

**BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO**

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

**INITIAL POST-HEARING BRIEF
SUBMITTED ON BEHALF OF THE STAFF OF
THE PUBLIC UTILITIES COMMISSION OF OHIO**

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INTRODUCTION

The \$355.72/MW-Day capacity rate proposed by American Electric Power¹ (“AEP Ohio” or “Company”) to charge Competitive Retail Electric Service (“CRES”) providers for shopping load over the next three years is unjustified and must be rejected by the Public Utilities Commission of Ohio (“Commission”). AEP Ohio’s proposed rate is not supported by any other party in the case. AEP Ohio’s proposed rate is, by far, the highest of all the parties proposing a capacity charge in this proceeding. If the Commission finds that the prevailing PJM Reliability Pricing Model (“RPM”) capacity rates dur-

¹ Columbus Southern Power Company (“CSP”) has been merged with Ohio Power (“OP”). For purposes of this brief, “AEP Ohio” refers to the post-merger electric distribution utility (“EDU”).

ing the June 1, 2012 through May 31, 2015 period are not appropriate, Staff proposes an alternative capacity charge that the Commission may want to consider for this case.

In general, Staff's position is that AEP Ohio should charge CRES providers the prevailing RPM rate in the unconstrained region of PJM. Staff, like many other parties, opposes AEP Ohio's request to recover capacity rates that are significantly above the market rate. Other investor owned utilities in Ohio, like Duke and FirstEnergy, are charging CRES providers RPM pricing,² so the RPM pricing option should be appropriate for AEP Ohio too. The evidentiary record does not support AEP Ohio's request to charge CRES providers \$355.72/MW-day for their shopping load. In the event the Commission finds RPM pricing inappropriate Staff proposes an alternate capacity rate, which is netted to account for appropriate cost adjustments and energy margin credits. Staff's alternative RPM rate may offer more financial stability to AEP Ohio than RPM pricing over the next three years, but it is not unjust or excessive like AEP Ohio's proposed rate. If the Commission finds the RPM clearing prices for 2012-2015 not to be appropriate for AEP Ohio then Staff proposes an alternate capacity rate of \$146.41/MW-Day be set as a state compensation mechanism for AEP Ohio as developed, calculated and recommended by Staff.

Staff's alternate proposed capacity rate balances the interests of AEP Ohio to recover its embedded costs to meet its Fixes Resource Requirement ("FRR") obligations while at the same time promoting alternative competitive supply and retail competition.

²

Tr. Vol. I at 97.

Staff's alternate proposed rate is compensatory, not confiscatory. Staff's rate neither discriminates against, nor provides a subsidy to, CRES providers; rather, Staff's alternative proposal would prevent the unjust enrichment of AEP Ohio's shareholders at the expense of CRES providers and their customers. Furthermore, Staff's alternate proposed rate would foster competition by providing adequate shopping while, at the same time, providing AEP Ohio financial stability of earnings that allows it to attract capital investment.

From 2007 to November of 2010, AEP Ohio was compensated for capacity supplied to CRES providers at the adjusted PJM RPM auction price.³ AEP Ohio did not complain about the PJM RPM prices not being compensatory back then because there was very little shopping and energy prices were higher than they are today.⁴ But as AEP Ohio looked ahead at forward auction prices (for PJM planning years 2012/2013 and 2013/2014), it decided it was time "to do something because capacity can't be free."⁵ In November 2010, AEP Ohio filed its application at the FERC requesting a cost-based mechanism for capacity.⁶ This Commission proceeding was initiated soon thereafter.

³ Tr. Vol. I at 82.

⁴ *Id.* at 84.

⁵ *Id.* at 84, 160; Tr. Vol. II at 330-331.

⁶ Tr. Vol. I at 82.

AEP Ohio's description of the PJM RPM market prices of \$20.01 and \$33.71 (as adjusted for scaling factors) for planning years 2012/2013 and 2013/2014⁷, respectively, as free is absurd. Staff's alternate proposed rate, which is more than the PJM RPM prices, certainly is not *free* to the CRES providers paying the charge. In fact, AEP Ohio charged CRES providers \$145.79/MW-day from June 1, 2011 through December 31, 2011,⁸ which is equivalent to Staff's alternate proposed rate of \$146.41/MW-day. Staff's alternative capacity rate proposal has support from Ohio Energy Group ("OEG") witness Kollen, who testified that he believed the maximum rate that AEP Ohio should charge CRES providers for capacity is \$145.79.⁹

As explained through testimony by Staff, the reduction of AEP Ohio's proposed rate of \$355.72/MW-Day to Staff's alternative recommendation of \$146.41/MW-Day is a result of removing and adjusting numerous items including: (1) return on equity; (2) rate of return; (3) construction work in progress; (4) plant held for future use; (5) cash working capital; (6) prepayments; (7) accumulated deferred income taxes; (8) payroll and benefits for eliminated positions; (9) 2010 severance program cost; (10) income tax expense; (11) domestic production activities; (12) deduction payroll tax expense; (13) capacity equalization revenue; (14) ancillary services revenue; and (15) energy sales margin and ancillary services receipts. Staff's assessment of the Energy credit was con-

⁷ PJM RPM Prices taken from AEP Ohio Exhibit 102 (Pearce Testimony) at Exhibit KDP-7.

⁸ FES Ex. 101 (Stoddard Testimony) at 20-21.

⁹ OEG Ex. 102 (Kollen Testimony) at 22; Tr. Vol. VI at 1180.

servative. Regardless, AEP Ohio opposes any energy credit offset to the capacity charge, which is inconsistent with industry practice and PJM's own approach to valuing capacity. And inconsistent with AEP Ohio's witness Pearce who under cross examination agreed that every dollar of positive energy margin earned on the resource can be a reduction in its net costs.¹⁰

When taking into account all of these adjustments and credits, the capacity rate of \$146.41/MW-Day proposed in the alternative by Staff is compensatory to the Company while still fostering competition among CRES providers in the state of Ohio.

BACKGROUND

In this case, AEP Ohio seeks authorization to establish a formula-based pricing method for generation capacity service sold to CRES provider within OP's service territory. The capacity pricing approval sought by AEP Ohio is governed by the rules of PJM under the approved Reliability Assurance Agreement ("RAA"). The rules create an organized capacity market generally referred to as the RPM and are embodied in PJM's open access transmission tariff. The RPM rules require a load-serving entity ("LSE") to obtain or arrange for adequate capacity to meet PJM's forecasted peak demand, including a reserve margin. The RPM includes, for pricing purposes, a capacity auction in which

¹⁰

Tr. Vol. II at 263-264.

generation and demand response resources are cleared to forecasted load based upon prices offered by qualifying resources three years prior to a June through May delivery year.

An LSE may elect to operate outside the RPM auction process through the Fixed Resource Requirement Alternative (“FRR Alternative”). An LSE electing the FRR Alternative is known as a Fixed Resource Requirement Entity (“FRR Entity”). To establish the compensation paid by CRES providers to the FRR Entity that elects the FRR Alternative, Section D.8 of Schedule 8.1 of the RAA provides, in relevant part:

In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity’s cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.¹¹

¹¹

RAA, Schedule 8.1., Section D.8.

AEP Ohio elected to operate as an FRR Entity for the 2007-2008 delivery year and thereafter.¹² As an FRR Entity, AEP Ohio charged CRES providers the RPM auction price.¹³ In late 2010, however, American Electric Power Service Corp. (“AEPSC”), on behalf of OP, requested that the Federal Energy Regulatory Commission (“FERC”) approve formula rates as the basis for establishing the capacity charges that would be levied upon CRES providers in Ohio.

The Commission initiated this proceeding by an Entry, on December 8, 2010.¹⁴ The Commission found that an investigation was necessary to determine the impact of the proposed change to capacity pricing contained in an Application AEPSC had made to FERC to implement a formula- or cost-based charge that CRES providers would be charged for capacity used to serve shopping customers in OP’s service territory. The Commission asked for comments and also adopted the RPM pricing mechanism as the state compensation mechanism under Section D.8 of Schedule 8.1 of the RAA.¹⁵

After Comments were filed, the Commission set this matter for hearing “in order to establish an evidentiary record on a state compensation mechanism.”¹⁶ Before the hearing started, the Commission approved a Stipulation that set forth a two-tier capacity

¹² Direct Testimony of Richard Munczinski at 5.

¹³ *Id.*

¹⁴ *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 re AEP Capacity Charges*) (Entry at 1) (December 8, 2010).

¹⁵ *Id.* at 1-2.

¹⁶ *In re AEP Capacity Charges* (Entry at 2) (August 11, 2011).

pricing mechanism under which the first 21% of each customer class, and all customers of governmental aggregations approved on or before November 8, 2011, shall be entitled to first-tier RPM-based pricing.¹⁷ The second-tier charge for capacity was set at \$255/MW/day.¹⁸ The Commission, however, later determined that the Stipulation was not in the public interest and rejected it in an Entry on Rehearing.¹⁹ In the Entry on Rehearing, the Commission directed AEP Ohio to implement “an appropriate application of capacity charges under the approved state compensation mechanism established in the capacity charge case.”²⁰ On March 7, 2012, the Commission ordered that the two-tiered pricing mechanism be established on an interim basis to expire May 31, 2012.²¹ This hearing commenced on April 17, 2012.

¹⁷ *In re AEP Capacity Charges* (Opinion and Order at 54-55) (December 14, 2011).

¹⁸ *Id.*

¹⁹ *In re AEP Capacity Charges* (Entry on Rehearing) (February 23, 2012).

²⁰ *Id.* at 12

²¹ *In re AEP Capacity Charges* (Entry) (March 7, 2012).

ARGUMENT

I. AEP Ohio fails to justify that the proposed \$355.72/MW-Day capacity rate it would charge CRES providers is appropriate.

A. As an alternate proposal, the Staff makes appropriate adjustments to AEP Ohio's proposed capacity rate.

1. Return on Equity

In his testimony, Staff Witness Smith applied a 10.0% return on equity ("ROE") for CSP and a 10.3% ROE for OPCo.²² As justification for his use of the ROEs, Mr. Smith stated that:

[b]oth of these [ROEs] are from the Commission's Opinion and Order dated December 14, 2011 in Case Nos. 11-351 - EL-AIR et al, at page 5, paragraph IIA(1)(e) and elsewhere in that other...In lieu of preparing a specific cost of capital analysis directed to AEP Ohio's capacity costs, the 10.0% and 10.3% ROEs noted above from the December 14, 2011 Opinion and Order are being used as reasonable inputs and appear to represent a consensus stipulation position. I also note that those stipulated ROEs were higher than Staff's recommendations in the respective AEP Ohio electric distribution utility rate cases.²³

The ROEs used and recommended by Witness Smith are the most current as applied to AEP Ohio in Commission cases and must be applied here.

²² Staff Ex. 103 (Smith Testimony) at 12.

²³ *Id.* at 12-13.

2. Rate of Return

In his testimony, Staff witness Smith applied an overall rate of return (“ROR”) of 7.78% for CSP and 7.97% for OPCo. Again, as justification for his use of these RORs, Mr. Smith stated that:

[b]oth of these [RORs] are from the Commission's Opinion and Order dated December 14, 2011 in Case Nos. 11-351-EL-AIR et al, at page 5, paragraph II-A-(l)(c) and (d), respectively.²⁴

Again, the RORs used and recommended by Staff Witness Smith are the most current as applied to AEP Ohio in Commission cases and must be applied here.

3. Construction Work in Progress

Construction work in progress (“CWIP”) should be excluded from rate base. R.C. 4909.15 provides that the Commission, in its discretion, may include a reasonable allowance for CWIP but, in no event may such allowance be made by the Commission until it has determined that the particular construction project is at least seventy-five percent complete.²⁵ It also states no allowance for CWIP shall be in rates for a period exceeding 48 months and any sums of money that the Company may have received must be given back to the customers once the property is used and useful and in service.²⁶

²⁴ Staff Ex. 103 (Smith Testimony) at 13.

²⁵ Ohio Rev. Code Ann. § 4909.15 (West 2012).

²⁶ *Id.* This concept of returning any sums of money that the Company may have received during the construction period to the customers once the property has been placed into service is sometimes referred to as “mirror CWIP.”

Furthermore, R.C. 4928.143 provides that a reasonable allowance for CWIP for any of the electric distribution utility's cost of constructing an electric generation facility or for an environmental expenditure for any electric generation facility of the electric distribution utility can be considered, provided the cost is incurred or the expenditure occurs on or after January 1, 2009.²⁷ Any such allowance shall be subject to the CWIP allowance limitations of R.C. 4905.15(A) except the Commission may authorize an allowance upon the incurrence of the cost or occurrence of the expenditure.²⁸ Additionally, the Commission must first determine in the proceeding that there is need for the facility based on resource planning.²⁹ Further, no CWIP allowance shall be authorized unless the facility's construction was sourced through a competitive bid process.³⁰

AEP Ohio has not demonstrated (1) that the CWIP it has requested is 75% complete; (2) that the concept of mirror-CWIP has been applied; (3) that the Commission has determined that there is need for each facility based on resource planning; or (4) that the facility's construction was sourced through a competitive bid process.³¹ Because these criteria have not been met, CWIP should be excluded from rate base.

²⁷ Staff Ex. 103 (Smith Testimony) at 14-15.

²⁸ *Id.* at 15.

²⁹ *Id.*

³⁰ *Id.*

³¹ *Id.*

4. Plant Held for Future Use

Plant Held for Future Use (“PHFFU”) must be excluded from rate base. AEP Ohio proposed to include \$5,366 million of PHFFU for CSP on Exhibit KDP-3, page 5, line 6. AEP Ohio’s request for CSP PHFFU appears to primarily relate to land and land rights for a Newbury Project.³² PHFFU should be excluded from utility rate base because it is not considered to be used and useful in providing utility service.³³ Staff witness Smith stated that:

[u]nless the utility demonstrates specific, definite plans for utilizing such property to provide utility service within a reasonable time frame, my experience has generally been that the PHFFU is excluded from utility rate base. Lacking such definite plans for utilization in the provision of utility service, the property is not used and useful for providing utility service, and the cost should therefore not be borne by ratepayers. AEP Ohio has presented no definite plans as to when it will utilize any of the Plant Held for Future Use that it is requesting be included in generation rate base. Consequently, I believe that a compelling argument can be made for the exclusion of this PHFFU from rate base, and my recommendation, therefore, is to exclude it entirely from rate base.

Furthermore, no PHFFU was included in AEP Ohio's rate base in the recent distribution rate cases. AEP Ohio's workpapers show that CSP functionalized the \$13,026 million of December 31, 2010 PHFFU that was reported in its 2010 FERC Form 1 as follows:

³² CSP's 2010 FERC Form 1, at page 214, lists as being originally included in account 105, Plant Held for Future Use, on 12/80 and 12/87 with balances of \$4,991,594 and \$61,220. Nothing is listed in CSP's 2010 FERC Form 1 for a “date expected to be used in utility service” for those items.

³³ Staff Ex. 103 (Smith Testimony) at 16.

Production	5,366,165
Transmission	3,796,688
Distribution	3,356,603
General	<u>506,771</u>
Total	13,026,227 ³⁴

However, the Staff Reports in AEP Ohio's most recent distribution rate cases³⁵ do not show any PHFFU included distribution rate base.³⁶ The \$5,366 million PHFFU that AEP Ohio included in its proposed production demand rate base for CSP should be removed for the reasons stated above.

5. Cash Working Capital

In the absence of a reliable lead-lag study, the Staff cannot recommend a Cash Working Capital (“CWC”) allowance. CWC is generally defined as the average amount of capital provided by investors in the Company, over and above the investments in plant and other specifically quantified rate base items, to bridge the gap between the time that expenditures are required to provide service and the time collections are received for the service.³⁷ Large utilities are typically required to prepare a lead-lag study to support a

³⁴ Staff Ex. 103 (Smith Testimony) at 17.

³⁵ *In the Matter of the Pre-Notification of the Application of Columbus Southern Power Company and Ohio Power Company, Individually and, if Their Proposed Merger is Approved, as a Merged Company (Collectively AEP Ohio) for an Increase in Electric Distribution Rates*, Case Nos. 11-351-EL-AIR, *et al.*

³⁶ Staff Ex. 103 (Smith Testimony) at 17.

³⁷ *Id.* at 18.

CWC allowance being includable in rate base. AEP Ohio is considered to be a large utility for supporting a CWC allowance.³⁸

AEP Ohio, in this case, did not prepare a lead-lag study to support its claim for CWC. Rather, AEP Ohio's claim is based on a one-eighth operation and maintenance ("O&M") formula. Staff witness Smith points out several conceptual problems with the use of the one-eighth formula method, including the following:

- (1) First and most importantly, there is no evidence that the formula accurately or appropriately calculates a CWC allowance that is based on AEP Ohio's actual requirements for cash working capital. The formula always produces a positive CWC allowance, even in situations where no CWC requirement exists, and even in situations where the utility's CWC requirement is negative.
- (2) AEP Ohio's filing has assumed a cash working capital allowance based on a one-eighth formula method, without providing any support for an assumption that AEP Ohio actually has a cash working capital requirement. The assumption underlying a one-eighth cash working capital allowance is that revenues for the service are collected, on average, 45 days after cash operating expenses are paid to produce the service. AEP Ohio has presented no reliable evidence that it has a net cash working capital requirement of 45 days (1/8th of 365 days = 45 days).
- (3) Included in AEP Ohio's operating expenses are charges from affiliates, such as charges from AEP Service Company. Providing for a cash working capital allowance based on affiliate charges would essentially amount to giving AEP Ohio a return on affiliate expenses. That would seem to be contradictory to the provision by the affiliated service company of services at cost.

³⁸

Staff Ex. 103 (Smith Testimony) at 18-19.

- (4) AEP Ohio's proposed allowance also fails to consider the lag in the payment of current income tax expense. In a legitimate lead-lag study, there would need to be recognition of the lag in income tax payments, which are required to be made quarterly. Because AEP Ohio has failed to prove that it has a cash working capital requirement, a zero allowance should be used. In the absence of a reliable lead-lag study, the presumption should be that there is a zero CWC requirement, and the CWC allowance should be set at zero. Setting the CWC allowance at zero thus places the burden of establishing and supporting with competent evidence any request for a positive CWC allowance where it belongs, on the utility that is requesting the allowance. Setting the CWC allowance presumptively at zero for determining a utility's revenue requirement thus also places the burden of establishing the amount of a negative CWC amount on the party advocating the use of a negative CWC allowance for ratemaking purposes.³⁹

Based on the above-noted information and conceptual concerns regarding the use of a formula method rather than a properly prepared lead-lag study, the CWC request by AEP Ohio must be removed from rate base.

6. Prepayments

Again, without a properly prepared lead-lag study, no prepayments should be included in rate base. AEP Ohio has proposed to include in generation demand rate base two items of prepayments: (1) non-labor prepayments of \$4.488 million for CSP and \$2.045 million for OPCo and (2) labor related prepayments consisting of prepaid pensions of \$37.952 million for CSP and \$73.653 million for OPCo.⁴⁰ This is improper.

³⁹ Staff Ex. 103 (Smith Testimony) at 19-21.

⁴⁰ *Id.* at 21-22.

In the Staff Reports in CSP's and OPCo's last distribution rate cases⁴¹, Staff removed Working Capital including the 13-month balances requested by AEP Ohio for materials and supplies, uncollectibles and prepayments, but Staff increased rate base to recognize a prepaid pension asset.⁴² To determine AEP Ohio's capacity rates, Staff witness Smith removed the one-eighth formula based Company request for CWC and removed prepayments including the prepaid pension asset.

a. Pension Asset

Inclusion of AEP Ohio's proposed labor related prepayments consisting of prepaid pensions is improper because: (1) AEP Ohio fails to demonstrate that it has a net prepaid pension asset, and information reported in the 2010 FERC Form 1 concerning pension funding status suggest there is a net liability; (2) pension funding levels are the result of discretionary AEP Ohio management decisions concerning the funding of defined benefit pensions; and (3) pension expense would typically be included in the determination of CWC in a lead lag study.

⁴¹ *In the Matter of the Pre-Notification of the Application of Columbus Southern Power Company and Ohio Power Company, Individually and, if Their Proposed Merger is Approved, as a Merged Company (Collectively AEP Ohio) for an Increase in Electric Distribution Rates*, Case Nos. 11-351-EL-AIR, *et al.*

⁴² Staff Ex. 103 (Smith Testimony) at 22.

i. FERC Form 1 Data

AEP Ohio's FERC Form 1 for 2010⁴³ shows the funded status of the defined benefit pension plans. For CSP, the FERC Form 1 reports pension plan benefit obligations of \$349.8 million at December 31, 2010 and pension plan assets of \$277.3 million, for a net underfunded status at December 31, 2010 of \$72.5 million. The FERC Form 1 also shows this net amount of \$72.5 million as a long-term liability. Staff witness Smith stated that:

For OPCo, the FERC Form 1 reports pension plan benefit obligations of \$629.9 million at December 31, 2010 and pension plan assets of \$518.7 million, for a net underfunded status at December 31, 2010 of \$111.2 million. OPCo's 2010 FERC Form 1 on page 123.33 also shows this net amount of \$111.2 million as a long-term liability.

The defined benefit pension plans for CSP and OPCo, as reported in the 2010 FERC Form 1 on pages 123.32 and 123.33, thus show pension plan obligations in excess of pension assets, and show a net long-term pension *liability* for both companies. The reporting of a significant long-term pension *liability* at December 31, 2010 for each company contradicts the Companies' proposal to include a pension asset amount in rate base.⁴⁴

The 2010 FERC Form 1 concerning pension funding status suggest there is a net liability and , therefore, AEP Ohio failed to demonstrate that it has a net prepaid pension asset.

Furthermore, the inclusion in generation capacity rate base of AEP Ohio's proposed pension asset provides a disincentive for making reasonable reforms to the Com-

⁴³ AEP 2010 FERC Form 1 at 123.32.

⁴⁴ Staff Ex. 103 (Smith Testimony) at 24.

pany's pension plans.⁴⁵ Factors such as worker mobility, the ERISA and other compliance and reporting requirements, and the increased costs of defined benefit pension plans in recent years have hastened their decline, and there is a discernible trend away from such plans.⁴⁶ Providing what essentially would amount to a guaranteed return on a pension asset could deter the Company from making reforms to its pension plans that would reduce cost, as many companies are doing.⁴⁷ Staff witness Smith also provided a plethora of evidence that utilities are trending away from defined benefit plans.⁴⁸

ii. Discretionary Management Decision

AEP Ohio's management has wide latitude in determining how and when to fund defined benefit pension plans. There is frequently a very large range between the minimum funding required under ERISA and the maximum annual funding, which is typically limited by the maximum tax-deductible funding contribution limitations under the Internal Revenue Code.⁴⁹ Further, additional funds contributed into the pension trust would earn a return and the earned return would reduce future pension expense, other things being equal.⁵⁰

⁴⁵ Staff Ex. 103 (Smith Testimony) at 24.

⁴⁶ *Id.*

⁴⁷ *Id.* at 24-25.

⁴⁸ *Id.* at 25-27.

⁴⁹ *Id.* at 27-28.

⁵⁰ *Id.* at 28.

In comparing CSP's and OPCo's 2010 pension expense compare with 2009, the 2010 FERC Form 1 for 2010 shows the net periodic pension cost recognized as expense for 2009 and 2010. For CSP, the defined benefit pension expense increased from \$1.788 million in 2009 to \$3.939 million in 2010, an increase of \$2.151 million or 120%. For OPCo, the defined benefit pension expense increased from \$1.788 million in 2009 to \$3.939 million in 2010, an increase of \$3.538 million or 67%, as summarized below:⁵¹

Net Periodic Pension Cost Recognized As Expense (\$000)		
Year	CSP	OPCo
2010	3,939	8,804
2009	1,788	5,266
Increase \$	2,151	3,538
Increase %	120%	67%
Source: FERC Form 1, page 123.39		

The increased 2010 defined benefit pension expense for CSP and OPCo have not been adjusted by Staff in determining AEP Ohio's revenue requirement for generating capacity.⁵²

Finally, the appropriateness of including a pension asset in utility rate base is different for determining a capacity rate rather than general rates for an electric distribution utility service.⁵³ Staff witness Smith stated:

⁵¹ Staff Ex. 103 (Smith Testimony) at 28-29.

⁵² *Id.* at 29.

⁵³ *Id.*

The situation with AEP [Ohio]'s distribution function and its generation function in this respect are different in the aspect of whether potential future reductions to pension cost that could occur from increased pension funding would inure to ratepayers. In this case, capacity rates are being developed for a relatively short time, i.e., until AEP Ohio's generation is market priced. This is a different situation from AEP Ohio's provision of distribution service, which has been and is expected to continue to be based on cost-based regulation. Thus, the ratepayers paying the rates established in the current case, i.e., the CRES providers, may not benefit over the long term from future reductions in AEP Ohio's pension cost.⁵⁴

Thus, including a pension asset in rate base for purposes of establishing a capacity rate would not be appropriate.

iii. Lead-Lag Study

AEP Ohio has not presented a lead-lag study regarding pension expense. Pension expense, associated with defined benefit pension plans and other types of retirement plans, is typically reflected in a lead-lag study by applying a calculated payment lag to the amount of related pension expense that is included in the utility's operating expenses.⁵⁵ The lack of a lead-lag study to properly measure a working capital requirement is another reason for rejecting inclusion of a pension asset in AEP Ohio's rate base in the current case for purposes of determining a capacity rate.

A lead-lag study was used recently by Appalachian Power Company ("APCO"), in Virginia State Corporation Commission Case No. PUE-2011-00037, to determine the

⁵⁴ Staff Ex. 103 (Smith Testimony) at 29-30.

⁵⁵ *Id.* at 30.

allowance for CWC, and pension expense was included in the expenses that were addressed in the study. APCO's detailed lead-lag study included a provision for cash working capital related to the net payment lag for labor costs, including pension and other employee benefits. In the Virginia Commission case, Staff witness Smith recommended:

in addition to removing the prepaid pension from rate base, making a corresponding adjustment to provide interest on the average prepaid pension balance, net of related ADIT, at the commercial paper interest rate. The allowance of financing costs on the net prepaid pension asset at the commercial paper rate addressed a source of financing for the prepaid pension asset.⁵⁶ The additional offsetting adjustment was intended to address concerns with respect to the relationship between pension expense in rate base and operating expenses, and to protect ratepayers from having their base rates for APCO's electric service increased unnecessarily as a result of the AEP management decision to pre-fund future pension obligations.⁵⁷

Staff also noted that a similar regulatory treatment of applying a debt-based return on pension asset amounts had been applied by the Illinois Commerce Commission in a series of rate cases involving Commonwealth Edison Company ("ComEd").⁵⁸

7. Accumulated Deferred Income Taxes

The Accumulated Deferred Income Taxes ("ADIT") related to AEP Ohio's pension assets must be removed from AEP's proposed generation demand rate base. AEP Ohio determined its rate base offset for ADIT by starting with the components of its

⁵⁶ The interest expense related to imputing the debt-based financing would then be included above-the-line as a utility operating expense for ratemaking purposes.

⁵⁷ Staff Ex. 103 (Smith Testimony) at 30-31.

⁵⁸ *Id.* at 31.

recorded balances of ADIT at December 31, 2010 and allocated them to the generation (demand) function. Staff's adjustments made for ADIT are shown on Schedule B-1 of Exhibit RCS-1 for CSP and Exhibit RCS-2 for OPCo where Mr. Smith explained:

[ITC Credits]

Referring to Exhibit RCS-1, Schedule B-1, line 1, CSP had increased rate base for \$5.228 million of ADIT in account 190 for a "gross up" related to federal investment tax credits ("ITC"). For ratemaking purposes, ITC is being amortized as a reduction to federal income tax expense. Amortizing ITC as a reduction to income tax expense is one of the methods provided for the normalization of ITC in the Internal Revenue Code and Treasury Regulations. When that method is selected, there is no rate base impact of the deferred ITC. An alternative method of reflecting ITC for ratemaking purposes that is also permitted by the tax code involves deducting ITC from rate base, and not reflecting an impact on income tax expense. Because CSP has chosen to reduce income taxes for the ITC amortization, there is no basis for either adding or deducting the ITC from rate base. CSP has provided no valid basis for adding the deferred ITC to jurisdictional rate base. Additionally, when the debit balance that CSP has recorded in Account 190 for the ITC is amortized, that amortization would reduce income tax expense; however, CSP has not reflected that additional reduction to income tax expense for this additional amortization of the ITC item it recorded in Account 190 in its proposed income tax expense. Removal of the Deferred ITC in account 190 that CSP had proposed to include in rate base reduces the Company's proposed production demand jurisdictional rate base by \$5.229 million.⁵⁹

⁵⁹

Staff Ex. 103 (Smith Testimony) at 33.

[ADIT debit balance in Account 190 for “IGCC Revenues”]

As shown on Exhibits RCS-1 and RCS-2, Schedule B-1, line 2, CSP and OPCo proposed to increase production demand rate base by \$4.324 million and \$4.160 million, respectively, for ADIT in account 190 for “IGCC Revenues.” CSP and OPCo have not identified an IGCC power plant that is in service and providing capacity. Page 123.21 of CSP’s and OPCo’s respective 2010 FERC Form 1 reports state that CSP and OPCo will not start construction of an IGCC plant until existing statutory barriers are addressed and sufficient assurance of cost recovery exists. The ADIT debit balance in account 190 is not related to a plant that is in service. Additionally, none of the revenue that CSP and OPCo collected for pre-construction costs of an IGCC plant has been reflected in their determinations of the revenue requirement for capacity in the current case. Consequently, the ADIT debit balance for the “IGCC Plant” should be removed from production demand rate base, as shown on Schedule B-1, line 2, of Exhibits RCS-1 and RCS-2.⁶⁰

[“FIN 48” items from account 190 ADIT]

Both CSP and OPCo included net debit balances in account 190 ADIT for “FIN 48” items that relate to uncertain tax positions. Those items should be removed from rate base, consistent with accounting guidance provided by FERC and for other reasons discussed below. Removal of the FIN 48 items from account 190 ADIT reduces CSP’s production demand rate base by \$275,544 as shown on Exhibit RCS-1, Schedule B-1, line 3, and reduces OPCo’s production demand rate base by \$1.772 million as shown on Exhibit RCS-2, Schedule B-1, line 3. Detail of each company’s account 190 FIN 48 items is presented on Schedule B-1, lines 9-13.... The FIN 48 liability represents the difference between the

⁶⁰

Staff Ex. 103 (Smith Testimony) at 34.

Company's position taken on the tax return versus the identification of "uncertain" tax positions as required for financial statement reporting.⁶¹ FIN 48 recognizes that differences in the interpretation of tax law exist (i.e. legislation and statutes, legislative intent, regulations, rulings and case law), and seeks to eliminate any uncertain tax benefit from the financial statements until the uncertainty associated with the position has been removed. An uncertainty may be removed by either (1) review of the technical merits of the position by the relevant taxing authority, (2) expiration of the statute of limitations or (3) law change.⁶²

The FERC has provided guidance on accounting and financial reporting for uncertainty in income taxes in Docket No. AI07-2-000, as follows:

Under existing Commission requirements, entities measure and recognize current and deferred tax liabilities (and assets) based on the positions taken or expected to be taken in a filed tax return and recognize uncertainties regarding those positions by recording a separate liability for the potential future payment of taxes when the criteria for recognition of a liability contained in FASB Statement No. 5, *Accounting for Contingencies*, are met, generally as part of the accrual for current payment of income tax. Where uncertainties exist with respect to tax positions involving temporary differences, the amounts recorded in the accounts established for accumulated deferred income taxes are based on the positions taken in the tax returns filed or expected to be filed. [Temporary difference as used here means a difference between the tax basis of an asset or liability as reflected or expected to be reflected in a tax return and its reported amount in the financial statements.] Recognition of a separate liability for any uncertainty related to temporary differences is therefore not necessary because the entity has already recorded a deferred tax liability for the item or would be entitled to record a deferred tax asset

⁶¹ Financial Accounting Standards Interpretation No. 48 ("FIN 48") has subsequently been codified in the Accounting Standards Codification ("ASC") as part of ASC 740 Income Taxes.

⁶² Staff Ex. 103 (Smith Testimony) at 34-36.

for the item if a separate liability for the uncertainty was recognized.⁶³

This practice results in the accumulated deferred income tax accounts reflecting an accurate measurement of the cash available to the entity as a result of temporary differences. This is an important measurement objective of the Commission Uniform Systems of Account because accumulated deferred income tax balances, which are significant in amount for most Commission jurisdictional entities, reduce the base on which cost-based, rate-regulated entities are permitted to earn a return. *FIN 48, which does not permit a liability for uncertain tax positions related to temporary differences to be classified as a deferred tax liability, frustrates this important measurement objective.* Therefore, entities should continue to recognize deferred income taxes for Commission accounting and reporting purposes based on the difference between positions taken in tax returns filed or expected to be filed and amounts reported in the financial statements. Also, consistent with the direction provided in Docket No. AI93-5 regarding the implementation of FASB Statement No. 109, *public utilities and licensees, natural gas companies and centralized service companies should not remove from accumulated deferred income taxes and reclassify as a current liability the amount of deferred income taxes payable within 12 months of the balance sheet date.*⁶⁴

Furthermore, another electric utility owned by AEP Ohio, Indiana Michigan Power Company (“IMPC”), has applied the FERC guidance.⁶⁵ IMPC has interpreted the FERC guidance on uncertain income tax positions to require that tax savings related to deductions taken on income tax returns should be reflected for ratemaking purposes and the FIN 48 ADIT balances are not to be taken into consideration for ratemaking pur-

⁶³ Staff Ex. 103 (Smith Testimony) at 36.

⁶⁴ *Id.* at 36-37 (emphasis added.).

⁶⁵ *Id.* at 38.

poses.⁶⁶ CSP and OPCo are also AEP Ohio-owned electric utilities and should thus be similarly following the FERC guidance for uncertain income taxes.⁶⁷ Following the FERC guidance for uncertain tax positions as IMPC has done is a good general practice, and should also be applied for AEP Ohio in the current case.⁶⁸

Continuing the explanation of the ADIT adjustments, as described above, Staff removed the net ADIT items related to FIN 48 from rate base.⁶⁹ Furthermore, ADIT in account 190 related to other asset or liability balances that are not reflected in rate base is removed for CSP and OPCo, respectively.⁷⁰ Staff witness Smith stated:

This decreases CSP's production demand rate base by \$1.362 million and increases OPCo's by \$1.884 million. Each of the "labor-related" ADIT balances in account 190 listed on Exhibit RCS-1, Schedule B-1, lines 14-22 and on Exhibit RCS-2, Schedule B-1, lines 14-23, must be removed. Each of these items apparently relates to other balance sheet accounts that are not being reflected in the determination of rate base. For example, there are apparently liability balances related to vacation pay, incentive compensation and other postretirement benefits (SFAS 106). Based on the matching principle, if the related ADIT debit balances are included in rate base, then the accrued liabilities and operating reserves giving rise to those deferred taxes should be deducted from rate base. However, those related liability balances or reserves are not being deducted from rate base. Consequently, the related ADIT balances in Account 190 for CSP and OPCo are being removed to reflect proper matching of related items. In par-

⁶⁶ Staff Ex. 103 (Smith Testimony) at 38.

⁶⁷ *Id.*

⁶⁸ *Id.*

⁶⁹ *Id.* at RCS-1 and RCS-2, Schedule B-1, line 3.

⁷⁰ *Id.* at RCS-1 and RCS-2, Schedule B-1, line 4.

particular, it is unusual to have a large credit balance for ADIT in account 190 for a reserve for workers compensation or SFAS 112 postemployment benefits, as OPCo had at December 31, 2010.⁷¹ Those balances may be indicative of unusual activity in 2010 for OPCo.⁷²

CSP and OPCo recorded ADIT in account 283 related to a pension asset. Because the pension asset is being excluded from production demand rate base, as explained above, the ADIT credits that relate to the pension asset should also be removed, consistent with the matching principle.⁷³ As shown on Exhibits RCS-1 and RCS-2, Schedule B-1, line 5, removal of the ADIT for prepaid pension increase CSP's production demand rate base by \$1.362 million and OPCo's by \$1.883 million.⁷⁴ These ADIT amounts related to the pension asset are credit balances and had decreased AEP Ohio's proposed rate base.⁷⁵ On a net basis, AEP Ohio's proposal to include a prepaid pension asset in rate base increased rate base by the net amount of the prepaid pension asset, less the related ADIT.⁷⁶ The pension asset and the directly related ADIT should

⁷¹ Staff Ex. 103 (Smith Testimony) at RCS-2, Schedule B-1, lines 14 and 22, respectively. AEP has indicated that it would be providing additional information for some of those items.

⁷² *Id.* at 39-40.

⁷³ *Id.* at 40.

⁷⁴ *Id.*

⁷⁵ *Id.*

⁷⁶ *Id.*

receive the same ratemaking treatment, *i.e.*, both should be excluded from rate base, based on the matching principle.⁷⁷

The adjustment to ADIT for item 906D, SFAS 106 postretirement benefits, non-deductible contribution, as shown on Exhibits RCS-1 and RCS-2, Schedule B-1, line 6, is a debit-balance item that CSP and OPCo included in account 283 and is also being removed from production demand rate base.⁷⁸ This item appears to be similar in concept to the ADIT items for various benefit items that were removed from account 190.⁷⁹ The debit-balance ADIT presumably relates to a deferred credit or liability account that is not being recognized in the determination of rate base.⁸⁰ Consequently, the related ADIT must also be removed.⁸¹

Overall, the net result from Staff's ADIT adjustments reduce CSP's production demand rate base by \$7.848 million as shown on Exhibit RCS-1, Schedule B-1, and increases OPCo's production demand rate base by \$8.480 million, as shown on Exhibit RCS-2, Schedule B-1.⁸²

⁷⁷ Staff Ex. 103 (Smith Testimony) at 40-41.

⁷⁸ *Id.* at 41.

⁷⁹ *Id.*

⁸⁰ *Id.*

⁸¹ *Id.*

⁸² *Id.*

8. Payroll and Benefits for Eliminated Positions

AEP Ohio must remove payroll and benefit costs associated with positions that were eliminated in the 2010 severance programs. Staff witness Smith stated:

AEP Ohio's unadjusted 2010 data includes the payroll, benefit and payroll tax expense for positions that have been eliminated as a result of AEP's 2010 voluntary and involuntary severance programs. Because the rates in this proceeding are to be applied prospectively, AEP's expenses should not include labor costs for personnel that were there in early 2010 but who, as a result of the 2010 severance programs, are no longer with the Company. Consequently, there is a need to adjust AEP Ohio's 2010 information to remove the costs related to the significant number of positions that were permanently eliminated as a result of the 2010 severance programs.⁸³

In response to PUCO Staff Set 1 INT-01-011, Attachment 1 provided work force information for CSP, OPCo and AEPSC and shows significant work force reductions occurred after May 2010⁸⁴:

⁸³ Staff Ex. 103 (Smith Testimony) at 43.

⁸⁴ *Id.* at 44.

Headcount Before and After 2010 Severance

Date	AEPSC	CSP	OPCo	
10-Jan	6,169	1,256	2,389	
10-Feb	6,134	1,244	2,386	
10-Mar	6,116	1,233	2,383	
10-Apr	6,088	1,227	2,375	
10-May	6,101	1,222	2,372	Severance
10-Jun	5,510	1,054	2,081	
10-Jul	5,479	1,049	2,071	
10-Aug	5,246	1,055	2,083	
10-Sep	5,208	1,047	2,081	
10-Oct	5,197	1,054	2,094	
10-Nov	5,179	1,062	2,103	
10-Dec	5,171	1,062	2,104	
11-Jan	5,138	1,056	2,098	
11-Feb	5,146	1,057	2,096	
11-Mar	5,152	1,058	2,103	
11-Apr	5,148	1,059	2,105	
11-May	5,156	1,055	2,101	
11-Jun	5,182	1,059	2,111	
11-Jul	5,170	1,055	2,125	
11-Aug	5,146	1,054	2,124	
11-Sep	5,094	1,055	2,106	
11-Oct	5,072	1,054	2,104	
11-Nov	5,064	1,054	2,099	
11-Dec	5,068	1,055	2,106	

The following tables compare the average work force for January through May 2010, with the average work force subsequently in 2010 and with the average work force in 2011:⁸⁵

⁸⁵

Staff Ex. 103 (Smith Testimony) at 44.

Average			
Jan-May 2010	6,122	1,236	2,381
Remainder of 2010	5,284	1,055	2,088
2011	5,128	1,056	2,107

Estimated net severed positions			
Jan-May 2010 versus remainder of 2010:			
Count	837	182	293
Percent	14%	15%	12%

Jan-May 2010 versus average 2011			
Count	994	180	275
Percent	16.2%	14.6%	11.5%

The information on work force levels summarized above reinforces that using unadjusted 2010 payroll and benefit expenses would not be representative of ongoing conditions since AEP's work force, including the work force at CSP, OPCo and AEPSC has been significantly reduced from the levels that existed in early 2010.⁸⁶

Staff has also removed payroll and benefit costs from AEP Ohio's 2010 O&M Expense allocated to the generation function.⁸⁷ As shown on Exhibit RCS-1, Schedule C-1, for CSP an amount of \$6.022 million is removed for direct payroll expense reductions for CSP allocated to the generation demand function, and \$0.495 million for reductions in expense to various employee benefits that were directly impacted by the work force reduction.⁸⁸ Additionally, \$3.533 million is removed for payroll for AEPSC employee payroll charged to CSP and allocated to CSP's generation demand function,

⁸⁶ Staff Ex. 103 (Smith Testimony) at 45.

⁸⁷ *Id.*

⁸⁸ *Id.*

and approximately \$290,000 for AEPSC employee benefits.⁸⁹ The total reduction in payroll and benefits allocated to CSP's generation function is \$10.340 million.⁹⁰

Similarly, as shown on Exhibit RCS-2, Schedule C-1, for OPCo, an amount of \$15.734 million is removed for direct payroll expense reductions for OPCo allocated to the generation demand function, and \$1.136 million for reductions in expense to various employee benefits that were directly impacted by the work force reduction.⁹¹ Additionally, \$7.323 million is removed for payroll for AEPSC employee payroll charged to OPCo allocated to OPCo's generation demand function, and approximately \$529,000 for AEPSC employee benefits.⁹² The total reduction in payroll and benefits allocated to OPCo's generation function is \$24.722 million.⁹³

9. AEP Ohio's 2010 Severance Program Cost

The 2010 severance cost must be removed from 2010 O&M expense because rates for AEP Ohio's generating capacity are being established prospectively and this was a significant non-recurring cost that was recorded in 2010. Staff witness Smith stated:

If the severance cost is amortized, the amortization should have commenced when the savings began, and there is no demonstrated need for a prospective amortization of 2010 severance cost in the current case to determine a revenue

⁸⁹ Staff Ex. 103 (Smith Testimony) at 45.

⁹⁰ *Id.* at 45.

⁹¹ *Id.*

⁹² *Id.* at 45-46.

⁹³ *Id.* at 46.

requirement for AEP Ohio's capacity. AEP began to realize cost *savings* due to the reduced salaries as soon as employees accepted the voluntary retirement offer and/or were involuntarily terminated in mid-2010. Amortization of the costs to achieve that savings should have commenced as soon as the savings from the reduced work force and reduced AEPSC charges commenced. AEP Ohio has not demonstrated that there is any net amount of remaining costs to achieve that has not already been absorbed by related savings experienced by AEP through June 1, 2012, the approximate effective date of new rates in this proceeding. Consequently, there is no need for a prospective amortization of 2010 severance costs in establishing AEP Ohio's revenue requirement for capacity rates that would be applied prospectively from June 1, 2012.⁹⁴

Severance costs recorded by CSP and OPCo in 2010, including AEPSC charges to these utilities, should therefore be removed in determining a revenue requirement for AEP Ohio's capacity.⁹⁵

AEP Ohio and its subsidiaries begin to realize savings from the severance program when it implemented a work force reduction program in 2010, and the related payroll savings commenced around June 2010.⁹⁶ One of the primary purposes of this work force reduction was to manage AEP Ohio's earnings in view of changing economic conditions.⁹⁷ AEP Ohio's Securities and Exchange Commission ("SEC") form 10-Q for the quarterly period ending June 30, 2011, for example, describes that cost reduction initiative at page 79 as follows:

⁹⁴ Staff Ex. 103 (Smith Testimony) at 46-47.

⁹⁵ *Id.*

⁹⁶ *Id.*

⁹⁷ *Id.*

In April 2010, we began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions were eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

We recorded a charge for \$293 million to Other Operation expense during the second quarter of 2010 primarily related to severance benefits as the result of the headcount reduction initiatives.⁹⁸

AEP Ohio's SEC Form 10-K for the year ending December 31, 2010 contains similar statements at page 403, and also states that:

Management recorded a charge to expense in 2010 primarily related to the headcount reduction initiatives. Management does not expect additional costs to be incurred related to this initiative.⁹⁹

AEP Ohio began to realize cost savings due to the reduced salaries and benefits as soon as employees accepted the voluntary retirement offer and/or were involuntarily terminated in mid-2010.¹⁰⁰

The regulatory commission in Virginia addressed amortization of severance costs associated with the AEP 2010 severance program in its Final Order dated November 30, 2011, in Case No. PUE-2011-00037.¹⁰¹ In that case, which APCO's application for the

⁹⁸ Staff Ex. 103 (Smith Testimony) at 48.

⁹⁹ *Id.*

¹⁰⁰ *Id.*

¹⁰¹ *Id.*

review of rates, the Virginia State Corporation Commission addressed the AEP Ohio's severance program cost at pages 16-17 as follows (footnotes omitted):

In 2010, AEP implemented cost reduction initiatives associated primarily with workforce reductions. The final cost of the workforce reduction was \$299 million at a total AEP level. The Company's "share of those costs was approximately \$26.7 million, of which \$16.7 million of such costs was directly related to [APCO's] workforce reductions and approximately \$10 million of such costs was for the Company's share of [American Electric Power Service Corporation's ('ASPSC')] workforce reductions." We reject the Company's request to defer and amortize the costs of the workforce reduction program over four years beginning with the effective date of the rates provided in this case, which would "cause customers to pay the full amount of the workforce reduction costs over that period of time."

We find that it is reasonable – for regulatory accounting purposes in this case – to match the specific costs of this severance program with the specific savings related thereto. We deny the Company's proposal to evaluate earnings to determine whether these 2010 costs should be deferred, amortized, and collected in full from ratepayers in the future. Rather, we conclude that it is appropriate for the amortization of the costs of this program to commence with – and to track – the realization of the savings related thereto in a manner that effectuates the matching of costs and savings. Moreover, this finding provides the Company with a reasonable opportunity to recover its severance costs.

In this regard, based on the evidence presented, we find that the savings realized from this cost reduction initiative exceed the costs therefore prior to the start of the rate year in this case. As a result, these severance costs will be completely amortized before the beginning of the rate year, and, thus, no such costs shall be included in rates prospectively.¹⁰²

102

Staff Ex. 103 (Smith Testimony) at 49.

This was the same AEP Ohio 2010 severance program that also impacted CSP and OPCo in 2010.¹⁰³

Staff evaluated the amortization period of severance cost for CSP and OPCo similarly to the method described in that Virginia APCO order.¹⁰⁴ Staff's evaluation is as follows:

As shown on Exhibit RCS-1, Schedule C-2, for CSP, total annual payroll savings of approximately \$34.536 million would provide for amortization of the total severance cost of \$32.213 million over a period of approximately 11 months. Thus, commencing with June 2010, the amortization of severance costs for CSP would be effectively completed in approximately May or June of 2011, roughly one year prior to the June 1, 2012 effective date for the CSP capacity rates being established in the current proceeding. Thus, there is no basis for a prospective amortization of CSP's severance cost to be included in operating expenses in the current case.

Similarly, as shown on Exhibit RCS-2, Schedule C-2, for OPCo, total annual payroll savings of approximately \$49.258 million would provide for amortization of the total severance cost of \$52.661 million over a period of approximately 13 months. Thus, commencing with June 2010, the amortization of severance costs for OPCo would be effectively completed in approximately July 2011, roughly ten months prior to the June 1, 2012 effective date for the OPCo capacity rates being established in the current proceeding. Thus, there is no basis for a prospective amortization of OPCO's severance cost to be included in operating expenses in the current case.

¹⁰³ In Virginia Case No. PUE-2011-00037, APCO had proposed to defer and amortize severance cost for itself and for AEPSC charges, commencing with December 1, 2012, the date when APCO's application had initially assumed new rates from that proceeding would become effective. Due to various delays encountered in processing that case, expectations about the rate effective date were adjusted accordingly such that the rate year was subsequently expected to commence on or about February 1, 2012.

¹⁰⁴ Staff Ex. 103 (Smith Testimony) at 50.

Overall, as shown on Exhibit RCS-1, Schedule C-2, an amount of \$9.852 million of severance cost for CSP and allocated AEP Service Company severance costs allocated to CSP's generation demand function must be removed. Similarly, as shown on Exhibit RCS-1, Schedule C-2, an amount of \$29.152 million of severance cost for OPCo and allocated AEPSC severance costs allocated to OPCo's generation demand function must be removed.¹⁰⁵

10. Income Tax Expense

AEP Ohio has proposed to provide for income tax expense in its capacity rates.

AEP Ohio proposes to calculate income tax expense based on an assumption that its requested equity return represents taxable income. AEP Ohio has calculated its proposed income tax expense by applying an income tax rate "gross up" factor to its requested return.¹⁰⁶ Staff made adjustments to AEP Ohio's calculation and revised the return amount to correspond with the rate base and cost of capital being used. Staff witness Smith also reflected a pro forma adjustment for a Domestic Production Activities Deduction ("DPAD") on a "separate return" basis. As shown on Exhibit RCS-1, Schedule E, this produces an allowance for income taxes for CSP of \$36.907 million (without the DPAD), for a reduction of \$8.984 million from CSP's requested amount of \$45.891 million. The tax effect of the "separate return" based DPAD calculation reduces that by \$3.379 million, for a total reduction to CSP's requested income taxes of \$12.363 million.¹⁰⁷

¹⁰⁵ Staff Ex. 103 (Smith Testimony) at 50-52.

¹⁰⁶ The AEP Ohio calculations of income taxes are reproduced for CSP and OPCo, respectively, on Exhibits RCS-1 and RCS-2, Schedule E, lines 1-5.

¹⁰⁷ Staff Ex. 103 (Smith Testimony) at 52-53.

Similarly, as shown on Exhibit RCS-2, Schedule E, this produces an allowance for income taxes for OPCO of \$108.811 million (without the DPAD), for a reduction of \$14.529 million from OPCO's requested amount of \$123.340 million.¹⁰⁸ The tax effect of the "separate return" based DPAD calculation reduces that by \$0.879 million, for a total reduction to OPCO's requested income taxes of \$15.409 million.¹⁰⁹

11. Domestic Production Activities Deduction

Section 199 of the Internal Revenue Code provides for a special deduction for Domestic Production Activities. This is known as the §199 Deduction or the DPAD. Because AEP Ohio has its own generation supply, such activities are considered domestic production activities, and thus AEP are eligible for the DPAD deduction for their generation operations if they have positive taxable income and meet the other requirements for claiming the deduction.¹¹⁰ For purposes of determining its capacity revenue requirement, AEP Ohio has taxable income, and otherwise meets the requirements of qualifying for a DPAD on a "separate return" basis.¹¹¹ Thus for purposes of determining a revenue requirement for AEP Ohio's generating capacity, the result

¹⁰⁸ Staff Ex. 103 (Smith Testimony) at 53.

¹⁰⁹ *Id.*

¹¹⁰ *Id.*

¹¹¹ *Id.*

should reflect the reduction to current federal income tax expense for the §199 deduction, computed on a “separate return” basis.¹¹²

AEP Ohio participates in the AEP corporate consolidated corporate federal income tax return.¹¹³ However, for purposes of determine a rate for AEP Ohio’s generation capacity, the Company’s federal income tax expense is based on an assumption of a “separate return” (*i.e.*, all impacts of the consolidated income tax are ignored for rate-making purposes). Consequently, for ratemaking purposes it is appropriate to compute the impact on current federal income tax expense for the Company’s generation function on a separate return basis, including the §199 deduction.¹¹⁴ AEP Ohio’s federal income tax expense is being determined on a “separate return” basis in the current case.¹¹⁵ For its income tax calculation for ratemaking purposes, AEP Ohio has assumed that it has federal taxable income and has requested a positive amount of federal income tax expense which is included in its proposed revenue requirement for generation capacity.¹¹⁶ The Company’s generation revenue requirement calculation assumes that the generation function has positive federal taxable income.¹¹⁷ It also appears from other

¹¹² Staff Ex. 103 (Smith Testimony) at 53-54.

¹¹³ *Id.* at 54.

¹¹⁴ *Id.*

¹¹⁵ *Id.*

¹¹⁶ *Id.*

¹¹⁷ *Id.*

information that both CSP and OPCo would have qualified for a DPAD for 2010 based on their “separate return” information.¹¹⁸

AEP Ohio did not include a calculation of the §199 deduction impact in its revenue requirement for generation capacity.¹¹⁹ Nowhere in the AEP Ohio revenue requirement calculation for capacity is the impact of a pro forma §199 deduction accounted for.¹²⁰ The §199 deduction for Domestic Production Activities is computed on IRS form 8903. The DPAD that is computed on form 8903 appears on the front page of the corporate federal income tax return (form 1120) on line 25.¹²¹ It is an additional deduction that is beyond the operating expenses recorded by the utility on its books and the other tax deductions.¹²²

Furthermore, the inconsistency in AEP Ohio’s application of the “separate return” concept causes AEP Ohio's income tax request to be overstated. Staff witness Smith stated:

[w]here a utility participates in a consolidated federal income tax return with other affiliates, the §199 deduction amount that is allocated to a utility as result of participating in the consolidated tax return can be lower than the Section 199 deduction when computed on a “stand alone” basis for the utility. Because of other impacts on the consolidated return, the amount of the allocated DPAD can be lower than if it had

¹¹⁸ Staff Ex. 103 (Smith Testimony) at 54-55.

¹¹⁹ *Id.* at 55.

¹²⁰ *Id.*

¹²¹ *Id.*

¹²² *Id.*

been computed on a separate standalone tax return basis. AEP's proposed revenue requirement for generating capacity and its computation of income tax expense for purposes of determining capacity rates in the current proceeding is essentially based on the assumption that CSP and OPCo each file a separate standalone tax return for all income and deductions. The §199 Deduction related to AEP's generation revenue requirement should therefore, also reflect the §199 deduction computed on separate return basis. In other words, for rate-making purposes, all components of the income tax expense should be computed on a standalone separate tax return basis, including the §199 Deduction, as a matter of conceptual and computational consistency. It would not be appropriate to randomly quantify certain components of an income tax expense computation on a standalone basis and other components on a consolidated basis. By omitting a DPAD for CSP and OPCo, AEP is applying a consolidated tax return concept, whereas for all other aspects of the income tax calculations, a "separate return" concept is being applied. Again, the inconsistency causes AEP's income tax request to be overstated.¹²³

The principle that it is not appropriate to randomly quantify certain components of an income tax expense computation on a standalone basis and other components on a consolidated basis would apply to AEP Ohio in the current case. Staff Witness smith stated that:

[f]or purposes of determining a revenue requirement and cost rate for capacity, AEP has computed its federal income tax expense for ratemaking purposes on a "separate return" basis. The Company has essentially based their request for income tax expense at proposed rates upon the current taxable income represented by the return on equity (grossed up for income taxes), and have reduced that only for ITC amortization, but not for other deductions, such as the DPAD, that CSP or OPCo would claim on a "separate return" basis. Nor have the companies reflected any benefit from participating in the AEP

¹²³

Staff Ex. 103 (Smith Testimony) at 55-56.

consolidated federal income tax return in their proposed income tax calculations. AEP has not reflected the §199 deduction that CSP and OPCo would be eligible for on a separate return basis. Consistent ratemaking treatment would thus require the §199 deduction to be reflected for ratemaking purposes by preparing a pro forma calculation that is consistent with the “separate return” concept that is being used for ratemaking purposes.¹²⁴

AEP Ohio provided calculations of the §199 deduction/DPAD for CSP and OPCo on a “separate return” basis for 2010.¹²⁵ For purposes of determining the generation capacity revenue requirement, Staff witness Smith prepared a calculation of the §199 deduction and the related reduction to current income tax expense on a separate return basis for CSP and OPCo.¹²⁶ Once it is determined that the entity has qualifying domestic production activities, which CSP and OPCo each do for their electric generation operations, there are three factors that limit the amount of deduction for domestic production activities: (1) Qualified Production Activities Income; (2) Taxable Income; and (3) W-2 wages.¹²⁷ As shown on Schedule E of Exhibits RCS-1 and RCS-2, for CSP’s and OPCo’s generation operations, respectively, Smith computed a pro forma §199 deduction on a separate return basis that takes into consideration each of these three factors.¹²⁸ The tax effect of the pro forma §199 deduction thus reduces income tax expense for CSP by

¹²⁴ Staff Ex. 103 (Smith Testimony) at 57.

¹²⁵ *Id.* at 58.

¹²⁶ *Id.* at RCS-1 and RCS-2, Schedule E, for each company.

¹²⁷ *Id.* at 58.

¹²⁸ *Id.*

\$3.379 million as shown on Exhibit RCS-1, Schedule E.¹²⁹ Similarly, the tax effect of the DPAD reduces income tax expense for OPCo by \$0.879 million, as shown on Exhibit RCS-2, Schedule E.¹³⁰

12. Payroll Tax Expense

Staff witness Smith reflected an adjustment for Taxes Other Than Income Taxes for CSP and OPCo.¹³¹ The reduction in 2010 payroll expense related to the lower work force after the AEP Ohio severance program, also reduces Payroll Tax Expense.¹³² To estimate the reduction to Payroll Tax Expense, Smith applied the combined FICA and Medicare rate of 7.65% to the reduction to Payroll Expense allocated to production demand.¹³³ As shown on Exhibit RCS-1, Schedule F, this reduces Taxes Other Than Income Taxes allocated to CSP's generation demand function by \$0.731 million.¹³⁴ Similarly, as shown on Exhibit RCS-2, Schedule F, this reduces Taxes Other Than Income Taxes allocated to OPCo's generation demand function by \$1.764 million.¹³⁵

¹²⁹ Staff Ex. 103 (Smith Testimony) at 58.

¹³⁰ *Id.*

¹³¹ *Id.* at Exhibits RCS-1 and RCS-2, Schedule F.

¹³² *Id.* at 59.

¹³³ *Id.*

¹³⁴ *Id.*

¹³⁵ *Id.*

13. Capacity Equalization Revenue

During 2010, both CSP and OPCo received significant amounts of Capacity Equalization Revenue from other members of the AEP East Pool, primarily from Appalachian Power Company.¹³⁶ AEP Ohio has reflected the Capacity Equalization Revenue received in 2010 by CSP and OPCo as a dollar-for-dollar offset against their capacity revenue requirement.¹³⁷ The Capacity Equalization Revenues received in 2010 by CSP and OPCo are included on Exhibits KDP-3 and KDP-4, respectively, at page 4, line 6, in the Sales for Resale Revenue, which AEP Ohio subtracted in determining its proposed revenue requirement for capacity on line 8, which is labeled there as the Annual Production Fixed Cost.¹³⁸

For CSP, Exhibit KDP-3, at page 4, line 6, shows an amount of \$30,785,441. That amount agrees with the \$30,785,441 demand charges amount on page 311.8 of CSP's 2010 FERC Form 1.¹³⁹ For OPCo, Exhibit KDP-4, at page 4, line 6, shows an amount of \$459,510,726. That amount agrees with the \$459,510,726 demand charges amount on page 311.6 of OPCo's 2010 FERC Form 1.¹⁴⁰

AEP Ohio's reflection of the Capacity Equalization Revenue is appropriate. The payments that AEP Ohio receives from the other members in the AEP East Pool for

¹³⁶ Staff Ex. 103 (Smith Testimony) at 60.

¹³⁷ *Id.*

¹³⁸ *Id.*

¹³⁹ *Id.*

¹⁴⁰ *Id.*

capacity equalization are payments for capacity.¹⁴¹ It is therefore necessary and appropriate to deduct such amounts in arriving at the capacity revenue requirement of AEP Ohio that remains, *i.e.*, that is *not* being covered by payments from the other members in the AEP East Pool.¹⁴²

14. Ancillary Services Revenue

As shown on Exhibits KDP-3 and KDP-4, page 4, line 7, AEP used \$29,070 for CSP and \$34,520 for OPCo, respectively, for Ancillary Services Revenue.¹⁴³ The source of those amounts is described in OPCo's FERC Form 1 for 2010 at page 450.1, as a footnote for Schedule page 310.1, line no. 5, as: "Carolina Power and Light transmission services from a grandfathered agreement."¹⁴⁴ Activity reflects both the base rate and Ancillary 1 base dollars."¹⁴⁵ AEP Ohio advised Staff that the grandfathered Carolina Power and Light agreement is also the source for the CSP Ancillary Services Revenue.¹⁴⁶

Those amounts do not appear to account for all of the receipts for providing Ancillary Services that AEP Ohio receives from PJM.¹⁴⁷ AEP Ohio receives payments from

¹⁴¹ Staff Ex. 103 (Smith Testimony) at 60.

¹⁴² *Id.*

¹⁴³ *Id.* at 61.

¹⁴⁴ *Id.*

¹⁴⁵ *Id.*

¹⁴⁶ *Id.*

¹⁴⁷ *Id.*

PJM when AEP Ohio is called upon to provide a variety of Ancillary Services.¹⁴⁸ The amount CSP and OPCo received from PJM in 2010 and 2011 for the provision of Ancillary Services was requested by Staff from AEP Ohio and has been analyzed and addressed, as described by Staff witness Harter.¹⁴⁹

15. Energy Sales Margin and Ancillary Services Receipts

Staff witness Emily Medine updated Staff witness Harter's calculation on the Energy Sales Margins and Ancillary Services Receipts, as shown on her Exhibit EMS-1.¹⁵⁰ Staff witness Smith had originally reflected Staff witness Harter's energy credits as deductions to the calculated rate for capacity as shown for CSP and OPCo, respectively, and for the merged CSP and OPCo, as shown on Exhibits RCS-1 and RCS-2, and RCS-3.¹⁵¹ But the energy credit changed as a result of the inadvertent errors that were discovered in Mr. Harter's testimony and workpapers. As a result, Staff witness Medine revised Exhibits RCS-1, RCS-2, and RCS-3, in the errata to the testimony of Staff witness Ralph C. Smith to conform to the revised energy credits.¹⁵² The revised capacity rates are reflected in Exhibits ESM-2, ESM-3, and ESM-4 of Staff witness Medine's testimony.

¹⁴⁸ Staff Ex. 103 (Smith Testimony) at 61.

¹⁴⁹ *Id.*

¹⁵⁰ Staff Ex. 105 (Medine Testimony).

¹⁵¹ Staff Ex. 103 (Smith Testimony) at 62.

¹⁵² Staff Ex. 105 (Medine Testimony) at 19-20.

II. In regard to Staff's alternate proposal, Energy sales margins and Ancillary receipts should be treated as deductions to the calculated rate for capacity.

AEP Ohio's calculation of costs to keep its generating assets operational overstates the capacity charge because it neglects to account for profits earned through generating electricity and providing ancillary services.¹⁵³ Staff calculated the energy credits by developing a forecasted total energy margin for AEP Ohio's generating assets.¹⁵⁴ To achieve this, Staff used the 8760 hourly dispatch power market model, AURORAxmp, which is licensed by EVA.¹⁵⁵ In addition to other Ohio utilities and other competitors of EVA using this model, including NERA¹⁵⁶, the model is also licensed for use by AEP Ohio.¹⁵⁷ Although one is an offset to the other, the analysis done by EVA to determine the energy credit was different than the analysis done by Mr. Smith when he calculated the cost of the capacity charge.¹⁵⁸ EVA did a market-based analysis and Mr. Smith did a cost-based analysis.¹⁵⁹

EVA generates a complete electricity market outlook by combining AURORAxmp's dispatch logic with EVA's high precision inputs it develops as part of

¹⁵³ Staff Ex. 101 (Harter Testimony) at 6.

¹⁵⁴ *Id.*

¹⁵⁵ *Id.*

¹⁵⁶ Tr. Vol. XII at 2766.

¹⁵⁷ Tr. Vol. X at 2146, 2149; Tr. Vol. XII at 2637.

¹⁵⁸ Tr. Vol. X at 2171.

¹⁵⁹ *Id.* at 2173-2174.

its FUELCAST services.¹⁶⁰ FUELCAST is a multi-client service.¹⁶¹ With this entire service, EVA produces both short-term and long-term reports to subscribers and clients that provide an analysis of data regarding electricity, coal, natural gas, oil, and emission allowances.¹⁶² The AURORAxmp model, which is widely used throughout the electricity industry, simulates a power market by sorting all available generation assets by marginal cost and dispatching the most economic assets until the zonal load is met.¹⁶³ To keep this model calibrated, EVA maintains a proprietary set of high granularity forecasts for its FUELCAST clients. The FUELCAST includes delivered fuel prices by generating unit, a complete regulatory outlook, a specialized load forecast, and several other key market insights.¹⁶⁴

The two types of projects that have benefited from the use of the AURORAxmp model are forecasting and valuation projects.¹⁶⁵ The dispatch model has enhanced forecasting by accounting for changes in coal plant dispatch, which is now dispatching after non-dispatchable renewable and natural gas combined cycle where and when natural gas

¹⁶⁰ Staff Ex. 101 (Harter Testimony) at 6-7.

¹⁶¹ Tr. Vol. X at 2157.

¹⁶² *Id.*

¹⁶³ Staff Ex. 101 (Harter Testimony) at 7.

¹⁶⁴ *Id.*

¹⁶⁵ Staff Ex. 105 (Medine Testimony) at 5-6.

prices have resulted in lower generation costs.¹⁶⁶ And in regard to valuation projects, the dispatch model allows the energy value associated with these assets to be modeled.¹⁶⁷

In building a delivered coal price forecast for each coal-fired plant in the U.S., Staff utilized data from the EIA-923 dataset, publicly available filings, government macroeconomic metrics, and industry press releases to develop its own estimates of commodity prices and transportation rates.¹⁶⁸ In building its delivered natural gas price forecasts, Staff witness Medine’s EVA firm publishes a quarterly natural gas forecast that analyzes detailed gas well production data for each U.S. natural gas play in combination with its assessment of future natural gas demand.¹⁶⁹ Delivered prices are developed based upon Staff’s estimate of the basis differential by hub combined with the estimated transportation costs from each hub to each plant.¹⁷⁰ The model is updated each time the natural gas price forecast is updated.

Other model inputs concern the emission allowance price forecasts, the effective date of the Cross States Air Pollution Rule (“CSAPR”), and O&M costs. EVA has an environmental group, which evaluates the costs and compliance strategies for meeting environmental requirements.¹⁷¹ Using the information derived from its group evaluation,

¹⁶⁶ Staff Ex. 105 (Medine Testimony) at 5-6.

¹⁶⁷ *Id.* at 6.

¹⁶⁸ *Id.* at 7.

¹⁶⁹ *Id.* at 8.

¹⁷⁰ *Id.*

¹⁷¹ *Id.* at 9.

EVA develops an emission allowance forecast for its clients. Whenever the information is updated, EVA updates the forecast in the model.¹⁷² For CSAPR, EVA assumes a one-year deferral until 2013.¹⁷³ In regard to O&M inputs, EVA used the AURORAxmp default numbers for the variable operating and maintenance costs.¹⁷⁴

Another input is the plant heat rate assumptions provided with the default AURORAxmp dataset. EVA chose to use the EPIS default heat rate assumptions for this analysis, which are based on the most efficient heat rate at which each generation unit could operate (also known as full output heat rate).¹⁷⁵ EVA states that the efficient heat rates, rather than those set forth in the FERC Form 1, are more appropriate to use for this model.¹⁷⁶ There is a high correlation between the default heat rates and the reported FERC Form 1 rates in relation to units operating at high capacity factors.¹⁷⁷ As shown in the table of Staff witness Medine's testimony, these relationships can be seen in a review of AEP Ohio owned plants.¹⁷⁸ The default heat rates for Gavin and the other plants that

¹⁷² Staff Ex. 105 (Medine Testimony) at 9.

¹⁷³ *Id.*

¹⁷⁴ Tr. Vol. X at 2283.

¹⁷⁵ Staff Ex. 105 (Medine Testimony) at 10.

¹⁷⁶ *Id.*

¹⁷⁷ *Id.* at 11.

¹⁷⁸ *Id.* at 12.

operate at high capacity factors are very similar to the FERC Form 1 heat rates due to its high capacity factor.¹⁷⁹

The use of the default heat rates or the most efficient heat rates improves the quality of the model results.¹⁸⁰ Most of AEP Ohio's generation comes from the higher capacity units.¹⁸¹ With respect to generation, the use of average heat rates would have little effect on the utilization of the coal units with high capacity factors because they are already similar. However, the use of average heat rates could suppress coal generation in the marginal units because it would make the marginal units less economic.¹⁸² But the net impact would likely be modest since all coal plants would be similarly affected.¹⁸³

EVA employed the zonal version of AURORAxmp for its analysis. The zonal model removes a large portion of complexity by setting a single energy price for areas that are well connected and have little internal congestion constraint.¹⁸⁴ Staff witness Medine testified that the results between a nodal and zonal model are similar when there is not much congestion. EVA's research showed that there was not a congestion issue

¹⁷⁹ Staff Ex. 105 (Medine Testimony) at 12.

¹⁸⁰ *Id.* at 11.

¹⁸¹ *Id.* at 13.

¹⁸² *Id.* at 13.

¹⁸³ *Id.*

¹⁸⁴ *Id.*

within the AEP Ohio zone.¹⁸⁵ Staff witness Medine confirmed there was not much congestion in the AEP Ohio zone with the PJM market monitor.¹⁸⁶

Both OPCo and CSP participate in the AEP Interconnect Agreement, which requires a portion of AEP Ohio's profits from off system sales ("OSS") to be redistributed to other members of the pool.¹⁸⁷ To estimate AEP Ohio's share of the profits, Staff compared hourly load simulated generation for OPCo and CSP assets with the forecasted hourly demand data provided by AEP Ohio.¹⁸⁸ Where the simulated hourly generation exceeded retail demand, EVA attributed the profit associated with the excess generation to OSS.¹⁸⁹ The portion of OSS revenue retained by AEP Ohio is determined by its Member Load Ratio ("MLR").¹⁹⁰ The average 2010 MLR provided in Mr. Pearce's Exhibit KDP-5 was used by Staff for the entire forecast period.¹⁹¹

AEP Ohio along with Appalachian Power, Indiana & Michigan, Kentucky Power, and AEPSC are parties to the Interconnection Agreement. This Agreement defines how the member companies share the costs and benefits associated with their generating

¹⁸⁵ Tr. Vol. X at 2282.

¹⁸⁶ *Id.*

¹⁸⁷ Staff Ex. 101 (Harter Testimony) at 7.

¹⁸⁸ *Id.*

¹⁸⁹ *Id.*

¹⁹⁰ *Id.*

¹⁹¹ *Id.*

plants.¹⁹² This sharing is based upon each company's MLR. The MLR is calculated monthly by dividing each company's highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all member companies.¹⁹³ The MLR multiplied by the aggregate generation capacity of all the member companies determines each member company's capacity obligation.¹⁹⁴ The difference between each member company's obligation and its own generation capacity determines the capacity surplus or deficit of each member company.¹⁹⁵

The Interconnection Agreement requires the deficit companies to make monthly capacity equalization payments to the surplus companies based on the surplus companies' average fixed cost of generation.¹⁹⁶ Member companies that deliver energy to other member companies to meet their internal load requirements are reimbursed at average variable costs.¹⁹⁷ All member companies share OSS margins based upon each member company's MLR.¹⁹⁸ EVA's treatment of OSS is conservative because it only takes into

¹⁹² Staff Ex. 105 (Medine Testimony) at 16.

¹⁹³ *Id.*

¹⁹⁴ *Id.* at 16.

¹⁹⁵ *Id.*

¹⁹⁶ *Id.* at 16-17.

¹⁹⁷ *Id.* at 17.

¹⁹⁸ *Id.*

account AEP Ohio's margin of OSS. EVA does not include any OSS margins AEP Ohio receives from other member companies.¹⁹⁹

While recognizing the MLR can change on a monthly basis, EVA and Larkin decided to fix the MLR for this analysis at 19%, 22%, and 40% for CSP, OPCo and AEP Ohio, respectively, based upon 2010 actuals.²⁰⁰ As the Staff's proposed energy credit is directly tied to the MLR, higher or lower numbers would cause similar movements in the energy credit.²⁰¹ AEP Ohio witness Nelson stated, while noting his exception with Wheeling Power, that Staff probably identified AEP Ohio's OSS and correctly applied the MLR to those OSS.²⁰²

In December 2010, each AEP Power pool member noticed the other members, and AEPSC, the pool's agent, of their respective decisions to terminate the Interconnection Agreement, effective January 1, 2014.²⁰³ However, the Agreement will not necessarily terminate at that time or after that time until accepted by FERC. As a result, the exact timing and implications of the termination are difficult to predict.²⁰⁴ Rather than speculate as to its consequences, which could either increase or decrease then energy credit,

¹⁹⁹ Tr. Vol. XII at 2660.

²⁰⁰ Staff Ex. 105 (Medine Testimony) at 17.

²⁰¹ *Id.* at 17.

²⁰² Tr. Vol. XII at 2664.

²⁰³ Staff Ex. 105 (Medine Testimony) at 18.

²⁰⁴ *Id.*

EVA and Larkin decided to hold the MLR adjustment constant throughout the period.²⁰⁵

Again, this is a conservative approach taken by EVA, who, unlike AEP Ohio, refuses to speculate when termination of the pool may be granted by FERC. AEP Ohio witness Nelson agreed that AEP Ohio needs FERC approval to terminate the pool agreement and if FERC does not grant termination by January 1, 2014, the Agreement will continue.²⁰⁶

Mr. Nelson also agreed that there is a level of uncertainty as to whether FERC will approve the termination of the pool agreement by January 1, 2014.²⁰⁷

EVA assumed 26% shopping for the AURORAxmp model. In calculating what portion of AEP Ohio's generation is used for OSS, Staff reduced AEP Ohio's SSO Retail load by 26%.²⁰⁸ This produces a higher level of OSS and causes a larger portion of the gross margin to be adjusted for the MLR.²⁰⁹ An increase in the switching assumption will tend to decrease the energy credit while a decrease in the switching assumption will tend to increase the energy credit.²¹⁰ EVA chose to be conservative by using a 26% shopping assumption for the reason that EVA did not forecast whether shopping would go up or down over the next three years.²¹¹

²⁰⁵ Staff Ex. 105 (Medine Testimony) at 18

²⁰⁶ Tr. Vol. XII at 2664.

²⁰⁷ *Id.* at 2665.

²⁰⁸ Staff Ex. 105 (Medine Testimony) at 19.

²⁰⁹ *Id.*

²¹⁰ *Id.*

²¹¹ Tr. Vol. X at 2193-2194.

In the 2007-2008 planning year, the RPM rate in the AEP load zone was \$46.73 per megawatt day.²¹² This is what AEP Ohio charged CRES providers to supply capacity for shopping customers in that planning year.²¹³ AEP Ohio witness Pearce testified that AEP Ohio had close to no shopping when the capacity rate was \$46.73.²¹⁴ Mr. Pearce answered the same way for the 2008-2009 and 2009-2010 planning years, when the capacity rates were \$129.71 and \$126.33, respectively.²¹⁵ That is, AEP Ohio had very little to no shopping.²¹⁶ In the 2011-2012 planning year, AEP Ohio was charging a capacity rate of \$145.79 to CRES providers, which is the same rate AEP Ohio proposes to charge CRES providers in the first tier of its modified ESP filing (Case No. 11-346-EL-SSO).²¹⁷

Finally, EVA converted the annual energy margins into a \$/MW Day value using the 2010 5-day coincident peak load (“CP-5”) formula provided in AEP witness Pearce’s Exhibit KDP-5 to be consistent with the capacity analysis provided by Staff witness

²¹² Tr. Vol. II at 327.

²¹³ *Id.*

²¹⁴ *Id.*

²¹⁵ *Id.* at 327-328.

²¹⁶ *Id.* at 328.

²¹⁷ *Id.* at 329.

Smith.²¹⁸ The MLR and CP-5 used to calculate the merged AEP Ohio rates are estimates and not actual 2010 data, which is consistent with Mr. Pearce's Exhibit KDP-5.²¹⁹

To account for the profits from AEP Ohio's participation in the ancillary services market, Staff used the total ancillary service credit AEP Ohio earned in 2011 as a proxy for future ancillary services profits.²²⁰ Staff converted these credits from an annual charge into a \$/MW Day value using a formula identical to that used for the energy credit calculation.²²¹

All retained profits from AEP Ohio's OSS are included in Staff's proposal. Staff's basis for inclusion is both regulatory and economic. From an economic perspective, because the profits from OSS incentivize AEP Ohio to keep its generating assets operational, the economically efficient capacity price will reflect an offset equal to this benefit.²²² In regard to the Ancillary services adjustment, these receipts incentivize the asset owner to maintain the plant.²²³ In addition, CRES providers are currently captive

²¹⁸ Staff Ex. 101 (Harter Testimony) at 8.

²¹⁹ *Id.*

²²⁰ *Id.*

²²¹ *Id.*

²²² *Id.* at 8-9.

²²³ *Id.* at 11.

customers.²²⁴ From a regulatory standpoint, profits from OSS are generally required to be redistributed to captive customers when a capacity charge is being collected.²²⁵

In order to provide a full and accurate record for the Commission to decide this case, Staff called Emily S. Medine to testify and clarify the description of Staff's model inputs and to correct inadvertent errors made in the aggregation of the results.²²⁶ The errors related to the aggregation of model outputs concerning the plants that AEP Ohio operated, instead of plants it owned, and the description of model inputs that were discovered when Mr. Harter testified and produced workpapers.²²⁷ Although the initial run of the model was fine, Staff conducted a rerun of the model to simply fine tune two of the retirement decisions.²²⁸ Staff adjusted retirement dates for the AEP Conesville 3 and Beckjord 6 coal plants.²²⁹

The changes had very little impact on the results. The work that was done was primarily in reaggregating the results.²³⁰ Mr. Harter served as a Staff expert on the operation of the AURORAxmp model and Ms. Medine served as an expert on the model inputs

²²⁴ Staff Ex. 101 (Harter Testimony) at 9.

²²⁵ *Id.*

²²⁶ Tr. Vol. X at 2116.

²²⁷ *Id.*

²²⁸ *Id.* at 2116-2117.

²²⁹ Staff Ex. 105 (Medine Testimony) at 7.

²³⁰ Tr. Vol. X at 2117.

and aggregated results, as model outputs.²³¹ Staff witness Medine revised the capacity rate provided by staff witness Smith to conform with the revised energy credits.²³²

Staff witness Medine revised the energy credits to address adjustments for owned capacity and retirement dates.²³³ The initial aggregations included the entire CSP and OPCo operated plants. The changes resulted in decreased capacity at Conesville 4 and capacity increases due to CSP's ownership shares of Beckjord 6, Stuart, and Zimmer and OPCo's ownership shares of Cardinal and Sporn.²³⁴ A table showing all plants owned or partially owned by CSP and OPCo is provided in Ms. Medine's testimony.²³⁵ Lawrenceburg was added to the table because of the long-term contract with CSP.²³⁶ EVA continued to exclude Amos and Mitchell because their full accounting costs are paid for by affiliates.²³⁷

The AURORAxmp model only has to be run once to calculate the initial data, but the model has, in fact, been run dozens of times before it was run for this case.²³⁸ For example, Staff witness Medine worked on an engagement for the federal government

²³¹ Tr. Vol. X at 2117.

²³² Staff Ex. 105 (Medine Testimony) at 19-20 and Exs. ESM-2, ESM-3, and ESM-4.

²³³ *Id.* at 14-15.

²³⁴ *Id.* at 15.

²³⁵ *Id.*

²³⁶ *Id.* at 116.

²³⁷ *Id.* at 115-116.

²³⁸ Tr. Vol. X at 2163.

using this model and exercised the model quite a bit.²³⁹ EVA keeps the model hot with their latest assumptions. Those assumptions did not change for this analysis and EVA did not pick and choose inputs to bias the results.²⁴⁰

The AURORAxmp was properly calibrated by EVA prior to the run it made for this case. EVA did multiple runs for another engagement prior to this case and conducted a sensitivity analysis using alternative gas prices, alternative coal prices, alternative emission allowances.²⁴¹ As a result, EVA was able to spend a considerable amount of time looking at the results and assessing how accurate they were, and *EVA did make some changes as part of that review and analysis.*²⁴²

It is EVA's position, after comparing the model's market prices against actual market prices, that its AURORAxmp model produces a justifiable LMP.²⁴³ EVA starts its analysis with actual prices and then they add to that understanding based upon being actively involved in buying and selling coal.²⁴⁴ EVA conducts a very detailed analysis to determine future market prices both in supply and demand.²⁴⁵ A fundamental forecast is more accurate to use than a forward price curve because forward price curves go up and

²³⁹ Tr. Vol. X at 2163.

²⁴⁰ *Id.* at 2164.

²⁴¹ *Id.* at 2209-2211.

²⁴² *Id.*

²⁴³ *Id.* at 2165.

²⁴⁴ *Id.*

²⁴⁵ *Id.* at 2165-2166.

down with everything.²⁴⁶ Forward price curves do influence EVA's analysis but it does not form EVA's forecast.²⁴⁷ No input was adjusted for the purposes of obtaining a pre-determined output.²⁴⁸ In other words, EVA did not run a results-oriented analysis. Anytime EVA generates a new delivered price for coal for their clients who get a forecast every quarter, EVA will put that in AURORAxmp.²⁴⁹ The same is true for gas and emission prices. EVA put the updated default prices in the model for use in this case.²⁵⁰

AEP Ohio witness Allen testified that he thought using forward prices when they exist are more appropriate to use as opposed to using fundamentals analysis.²⁵¹ On cross, Mr. Allen reviewed Staff Exhibit 106 and testified that changes did occur at the AEP Dayton Hub for Peak Forward Power prices between December 29, 2011 and January 5, 2012.²⁵² Mr. Allen testified that changes in forward prices, according to Staff Exhibit 106, declined 9% for Jan-12, forward prices declined 7% for Jul-12, and forward prices declined 6% for Jan-13.²⁵³ The changes to the Forward Power Price curves between December 29, 2011 and January 5, 2012, as reflected at the AEP-Dayton Hub and shown

²⁴⁶ Tr. Vol. X at 2166.

²⁴⁷ *Id.* at 2168.

²⁴⁸ *Id.* at 2169.

²⁴⁹ *Id.*

²⁵⁰ *Id.*

²⁵¹ Tr. Vol. XI at 2414.

²⁵² *Id.* at 2417-2418.

²⁵³ *Id.* at 2418-2419.

in Staff Exhibit 106, are significant. In regard to AEP Ohio's analysis of the energy credit involving the CSAPR, Mr. Allen testified that he makes the same assumption that the market as a whole makes about that regulation by using the forward price curves.²⁵⁴

AEP Ohio witness Meehan was shown Staff Exhibit 110 that depicted forward price curves for power from trading between January 4, 2010 and May 7, 2012.²⁵⁵ He testified that gross margins on December 31, 2010 are significantly higher than what gross margins would be in March 2012 based on the change in price curves depicted in the graph in between that time frame.²⁵⁶

Furthermore, on cross examination, Mr. Allen acknowledged that AEP's Kentucky Power Company recently used the AURORAxmp model before the Public Service Commission of Kentucky to justify the costs of retrofitting a scrubber for its Big Sandy plant in Kentucky.²⁵⁷ In its application to the Kentucky Commission, Kentucky Power Company describes the AURORAxmp model as a tool to forecast power prices for all regions within the Eastern Interconnect.²⁵⁸ EVA used the same model to forecast power prices within the Eastern interconnect. Mr. Allen further confirmed that the AEP Fun-

²⁵⁴ Tr. Vol. XI at 2415-2416.

²⁵⁵ Tr. Vol. XII at 2768-2770.

²⁵⁶ *Id.*

²⁵⁷ Tr. Vol. XI at 2420-2422.

²⁵⁸ *Id.* at 2422.

damental Analysis Group that operates the AURORAxmp model for AEP also runs a zonal analysis.²⁵⁹

Mr. Allen further acknowledged that the Summary of Long-Term Commodity Price Forecast Scenarios conducted by the same AEP Fundamental Analysis Group, as depicted in FES Exhibit 124, shows Natural Gas (Henry Hub) base prices going up from 4.48 in 2012 to 4.94 in 2013 with a low of 4.35 and a high of 5.43; and up to 5.38 in 2014 with a low of 4.73 and a high of 6.02.²⁶⁰ This evidence contradicts AEP's argument that Staff's energy prices are overstated because FES Exhibit 124 demonstrates that AEP's forecast of energy prices over the next three years are higher than Staff's forecasted energy prices in this case.

Mr. Allen also acknowledged from Staff Exhibit 108 (EIA Short-Term Energy Outlook Released May 8, 2012) that EIA forecasts the average delivered coal price in 2012 will be 2.8% lower than the 2011 average price and the average delivered coal price in 2013 will be 3.8% lower than 2012.²⁶¹ This outlook supports Staff witness Medine's modeled forecast and analysis with respect to coal prices.

AEP Ohio's argument opposing Staff's energy credit to offset the capacity price is inconsistent with how PJM calculates a capacity rate. Gross cone (gross cost of new entry) is the benchmark for building a new simple cycle unit. To calculate net cone, PJM

²⁵⁹ Tr. Vol. XI at 2423-2424.

²⁶⁰ *Id.* at 2424-2425.

²⁶¹ *Id.* at 2429-2430.

makes an energy and ancillary services adjustment to gross cone.²⁶² EVA's methodology in this regard is the same as PJM's.

AEP Ohio agreed that the way the pool agreement works is the resources of the pool are assigned first to the internal load of members based on lowest cost per megawatt hour.²⁶³ And once the internal load is satisfied the OSS are made from the remaining resources.²⁶⁴ And then from the sales of those resources AEP Ohio could receive 40% of the revenues.²⁶⁵ APCo, as a member of the pool, receives a percentage of those sales.²⁶⁶ But West Virginia requires that 100% of those revenues that are shared under the pool and received by APCo must be credited 100% to retail customers.²⁶⁷ AEP Ohio declined to characterize this credit as a subsidy.²⁶⁸ Instead, it characterized it as inequitable.²⁶⁹

²⁶² Tr. Vol. II at 267.

²⁶³ *Id.* at 275.

²⁶⁴ *Id.*

²⁶⁵ *Id.*

²⁶⁶ *Id.* at 275-276.

²⁶⁷ *Id.* at 276.

²⁶⁸ *Id.*

²⁶⁹ *Id.*

CONCLUSION

The \$355.72/MW-Day capacity rate proposed by AEP Ohio is unjustified and must be rejected by the Commission. Staff's position is that AEP Ohio should charge CRES providers the prevailing RPM rate for the 2012-2015 period during which AEP Ohio will remain an FRR entity. But if the Commission finds that the prevailing RPM rate is not appropriate for AEP Ohio, then Staff recommends \$146.41/MW-Day should be the appropriate capacity rate to be set as a state compensation mechanism for AEP Ohio to charge CRES for their shopping load. In the alternate proposal, Staff's cost adjustments and Energy credits to AEP's proposed rate of \$355.72/MW are justified. Staff's alternative net capacity charge is compensatory to the Company while still fostering competition among CRES providers in the State of Ohio. Accordingly, the Commission should deny AEP Ohio's proposed capacity rate and adopt, instead, the RPM price or, in the alternative, Staff's netted capacity price proposal, as the state compensation mechanism for AEP Ohio.

Respectfully submitted,

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PROOF OF SERVICE

I hereby certify that a true copy of the foregoing **Initial Post-Hearing Brief** submitted on behalf of the Staff of the Public Utilities Commission of Ohio, was served by electronic mail, upon the following parties of record, this 23rd day of May, 2012.

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