,971	$38,983	$49,326	$70,526	$91,449	$88,669	$86,256	$46,682	$67,966	$60,297	$78,347	$83,004	$85,531	$87,972	$90,353	$462,951
21) Deferred FITITC 35.00%	Input	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)
22) Total Income Taxes	Calculated	$14,671	$16,757	$36,858	$48,013	$69,313	$90,253	$87,446	$85,041	$45,469	$66,775	$59,074	$66,134	$81,823	$84,318	$86,759	$89,140	$463,947
23) Net Income Before Preferred	Calculated	$20,747	$24,093	$61,790	$68,888	$101,101	$131,799	$127,575	$124,152	$66,041	$97,382	$86,097	$126,839	$119,436	$123,092	$126,669	$130,156	$681,732
Cash Flow																		
24) Net Income Before Preferred	From above	$20,747	$24,093	$61,790	$68,888	$101,101	$131,799	$127,575	$124,152	$66,041	$97,382	$86,097	$126,839	$119,436	$123,092	$126,669	$130,156	$681,732
25) Plus Interest Expense	From above	$38,150	$38,982	$43,790	$44,549	$45,748	$46,312	$42,869	$41,730	$38,485	$37,211	$35,801	$33,977	$32,831	$31,292	$29,898	$28,450	$294,849
26) Plus Deferred Taxes	From above	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
27) Plus Depreciation	From above	$93,967	$100,181	$109,166	$112,727	$115,961	$119,053	$122,379	$125,424	$127,235	$129,063	$131,586	$134,177	$137,156	$140,209	$143,338	$146,546	
28) Plus Retirements	From above	$0	$0	$0	$0	$0	$0	$0	$0	$58,750	$0	$18,413	$0	$0	$0	$0	$0	
29) Less Construction		$87,736	$105,584	$90,117	$87,163	$89,919	$94,319	$98,677	$81,801	$83,930	$82,562	$84,411	$86,821	$88,884	$90,901	$93,174	$95,605	$641,996
30) Less NOx (SNCR)	External File	$0	$102,512	$104,436	$10,173	$18,982	$4,839	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$241,454
31) Less NOx (SCR) and Scrubber		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
32) Total	Calculated	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$906,821
Capitalization																		
33) Debt	Input	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	
34) Equity	Input	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	
Investment																		
35) Gross Plant in Service - Steam Gen	Input	$2,725,998	$2,890,364	$3,194,916	$3,262,272	$3,365,152	$3,484,136	$3,580,798	$3,642,979	$3,707,800	$3,760,219	$3,818,217	$3,902,736	$3,961,422	$4,062,323	$4,176,480	$4,270,909	
36) - Hydro	Input	$106,453	$108,409	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	$109,453	
37) Accum. Depreciation - Steam Gen	Calculated	1,587,274	$1,684,440	$1,790,580	$1,903,352	$2,012,928	$2,128,126	$2,247,549	$2,370,008	$2,494,287	$2,620,395	$2,748,024	$2,880,948	$3,014,447	$3,151,791	$3,292,054	$2,435,874	
38) - Hydro	Input	$45,176	$47,131	$50,088	$53,042	$55,997	$58,952	$61,907	$64,863	$67,818	$70,773	$73,729	$76,684	$79,639	$82,594	$85,549	$88,504	
39) Net Plant	Calculated	$1,209,299	$1,308,245	$1,404,992	$1,410,321	$1,406,680	$1,306,485	$1,300,764	$1,317,261	$1,215,216	$1,196,505	$1,192,818	$1,065,261	$1,006,788	$967,481	$987,318	$864,274	
40) Plus Fuel Inventory	Input	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$90,000	$90,000	$79,043	$79,043	$79,043	$79,043	$79,043	$79,043	
41) Plus M&S & Prepayments	Input	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	
42) Less Accum DFIT	Calculated	$24,538	$23,623	$22,419	$21,187	$19,994	$18,771	$17,558	$16,346	$15,132	$13,919	$12,706	$11,492	$10,279	$9,066	$7,853	$6,640	
43) Net Investment	Calculated	$1,209,382	$1,475,551	$1,573,211	$1,520,053	$1,517,595	$1,418,644	$1,414,134	$1,431,846	$1,318,081	$1,272,504	$1,206,255	$1,110,812	$1,112,553	$1,094,459	$1,016,507	$985,677	
44) Net Investment	Calculated	$1,209,382																

45) NPV of Cash Flow 2016 - 2030 $263,210

Projected Generation Related Net Stranded Costs
Columbus and Southern Company
High Gas + Alternative Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$480,518
NPV of Cash Flow 2016 - 2030	$87,115
Total NPV Cash Flow	$487,631
Base	$974,329
Net Stranded Costs	$478,698

Income Statement	Source	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Present Value @ 10.78%
Revenues																		
1) Total GWH Generation	Input	16,238	16,400	16,564	16,730	16,903	17,068	16,739	16,427	16,121	15,821	15,526	15,326	15,132	14,939	14,749	14,590	
2) AEP Price	Input	$23.02	$24.64	$25.81	$27.04	$28.54	$30.23	$30.63	$31.44	$32.08	$32.79	$33.34	$34.34	$35.36	$36.41	$37.49	$38.60	
3) Total Revenues		$386,790	$421,720	$448,249	$476,435	$507,138	$537,841	$537,862	$536,224	$536,558	$534,812	$534,067	$541,283	$549,214	$558,963	$564,801	$572,760	
Expenses																		
4) Production Expense and fuel	Input	$68,658	$61,292	$60,619	$60,016	$60,463	$72,511	$70,875	$63,606	$60,527	$65,968	$102,658	$106,254	$107,654	$110,550	$113,313	$116,146	$300,000
5) Fuel Expense	Input	$179,519	$181,510	$183,126	$184,763	$190,284	$196,778	$198,962	$197,613	$196,630	$199,488	$200,402	$200,756	$201,110	$201,465	$201,821	$202,177	$1,400,362
6) Decommissioning/Dismantling	Input	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,563	$18,492	$0	$3,725	
7) SO2 allowance costs	Input	$0	$14,121	$17,363	$5,053	$20,860	$7,318	$16,659	$14,860	$11,010	$7,525	$0	$0	$0	$0	$0	$0	$73,802
8) A&G Expense	Input	$61,881	$65,843	$66,996	$69,305	$70,479	$73,654	$71,860	$75,866	$62,798	$76,590	$79,724	$77,874	$79,043	$80,228	$81,432	$82,653	$832,836
9) Depreciation - Steam Gen 3.50%	Calculated	$49,864	$51,000	$52,718	$54,365	$55,477	$57,541	$58,187	$62,542	$65,578	$66,860	$72,298	$74,247	$74,960	$76,592	$78,364	$77,151	
10) - Hydro	Calculated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
11) Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,599	$0	$0	$1,829	
12) Taxes - NOx and Scrubber 0.15%	Calculated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13) Taxes Other - Other	Input	$41,108	$42,767	$13,983	$14,183	$14,879	$16,218	$16,774	$18,361	$18,950	$17,573	$18,218	$18,886	$19,578	$20,293	$21,035	$21,806	$143,429
14) Total Expenses	Calculated	$381,043	$417,472	$388,478	$394,866	$422,844	$421,487	$453,876	$460,050	$464,367	$464,012	$470,290	$477,197	$511,516	$506,630	$493,965	$505,488	$2,904,887
15) Operating Income	Calculated	$5,948	$4,248	$61,772	$81,570	$86,094	$116,343	$87,408	$85,095	$71,181	$69,800	$63,747	$64,088	$37,698	$50,425	$70,816	$67,273	$485,742
16) Interest Expense 7.30%	Calculated	$31,504	$30,810	$30,083	$31,380	$31,105	$30,050	$30,128	$31,208	$32,502	$33,864	$34,782	$34,531	$32,713	$30,896	$29,259	$27,572	$229,376
17) Income Before Taxes	Calculated	($26,556)	($26,562)	$30,808	$50,190	$53,989	$86,294	$57,280	$54,739	$38,679	$35,946	$29,965	$29,525	$4,985	$19,527	$41,557	$39,701	$257,366
18) Schedule M	Input	($2,986)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($463)	($3,379)
19) Taxable Income	Calculated	($29,463)	($27,018)	$29,446	$49,727	$53,526	$85,831	$56,817	$54,276	$38,216	$35,783	$29,502	$29,062	$4,522	$19,064	$41,094	$39,238	$253,986
20) Current Fed/State Tax 40.88%	Calculated	($11,949)	($10,967)	$8,253	$20,389	$21,719	$34,813	$27,101	$22,614	$15,620	$14,513	$11,886	$11,360	$1,834	$7,732	$16,666	$15,916	$103,021
21) Deferred FITITC 36.00%	Input	$1,010	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	
22) Total Income Taxes	Calculated	($10,939)	($10,785)	$8,435	$20,232	$21,572	$34,976	$27,283	$22,178	$15,802	$14,675	$11,750	$11,112	$1,999	$7,895	$16,530	$15,877	$104,200
23) Net Income Before Preferred	Calculated	($15,930)	($15,757)	$12,454	$29,958	$32,117	$51,319	$40,017	$32,583	$23,016	$21,570	$17,254	$17,813	$2,986	$11,633	$24,727	$23,824	$153,166
Cash Flow																		
24) Net Income Before Preferred	From above	($15,930)	($15,757)	$12,454	$29,958	$32,117	$51,319	$40,017	$32,583	$23,016	$21,570	$17,254	$17,813	$2,986	$11,633	$24,727	$23,824	$153,166
25) Plus Interest Expense	From above	$31,504	$30,810	$30,083	$31,380	$31,105	$30,050	$30,128	$31,208	$32,502	$33,864	$34,782	$34,531	$32,713	$30,896	$29,259	$27,572	$229,376
26) Plus Deferred Taxes	From above	$1,010	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	
27) Plus Depreciation	From above	$49,864	$51,000	$52,718	$54,365	$55,477	$57,541	$58,187	$62,542	$65,578	$66,860	$72,298	$74,247	$74,960	$76,592	$78,364	$77,151	
28) Plus Retirements	From above	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,599	$0	$0	$1,829	
29) Less Construction	External File	$31,943	$37,798	$35,232	$38,503	$23,898	$24,198	$34,793	$25,413	$26,048	$26,558	$27,267	$23,723	$24,316	$24,924	$24,579	$25,193	$203,698
30) Less NOx (BACR)	External File	$0	$0	$44,298	$32,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$68,873
31) Less NOx (BCR) and Scrubber	External File	$0	$0	$0	$0	$0	$0	$72,587	$74,401	$76,261	$78,168	$80,122	$0	$0	$0	$0	$0	
32) Total	Calculated	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$400,518
Capitalization																		
33) Debt	Input	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	
34) Equity	Input	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	
Investment																		
35) Gross Plant in Service - Steam Gen	Input	$1,374,941	$1,412,658	$1,462,339	$1,753,162	$1,776,700	$1,830,866	$1,866,268	$1,866,282	$2,100,282	$2,206,250	$2,312,746	$2,336,471	$2,343,787	$2,374,711	$2,399,290	$2,422,863	
36) - Hydro	Input	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
37) Accum. Depreciation - Steam Gen	Calculated	$629,812	$680,812	$733,529	$786,894	$844,371	$902,912	$961,099	$1,023,741	$1,089,319	$1,156,207	$1,228,506	$1,304,752	$1,379,712	$1,456,304	$1,531,668	$1,608,819	
38) - Hydro	Input	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
39) Net Plant	Calculated	$945,029	$931,846	$948,810	$966,268	$931,329	$928,954	$905,169	$874,542	$1,011,076	$1,047,052	$1,082,239	$1,031,719	$964,075	$918,407	$867,621	$813,044	
40) Plus Fuel Inventory	Input	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$22,140	$20,803	$20,803	$20,803	$20,803	
41) Plus M&S & Prepayments	Input	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	$18,000	
42) Less Accum DFIT	Calculated	$10,849	$11,032	$11,164	$11,326	$11,488	$11,650	$11,812	$11,974	$12,136	$12,298	$12,461	$12,623	$12,786	$12,947	$13,109	$13,271	
43) Net Investment	Calculated	$974,329	$960,954	$977,786	$992,482	$960,381	$957,105	$935,197	$1,002,207	$1,039,079	$1,074,894	$1,109,533	$1,059,106	$995,743	$944,913	$892,315	$838,576	
44) Net Investment	Calculated	$974,329																

45) NPV of Cash Flow 2016 - 2030 $87,115

Projected Generation Related Net Stranded Costs
Ohio Power Company
High Gas + Alternative Environment

Stranded Cost Calculation Summary	
NPV of Cash Flow 2001 - 2015	$954,872
NPV of Cash Flow 2016 - 2030	$309,820
Total NPV Cash Flow	$1,265,492
Base	$1,309,362
Net Stranded Costs	$45,869

Income Statement	Source	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Present Value @ 10.47%
Revenues																		
1) Total GWH Generation	Input	48,524	48,408	50,204	51,012	51,487	51,962	48,969	48,446	48,235	47,054	46,873	45,950	46,027	46,104	46,182	46,259	
2) AEP Price	Input	$23.52	$24.84	$25.81	$27.04	$28.84	$30.23	$30.83	$31.44	$32.08	$32.79	$33.34	$34.34	$35.36	$36.41	$37.49	$38.60	
3) Total Revenue		$1,228,139	$1,206,845	$1,294,955	$1,444,517	$1,500,490	$1,564,483	$1,493,511	$1,533,124	$1,503,293	$1,574,008	$1,545,253	$1,563,258	$1,642,773	$1,693,810	$1,746,445	$1,800,709	
Expenses																		
4) Production Expense and fuel	Input	$245,453	$255,965	$266,926	$278,380	$292,875	$305,799	$318,883	$334,206	$349,599	$365,283	$381,857	$399,555	$418,072	$437,449	$457,722	$478,938	$2,430,101
5) Fuel Expense	Input	$643,828	$622,064	$600,945	$580,543	$596,752	$610,941	$608,725	$604,498	$604,278	$602,064	$599,840	$609,840	$620,186	$630,610	$641,204	$651,960	$4,604,574
6) Decommissioning/Dismantling	Input	$0	$0	$0	$0	$0	$0	$0	$0	$34,880	$35,731	$24,401	$25,011	$0	$0	$0	$0	
7) SO2 allowance costs	Input	$0	$22,793	$31,871	$20,468	$29,063	$28,848	$22,404	$18,161	$8,847	$3,448	$0	$0	$0	$0	$0	($16,042)	$127,473
8) A&G Expense	Input	$93,278	$94,570	$101,484	$102,757	$103,708	$104,803	$105,997	$106,927	$108,064	$109,114	$110,205	$111,307	$112,420	$113,544	$114,680	$115,826	$780,750
9) Depreciation - Steam Gen 3.40%	Calculated	$90,998	$97,196	$105,158	$109,772	$112,898	$115,097	$124,872	$138,520	$147,988	$159,704	$172,365	$180,588	$183,067	$186,120	$188,219	$192,458	
10) - Hydro 2.70%	Calculated	$2,959	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	$2,955	
11) Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$58,780	$0	$18,413	$0	$0	$0	$0	$0	
12) Taxes - NOx and Scrubber 0.18%	Calculated	$0	$41	$71	$80	$96	$103	$103	$308	$518	$733	$953	$1,179	$1,179	$1,179	$1,179	$1,179	$3,808
13) Taxes Other - Other	Input	$78,147	$78,828	$42,538	$42,961	$43,172	$43,509	$43,635	$44,177	$44,587	$44,984	$45,248	$45,820	$46,000	$46,367	$46,783	$47,196	$358,578
14) Total Expenses	Calculated	$1,154,781	$1,174,474	$1,151,120	$1,146,786	$1,178,518	$1,212,706	$1,227,863	$1,267,451	$1,361,175	$1,323,905	$1,356,257	$1,376,856	$1,383,882	$1,418,243	$1,453,773	$1,474,477	$9,297,572
15) Operating Income	Calculated	$73,378	$134,371	$243,735	$338,751	$410,871	$481,865	$435,828	$365,673	$242,118	$250,111	$189,997	$217,613	$258,891	$275,572	$292,671	$326,232	$2,227,584
16) Interest Expense 7.18%	Calculated	$38,160	$38,992	$43,798	$44,548	$43,748	$43,312	$46,548	$53,272	$58,838	$63,884	$68,758	$71,171	$66,422	$65,649	$62,852	$60,030	$382,131
17) Income Before Taxes	Calculated	$35,218	$94,379	$199,955	$295,202	$367,223	$438,553	$389,279	$332,401	$183,478	$186,227	$119,239	$146,442	$190,469	$209,923	$229,819	$266,201	$1,844,757
18) Schedule M	Input	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$3,466	$25,070
19) Taxable Income	Calculated	$38,684	$97,845	$203,421	$298,668	$370,688	$441,819	$392,745	$335,867	$186,944	$189,693	$122,705	$149,908	$193,935	$213,389	$233,285	$269,667	$1,870,428
20) Current Fed/State Tax 40.99%	Calculated	$15,994	$38,686	$82,508	$121,140	$150,351	$179,202	$158,287	$136,229	$75,825	$76,940	$49,798	$60,803	$78,700	$86,551	$94,629	$109,377	$758,945
21) Deferred FIT/ITC 35.00%	Input	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
22) Total Income Taxes	Calculated	$14,481	$36,473	$81,294	$119,927	$149,138	$177,988	$156,084	$134,014	$74,612	$75,726	$48,585	$59,590	$77,447	$85,338	$93,407	$108,164	$749,961
23) Net Income Before Preferred	Calculated	$20,747	$55,906	$118,661	$176,275	$218,084	$260,364	$231,195	$197,386	$108,867	$110,501	$70,653	$86,852	$113,022	$124,584	$134,412	$158,037	$1,095,096
Cash Flow																		
24) Net Income Before Preferred	From above	$20,747	$55,906	$118,661	$176,275	$218,084	$260,364	$231,195	$197,386	$108,867	$110,501	$70,653	$86,852	$113,022	$124,584	$134,412	$158,037	$1,095,096
25) Plus Interest Expense	From above	$38,160	$38,992	$43,798	$44,548	$43,748	$43,312	$46,548	$53,272	$58,838	$63,884	$68,758	$71,171	$66,422	$65,649	$62,852	$60,030	$382,131
26) Plus Deferred Taxes	From above	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,212)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	($1,213)	
27) Plus Depreciation	From above	$93,957	$100,151	$108,113	$112,727	$115,853	$118,053	$127,827	$138,475	$150,944	$162,661	$175,320	$183,044	$186,022	$189,075	$192,204	$195,412	
28) Plus Retirements	From above	$0	$0	$0	$0	$0	$0	$0	$0	$58,780	$0	$18,413	$0	$0	$0	$0	$0	
29) Less Construction		$87,735	$102,598	$90,117	$57,183	$62,018	$64,319	$98,677	$91,991	$83,930	$82,352	$84,611	$86,621	$88,884	$90,901	$93,174	$95,583	$641,905
30) Less NOx (SNCR)	External File	$0	$162,512	$124,436	$10,173	$10,862	$4,838	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$561,454
31) Less NOx (SCR) and Scrubber		$0	$0	$0	$0	$0	$0	$273,430	$280,268	$287,272	$294,454	$301,815	$0	$0	$0	$0	$0	
32) Total	Calculated	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$954,872
Capitalization																		
33) Debt	Input	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	
34) Equity	Input	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	
Investment																		
35) Gross Plant in Service - Steam Gen	Input	$2,725,290	$2,990,364	$3,194,915	$3,282,272	$3,385,152	$3,484,110	$3,854,217	$4,196,374	$4,588,835	$4,865,841	$5,253,454	$5,339,975	$5,428,659	$5,518,580	$5,612,733	$5,708,238	
36) - Hydro	Input	$108,453	$108,453	$108,453	$108,453	$108,453	$108,453	$108,453	$108,453	$108,453	$108,453	$108,453	$108,453	$108,453	$108,453	$108,453	$108,453	
37) Accum. Depreciation - Steam Gen	Calculated	1,587,274	$1,684,440	$1,789,598	$1,889,362	$2,012,028	$2,125,128	$2,252,167	$2,384,717	$2,534,706	$2,696,412	$2,868,777	$3,048,865	$3,231,932	$3,418,051	$3,607,300	$3,799,757	
38) - Hydro	Input	$44,178	$47,131	$50,086	$53,042	$55,997	$58,952	$61,907	$64,863	$67,818	$70,773	$73,728	$76,684	$79,639	$82,594	$85,549	$88,504	
39) Net Plant	Calculated	$1,203,269	$1,368,245	$1,464,882	$1,419,321	$1,408,580	$1,368,485	$1,929,368	$1,852,947	$2,013,764	$2,227,909	$2,420,402	$2,353,879	$2,228,541	$2,120,387	$2,029,237	$1,929,428	
40) Plus Fuel Inventory	Input	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$92,929	$90,052	$90,052	$90,052	$90,052	$90,052	$90,052	$90,052	$90,052	
41) Plus M&S & Prepayments	Input	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	$38,000	
42) Less Accum DFIT	Calculated	$24,838	$23,625	$22,410	$21,197	$19,984	$18,771	$17,558	$16,345	$15,132	$13,919	$12,705	$11,492	$10,279	$9,066	$7,853	$6,640	
43) Net Investment	Calculated	$1,309,362	$1,475,551	$1,573,211	$1,529,053	$1,517,525	$1,480,644	$1,942,837	$1,968,832	$2,118,684	$2,332,042	$2,525,748	$2,430,434	$2,334,313	$2,237,353	$2,139,535	$2,040,839	
44) Net Investment	Calculated	$1,309,362																

45) NPV of Cash Flow 2016 - 2030 $309,820

EXHIBIT NO. ___ JHL-2
Page 4 of 4

Print

Exhibit JEH-2

AEP Ohio Files Motion For Relief And Expedited Ruling

COLUMBUS, Ohio, Feb. 27, 2012 – AEP Ohio, a unit of American Electric Power (NYSE: AEP), filed today with the Public Utilities Commission of Ohio (PUCO) a motion for relief and request for expedited ruling related to the Commission's Feb. 23 order, specifically regarding generation capacity charges.

Upon rejecting the settlement agreement, the PUCO recognized that the case to determine a capacity charge that competitive retail generation suppliers would pay AEP Ohio needed to proceed independently and that a procedural schedule would be established. While a more permanent decision remains pending regarding the appropriate capacity charge, AEP Ohio is requesting interim relief and an expedited ruling in order to avoid undue prejudice, in the form of substantial and adverse financial impacts.

"AEP Ohio has committed significant capital investment in its Ohio generation fleet under what was a regulated environment to serve our customers' generation needs," said Nicholas K. Akins, AEP president and chief executive officer. "The settlement agreement allowed AEP Ohio a reasonable transition to market over a period of time. Without that transition, we will basically be giving the capacity we built to competitive suppliers for the taking."

The company estimates that if it is required to flash cut to RPM-priced capacity this year, it would cause the company's projected 2012 earnings to drop by 27 percent and produce a return on equity (ROE) of 7.6 percent. Projected earnings for 2013 also would drop significantly by 67 percent and produce an ROE of 2.4 percent.

In the filing, AEP Ohio is asking the PUCO to maintain the status quo of what was proposed and in place for 2012 by the previously approved stipulated agreement pending an expedited resolution of the proceeding. In that agreement, AEP Ohio was to provide a percentage of its generation capacity to competitive retail suppliers at the deeply discounted RPM price.

The company also has proposed another alternative to the Commission that would permit RPM-priced capacity for any customer that has shopped for generation supply to date, while allowing AEP Ohio to use a reduced cost-based rate for new shopping, pending resolution of the proceeding.

"We feel these proposed interim solutions give the Commission alternatives to dealing with the capacity issue fairly and without prejudice until the proceeding can be resolved," said Joseph Hamrock, AEP Ohio president and chief operating officer. "Making AEP Ohio flash cut to RPM-priced capacity would have a significant financial impact on AEP Ohio and cause uncertainty and instability for our customers, the company and its investors."

AEP Ohio has proposed a procedural schedule for resolution of this case that fully submits the record for decision in 60 days and a decision on the proceeding within 90 days.

AEP Ohio provides electricity to nearly 1.5 million customers of major AEP subsidiaries Columbus Southern Power Company and Ohio Power Company in Ohio, and Wheeling Power Company in the northern panhandle of West Virginia. AEP Ohio is based in Gahanna, Ohio, and is a unit of American Electric Power. News and information about AEP Ohio can be found at aepohio.com.

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

This report made by American Electric Power contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP believes that its expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: Electric load and customer growth; weather conditions, including storms; available sources and costs of, and transportation for, fuels and the creditworthiness of fuel suppliers and transporters; availability of generating capacity and the performance of AEP's generating plants; the ability to recover regulatory assets and stranded costs in connection with deregulation; the ability to recover increases in fuel and other energy costs through regulated or competitive electric rates; the ability to build or acquire generating capacity when needed at acceptable prices and terms and to recover those costs through applicable rate cases; new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon and other substances; timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery for new investments, transmission service and environmental compliance); resolution of litigation (including pending Clean Air Act enforcement actions and disputes arising from the bankruptcy of Enron Corp.); AEP's ability to constrain its operation and maintenance costs; AEP's ability to sell assets at acceptable prices and on other acceptable terms, including rights to share in earnings derived from the assets subsequent to their sale; the economic climate and growth in its service territory and changes in market demand and demographic patterns; inflationary trends; its ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities; changes in the creditworthiness and number of participants in the energy trading market; changes in the financial markets, particularly those affecting the availability of capital and AEP's ability to refinance existing debt at attractive rates; actions of rating agencies, including changes in the ratings of debt; volatility and changes in markets for electricity, natural gas and other energy-related commodities; changes in utility regulation, including membership and integration into regional transmission structures; accounting pronouncements periodically issued by accounting standard-setting bodies; the performance of AEP's pension and other postretirement benefit plans; prices for power that AEP generates and sells at wholesale; changes in technology, particularly with respect to new, developing or alternative sources of generation and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events.

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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Direct Testimony of J. Edward Hess on Behalf of Industrial Energy Users-Ohio* was served upon the following parties of record this 4th day of April, 2012, *via* electronic transmission, hand-delivery, or ordinary U.S. mail, postage prepaid.

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