ORIGINAL

IN THE SUPREME COURT OF OHIO

Ohio Power Company,	)	Supreme Court Case No. 2012-1484
	)	
Appellant/Cross-Appellee,	)	Appeal from the Public Utilities
	)	Commission of Ohio
v.	)	
	)	
The Public Utilities Commission of	)	Public Utilities Commission of Ohio
	)	Case Nos. 09-872-EL-FAC and
Ohio,	)	09-873-EL-FAC
	)	
Appellee.	)	

APPENDIX TO SECOND MERIT BRIEF OF APPELLEE/CROSS APPELLANT INDUSTRIAL ENERGY USERS-OHIO

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{C39523: }

ORIGINAL

IN THE SUPREME COURT OF OHIO

12-1484

In the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company.	)))))))	Supreme Court Case No. 2012-___ Appeal from the Public Utilities Commission of Ohio PUCO Case Nos. 09-872-EL-FAC and 09-873-EL-FAC

NOTICE OF APPEAL OF APPELLANT INDUSTRIAL ENERGY USERS-OHIO

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NOTICE OF APPEAL OF APPELLANT
INDUSTRIAL ENERGY USERS-OHIO

Appellant, Industrial Energy Users-Ohio ("IEU-Ohio" or "Appellant") hereby gives notice of its appeal, pursuant to Section 4903.11 and Section 4903.13, Revised Code, and Supreme Court Rule of Practice 2.3(B), to the Supreme Court of Ohio and Appellee, Public Utilities Commission of Ohio ("Commission"), from an Entry on Rehearing dated April 11, 2012[1] (Attachment A) and an Entry on Rehearing dated July 2, 2012 (Attachment B) in Case Nos. 09-872-EL-FAC and 09-873-EL-FAC. The Entry on Rehearing dated April 11, 2012 (Attachment A) granted Ohio Power Company's Application for Rehearing of the Commission's Opinion and Order dated January 23, 2012 (Attachment C). Thus, the April 11, 2012 Entry on Rehearing modifying the January 23, 2012 Opinion and Order was the first Order adverse to Appellant. The Entry on Rehearing dated July 2, 2012 (Attachment B) denied Appellant's Application for Rehearing of the April 11, 2012 Entry on Rehearing.

Appellant was and is a party of record in Case Nos. 09-872-EL-FAC and 09-873-EL-FAC and timely filed its Application for Rehearing on Appellee's Entry on Rehearing on May 11, 2012. Appellant's Application for Rehearing was denied on July 2, 2012.

The Commission's April 11, 2012 Entry on Rehearing and July 2, 2012 Entry on Rehearing are unlawful and unreasonable for the reason set forth in the following Assignment of Error:

1. The Commission's Entry on Rehearing is Unlawful and Unreasonable

[1] On June 8, 2012, Ohio Power Company prematurely filed a Notice of Appeal (Case No. 2012-0976) of the Commission's April 11, 2012 Entry on Rehearing. On June 15, 2012, the Commission filed a Motion to Dismiss the Notice of Appeal because IEU-Ohio's May 11, 2011 Application for Rehearing was still pending. IEU-Ohio's Notice of Appeal stems from the Commission's denial of IEU-Ohio's May 11, 2012 Application for Rehearing. The Court has yet to rule upon the Motion to Dismiss.

in that the Commission Failed to Clarify that 100 Percent of the Credit for the Settlement Agreement Must be Allocated to Ohio Retail Jurisdictional Customers.

WHEREFORE, Appellant respectfully submits that Appellee's April 11, 2012 Entry on Rehearing and July 2, 2012 Entry on Rehearing are unlawful, unjust, and unreasonable and should be reversed. The case should be remanded to the Appellee with instructions to correct the errors complained of herein.

Respectfully Submitted

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CERTIFICATE OF SERVICE

I hereby certify that a copy of this *Notice of Appeal of Appellant Industrial Energy Users-Ohio* was sent by ordinary United States mail, postage prepaid, or hand-delivered to all parties to the proceeding before the Public Utilities Commission of Ohio, listed below, and pursuant to Section 4903.13 of the Ohio Revised Code on August 30, 2012.

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CERTIFICATE OF FILING

I hereby certify that a *Notice of Appeal of Appellant Industrial Energy Users-Ohio* has been filed with the docketing division of the Public Utilities Commission of Ohio in accordance with Rules 4901-1-02-(A) and 4901-1-36 of the Ohio Administrative Code on August 30, 2012.

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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company.	)))	Case No. 09-872-EL-FAC Case No. 09-873-EL-FAC

OPINION AND ORDER

The Public Utilities Commission of Ohio, having considered the record in these matters and the stipulation and recommendation submitted by the signatory parties, and being otherwise fully advised, hereby issues its opinion and order.

APPEARANCES:

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Janine L. Migden-Ostrander, Ohio Consumers' Counsel, by Maureen Grady, Melissa Yost, and Kyle Lynn Verrett, Assistant Consumers' Counsel, 10 West Broad Street, Suite 1800, Columbus, Ohio 43215, on behalf of the residential utility consumers of Columbus Southern Power Company and Ohio Power Company.

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OPINION:

I. Background

Columbus Southern Power Company (CSP) and Ohio Power Company (OP) are public utilities as defined in Section 4905.02, Revised Code, and, as such, are subject to the jurisdiction of this Commission.

On March 18, 2009, the Commission issued its Opinion and Order in CSP's and OP's (jointly, AEP-Ohio or Companies) electric security plan (ESP) cases (ESP Order).[1] By entries on rehearing issued July 23, 2009, and November 4, 2009, the Commission affirmed and clarified certain issues raised in AEP-Ohio's ESP Order. In the ESP Order, the Commission approved fuel adjustment clauses (FAC) for the Companies including an annual audit of the FAC. Further, in the ESP cases, the Commission authorized 2010 rate increases of six percent for CSP and seven percent for OP and 2011 rate increases of six percent for CSP and eight percent for OP.

Pursuant to the Commission entry issued January 7, 2010, in Case Nos. 09-872-EL-FAC and 09-873-EL-FAC (2009 FAC cases), Energy Ventures Analysis, Inc., (EVA) was selected to perform AEP-Ohio's FAC audit for 2009. In accordance with the request for proposal, EVA is performing the audits for 2010 and 2011, unless the Commission determines otherwise. Pursuant to the request for proposal, the Commission reserves the right to rescind the award of future audits.

On May 14, 2010, both redacted and unredacted versions of EVA's management/performance (m/p) and financial audit of AEP-Ohio's FAC for 2009 (audit report) were filed in these cases. By entry issued June 29, 2010, the attorney examiner granted AEP-Ohio's motion for protective treatment regarding certain information contained in the audit report for a period of 18 months, ending on December 29, 2011.

The office of the Ohio Consumers' Counsel (OCC), Industrial Energy Users-Ohio (IEU-Ohio), and Ormet Primary Aluminum Company (Ormet) were granted intervention in the 2009 FAC cases in a Commission finding and order issued on January 7, 2010.

In accordance with the attorney examiner's June 29, 2010, entry, the hearing was held in these matters on August 23 and August 24, 2010, at the offices of the Commission. At the hearing, AEP-Ohio submitted a stipulation and recommendation (Ormet stipulation) which was filed in these dockets on August 23, 2010, and signed by the Companies, Staff, OCC, IEU-Ohio, and Ormet Primary Aluminum Corporation (Jt. Ex. 1). Additionally, at the hearing, AEP-Ohio submitted the public and rebuttal testimony of four individuals (AEP-Ohio Exs. 1 and 1A through 7 and 7A) while OCC and IEU-Ohio each offered the testimony of one witness (OCC Exs. 1 and 1A; IEU-Ohio Exs. 1 and 1A). In addition, the redacted and unredacted versions of the audit report were entered into the record without objection (Bench Exs. 1A and 1B).

As stated previously, a stipulation, signed by AEP-Ohio, Staff, OCC, IEU-Ohio, and Ormet was submitted on the record, at the hearing held on August 23, 2010. Through the stipulation, the parties agree that a determination on the collection of deferrals and

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1 *In re AEP-Ohio ESP cases*, Case Nos. 08-917-EL-SSO and 08-918-EL-SSO, Opinion and Order (March 18, 2009).

carrying charges associated with an Ormet Interim Agreement is the subject of a pending case before the Commission, *In the Matter of the Application of Columbus Southern Power and the Ohio Power Company to Recover Commission-Authorized Deferrals Through each Company's Fuel Adjustment Clause*, Case No. 09-1094-EL-FAC, and that issues associated with the Ormet Interim Agreement will be addressed in that proceeding.

On November 30, 2010, a stipulation and recommendation intended to resolve all the issues in this FAC proceeding as well as in the Companies significantly excessive earnings proceeding, Case No. 10-1261-EL-UNC *In the Matter of the 2009 Annual Filing of Columbus Southern Power Company and Ohio Power Company Required by Rule 4901:1-35-10, Ohio Administrative Code*, was filed on behalf of AEP-Ohio, Staff, the Ohio Hospital Association, the Ohio Manufacturers' Association, The Kroger Company, and Ormet. On December 16, 2010, the Companies filed a notice of withdrawal from the November 30, 2010, stipulation and recommendation thus rendering the stipulation moot.

II. Summary of the Audit Report

The audit report submitted by EVA and its subcontractor Larkin and Associates PLLC (Larkin) presents the results of the m/p and financial audit for the fuel adjustment clause which is the mechanism being used to recover prudently incurred fuel, purchased power, and other miscellaneous expenses. The FAC includes: Account 501 (Fuel); Account 502 (Steam Expenses); Account 509 (Allowances); Account 518 (Nuclear Fuel Expense); Account 547 (Non-Steam Fuel); Account 555 (Purchased Power); Account 507 (Rents); Account 557 (Other Expenses); Accounts 411.8 and 411.9 (Gains and Loses from Disposition of Allowance); and Other Accounts. EVA and Larkin (jointly, auditors) conducted this audit through a combination of document review, interrogatories, site visits, and interviews. Additionally, EVA and Larkin visited the Conesville Coal Preparation Plant and the Conesville power plant. In its initial ESP application, the Companies proposed mitigating the rate impact of any FAC increases on customers by phasing in the new ESP rates by deferring a portion of the annual incremental FAC costs such that total bill increases to customers would not exceed 15 percent during each year of the ESP. The Commission's ESP order, issued on March 18, 2009, modified AEP-Ohio's proposal to mitigate the rate impact on customers by limiting the phase-in of any FAC increases on a total bill basis by seven, six, and six percent for CSP and by eight, seven, and eight percent for OP for years, 2009, 2010, and 2011, respectively. The Commission's ESP order also stated that the collection of any deferrals including carrying costs remaining at the end of the ESP shall occur from 2012 through 2018 as necessary to recover the actual fuel expense incurred plus carrying costs. (Jt. Ex. 1 at 1-2 through 1-3; ESP order at 23.)

The audit report found that AEP-Ohio's fleet is largely coal-based and coal procurement costs are by far the largest component of the FAC. The auditors noted that since mid-2007, the coal industry has demonstrated unprecedented volatility which has resulted in utility fuel procurement personnel facing enormous challenges. Additionally, from mid-2007 until the third quarter of 2008, a global coal supply/demand imbalance increased the demand for and price of United States (U.S.) coals. In the auditors' opinion, American Electric Power Service Corporation (AEPSC) did an exceptional job during this period particularly with those suppliers that faced financial difficulties. Since the third quarter of 2008, electricity demand slowed as a result of the severe economic recession thus leading many utilities to end up with more coal under contract than needed. Thus, from mid-2007 through the end of 2008, electric utilities went from having to acquire coal under contract to having to manage a surplus of coal inventories. In the auditors' view, AEPSC also did an outstanding job managing its excess coal inventories. The auditors found this to be the case based, in part, on the treatment AEPSC afforded its suppliers, many of which were willing to defer shipments at no cost. Additionally, the auditors noted, AEPSC chose to allow stockpiles to increase rather than pay for reduced shipments which should benefit ratepayers in the long term. AEP's coal costs in 2009 were, according to the auditors, comparable to the coal procurement costs of other nearby utilities. (Jt. Ex. 1 at 1-4 through 1-5.)

The audit report further determines that, at the end of the first year of the FAC, AEP-Ohio experienced a large under-recovery. The under-recovery amounts to $37.5 million for CSP and $297.6 million for OP. The auditors note that there many components contributing to the under-recovery but that two coal contract events alone explain more than half of OP's under-recovery. The first decision attributing to the under-recovery was the decision to increase the contract price under two contracts in 2009. This surcharge under the two contracts at issue was a well-considered decision at a difficult time according to the audit report. While expensive, the auditors note that, without the surcharge, an insolvency of this coal supplier would have led to greater expense for AEP-Ohio and ultimately its ratepayers. The second contributing factor was a buy-out of a coal contract in 2007 which resulted in an increase in 2009 fuel expenses. The 2007 buy-out was structured as a Settlement Agreement arising out of contract dispute. According to the auditors, a hindsight review of such a Settlement Agreement is always difficult because its merits need to be considered at the time it was entered into. This Settlement Agreement was effectively a buy-out of the contract with this supplier after 2008. Otherwise, shipments would have continued under the contract through the ESP period. In return for agreeing to the buy-out, AEP received a settlement and a coal reserve in West Virginia. AEP booked the coal reserve as an un-regulated asset in 2008. (*Id.* at 1-5.)

The audit report further found that AEPSC's fuel procurement operation is run in a professional manner using leading industry practices in acquiring coal and transportation. To support this position, the audit report notes that AEPSC uses a portfolio strategy to purchase coal such that its market exposure at any one time is limited. Moreover, AEPSC purchases most of its coal through competitive solicitations, and AEPSC uses active management of its coal supply to match deliveries and burn where possible. The auditors noted that AEPSC was in the process of revising its fuel procurement manual to guide its practices (*Id.*)

The audit report also addresses AEP-Ohio's coal supply and scrubber retrofit at various generating facilities as well as the reduction in the need for washed coal from the Conesville Coal Preparation Plant due to the conversion of an existing coal supply agreement from unwashed coal to washed coal. The audit report notes that AEP-Ohio has met its 2009 alternative energy obligations through compliance with reduced solar obligations, the purchase of non-solar renewable energy credits (RECs) from wind and landfill gas, purchased solar (RECs), solar installations on two AEP-Ohio service centers, and wind from two purchase power agreements (PPAs). During 2009, the Companies entered into three 20-year PPAs: two for wind and one for solar. The auditors note that the resulting power prices under all three PPAs are high compared to current power prices although competitive with current market prices for renewable power. These PPAs provide no market reopeners or early outs thereby obligating AEP-Ohio to these high rates for 20 years. The auditors note that AEPSC's strategy is to continue to examine all options including self-build options (*Id.* at 1-6.) Finally, the auditors found that the quarterly FAC filings were made in a timely manner and contained sufficient documentation to support the numbers therein. However, the back-up documentation was less well organized making the audit trail more difficult. Also, the auditors reported that AEPSC was notably well-prepared and responsive to the auditors (*Id.*)

III. Management Audit Recommendations[2]

A. <u>Auditors' Recommendations</u>

The audit report recommends that the Commission should review whether any proceeds from the Settlement Agreement (i.e., the 2008 lump sum payment AEP-Ohio received as well as the West Virgnia coal reserve) should be credited against OP's FAC under-recovery. The auditors note that this buy-out was unique as it occurred during a period in which fuel cost recovery was not regulated yet the entire value received was for tons of coal that would have been shipped during the ESP period. The auditors do not suggest any motivation on the part of AEPSC to transfer value from ratepayers in 2009 to 2011 to an earlier date. Clearly, it was the coal supplier who initiated the Settlement Agreement because the contract price was well below market. Nonetheless, the contract was an OP asset and the value associated with it would have flowed through to OP ratepayers through the ESP period had there not been an early termination of the contract. Further, the difference between the price of the replacement coal and the contract price is

2 The following is a summary of the recommendations from the audit report. The Commission notes that these summaries are in no way intended to replace or supplement the text of the audit report.

one factor behind the large OP FAC under-recovery. Equity suggests that the Commission should consider whether some of the realized value should be credited against the under-recovery according to the auditors. (*Id.* at 1-6; 2-21 through 2-22.)

The audit report also recommends that coal could become the new swing fuel; therefore, AEPSC should reconsider new coal procurement strategies to avoid over-commitments in the future. Further, the audit report recommends that the next m/p auditor review the Cardinal 1 scrubber situation and determine what, if any, FAC costs are due to this situation. AEPSC should also undertake a study to determine whether there is an economic justification for continuing to operate the Conesville Coal Preparation Plant. The auditors next recommend that AEPSC should finalize the update of its policies and procedures manual to reflect current business practices and that both the policies and procedures manual and the Conesville Coal Preparation Plant study should be reviewed in the next m/p audit. Lastly, the audit report recommends that prior to entering into long-term agreements for renewables with fixed pricing, AEP-Ohio should fully evaluate self-build and biomass co-firing alternatives and should explore contract options that would provide some protection in the event that the contract pricing for power and/or RECs diverge with market prices. (*Id.* at 1-7.)

B. AEP-Ohio's Position on Management Audit Recommendations

AEP-Ohio witnesses generally testified that the Companies are either in agreement with or not opposed to the auditor's m/p recommendations 2 through 6 found at pages 1-7 of the audit. Regarding m/p audit recommendation 2, the reconsideration of new coal procurement strategies, AEP-Ohio witness Rusk testified that the Companies agree with the recommendation and are currently undertaking such an effort (Co. Ex. 2 at 3). AEP-Ohio witness Nelson testified regarding m/p audit recommendation 3 that the Companies are not opposed to a review of the audit period operational issues concerning the Cardinal 1 scrubber in the next fuel adjustment clause proceeding (Co. Ex. 3 at 8-9). Regarding m/p audit recommendation 4, AEP-Ohio witness Rusk explained that AEPSC has already begun an effort to study the continued use of the Conesville Preparation Plant with the goal of formulating a recommendation on this facility for the next management performance audit (Co. Ex. 2 at 4). AEP-Ohio witness Rusk also testified regarding m/p audit recommendation 5. Mr. Rusk observed that AESPC is currently updating its fuel procurement policies and should have those updates in time for the next m/p audit. However, Mr. Rusk clarified that these revisions are focused on procurement policies and not focused on procurement procedures as the Companies believe that the current approach results in the efficient procurement of fuel at the lowest reasonable cost. (*Id.* at 5.) Regarding m/p audit recommendation 6, that the Companies should fully evaluate and explore self-build and biomass co-firing alternatives before entering long-term agreements for renewables with fixed pricing, AEP-Ohio witness Simmons testified the Companies are constantly exploring the most cost effective sources of renewable generation. Witness Simmons explained that bio-mass is one renewable already under consideration. The witness discussed two requests for proposal issued by AEPSC in 2010, one for bio-mass and one for a pre-blended bio-mass and coal mixture. Additionally, AEPSC is also considering other co-firing alternatives such as biodiesel. Finally, witness Simmons testified that the self-build option is being evaluated but is less likely without a clear cost recovery path. (Co. Ex. 4 at 4-6.) The sole m/p audit recommendation that generated substantial disagreement among the parties and was the primary focus of the hearing and post-hearing briefs involved m/p audit recommendation 1 discussed in detail below.

C. Disputed Management Audit Recommendation 1

Management audit recommendation 1 states that:

> EVA believes that the PUCO should review whether any proceeds from the Settlement Agreement should be a credit against OPCO's FAC under-recovery. This buy-out is somewhat unique as it occurred during a period in which fuel cost recovery was not regulated yet the entire value received was for tons that would have been shipped during the ESP period.

1. AEP-Ohio's Position

AEP-Ohio maintains that, contrary to the position of OCC and IEU-Ohio, it is important to note that the explicit language of m/p audit recommendation 1 is limited to deciding whether proceeds from the 2008 Settlement Agreement should be used to offset OP's under-recovery of fuel costs in 2009 (Jt. Ex. 1 at 1-6). The Companies explain that the proceeds of the 2008 Settlement Agreement include a lump sum payment (made in three equal payments) and a coal reserves asset located in West Virginia AEP-Ohio witness Dooley testified that a substantial portion of the lump sum payment was already credited, in part, against 2009 fuel costs flowed through the FAC with the other portion to be credited against 2010 fuel costs flowed through the FAC (Cos. Ex. 1 at 4). Moreover, according to AEP-Ohio, the present value of the undeveloped, unpermitted coal reserve is simply not known, but, in any event, the coal reserve is an OP asset that ratepayers have no claim upon. Additionally, the Companies note, the auditor clarified that the separate 2008 Delivery Shortfall Agreement was not a part of the equity issue raised in m/p audit recommendation 1. The auditor further clarified, according to the Companies, that EVA was not making a recommendation but merely felt that the Commission should consider the issue (Tr. I at 38). AEP-Ohio states that, while the auditor may have had good intentions in raising this equity issue, it would be inappropriate for the Commission to entertain the notion because it creates a host of legal issues and because the issue is susceptible to expansion of the issue as OCC and IEU-Ohio have done.

Contrary to the positions of IEU-Ohio and OCC, discussed below, the Companies, citing to the ESP Cases order at 20-22, assert that the Commission fully understood and expected that the projected magnitude of the OP fuel deferrals by the end of the ESP was approximately $550 million and the Commission built this factor into the structure of the rate cap/phase-in plan as part of the modified ESP. AEP-Ohio claims that the opportunistic positions of OCC and IEU-Ohio constitute selective and unlawful retroactive ratemaking in violation of *Keco Industries, Inc., v. Cincinnati & Suburban Bell Tel. Co.* (1957), 166 Ohio St. 254 and *Lucas Cty. Commrs. v. Pub. Util. Comm.* (1997), 80 Ohio St.3d 344. Additionally, the Companies maintain that, pursuant to the determinations made in the ESP cases and the entry in this proceeding, the audit period is for 2009 and the prudence review must be limited to 2009 fuel procurement activities. These two key Commission determinations involving operation of the FAC mechanism during the ESP were fully adjudicated and decided as part of the Commission's decision in the ESP case. Thus, these determinations are res judicata and cannot be relitigated or reapplied on a retroactive basis. See *Ohio Consumers' Counsel v. Pub. Util. Comm.* (2006), 111 Ohio St.3d 300, 318; *Ohio Consumers' Counsel v. Pub. Util. Comm.* (1985), 16 Ohio St.3d 9, 10.

Moreover, the Companies assert that the FAC baseline was a hotly contested, fully litigated issue decided in the ESP cases and cannot now be modified in this case. AEP-Ohio asserts that the Commission and the parties understood in the ESP cases that adopting a lower FAC baseline created a higher non-FAC generation rate which when coupled with the rate caps adopted as part of the modified ESP resulted in large fuel deferrals recoverable in the future through a nonbypassable surcharge on all customers in order to mitigate a larger initial rate increase. These are the same fuel deferrals OCC and IEU-Ohio are challenging at the Ohio Supreme Court claims AEP-Ohio. Since these same issues have been appealed to the Ohio Supreme Court, the Companies aver that any attempt to collaterally attack the FAC in this proceeding should not be entertained. As a final matter AEP-Ohio opines that each of the 2008 agreements raised by OCC and IEU-Ohio were prudently adopted and the Commission should not disturb any continuing effects of those agreements, especially given that each agreement was entered into by OP prior to commencement of the ESP's new FAC and before the 2009 audit period.

2. IEU-Ohio's Position

IEU-Ohio maintains that the record reflects that the Companies received benefits or value in return for the voluntarily renegotiated contracts, that the Companies accounting failed to flow through the benefits of the voluntarily renegotiated contracts, and that, as a result, customers paid more in fuel costs in 2009 than they would have had AEP-Ohio not renegotiated certain contracts. Specifically, IEU-Ohio states that the Commission should credit to customers the full benefit of the voluntary 2008 Settlement Agreement. In this regard, IEU-Ohio recommends crediting the full lump sum cash payment resulting from the 2008 Settlement Agreement rather than only a portion of the lump sum payment as the Companies have done (IEU-Ohio Ex. 1 at 6). Additionally, IEU-Ohio argues that the Commission should direct the auditor in the next m/p audit to review and provide a current valuation of the West Virginia coal reserve to be credited against OP's FAC under-recovery that AEP-Ohio will begin collecting in 2012. In the meantime, however, IEU-Ohio recommends that the Commission use the booked value of the West Virginia coal reserve to make an initial downward adjustment to the OP FAC under-recovery. (*Id.* at 7.) Crediting the booked value to the under-recovery now, claims IEU-Ohio, will ensure that customers do not pay carrying costs associated with the booked value while the Commission works to ensure a more accurate valuation of the West Virginia coal reserve. Additionally, claims IEU-Ohio, the booked reserve credit will not impact rates or harm OP's cash flow due to OP's FAC under-recovery deferral. IEU-Ohio also maintains that the Commission should credit against the OP FAC under-recovery the full value of the note receivable by the Companies for the remaining 2008 tonnage that was never delivered as a result of the 2008 Buyout Agreement (*Id.* at 5).

As an alternative recommendation, IEU-Ohio states that the Commission credit against OP's FAC under-recovery the difference between the coal contract price under the contract subject to the 2008 Settlement Agreement and the price per ton paid for the replacement coal multiplied by the number of replacement tons of coal purchased during 2009 (*Id.* at 8). The primary benefit of this option is one of administrative convenience claims IEU-Ohio as it does not require either a future auditor or the Commission to make a subsequent determination of the value of the West Virginia coal reserve (*Id.*). Adopting this option would moot the need to determine whether the full benefit of the lump sum 2008 Settlement Agreement should be credited to customers, the need to properly determine the value of the West Virginia coal reserve, and a determination of whether to credit customers for the proceeds of from the subsequent 2008 Buyout Agreement (*Id.* at 9).

The last adjustment recommended by IEU-Ohio involves a 2008 Contract Support Agreement. Under the 2008 Contract Support Agreement, CSP agreed to increase the base price for a certain tonnage of coal during 2009 with the option for CSP to acquire coal at a discount off the market price per ton for two three-year extensions of the agreement beginning in 2013. IEU-Ohio recommends that the Commission require CSP to refund the increased price per ton that AEP-Ohio agreed to pay for coal during 2009 as part of the 2008 Contract Support Agreement to its FAC customers and account for the total increase as a deferred expense with no carrying costs (*Id.* at 11-12). Should the Commission determine that carrying costs on the deferred expense are appropriate, IEU-Ohio argues that the carrying costs should be a debt-only rate. The deferred expense would then be amortized if and when CSP actually exercises the options for the respective three-year extensions of the 2008 Contract Support Agreement beginning in 2013. (*Id.*) Without this adjustment, IEU-Ohio claims that the present customers incurred higher costs for coal in 2009 but have no assurance that they will receive any of the future benefits. IEU-Ohio concludes by noting that its recommendations more fairly balance the benefits and costs associated with the coal supply contracts.

In response to AEP-Ohio's case-in-chief, IEU-Ohio urges the Commission to direct the Companies to provide its customers the benefits due them from the voluntary coal contract negotiations. IEU-Ohio also took issue with the Companies' claims that the relief requested by the intervenors and by Staff involves retroactive ratemaking and is prohibited under *Keco* and *Lucas Cty*. *Keco* is inapplicable, argues IEU-Ohio, as that case involved traditional regulation and did not involve issues associated with a self-reconciling automatic adjustment clause. Even if the Commission were to find some credibility in AEP-Ohio's argument, IEU-Ohio maintains that the Commission could easily remedy that situation by merely repricing the coal as outlined in the testimony of IEU-Ohio witness Hess (*Id.* at 7-8).

IEU-Ohio also urges the Commission to reject the Companies' claims that the Commission is merely limited to looking at fuel procurement activities during calendar year 2009. IEU-Ohio notes that AEP-Ohio's own witness acknowledged that in conducting the 2009 audit that it was necessary for the auditor to determine whether contracts entered into prior to the audit period had any impact on audit period costs (Tr. I at 162-163). AEP-Ohio's claims of res judicata are also suspect, IEU-Ohio avers, as neither claim preclusion nor issue preclusion, two necessary components of res judicata, apply in this instance. IEU-Ohio next takes issue with the Companies' position that the parties are attempting to illegally relitigate the FAC baseline established in the ESP case. Neither the intervenors nor Staff advanced proposals to modify the FAC baseline asserts IEU-Ohio.

IEU-Ohio next disputes the Companies' argument that the intervenors are claiming a property ownership interest in the coal reserve for ratepayers. IEU-Ohio asserts that nowhere did the intervenors or Staff claim such an ownership interest but simply that the benefits that have been deprived of OP customers be netted against the costs that OP has billed and collected from customers. Next, IEU-Ohio maintains that it is not challenging the appropriateness of the accounting based on any conflict with GAAP, but rather makes a ratemaking recommendation for the Commission's consideration. Lastly, IEU-Ohio avers that, contrary to the Companies position, IEU-Ohio did consider the production bonus payment made in 2008 and agreed that the FAC customers had paid their fair share of the costs of that contract (Tr. II at 255). For these reasons, IEU-Ohio urges the Commission to adopt its recommendations to more fairly balance the benefits and the costs associated with the coal supply contracts discussed in this proceeding.

3. OCC's Position

OCC submits that AEP-Ohio is attempting to pass on to its customers all of the Companies costs under certain fuel procurement contracts, while keeping the majority of the benefits acquired in the contracts, thereby causing its customers to pay more fuel cost than authorized by law in violation of Section 4928.143(B)(2)(a), Revised Code, and Rule 4901:1-35-03(C)(9)(a)(ii), O.A.C. For example, similar to the position taken by IEU-Ohio, OCC asserts that the Companies 2008 Settlement Agreement produced added costs for customers while AEP-Ohio only shared a portion of the lump sum payments the Companies received as well as only a portion of the West Virginia coal reserve. Another example of AEP-Ohio passing along increased costs while keeping the majority of the benefits is the renegotiated coal procurement contract whereby AEP-Ohio agreed to pay the coal provider an increased price of coal per ton during 2009 while having the opportunity to receive a per ton discount on all tons of coal delivered from 2013-2018.

To prevent AEP-Ohio from recovering more fuel cost from its customers than the Companies should under law, OCC submits that the Commission should order that AEP-Ohio's customers receive the financial benefits from the Companies fuel procurement contracts through immediate credits to AEP-Ohio's FAC deferral balance. As previously discussed, those fuel procurement benefits that should be credited against the FAC deferral balance include the full lump sum payment and the fair value of the West Virginia coal reserve that was part of the settlement agreement as well as the fair value of the coal market price discount option for future coal delivery negotiated as part of the 2008 Contract Support Agreement. Any delay in applying these credits will unnecessarily increase the burden to the customers of OP because the carrying charges associated with OP's fuel cost deferral can exceed $10 million every three months (OCC Ex. 1 at 16).

Responding to the Companies' arguments, OCC asserts that the underlying ESP decision and the January 7, 2010, entry in this case do not limit the Commission's review of AEP-Ohio's fuel procurement contracts to only those entered into during the 2009 FAC period. Additionally, OCC argues that neither OCC nor IEU-Ohio are attempting to "claw back" revenue from a prior rate plan as argued by AEP-Ohio. Moreover, the FAC baseline is not relevant, claims OCC, to the issue of requiring AEP-Ohio to recover only its actual fuel cost nor does the FAC baseline constitute res judicata. OCC's final argument is that requiring AEP-Ohio to recover only its actual fuel cost does not constitute selective or retroactive ratemaking as argued by the Companies.

4. Staff's Position

As a general matter, Staff supports the findings and recommendations contained in the Audit Report and recommends that those recommendations be adopted by the Commission. Staff acknowledges that the Companies are entitled to recover the costs of fuel but only to recover the true cost incurred. In other words, Staff asserts that any proceeds received offsetting the cost of fuel should be credited against under-recoveries, regardless of the period in which the proceeds are recognized. Since the value of such credits cannot be determined at this time, Staff recommends that the Commission direct the auditor to evaluate the value of proceeds received by the Companies and not credited either to the FAC or to deferred under-recoveries and make recommendations in the next audit proceeding as to the value to be credited.

Responding to a number of AEP-Ohio arguments, Staff notes that arguments concerning prohibited retroactive ratemaking and imprudence are irrelevant and have not been raised by the auditor's report. AEP-Ohio's arguments concerning regulatory accounting are rejected by Staff as the Commission and not the Companies determine the appropriate accounting for regulatory purposes. Staff does agree with the Companies that Ohio ratepayers do not own the coal reserves that were part of the Settlement Agreement, however, Staff asserts that the value of the coal reserves is part of the cost of fuel and therefore should be examined by the next auditor.

D. Commission Conclusion on Management Audit Recommendations

Initially, the Commission notes that there were very few concerns raised by the parties as to the auditor's m/p recommendations 2 through 6 found at pages 1-7 of the audit. Therefore, the Commission will adopt the auditor's m/p recommendations 2 through 6 as outlined in the audit. The Commission notes that there were, however, widely contrasting positions taken by the parties concerning m/p audit recommendation 1 which recommends that the Commission should review whether any proceeds from the Settlement Agreement (i.e., the 2008 lump sum payment AEP-Ohio received as well as the West Virginia coal reserve) should be a credit against OP's FAC under-recovery.

Following a thorough review of the record and the arguments raised by the parties in this matter, the Commission determines that all of the realized value from the Settlement Agreement should be credited against OP's FAC under-recovery namely the portion of the $30 million 2008 lump sum payment not already credited to OP ratepayers as well as the $41 million value of the West Virginia coal reserve that AEP booked when the Settlement Agreement was executed. Additionally, because the value of the West Virginia coal reserve is not clear and because AEP had planned to begin the permitting process at the time of the audit which should enhance the value of the coal reserve, we direct AEP to hire an auditor specifically to examine the value of the West Virginia coal reserve and to make a recommendation to the Commission as to whether the increased value, if any above the $41 million already required to be credited against OP's under-recovery, should accrue to OP ratepayers beyond the value of the reserve that AEPSC booked under the Settlement Agreement. The Commission will issue by subsequent entry a Request for Proposal to hire the auditor discussed above.

In making the above determination the Commission notes that the record reflects that the Settlement Agreement was entered into in order to terminate a long-term coal supply agreement, entered into in 1992, because the price of coal under the agreement was significantly below market in mid-2007. This long-term agreement was replaced with a new agreement which resulted in OP ratepayers paying significantly more for coal beginning in 2009, the start of the ESP period, than would have been paid had the Settlement Agreement not been entered into. We recognize that this situation is somewhat unique given that OP's fuel costs were not regulated during the period when the buyout occurred and the benefits booked yet the value was realized from coal that should have been delivered during the ESP period. While we do not find any motivation by AEPSC to transfer value from ratepayers during the ESP to an earlier date, nevertheless, the long-term coal agreement was an OP asset for which the value would have flowed through to OP ratepayers through the ESP period but for the extraordinary circumstances related to the early contract termination. Given these factors, we agree with Staff that, in order to determine the real economic cost of coal used during the audit period, more of the value realized by AEP for entering into the Settlement Agreement should flow through to OP ratepayers through a credit to OP's under-recovery and deferrals.

Citing to the ESP cases (Case Nos. 08-917-EL-SSO and 08-918-EL-SSO, Opinion and Order, March 18, 2009, at pages 14-15) and an earlier entry in this proceeding, AEP-Ohio argues that the Commission limited the audit period and the prudence review in this case to 2009 procurement activities and that the only relevant factor is the price the Companies paid for coal during 2009. The Commission disagrees. Contrary to the Companies argument, the Commission is not seeking to reach into another audit period in order to modify rates charged during the audit period but rather is rendering its decision in order to match the revenues and benefits incurred during the audit period. Nor has the Commission found that entering into the Settlement Agreement was imprudent. Again, the Commission is only finding that to determine the real economic cost of coal during the audit period, the Commission must consider both the revenues and the benefits received by the Companies pursuant to the Settlement Agreement and not rely solely on the price paid for coal during 2009. AEP-Ohio further claims that the parties in this case are attempting to illegally relitigate the FAC baseline established in the ESP cases. AEP-Ohio's claims are without merit as the Commission has not adjusted the baseline for the 2009 period as decided in the Companies ESP cases. Rather, the Commission, in this case, is engaging in a reconciliation and accounting which was explicitly contemplated by the ESP cases in future FAC proceedings. Otherwise, there would be no rationale for undertaking an annual audit. In this case, the Commission is making an accounting adjustment to recognize extraordinary events affecting 2009 costs such that the Companies 2009 real costs will be comparable to the proxy baseline selected in the ESP proceedings.

AEP-Ohio's arguments concerning the applicability of *Keco* and *Lucas Cty.* are likewise unavailing. According to the Companies, any attempt to credit amounts booked in 2008 during the prior rate plan would violate the longstanding prohibition against retroactive ratemaking established in *Keco*. However, *Keco* does not apply in this situation. The Commission is not considering modifying a previous rate established by a Commission order through the ratemaking process as the Court considered in *Keco*. Rather, the Commission, by ordering the Companies to credit more of the proceeds from the Settlement Agreement to OP's deferral balance, is establishing a future rate based upon the real cost of the coal used by the Companies to generate electricity during the 2009 FAC audit period. The proceeds AEP-Ohio received for entering into the Settlement Agreement are but one of the components which impact the Companies cost to provision electricity during 2009. Likewise, *Lucas Cty.* does not apply to the present situation. In *Lucas Cty.*, the Court held that the Commission was not statutorily authorized to order a refund of, or credit for, charges previously collected by a public utility where those charges were calculated in accordance with an experimental rate program which has expired. As noted above, the Commission has not made a determination modifying the rate the Companies collected during 2009. Additionally, there is no experimental rate program involved in the current case. Thus, *Lucas Cty.* does not apply in this matter.

As to any benefits associated with the delivery shortfall agreement and the contract support agreement that OCC and IEU-Ohio assert should also be factored into the Companies FAC under-recovery, the Commission determines that any effect these agreements may have had on AEP-Ohio's fuel costs, if any, would appear to apply in time periods outside of the current audit. Therefore, while those agreements may be examined by a future audit, those agreements will not be further examined as part of the current audit.

IV. Financial Audit Recommendations

The audit report also included six financial audit recommendations. In the first recommendation, the auditors submit that the FAC workbooks should be modified to include explanations that identify and/or explain differences between includable FAC amounts recorded in the general ledger versus includable FAC amounts derived from other sources (e.g., Monthly Purchase Summary Reports). Additionally, these explanations should also apply to issues such as timing differences and/or prior period adjustments. The second recommendation is that CSP and OP should include the reconciliation of the fuel and purchased power accounts that have been designated as includable FAC costs with the monthly FAC workbooks, to facilitate a clear audit trail. The third financial audit recommendation is that the Companies overall should provide a better audit trail for tracing costs. Fourth, the auditors suggest that the Commission may want to have AEP-Ohio explain further how the four generating units designated as "must run" units by PJM are affecting the costs that are recoverable in the FAC. The fifth financial audit recommendation is that the Companies should update and/or modify its systems in order to better indicate hourly or 24-hour dispatch costs and off-system sales cost information related to forced outages.

AEP-Ohio witness Dooley testified that the Companies agree with and plan to implement the auditors recommendations regarding financial audit items 1, 2, and 3 (Co. Ex. 1 at 6). The Companies' witnesses did not specifically address financial audit recommendations 4 and 5. The Companies otherwise did acknowledge, however, that AEP-Ohio agreed with and planned to implement the financial audit recommendations as clarified in the Companies' testimony (Cos. Brief at 51).

As AEP-Ohio does not challenge financial audit recommendations 1 through 5, the Commission will adopt such recommendations made in the audit report.

The final financial audit recommendation involves the River Transportation Division (RTD) and has 10 sub-components. The audit report suggests that RTD should respond to the following prior to the next audit and that the next auditor should review the results of this additional information:

(a) RTD should be required to explain and justify the rationale of the Net Investment Base and Cost of Capital Billing Adder formula presented in EVA 4-5, Confidential Attachments 1 and 2.

(b) RTD should be required to provide a procedure for updating the cost of capital and the Return on Equity (ROE) component that is commensurate with the risk of the operation.

(c) An Over Collection by RTD indicates that RTD collected too much from the affiliated companies for barge operations in a particular year. The Over Collection should be a subtraction from the Investment Base (rather than an addition to RTD's expenses).

(d) RTD should provide documentation that it corrected its calculation of the 2008 Working Capital Requirement and the 2009 Working Capital Requirement and the resulting credits \$43,314 (2008) and \$45,117 (2009) to RTD's customers were recorded in its 2nd Quarter's 2010 true up and credited to the operating companies in August 2010. OP's portion of these credits is \$15, 298 (2008) and \$17,325 (2009).

(e) Balance Sheet items such as Prepayments, Materials and Supplies inventory and Other Current and Accrued Liabilities, if considered in developing a utility's rate base, are typically added or subtracted on a 13-month average balance basis. RTD should be required to explain why its current methodology of dividing balance sheet items (such as prepayments, materials and supplies inventory, and other current and accrued liabilities) by eight to derive the Investment Base is a reasonable and appropriate method.

(f) OP, RTD and other AEP affiliates that utilize the RTD should work together to revise the RTD formula to conform with generally accepted public utility industry rate base and ratemaking standards. OP should report quarterly concerning the progress of these efforts by including a description of progress made in its quarterly FAC filings.

(g) The details of RTD charges including, but not limited to, Other Administration Expenses and "AEP Admin Charges" such as those provided by AEP in response to LA 7-17, should be reviewed in detail in the next audit period.

(h) RTD should prepare a justification for how RTD's income tax expense and Accumulated Deferred Income Taxes are handled.

(i) RTD should explain the Accumulated Deferred Income Taxes (ADIT) amounts on its Balance Sheet and identify any amounts and components related to the use of accelerated tax depreciation.

(j) To the extent that RTD has cost-free capital in the form of ADIT related to the use of accelerated tax depreciation (which would typically be associated with credit-balance ADIT amounts), RTD should prepare an explanation why that cost-free capital should not be subtracted in deriving the Investment Base, similar to how ADIT balances would be subtracted in deriving a utility's rate base.

Regarding financial audit recommendations 6a, 6e, 6f, and 6j, the Companies state that, although the current treatment is a reasonable approach, AEP-Ohio is willing to have the RTD division amend its calculation to be in accordance with the traditional base treatment recommended by the audit report starting January 1, 2011 (Co. Ex. 3 at 11). Financial audit recommendation 6b is unnecessary, says AEP-Ohio, because there is already a procedure in place for updating the cost of capital and Return on Equity component commensurate with the risk (*Id.*). AEP-Ohio witness Nelson testified that the ROE is adjusted on January 1 each year to the return allowed by FERC. In the absence of a recent FERC order, the ROE becomes that established by the Indiana Utility Regulatory Commission in its most recent order (*Id.* at 11-12). Regarding financial audit recommendations 6c and 6d, the Companies explain that RTD has made all necessary changes to correct the Working Capital Requirement for 2008 and 2009 and will appropriately credit the applicable operating companies including OP. Documentation will be available for the next audit states AEP-Ohio (Co. Ex. 1 at 6). Similarly, the Companies have no objections to financial audit recommendations 6g, 6h, and 6i. AEP-

Ohio commits that the necessary explanations will be available for the next audit (Co. Ex. 1 at 6-7; Co. Ex. 3 at 12).

Generally, the Companies agree with and plan to implement financial audit recommendations 6a through 6i. Regarding financial audit recommendation 6b, the Companies have adequately explained and thus have complied with the auditors' recommendation. Therefore, no further action is required by the Companies on financial audit recommendation 6b. The Commission adopts as its determinations in this matter, financial audit recommendations 6a through 6i with the exclusion of recommendation 6b discussed in the preceding sentence.

V. Ormet stipulation

Rule 4901-1-30, Ohio Administrative Code, authorizes parties to Commission proceedings to enter into a stipulation. Although not binding on the Commission, the terms of such an agreement are accorded substantial weight. *Consumers' Counsel v. Pub. Util. Comm.* (1992), 64 Ohio St.3d 123, 125, *citing Akron v. Pub. Util. Comm.* (1978), 55 Ohio St.2d 155. This concept is particularly valid where the stipulation is unopposed by any party and resolves all issues presented in the proceeding in which it is offered.

The standard of review for considering the reasonableness of a stipulation has been discussed in a number of prior Commission proceedings. *Cincinnati Gas & Electric Co.*, Case No. 91-410-EL-AIR (April 14, 1994); *Western Reserve Telephone Co.*, Case No. 93-230-TP-ALT (March 30, 1994); *Ohio Edison Co.*, Case No. 91-698-EL-FOR *et al.* (December 30, 1993); *Cleveland Electric Illum. Co.*, Case No. 88-170-EL-AIR (January 30, 1989); *Restatement of Accounts and Records (Zimmer Plant)*, Case No. 84-1187-EL-UNC (November 26, 1985). The ultimate issue for our consideration is whether the agreement, which embodies considerable time and effort by the signatory parties, is reasonable and should be adopted. In considering the reasonableness of a stipulation, the Commission has used the following criteria:

(1) Is the settlement a product of serious bargaining among capable, knowledgeable parties?

(2) Does the settlement, as a package, benefit ratepayers and the public interest?

(3) Does the settlement package violate any important regulatory principle or practice?

The Ohio Supreme Court has endorsed the Commission's analysis using these criteria to resolve issues in a manner economical to ratepayers and public utilities. *Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.* (1994), 68 Ohio St.3d 559, *citing*

Consumers' Counsel, supra, at 126. The court stated in that case that the Commission may place substantial weight on the terms of a stipulation, even though the stipulation does not bind the Commission (*Id.*).

We find that the Ormet stipulation entered into by the stipulating parties is reasonable and should be adopted. In making this determination, the Commission notes that the Ormet stipulation is a product of serious bargaining among capable, knowledgeable parties and is the product of an open process. Moreover, as a package, the Ormet stipulation benefits ratepayers and furthers the public interest as a more thorough examination involving the collection of deferrals and carrying charges associated with the provision of service to Ormet is already the subject of a pending case before the Commission in *In the Matter of the Application of Columbus Southern Power and the Ohio Power Company to Recover Commission-Authorized Deferrals Through each Company's Fuel Adjustment Clause,* Case No. 09-1094-EL-FAC (09-1094). Therefore, a detailed examination of the complex issues surrounding AEP-Ohio's provision of service to Ormet, the largest, most energy-intensive customer that the Companies serve in Ohio, does not have to be considered in this proceeding. Finally, the Commission finds that there is no evidence that the stipulation violates any important regulatory principle or practice and, therefore, the stipulation meets the third criterion. Accordingly, the Ormet stipulation is approved.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) CSP and OP are public utilities under Section 4905.02, Revised Code, and are subject to the jurisdiction of this Commission.

(2) These cases relate to the Commission's review of CSP and OP's fuel costs during the period from January 1, 2009, through December 31, 2009.

(3) By entry issued January 7, 2010, the Commission selected EVA to perform CSP and OP's audit for the period of January 1, 2009, through December 31, 2009. On May 14, 2010, EVA filed its audit report.

(4) On January 7, 2010, IEU-Ohio, OCC, and Ormet were granted intervention in these cases.

(5) A hearing in these matters was held on August 23 and August 24, 2010.

(6) Briefs and reply were filed on September 23, 2010, and October 15, 2010, respectively.

(7) At the hearing, a stipulation was submitted acknowledging that a determination on the collection of deferrals and carrying charges associated with an Ormet Interim Agreement is the subject of a pending case before the Commission and that the issues associated with the Ormet Interim Agreement would be addressed in that proceeding. The stipulation was signed by AEP-Ohio, Staff, OCC, IEU-Ohio, and Ormet. The stipulation meets the criteria used by the Commission to evaluate stipulations, is reasonable, and should be adopted.

ORDER:

It is, therefore,

ORDERED, That the Companies credit OP's FAC under-recovery as discussed herein. It is, further,

ORDERED, That the Companies hire an auditor as discussed herein. It is, further,

ORDERED, That the stipulation entered into by AEP-Ohio, Staff, OCC, IEU-Ohio, and Ormet be adopted and approved. It is, further,

ORDERED, That AEP-Ohio take all necessary steps to carry out the terms of this opinion and order. It is, further,

ORDERED, That nothing in this opinion and order shall be binding upon the Commission in any future proceeding or investigation involving the justness or reasonableness of any rate, charge, rule, or regulation. It is, further, ORDERED, That a copy of this opinion and order be served upon each party of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Paul A. Centolella

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto

JRJ/vrm

Entered in the Journal

JAN 2 3 2012

Betty McCauley

Betty McCauley
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company.	)))	Case No. 09-872-EL-FAC Case No. 09-873-EL-FAC

ENTRY ON REHEARING

The Commission finds:

(1) Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly, AEP-Ohio or the Companies)[1] are public utilities as defined in Section 4905.02, Revised Code, and, as such, are subject to the jurisdiction of this Commission.

(2) By opinion and order issued March 18, 2009, as clarified by the entry on rehearing issued July 23, 2009, in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO, the Commission modified and approved AEP-Ohio's application for an electric security plan (ESP) for 2009 through 2011, which included approval of a fuel adjustment clause (FAC) mechanism for CSP and OP, under which the Companies recovered prudently incurred costs associated with fuel, including consumables related to environmental compliance, purchased power costs, emission allowances, and costs associated with carbon-based taxes and other carbon-related regulations (ESP 1 order).[2] The approved FAC mechanism provided for quarterly reconciliations to actual FAC costs incurred by the Companies, which established the FAC rates for the subsequent quarter, as well as an annual audit of the accounting of the FAC costs. The Commission also authorized a phase-in of AEP-Ohio's ESP rates during the term of the ESP by deferring a portion of the annual incremental FAC costs such that the amount of the incremental FAC expense to be recovered from customers would be limited so as not to exceed specified percentage increases on a total bill basis.

1 By entry issued March 7, 2012, the Commission approved and confirmed the merger of CSP into OP. *In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals* (Merger Case), Case No. 10-2376-EL-UNC.

2 *In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets*, Case No. 08-917-EL-SSO; *In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan*, Case No. 08-918-EL-SSO.

(3) On May 14, 2010, Energy Ventures Analysis, Inc. (EVA) filed, in the present cases, a management/performance (m/p) and financial audit report in response to its annual audit of AEP-Ohio's FAC mechanism for 2009 (audit report).

(4) On January 27, 2011, in Case No. 11-346-EL-SSO, *et al.*, AEP-Ohio filed an application for approval of a second ESP to begin on January 1, 2012 (ESP 2 cases).[3]

(5) On September 7, 2011, a stipulation and recommendation (ESP 2 stipulation) was filed by AEP-Ohio, Staff, and other parties to resolve the issues raised in the ESP 2 cases and several other cases pending before the Commission (consolidated cases).[4] The ESP 2 stipulation provided, *inter alia*, that the current FAC mechanism was to continue through May 31, 2015.

(6) On December 14, 2011, the Commission issued an opinion and order in the consolidated cases, modifying and adopting the ESP 2 stipulation (ESP 2 order).

(7) On January 23, 2012, the Commission issued its opinion and order in the present proceedings regarding the annual audit of AEP-Ohio's FAC mechanism for 2009 (FAC order). With respect to the financial audit recommendations contained in the audit report, the Commission adopted financial audit recommendations 1 through 5, as well as 6a through 6i, with the exclusion of 6b. The Commission also adopted m/p audit recommendations 2 through 6, as contained in the audit report.

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3 *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan,* Case Nos. 11-346-EL-SSO and 11-348-EL-SSO; *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority,* Case Nos. 11-349-EL-AAM and 11-350-EL-AAM.

4 Merger Case, Case No. 10-2376-EL-UNC; *In the Matter of the Application of Columbus Southern Power Company to Amend its Emergency Curtailment Service Riders,* Case No. 10-343-EL-ATA; *In the Matter of the Application of Ohio Power Company to Amend its Emergency Curtailment Service Riders,* Case No. 10-344-EL-ATA; *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company,* Case No. 10-2929-EL-UNC; *In the Matter of the Application of Columbus Southern Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Pursuant to Section 4928.144, Revised Code,* Case No. 11-4920-EL-RDR; *In the Matter of the Application of Ohio Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Pursuant to Section 4928.144,* Revised Code, Case No. 11-4921-EL-RDR.

In m/p audit recommendation 1, EVA recommended that the Commission consider whether any proceeds from a settlement agreement that American Electric Power Service Corporation (AEPSC) had executed with a coal supplier in 2007 (settlement agreement) should be credited against OP's FAC under-recovery for 2009. The settlement agreement was effectively a buy-out of the contract with the coal supplier after 2008. Pursuant to the terms of the settlement agreement, OP received a lump sum payment (made in three equal payments) and coal reserve in West Virginia. In the FAC order, the Commission determined that all of the realized value from the settlement agreement should be credited against OP's FAC under-recovery for 2009. The Commission specified that the portion of the $30 million lump sum payment not already credited to the ratepayers of OP, as well as the $41 million value of the West Virginia coal reserve booked when the settlement agreement was executed, should be credited against the FAC under-recovery. Additionally, because the present value of the West Virginia coal reserve is unknown and the permitting process is expected to enhance its value, the Commission indicated that a request for proposal (RFP) would be issued by subsequent entry to hire an auditor to examine the value of the West Virginia coal reserve. The Commission noted that the auditor would be expected to make a recommendation as to whether the increased value of the West Virginia coal reserve, if any, above the $41 million already required to be credited against OP's FAC under-recovery should accrue to ratepayers.

Finally, the Commission determined that the delivery shortfall agreement and the contract support agreement would not be further examined as part of the current audit. The Commission noted, however, that these agreements may be examined in a future audit, given that their impact on AEP-Ohio's fuel costs, if any, appeared to occur in time periods outside of the current audit.

(8) Section 4903.10, Revised Code, states that any party who has entered an appearance in a Commission proceeding may apply for a rehearing with respect to any matters determined therein by filing an application within 30 days after the entry of the order upon the Commission's journal.

(9) On February 22, 2012, applications for rehearing of the FAC order were filed by AEP-Ohio, Industrial Energy Users-Ohio (IEU-Ohio), and the Ohio Consumers' Counsel (OCC).

(10) On February 23, 2012, the Commission issued an entry on rehearing in the consolidated cases, granting rehearing in part (ESP 2 entry on rehearing). Finding that the signatory parties to the ESP 2 stipulation had not met their burden of demonstrating that the stipulation, as a package, benefits ratepayers and the public interest, as required by the Commission's three-part test for the consideration of stipulations, the Commission rejected the stipulation.

(11) On March 2, 2012, in the above-captioned cases, AEP-Ohio filed a memorandum contra the applications for rehearing of the FAC order filed by IEU-Ohio and OCC. On March 5, 2012, IEU-Ohio and OCC filed memoranda contra AEP-Ohio's application for rehearing of the FAC order.

(12) By entry on rehearing issued March 21, 2012, the Commission granted the applications for rehearing of the FAC order to allow further consideration of the matters specified in the applications.

(13) The Commission has reviewed and considered all of the arguments on rehearing. Any arguments on rehearing not specifically discussed herein have been thoroughly and adequately considered by the Commission and should be denied.

Re-adjudication of the ESP 1 Order

(14) In its fourth assignment of error, AEP-Ohio contends that the FAC order unreasonably and unlawfully modifies the ESP 1 order wherein the Commission directed that annual FAC audits examine fuel procurement practices and expenses for the audit period. AEP-Ohio offers that expanding the scope of the FAC audit, as litigated and decided in the ESP 1 order, violates the principles of res judicata and collateral estoppel. According to AEP-Ohio, the FAC audit period is strictly limited to January 2009 through December 2009. Similarly, in the Companies' fifth assignment of error, AEP-Ohio claims that through the FAC order, the Commission is unreasonably and unlawfully

retroactively modifying the decision in the ESP 1 order, which established the FAC baselines to facilitate the Companies' transition from a period without a FAC mechanism to a period with a FAC mechanism. With the establishment of the FAC baseline, AEP-Ohio asserts that the FAC order in this case is a retreat from the agreement with the Companies to implement fuel deferrals to stabilize recovery. AEP-Ohio reasons that the FAC baseline is res judicata and collateral estoppel prevents the Commission from revision of its decision in these proceedings. OCC and IEU-Ohio submit that these arguments are baseless. OCC states that the purpose of Commission audits, as was the case in these proceedings, is to assist the Commission in determining the prudence and true cost of a company's fuel-related purchases so that customers pay no more than what is reasonable for electricity. IEU-Ohio offers that the FAC order properly concluded that the Companies' claim of res judicata is without merit as 2009 fuel costs were not litigated in the first ESP proceedings.

(15) For the same reasons as stated in the FAC order, we again reject both of these arguments by the Companies. The scope and extent of the audit and the audit period were not revised or expanded as a result of the FAC order. As IEU-Ohio reasoned, the focus of the dispute in these proceedings is OP's 2009 fuel costs. OP's 2009 fuel costs were not litigated in the first ESP proceedings and could not have been litigated because the 2009 fuel costs were not known at that time. The purpose of the FAC audit was to evaluate 2009 fuel and fuel-related costs and the prudency of the Companies' fuel transactions, including the true costs and accounting accuracy of the fuel transactions. AEP-Ohio's claims to the contrary are without merit. Accordingly, we deny AEP-Ohio's fourth and fifth assignments of error.

Settlement Agreement

(16) In its first assignment of error, AEP-Ohio requests that the Commission clarify that the FAC order does not include the return of any amounts allocable to wholesale and non-Ohio retail jurisdictions.

(17) IEU-Ohio initially asserts that AEP-Ohio failed to offer evidence to support its jurisdictional argument as a part of the hearing and, is, therefore, precluded from raising the subject on rehearing. IEU-Ohio argues that AEP-Ohio selectively raises the jurisdictional argument, where it advocates just the opposite in its significantly excessive earnings proceedings,[5] and does so in this case to retain the benefits of the settlement agreement for its shareholders.

(18) We disagree with IEU-Ohio that AEP-Ohio is precluded from raising the jurisdictional issue at the rehearing stage. AEP-Ohio's claim is prompted by its interpretation of the language in the FAC order. AEP-Ohio witnesses and the financial auditor recognized that fuel expenses are allocated between Ohio retail expenses, non-Ohio retail expenses, or wholesale expenses. The same is true regarding the allocation of revenues. Therefore, we find that the record includes sufficient evidence to justify presentation of the claim by AEP-Ohio. We clarify that the 2009 FAC under-recovery need only be credited for the share of the settlement agreement allocable to Ohio's retail jurisdictional customers.

(19) In its third assignment of error, AEP-Ohio reasons that the FAC order's direction that all of the realized value from the settlement agreement should be credited against OP's FAC under-recovery amounts to selective and unlawful retroactive ratemaking in violation of *Keco Industries, Inc. v. Cincinnati & Suburban Bell Tel. Co.* (1957), 166 Ohio St. 254, and *Lucas Cty. Commrs. v. Pub. Util Comm.* (1997), 80 Ohio St.3d 344. OCC believes that OP's arguments are faulty. In this case, OCC argues, and the Commission agrees, that the FAC order did not modify a previously established rate as part of a ratemaking proceeding, as was the case in *Keco*, or direct the issuance of a refund of unlawfully collected rates, as was the case in *Lucas Cty*.

AEP-Ohio mischaracterizes the FAC order. Further, the Commission acknowledged the Companies' arguments on retroactive ratemaking and refunds, as summarized in the

5 See *In re AEP-Ohio*, Case No. 10-1261-EL-UNC, Order at 11-12 (January 11, 2011).

order (FAC order at 7-8). As explained in the order, the FAC adjustments ordered as a result of the settlement agreement are to align the fuel costs charged to ratepayers with the real economic cost of fuel for 2009. Nothing in OP's application for rehearing convinces the Commission that our decision should be reversed. Accordingly, OP's third assignment of error should be denied.

(20) In its sixth assignment of error, AEP-Ohio reasons that, since the auditor and the Commission did not find the settlement agreement to be imprudent, the FAC order unreasonably and unlawfully impairs the settlement agreement, which was executed by AEP-Ohio at a time when fuel costs and fuel contracts were not regulated. IEU-Ohio replies that the Companies' position is illogical as Rule 4901:1-35-03(C)(9)(a), Ohio Administrative Code, provides that a utility's FAC must include "any benefits available to the electric utility as a result of or in connection with such costs including but not limited to profits from emission allowance sales...." Thus, IEU-Ohio reasons that AEP-Ohio was required to account for the reduction in fuel costs.

(21) Despite AEP-Ohio's arguments to the contrary, it is not a condition precedent to reflecting the realized value of the Companies' fuel costs in the FAC, that the Commission find the settlement agreement imprudent. Pursuant to the requirements of division (B)(2) of Section 4928.143, Revised Code, to include the FAC mechanism as a part of the first ESP, AEP-Ohio was required to include "in the application any benefits available to the electric utility as a result of or in connection with such [FAC] costs including but not limited to profits from emission allowance sales and profits from resold coal contracts." The purpose of the FAC audit was to ensure and verify the FAC costs and expenses as well as to review the prudency of the Companies' transactions. Accordingly, we deny AEP-Ohio's sixth assignment of error.

(22) In its seventh assignment of error, AEP-Ohio argues that the FAC order selectively considers the settlement agreement, to direct a decrease in the fuel costs for 2009, but ignores the 2008 production bonus agreement also entered into when fuel contracts were not regulated. AEP-Ohio states that the 2008

production bonus agreement ensured that one of its suppliers remained in business and was able to provide the Companies' coal at below-market prices during 2008. AEP-Ohio admits that it did not seek to recover the $28.6 million dollar payment in 2009 FAC rates since it was incurred before the FAC regulatory structure was implemented. AEP-Ohio argues that this agreement is an example of why the Commission should not reach outside of the audit period to adjust AEP-Ohio's 2009 FAC under-recovered balance. Alternatively, AEP-Ohio states that the 2008 production bonus agreement fuel cost should be used to offset any "claw-back" into amounts relating to the settlement agreement. IEU-Ohio notes that AEP-Ohio overlooks the fact that the Companies received annual generation increases during the rate stabilization plan period (2005-2008),[6] which facilitated AEP-Ohio's recovery of increases in generation costs. As such, IEU-Ohio argues that customers paid their fair share of the total cost of the 2008 production bonus agreement.

(23) The Commission notes that the audit report did not recommend that the 2008 production bonus agreement be taken into consideration, in contrast to the auditor's recommendation in regards to the settlement agreement, nor recommend that the 2008 production bonus agreement be used as an offset to the benefits accrued as a result of the settlement agreement. Based on the generation rate increases built into the rate stabilization plan in effect prior to the first ESP in 2009, and the evidence of record in these proceedings, the Commission finds that the record does not support offsetting the adjustments to the deferred fuel costs for the settlement agreement, as directed in the FAC order, by the 2008 production bonus agreement. Accordingly, AEP-Ohio's seventh assignment of error is denied.

(24) In its first assignment of error, IEU-Ohio asserts that the FAC order unreasonably and unlawfully failed to require AEP-Ohio to include a carrying cost component in the value associated with the lump sum payment and West Virginia coal reserve to be credited against the FAC deferral balance. In its second

6 See *In re AEP-Ohio*, Case No. 04-169-EL-UNC, Order at 15-19 (January 26, 2005); and *In re AEP-Ohio*, Case No. 07-1132-EL-UNC, Order at 3 (January 30, 2008).

assignment of error, OCC makes a comparable argument that the Commission erred in failing to require AEP-Ohio to credit customers for the interest accrued from 2009 until the date of the FAC order on the value of the lump sum payment and the West Virginia coal reserve. In its memorandum contra, AEP-Ohio replies that the award of interest or the reduction of carrying charges would constitute retroactive ratemaking and an unlawful modification of the ESP 1 order, and would also inequitably add to the under-recovery of actual FAC expenses for 2009.

(25) In the FAC order, the Commission determined that all of the realized value from the settlement agreement should be credited against OP's FAC under-recovery. We noted the unique circumstances of the settlement agreement and determined that, in order to assess the real economic cost of coal used during the audit period, more of the value realized as a result of entering into the settlement agreement should flow through to ratepayers by way of a credit to the FAC under-recovery. (FAC order at 12-13.) In accordance with our finding that all of the realized value from the settlement agreement should be credited to the benefit of ratepayers, we find that AEP-Ohio should flow through to its customers a carrying charge component in applying the credit to OP's FAC under-recovery. Such carrying charge component should be calculated in a manner consistent with calculation of the FAC deferrals, as approved in the ESP 1 order, including use of the approved weighted average cost of capital.[7] Thus, the Commission disagrees with OP's argument that the award of interest or the reduction of carrying charges constitutes retroactive ratemaking because a calculation that is consistent with the approved FAC deferrals is, by definition, not a modification of a previously established rate, as was the case in *Keco*. Accordingly, we find that IEU-Ohio's first assignment of error and OCC's second assignment of error should be granted.

(26) IEU-Ohio's second assignment of error is that the Commission unlawfully and unreasonably failed to direct AEP-Ohio to recalculate its phase-in recovery rider (PIRR) rates to reflect the immediate reduction of the FAC deferral balance that is

7 ESP 1 order at 23.

collected through the rider. OCC raises a similar argument in its first assignment of error. In particular, OCC contends that the Commission unreasonably failed to specify that AEP-Ohio should immediately credit to customers the full value of the settlement agreement and also credit the increased value of the West Virginia coal reserve as soon as the valuation is completed by the auditor. OCC notes that an immediate credit to the FAC deferral balance will minimize carrying charges and reduce the amount that customers are charged through the PIRR. In response, AEP-Ohio argues that it would be unreasonable and imprudent to reduce the PIRR rates immediately. AEP-Ohio claims that, if an immediate credit is implemented and the FAC order is subsequently found to be unlawful, excessive revenue and rate volatility would result. AEP-Ohio adds that it is impossible to reduce the PIRR immediately to reflect the value of the West Virginia coal reserve, as its value is unknown and can only be accurately determined through a sale of the asset. Finally, AEP-Ohio notes that the arguments of IEU-Ohio and OCC fail to account for the fact that the PIRR as approved in the ESP 2 order has been effectively vacated by the ESP 2 entry on rehearing.

(27) Pursuant to Section 4903.15, Revised Code, Commission orders are effective immediately upon entry in the journal. Additionally, in the FAC order, the Commission specifically directed AEP-Ohio to credit the FAC under-recovery as addressed in the order, and did not grant a stay of the order (FAC order at 19). To the extent necessary to resolve any confusion on the part of the parties, the Commission now makes explicit its intention that AEP-Ohio should immediately implement the credit to reduce the FAC deferral balance in accordance with the FAC order and this entry on rehearing. We also note that AEP-Ohio's PIRR rates are the subject of separate proceedings in which the Commission will consider recovery of the deferred FAC costs and determine the proper rates, including any adjustments that may be necessary in light of the present cases.[8] With this clarification, we find that

8 *In the Matter of the Application of Columbus Southern Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Pursuant to Section 4928.144, Revised Code,* Case No. 11-4920-EL-RDR; *In the Matter of the Application of Ohio Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Pursuant to Section 4928.144,* Revised Code, Case No. 11-4921-EL-RDR.

IEU-Ohio's second assignment of error and OCC's first assignment of error should be denied.

(28) In AEP-Ohio's eighth assignment of error, the Companies note that the West Virginia coal reserve is an OP asset properly accounted for as part of the settlement agreement. The valuation of the coal reserve directed in the FAC order, according to AEP-Ohio, is based on the unlawful and unreasonable premise that AEP-Ohio ratepayers have an ownership interest in the coal reserve, in contrast to Commission precedent.[9] The Companies argue that ratepayers do not acquire an ownership interest in utility assets by paying the rates for service. Accordingly, AEP-Ohio reasons there is no legal basis for the FAC order's seizure of the value of the coal reserve to reduce the 2009 fuel costs or any future fuel costs.

(29) AEP-Ohio made similar arguments in its brief and again takes the opportunity to mischaracterize the FAC order. The FAC order does not imply or recognize any ratepayer ownership interest in the coal reserve. We agree with AEP-Ohio that ratepayers do not earn or acquire an ownership interest in the utility's assets as a result of paying for utility services. An ownership interest is not necessary for the Commission to order, as it did in the FAC order, the alignment of fuel costs with the benefits of AEP-Ohio's fuel contracts. For these reasons, we again reject AEP-Ohio's claims and deny the request for rehearing.

Determination of Value of Coal Reserve

(30) In its second assignment of error, AEP-Ohio requests that the Commission clarify the methodology to be used to determine the value of the West Virginia coal reserve to include, as an alterative to the valuation by way of an appraisal, the sale of the property after a final, non-appealable decision is issued in these cases. The Companies reason that the only way to determine the proper value of the coal reserve is by sale. The Companies also request that the Commission recognize that the

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9 *In the Matter of the Regulation of the Electric Fuel Component Contained Within the Rate Schedules of the Columbus Southern Power Company and Related Matters*, Case No. 88-102-EL-EFC, Order (October 28, 1988).

value of the coal reserve could be more or less than the $41.6 million net book value. IEU-Ohio reasons that an appraisal of the value of the coal reserve, as directed in the FAC order, is the most expedient means to determine the amount by which the FAC under-recovery should be credited.

(31) We reject AEP-Ohio's request to require the sale of the coal reserve to determine its value. It was not the intent of the FAC order to permanently terminate OP's ownership of the asset but to direct that the value of the coal reserve be determined by an independent, third-party. We expect that an independent appraisal will facilitate a more expedient resolution of the issue, even assuming more litigation, as the Companies imply, than the sale of the coal reserve. Nonetheless, we clarify that the value of the coal reserve, to be determined by an independent auditor, may be more or less than the $41.6 million net book value reflected on OP's books. Accordingly, we deny AEP-Ohio's request for rehearing on this issue.

Selection of Auditor

(32) In its third assignment of error, IEU-Ohio argues that the FAC order is unreasonable and unlawful because it did not direct Staff to hire and supervise an independent auditor and set a timeframe for the valuation of the West Virginia coal reserve. Asserting that the FAC order is unclear as to how the auditor will be selected, IEU-Ohio requests that the Commission provide clarification on this point to ensure that the audit is conducted in a fair, transparent, and timely manner. OCC, likewise, asserts in its third assignment of error that the Commission erred in directing AEP-Ohio to hire the auditor. OCC argues that the Commission should clarify that it will select an independent auditor to work under the direction of Staff and that OP's shareholders will pay for the audit. In response, AEP-Ohio maintains that the Commission should reject the requests of IEU-Ohio and OCC for an independent, Commission-hired auditor. AEP-Ohio contends that the value of the West Virginia coal reserve should be determined through a sale of the asset and that OP should be permitted to direct the sale.

(33) The Commission finds that the FAC order specifically indicated that an RFP would be issued by subsequent entry for the purpose of selecting and hiring an auditor to examine the value of the West Virginia coal reserve (FAC order at 12). Upon review of the proposals received in response to the RFP, the Commission will select an appropriate individual or firm with the technical expertise to independently determine the value of the West Virginia coal reserve. We note that both the auditor/appraiser and AEP-Ohio will be expected to adhere to the terms set forth in the entry selecting the auditor/appraiser. With this clarification, we find that the third assignments of error of IEU-Ohio and OCC should be denied.

Delivery Shortfall Agreement and Contract Support Agreement

(34) In its ninth assignment of error, AEP-Ohio argues that the Commission's conclusion that the delivery shortfall agreement and the contract support agreement may be examined in a future audit is unreasonable and unlawful for the same reasons asserted regarding its third through eighth assignments of error. In their memoranda contra, IEU-Ohio and OCC assert that the Commission properly determined that the delivery shortfall agreement and the contract support agreement may be considered in a future audit.

(35) In its fourth assignment of error, IEU-Ohio contends that the Commission unreasonably and unlawfully failed to direct AEP-Ohio to credit the benefits received under the contract support agreement against the FAC under-recovery. IEU-Ohio maintains that the contract support agreement contributed to increased fuel costs in 2009 and that, in the absence of a FAC mechanism, there will be little benefit to customers in future years when AEP-Ohio exercises its option to purchase coal at a discount off the market price beginning in 2013. Similarly, OCC asserts in its fourth assignment of error that the Commission erred in failing to credit customers for the increased price of coal that AEP-Ohio agreed to pay during 2009 pursuant to the contract support agreement and in failing to account for carrying charges. In its memorandum contra, AEP-Ohio contends that any benefit that it may receive from the contract support agreement will not ripen until it exercises its option to take the discounted pricing and will, therefore,

apply to time periods outside of the current audit, if the option is even fully exercised.

(36) The Commission finds that the fourth assignments of error of IEU-Ohio and OCC, as well as AEP-Ohio's ninth assignment of error, should be denied. We find that IEU-Ohio and OCC have raised no new arguments on rehearing that would warrant reconsideration of the FAC order and that there is no merit in AEP-Ohio's arguments for the reasons discussed above with respect to its third through eighth assignments of error. To the extent that a benefit is realized from the contract support agreement, such benefit will not accrue until after AEP-Ohio elects to exercise its option in 2013, which is well beyond the time period under review in the present proceedings. Therefore, although it is premature at this point to consider the purported benefits of the contract support agreement, we note that both the contract support agreement and the delivery shortfall agreement may be examined in a future audit of AEP-Ohio's fuel costs.

Fuel Procurement Procedures

(37) AEP-Ohio, in its tenth assignment of error, argues that AEPSC should not be required to add fuel procurement procedures as it completes the process of updating its policies and procedures manual. AEP-Ohio asserts that policies, not procedures, result in the most efficient procurement of fuel at the lowest reasonable price and, for that reason, the revisions to the manual are focused on procurement policies. AEP-Ohio requests that the Commission clarify that only the fuel procurement policies be updated in the manual and that the auditor is directed to review those updated policies in the next m/p audit proceeding. IEU-Ohio responds that AEPSC should be required to update the policies and procedures manual in accordance with EVA's recommendation. According to IEU-Ohio, the Commission should reject AEP-Ohio's attempt to avoid updating the manual to include fuel procurement procedures.

(38) In the FAC order, the Commission adopted m/p audit recommendation 5, which recommended that AEPSC finalize its update of its policies and procedures manual to reflect

current business practices and that the update be completed in time for it to be reviewed in the next m/p audit (FAC order at 6, 12; Commission-ordered Ex. 1A at 1-7). Although EVA enumerated eight items including certain procedural information that it hoped the updated manual would include, EVA recommended only that the update be completed and that the revised manual be reviewed in the next m/p audit (Commission-ordered Ex. 1A at 1-7, 2-11). Thus, we clarify that, in accordance with m/p audit recommendation 5, there is no specific requirement that AEPSC's policies and procedures manual include a formal procedural section. Upon review of the updated manual in the course of the next m/p audit, the auditor may recommend that the manual be further revised to include a procedural section, as the auditor deems necessary. With this clarification, AEP-Ohio's tenth assignment of error should be denied.

It is, therefore,

ORDERED, That the applications for rehearing filed by AEP-Ohio, IEU-Ohio, and OCC be granted or denied, as discussed above. It is, further, ORDERED, That a copy of this entry on rehearing be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto

Lynn Slaby

GNS/SJP/sc

Entered in the Journal APR 1 1 2012

Barcy F. McNeal

Barcy F. McNeal
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company.	)))	Case No. 09-872-EL-FAC Case No. 09-873-EL-FAC

FOURTH ENTRY ON REHEARING

The Commission finds:

(1) Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly, AEP-Ohio or the Companies)[1] are public utilities as defined in Section 4905.02, Revised Code, and, as such, are subject to the jurisdiction of this Commission.

(2) By opinion and order issued on March 18, 2009, as clarified by the entry on rehearing issued on July 23, 2009, in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO, the Commission modified and approved AEP-Ohio's application for an electric security plan (ESP) for 2009 through 2011, which included approval of a fuel adjustment clause (FAC) mechanism for CSP and OP, under which the Companies recovered prudently incurred costs associated with fuel, including consumables related to environmental compliance, purchased power costs, emission allowances, and costs associated with carbon-based taxes and other carbon-related regulations.[2] The approved FAC mechanism provided for quarterly reconciliations to actual FAC costs incurred by the Companies, which established the FAC rates for the subsequent quarter, as well as an annual audit of the accounting of the FAC costs. The Commission also authorized a phase-in of AEP-Ohio's ESP rates during the term of the ESP by deferring a portion of the annual

1 By entry issued on March 7, 2012, the Commission approved and confirmed the merger of CSP into OP. *In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals*, Case No. 10-2376-EL-UNC.

2 *In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets*, Case No. 08-917-EL-SSO; *In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan*, Case No. 08-918-EL-SSO.

incremental FAC costs such that the amount of the incremental FAC expense to be recovered from customers would be limited so as not to exceed specified percentage increases on a total bill basis.

(3) On May 14, 2010, Energy Ventures Analysis, Inc. (EVA) filed, in the present cases, a management/performance (m/p) and financial audit report in response to its annual audit of AEP-Ohio's FAC mechanism for 2009 (audit report).

(4) On January 23, 2012, the Commission issued its opinion and order regarding the annual audit of AEP-Ohio's FAC mechanism for 2009 (FAC order). With respect to the financial audit recommendations contained in the audit report, the Commission adopted financial audit recommendations 1 through 5, as well as 6a through 6i, with the exclusion of 6b. The Commission also adopted m/p audit recommendations 2 through 6, as contained in the audit report.

In m/p audit recommendation 1, EVA recommended that the Commission consider whether any proceeds from a settlement agreement that American Electric Power Service Corporation had executed with a coal supplier in 2007 (settlement agreement) should be credited against OP's FAC under-recovery for 2009. The settlement agreement was effectively a buy-out of the contract with the coal supplier after 2008. Pursuant to the terms of the settlement agreement, OP received a lump sum payment (made in three equal payments) and coal reserve in West Virginia. In the FAC order, the Commission determined that all of the realized value from the settlement agreement should be credited against OP's FAC under-recovery for 2009. The Commission specified that the portion of the $30 million lump sum payment not already credited to the ratepayers of OP, as well as the $41 million value of the West Virginia coal reserve booked when the settlement agreement was executed, should be credited against the FAC under-recovery. Additionally, because the present value of the West Virginia coal reserve is unknown and the permitting process is expected to enhance its value, the Commission indicated that a request for proposal would be issued by subsequent entry to hire an auditor to examine the value of the West Virginia coal reserve. The Commission noted that the auditor would be expected to make a recommendation as to whether the increased value of the West Virginia coal reserve, if any, above the $41 million already required to be credited against OP's FAC under-recovery should accrue to ratepayers.

Finally, the Commission determined that the delivery shortfall agreement and the contract support agreement would not be further examined as part of the current audit. The Commission noted, however, that these agreements may be examined in a future audit, given that their impact on AEP-Ohio's fuel costs, if any, appeared to occur in time periods outside of the current audit.

(5) Section 4903.10, Revised Code, states that any party who has entered an appearance in a Commission proceeding may apply for a rehearing with respect to any matters determined therein by filing an application within 30 days after the entry of the order upon the Commission's journal.

(6) On February 22, 2012, applications for rehearing of the FAC order were filed by AEP-Ohio, Industrial Energy Users-Ohio (IEU-Ohio), and the Ohio Consumers' Counsel (OCC).

(7) On March 2, 2012, AEP-Ohio filed a memorandum contra the applications for rehearing of the FAC order filed by IEU-Ohio and OCC. On March 5, 2012, IEU-Ohio and OCC filed memoranda contra AEP-Ohio's application for rehearing of the FAC order.

(8) By entry on rehearing issued on March 21, 2012, the Commission granted the applications for rehearing of the FAC order to allow further consideration of the matters specified in the applications.

(9) On April 11, 2012, the Commission issued an entry on rehearing granting, in part, and denying, in part, the applications for rehearing filed by AEP-Ohio, IEU-Ohio, and OCC, as discussed in the entry (FAC entry on rehearing). With respect to AEP-Ohio's first assignment of error, the

Commission clarified that the 2009 FAC under-recovery need only be credited for the share of the settlement agreement allocable to Ohio's retail jurisdictional customers.

(10) On May 11, 2012, IEU-Ohio filed an application for rehearing of the FAC entry on rehearing. In its only assignment of error, IEU-Ohio asserts that the FAC entry on rehearing is unlawful and unreasonable in that the Commission limited the amount of the credit for the settlement agreement to the portion allocable to the Ohio retail jurisdiction. IEU-Ohio requests that the Commission grant rehearing on this issue or, alternatively, clarify that all of the credit is allocable to Ohio retail jurisdictional customers. IEU-Ohio contends that, because AEP-Ohio was required, pursuant to its ESP, to allocate its least cost fuel to standard service offer (SSO) customers, the entire credit from the settlement of the below-market coal contract should be allocated to SSO customers. IEU-Ohio notes that AEP-Ohio has not claimed that the coal contract was not its lowest cost fuel source. IEU-Ohio argues that the costs of the contract would have been fully allocated to the Ohio retail jurisdiction and that any benefits received as a result of a renegotiation of the contract should likewise be fully allocated to Ohio retail jurisdictional customers. IEU-Ohio adds that AEP-Ohio's jurisdictional argument is only relevant in a traditional cost-of-service ratemaking context, which is inapplicable under circumstances involving default generation service. IEU-Ohio also notes that AEP-Ohio has not shown that Ohio customers should not receive the full benefits of the settlement agreement, which were accepted by AEP-Ohio in exchange for higher fuel costs paid by such customers. IEU-Ohio adds that AEP-Ohio failed to raise its jurisdictional argument during the hearing or briefing and should thus be precluded from making the argument at this point in the proceedings. Finally, IEU-Ohio argues that AEP-Ohio's jurisdictional argument should be rejected because it is selectively advanced only when it works to the detriment of Ohio customers.

(11) On May 21, 2012, AEP-Ohio filed a memorandum contra IEU-Ohio's application for rehearing. AEP-Ohio responds that IEU-Ohio has raised no new arguments for the

Commission's consideration and that IEU-Ohio improperly seeks rehearing of an issue that has already been fully briefed and was merely clarified on rehearing. AEP-Ohio notes that IEU-Ohio raised the same arguments in its March 5, 2012, memorandum contra AEP-Ohio's application for rehearing. AEP-Ohio also asserts that the Commission properly found in the FAC entry on rehearing that the record supports AEP-Ohio's jurisdictional claim, noting that the testimony in the record is clear that the FAC involves only the retail share of AEP-Ohio's fuel costs and that the portion of the settlement agreement already passed through the FAC was based on the retail jurisdictional allocation. AEP-Ohio contends that the Commission's clarification that the 2009 FAC under-recovery need only be credited for the share of the settlement agreement allocable to Ohio's retail jurisdictional customers is required by state and federal law, prior Commission orders, and the record in these proceedings. AEP-Ohio notes that the Commission has no authority to regulate wholesale sales of electricity or the provision of retail electric service in other states. AEP-Ohio further notes that it has been consistent in recognizing the need to respect jurisdictional lines, contrary to IEU-Ohio's position. AEP-Ohio also adds that the supplier contract in question was not an available coal source from the outset of the ESP in 2009 and that AEP-Ohio fully complied with any obligation to allocate the lowest cost fuel actually available to it in 2009 to its SSO customers.

(12) By entry on rehearing issued on June 6, 2012, the Commission granted IEU-Ohio's application for rehearing to allow further consideration of the matters specified in the application.

(13) Upon review of the application for rehearing filed by IEU-Ohio on May 11, 2012, the Commission finds that the application should be denied. In the FAC entry on rehearing, the Commission clarified that the 2009 FAC under-recovery need only be credited for the share of the settlement agreement allocable to Ohio's retail jurisdictional customers. We explicitly disagreed with IEU-Ohio's argument that AEP-Ohio was precluded from raising this issue at the rehearing stage, finding that AEP-Ohio's claim was prompted by its interpretation of the FAC order and that there was

evidence in the record on this issue. We likewise find no merit in the arguments raised by IEU-Ohio in its May 11, 2012, application for rehearing and find that IEU-Ohio has raised no argument that was not already considered and rejected. In the FAC entry on rehearing, we properly clarified our intention that only the portion of the proceeds from the settlement agreement allocable to Ohio's retail jurisdictional customers must be applied to the 2009 FAC under-recovery. As in many cases before the Commission, it is necessary that certain allocations be made so that only the accounts, property, expenses, revenues, and so forth associated with rendering service to jurisdictional customers are included within the scope of the proceedings.

IEU-Ohio contends that, because AEP-Ohio was required pursuant to its ESP to allocate its least cost fuel to SSO customers, and the coal contract at issue was the Company's least cost fuel source, the Company should be required to allocate all of the settlement proceeds to SSO customers. In making its argument, IEU-Ohio points to the Commission's July 23, 2009, entry on rehearing in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO, in which the Commission stated that FAC costs were "to continue to be allocated on a least cost basis to [provider of last resort] customers and then to other types of sale customers."[3] IEU-Ohio appears to infer a meaning from this statement beyond what the Commission intended. The entry on rehearing does no more than emphasize that AEP-Ohio was expected to continue its usual fuel cost accounting procedures for allocating costs to SSO customers on a least cost basis, which, as the Company notes, is dependent on the average dispatch cost associated with a unit for a particular period of time, rather than any one particular supply contract. Accordingly, we affirm our prior findings in the FAC entry on rehearing.

3 *In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets*, Case No. 08-917-EL-SSO, *et al.*, Entry on Rehearing (July 23, 2009), at 4.

It is, therefore,

ORDERED, That the application for rehearing filed by IEU-Ohio on May 11, 2012, be denied. It is, further,

ORDERED, That a copy of this fourth entry on rehearing be served upon all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto

Lynn Slaby

SJP/sc

Entered in the Journal

JUL 02 2012

Barcy F. McNeal

Barcy F. McNeal
Secretary

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company.	)))	Case No. 09-872-EL-FAC Case No. 09-873-EL-FAC

APPLICATION FOR REHEARING AND MEMORANDUM IN SUPPORT OF INDUSTRIAL ENERGY USERS-OHIO

Pursuant to Section 4903.10, Revised Code, and Rule 4901-1-35, Ohio Administrative Code ("OAC"), Industrial Energy Users-Ohio ("IEU-Ohio") respectfully submits this Application for Rehearing of the Entry on Rehearing issued by the Public Utilities Commission of Ohio ("Commission") on April 11, 2012, *in the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company.* The Commission's Entry on Rehearing is unlawful and unreasonable for the following reason:

The Commission's Entry on Rehearing is Unlawful and Unreasonable in that the Commission Limited the Credit for the Settlement Agreement to the Ohio Retail Jurisdiction.

As discussed in greater detail in the Memorandum in Support, IEU-Ohio respectfully requests that the Commission grant this Application for Rehearing and modify the Entry on Rehearing to remove the unlawful and unreasonable provisions. In the alternative, the Commission should clarify its Entry on Rehearing so as to provide that 100% of the credit is allocable to Ohio retail jurisdictional customers.

{C37599:3 }

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May 11, 2012

Attorneys for Industrial Energy Users-Ohio

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company.	)))	Case No. 09-872-EL-FAC Case No. 09-873-EL-FAC

MEMORANDUM IN SUPPORT OF INDUSTRIAL ENERGY USERS-OHIO

I. INTRODUCTION

On January 23, 2012, following an audit of the Columbus Southern Power Company's ("CSP") and Ohio Power Company's[1] ("OP") fuel adjustment clauses ("FAC") for 2009, the Public Utilities Commission of Ohio ("Commission") issued an Opinion and Order directing OP to credit against the deferral balance all of the benefits OP received from a settlement agreement with one of its coal suppliers. The Commission's Opinion and Order, however, did not specify the extent to which the deferral balance needs to be adjusted to account for carrying charges.

Industrial Energy Users-Ohio ("IEU-Ohio") filed an Application for Rehearing, requesting that the Commission clarify that the credit should contain a carrying cost component.[2] The Commission granted IEU-Ohio's Application for Rehearing.[3]

[1] The merger of CSP and OP was approved by the Commission and the remaining company is hereinafter referred to as OP. *In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals*, Case No. 10-2376-EL-UNC, Entry (Mar. 7, 2012).

[2] Application for Rehearing and Memorandum in Support of Industrial Energy Users-Ohio at 8-10 (Feb. 22, 2012).

[3] Entry on Rehearing at 9 (Apr. 11, 2012).

OP, however, also filed an Application for Rehearing, claiming it would be unlawful and unreasonable to direct OP to return any amounts allocable to wholesale and non-Ohio retail jurisdictions.[4] In its Entry on Rehearing, the Commission stated, "[w]e clarify that the 2009 FAC under-recovery need only be credited for the share of the settlement agreement allocable to Ohio's retail jurisdictional customers."[5] On Rehearing, the Commission should clarify that all of the credit should be allocated to Ohio retail jurisdictional customers. Since OP was required to allocate its least cost fuel to standard service offer ("SSO") customers, 100% of the credit stemming from a below-market coal contract should be allocated to Ohio retail jurisdictional customers (SSO customers).[6] To the extent that the Commission determines that OP need not allocate 100% of the credit to Ohio retail jurisdictional customers, the Entry on Rehearing is unlawful and unreasonable.

II. BACKGROUND

A. The Companies' Electric Security Plan

On March 18, 2009, the Commission issued an Opinion and Order approving an electric security plan ("ESP") for OP.[7] In *ESP I*, the Commission authorized OP to establish a FAC subject to annual audit and reconciliation. But the Commission stated, "***we emphasize that FAC costs are to continue to be allocated on a least cost***

[4] Application for Rehearing and Memorandum in Support of Ohio Power Company at 12-14 (Feb. 22, 2012).

[5] Entry on Rehearing at 6 (Apr. 11, 2012).

[6] *In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets*, Case Nos. 08-917-EL-SSO, *et al.*, Entry on Rehearing at 4 (Jul. 23, 2009) (hereinafter "*ESP I*").

[7] *ESP I*, Opinion and Order (Mar. 18, 2009).

basis to POLR customers and then to other types of sale customers. Allocating the lowest fuel cost to POLR service customers is consistent with the electric utilities' obligation to POLR customers and will minimize the burden on most ratepayers."[8] OP did not file an application for rehearing with respect to this aspect of the order.

B. The Coal Contract Buy-Out

The main dispute in this proceeding stems from OP's voluntary renegotiation of a below-market coal contract ("Supplier Contract"). In 2007, OP entered into a settlement agreement ("Buy-Out") with one of its coal suppliers which relieved the supplier from performing under the terms of the Supplier Contract. The Supplier Contract required the coal supplier to deliver coal at a price that was below the prevailing market price.[9] Had OP not voluntarily renegotiated the Supplier Contract, ratepayers would have received the benefits of the lower priced coal through at least 2012.[10] OP has never claimed that the Supplier Contract was not its lowest cost fuel. In return for agreeing to the Buy-Out, OP received $30 million, paid in installments,[11] and a coal reserve in West Virginia (the "Coal Reserve").[12] OP booked the value of the Coal Reserve at approximately $41 million.[13]

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[8] *ESP I*, Entry on Rehearing at 4 (Jul. 23, 2009). POLR stands for provider of last resort. POLR customers are SSO customers.

[9] Opinion and Order at 4-5 (Jan. 23, 2012).

[10] *Id.* The Companies had the unilateral option to extend the Supplier Contract for an additional five years at the same price. *In the Matter of the Regulation of the Electric Fuel Component Contained Within the Rate Schedule of Ohio Power Company and Related Matters*, Case No. 93-01-EL-EFC, Opinion and Order, 1993 WL 316749 at *13 (May 26, 1993).

[11] Only a portion of the $30 million has been flowed back to ratepayers. Opinion and Order at 12; *see also* Tr. Vol. I at 121-123.

[12] Opinion and Order at 12.

As a result of the Buy-Out, OP had to purchase coal in the market to replace the coal that would have otherwise been delivered pursuant to the Supplier Contract.[14] The replacement coal was significantly more expensive.[15] OP passed the cost of the more expensive coal onto customers through the FAC while retaining the benefits realized from the Buy-Out for shareholders.[16]

Energy Ventures Analysis ("EVA") performed a management performance and financial audit of the FAC for the term of January 1, 2009 to December 31, 2009. Due to the inequity of OP's treatment of the Buy-Out—booking the benefits for shareholders and passing the higher costs onto ratepayers—EVA recommended that the Commission consider whether OP should be required to credit the deferral balance for the entire value realized by OP as a result of the Buy-Out.[17] In its Post-Hearing Brief and Reply Brief, IEU-Ohio advocated that all of the benefits of the Buy-Out should flow to Ohio retail customers.

On January 23, 2012, the Commission issued an Opinion and Order adopting EVA's recommendation and directed OP to credit the deferral balance so that customers received the benefits to which they are entitled under the Buy-Out. Specifically, the Commission held:

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[13] *Id.*

[14] *Id.*

[15] *Id.* at 5-6.

[16] Opinion and Order at 12; *see also* Tr. Vol. I at 125, 166.

[17] Opinion and Order at 7.

> ***[T]he Commission determines that <u>all</u> of the realized value from the Settlement Agreement should be credited against OP's FAC under-recovery namely the portion of the $30 million 2008 lump sum payment not already credited to OP ratepayers as well as the $41 million value of the West Virginia coal reserve that AEP booked when the Settlement Agreement was executed.*** Additionally, because the value of the West Virginia coal reserve is not clear and because AEP had planned to begin the permitting process at the time of the audit which should enhance the value of the coal reserve, we direct AEP to hire an auditor specifically to examine the value of the West Virginia coal reserve and to make a recommendation to the Commission as to whether the increased value, if any above the $41 million already required to be credited against OP's under-recovery, should accrue to OP ratepayers beyond the value of the reserve that AEPSC booked under the Settlement Agreement. The Commission will issue by subsequent entry a Request for Proposal to hire the auditor discussed above.[18]

Despite determining that customers should receive <u>all</u> of the value realized from the Buy-Out, on Rehearing the Commission clarified that Ohio customers are only entitled to the portion of the benefits associated with the Buy-Out that are "allocable to Ohio's retail jurisdictional customers."[19] The Commission should clarify its Entry on Rehearing to state that 100% of the benefits associated with the Buy-Out should be allocated to Ohio customers. To the extent that the Commission does not make this clarification, the Entry on Rehearing is unlawful and unreasonable because OP must allocate its lowest cost fuel to Ohio customers.

III. ARGUMENT

A. The Commission's Entry on Rehearing is Unlawful and Unreasonable in that the Commission Limited the Credit for the Settlement Agreement to the Ohio Retail Jurisdiction.

In *ESP I*, the Commission authorized OP to establish the FAC. In return for granting OP a dollar for dollar recovery mechanism, the Commission required OP to

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[18] *Id. at* 12 (emphasis added).

[19] Entry on Rehearing at 6 (Apr. 11, 2012).

allocate its lowest cost fuel to SSO customers.[20] OP has not claimed that the Supplier Contract at issue in this proceeding was not OP's lowest cost fuel source. Based on the Commission's July 23, 2009 Entry on Rehearing in *ESP I*, the below-market Supplier Contract would have been fully allocated to the Ohio retail jurisdiction.[21] Accordingly, any benefits obtained from renegotiating the Supplier Contract should also have been allocated 100% to Ohio retail jurisdictional customers. The Commission should clarify on Rehearing to indicate that 100% of the benefits from the Buy-Out should be allocated to Ohio retail jurisdictional customers. To the extent the Commission fails to make this clarification, and OP is permitted to keep a portion of the benefits obtained from the Buy-Out, the Commission's Entry on Rehearing is unlawful and unreasonable.

Second, OP's jurisdictional argument is only conceptually relevant, if at all, in a traditional cost of service ratemaking context which does not exist here. Here, the Commission is dealing with pricing for default generation supply service which is, as a matter of law, not based on a jurisdictionalized cost of service methodology. Generation rates are fixed at a set rate and OP is given a dollar for dollar recovery mechanism for fuel, with the caveat that OP must allocate its least cost fuel to SSO customers.

Third, OP has failed to provide any proof that Ohio consumers should be deprived of the full amount of the benefits received by OP in exchange for the higher costs of fuel paid by Ohio customers. It is important to note that OP's voluntary

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[20] *ESP I*, Entry on Rehearing (Jul. 23, 2009). In approving the FAC, the Commission relied upon the testimony of Philip Nelson, who stated that OP's internal load, including the default supply provided to SSO consumers, is supplied from its lowest-cost generation resources. *ESP I*, Cos. Ex. 7 at 12 (Direct Testimony of Phillip Nelson). Since the Buy-Out involved a below-market Supplier Contract, the generation resources that would have used that coal, but for OP's voluntary termination, would have supplied the needs of Ohio customers.

[21] *ESP I*, Entry on Rehearing at 4 (Jul. 23, 2009).

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termination of the Supplier Contract also eliminated an option to further extend the below-market Supplier Contract for five years.[22] Rather than compensate customers for the harm caused by OP's voluntary termination, OP claims that it should keep the non-jurisdictional gains for its shareholders. A more inequitable result is hard to fathom.

Fourth, OP failed to claim that customers were entitled to only the Ohio retail jurisdictional portion of the benefits of the Buy-Out in either its Initial Brief or Reply Brief. Section 4903.10(B), Revised Code, states that if the Commission grants rehearing it **shall** not, upon such rehearing, take any evidence that could have been offered in the original hearing. Clearly, OP could have and should have offered evidence to support its jurisdictional claim during the litigation phase of this proceeding but it elected to not do so and it also failed to mention this topic during the briefing phase. The only evidence[23] that OP offered during the litigation phase was that OP had fuel costs associated with non-jurisdictional sales—but OP never argued that there was a basis to allocate its lowest cost fuel to non-jurisidictional sales. OP's belated interest in a jurisdictional analysis operates to preclude OP from introducing this subject at the rehearing phase. Thus, it was unlawful and unreasonable for the Commission to grant this aspect of OP's Application for Rehearing.

Finally, the Commission should also reject OP's jurisdictional claim because it is a claim that OP selectively advances when it operates to tilt the playing field against

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[22] *In the Matter of the Regulation of the Electric Fuel Component Contained Within the Rate Schedule of Ohio Power Company and Related Matters*, Case No. 93-01-EL-EFC, Opinion and Order, 1993 WL 316749 at *13 (May 26, 1993).

[23] Application for Rehearing of Ohio Power Company and Memorandum in Support at 12-14 (Feb. 22, 2012); *see* Tr. Vol. I at 15-16 and 121-122.

Ohio consumers. OP has demonstrated that it will either support or oppose a jurisdictional allocation depending on its impact on earnings.[24]

IV. CONCLUSION

For the reasons stated herein, the Commission should grant IEU-Ohio's Application for Rehearing.

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[24] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Administration of the Significantly Excessive Earnings Test under Section 4928.143(F), Revised Code, and Rule 4901:1-35-10, Ohio Administrative Code*, Case No. 10-1261-EL-UNC, Opinion and Order at 11-12 (Jan. 11, 2011).

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Application for Rehearing and Memorandum in Support of Industrial Energy Users-Ohio* was served upon the following parties of record this 11th day of May, 2012, via electronic transmission, hand-delivery or first class mail, postage prepaid.

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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of an Additional Generation Service Rate Increase Pursuant to Their Post-Market Development Period Rate Stabilization Plan.	))))))	Case No. 07-1132-EL-UNC
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of an Additional Generation Service Rate Increase Pursuant to Their Post-Market Development Period Rate Stabilization Plan.	))))))	Case No. 07-1191-EL-UNC
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of an Additional Generation Service Rate Increase Pursuant to Their Post-Market Development Period Rate Stabilization Plan.	))))))	Case No. 07-1278-EL-UNC
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company to Update Each Company's Transmission Cost Recovery Rider.	))))	Case No. 07-1156-EL-UNC

OPINION AND ORDER

The Public Utilities Commission of Ohio (Commission), considering the application, the testimony, all other evidence of record, and being otherwise fully advised, hereby issues its opinion and order.

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Richard L. Sites, 155 East Broad Street, 15th Floor, Columbus, Ohio 43215, on behalf of the Ohio Hospital Association.

OPINION:

I. INTRODUCTION

A. Background

On February 9, 2004, Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly AEP-Ohio) filed an application with the Commission for approval of a rate stabilization plan (RSP) to continue to allow the competitive electric market to develop beyond the market development period approved in AEP-Ohio's electric transition plan cases, Case No. 04-169-EL-UNC, *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of a Post-Market Development Period Rate Stabilization Plan* (RSP case). The proposed RSP provided for limited increases in the rates customers pay for generation service, beyond those specified in the RSP, through 2008. Furthermore, the RSP proposed by AEP-Ohio also included a provision that limits the potential generation rate increases. The proposed RSP provided that a hearing would be held on such limited adjustments to the generation service rates and established a 90-day time frame, after which the proposed increase could become effective on an interim basis until the Commission's final order is implemented.

By opinion and order issued January 26, 2005, (RSP order) in the RSP case, the Commission approved AEP-Ohio's RSP with certain modifications. Among the proposed provisions approved in the RSP case are Sections 2 and 3. Section 2 allows the companies to increase the generation rates of all customers by three percent for CSP customers and by seven percent for OP customers. Further, in addition, Section 3 of the approved RSP provides that:

> During the RSP, the Companies may further adjust the generation rates and related riders of the standard service tariff, beyond those specified in Section 2 of the Plan, for increased expenditures (whether capitalized or expensed) incurred either directly, or indirectly through an affiliated pooling arrangement, for complying with changes in laws, rules or regulations related to environmental requirements, security, taxes and any new generation-related regulatory requirement imposed by statute, rule, regulation or administrative or court order...after a hearing and a showing that such expenditures were reasonably incurred....

Pursuant to Section 3 of the RSP, on January 23, 2007, AEP-Ohio filed an application in Case No. 07-63-EL-UNC, *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of an Additional Generation Service Rate Increase Pursuant to Their Post-Market Development Period Rate Stabilization Plan* (07-63). By order issued October 3, 2007, as confirmed by entry on rehearing issued November 28, 2007, in 07-63, the Commission approved, in part, the companies' request for an additional generation service increase. Further, the Commission clarified that recovery of expenditures pursuant to Section 3 of the RSP requires that the rate increase be based on actual, incurred expenses at the time the application is filed, that the incurred expenses represent an increase in expenditures in excess of the baseline approved in the RSP, and that CSP and OP are each permitted to apply for an additional generation rate increase that is no greater than an average of four percent per year for 2006 through 2008. In accordance with the Commission's findings in 07-63, AEP-Ohio was authorized to implement generation cost recovery riders (GCRRs) to recover the additional generation-related revenues in customer bills issued through December 2008.

Since the issuance of the order in 07-63, the companies have filed three more applications to recover additional generation service rate increases pursuant to Section 3 of the RSP. In each of the applications, AEP-Ohio states the companies continue to pursue activities, which have related expenditures that are recoverable under the RSP. In recognition of these expenditures, CSP and OP request that the Commission authorize an adjustment to the GCRR riders to recover additional generation-related revenues in customer bills. Each GCRR application will be addressed in greater detail below.

B. September GCRR Case No. 07-1132-EL-UNC

On October 24, 2007, AEP-Ohio filed an application docketed at Case No. 07-1132-EL-UNC, *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of an Additional Generation Service Rate Increase Pursuant to Their Post-Market Development Period Rate Stabilization Plan* (September GCRR). In the September GCRR application, AEP-Ohio states that the companies have incurred expenses from January 1, 2007, through September 30, 2007, that are recoverable under the RSP and requests an increase of $35,167,037 for CSP and an increase of $11,944,953 for OP. AEP-Ohio requests that these increases be reflected in customer bills issued January through December 2008. As part of the application, AEP-Ohio filed the direct testimony of company witnesses. AEP-Ohio served a copy of this application on all the parties to 07-63.

By entry issued November 2, 2007, in the September GCRR case, the procedural schedule and processes were set forth and pursuant thereto all motions to intervene were due November 13, 2007, staff's and interveners' witness lists were due December 4, 2007, staff's and interveners' testimony were due December 11, 2007, and the hearing was scheduled to commence on December 17, 2007.

Motions to intervene in the September GCRR case were filed by the Industrial Energy Users-Ohio (IEU-Ohio), Ohio Energy Group (OEG), Ohio Partners of Affordable Energy (OPAE), the Office of the Ohio Consumers' Counsel (OCC), the Ohio Hospital Association (OHA), and the Appalachian People's Action Coalition (APAC), all of whom were parties to the 07-63 proceeding. By entry issued November 21, 2007, these parties were granted intervention in the September GCRR proceeding.

On November 9, 2007, in the September GCRR case, OCC filed a motion for continuance of the hearing and an extension of time to file intervener testimony. In its motion, OCC requested that the hearing commence on February 20, 2008, and that the due date for intervener testimony be extended to February 11, 2008. OCC stated that it requires additional time to engage an expert and prepare for hearing. On November 14, 2007, AEP-Ohio filed a memorandum contra OCC's motion for a continuance of the hearing and an extension opposing OCC's request to delay the schedule for two months. By entry issued November 21, 2007, in the September GCRR case, the attorney examiner concluded that OCC's request should be granted, in part. The attorney examiner concluded that it is incumbent upon the examiners and the parties in these types of proceedings to move forward within the 90-day time frame approved by the Commission in the RSP order. However, to afford OCC some additional time, the procedural schedule was extended and the hearing continued. Thus, staff and intervener witness lists were due in the September GCRR case on December 14, 2007, staff and intervener testimony were due to be filed with the Commission on December 21, 2007, and the evidentiary hearing was continued until January 3, 2008.

On November 26, 2007, OCC filed an application for review and interlocutory appeal of the attorney examiner's November 21, 2007, entry in the September GCRR case. In the application for interlocutory appeal, OCC requests that staff and intervener testimony be due by January 11, 2008, and the hearing commence on January 17, 2008. OCC requests certification of this appeal to the full Commission, or in the alternative, that the appeal be reviewed without certification pursuant to Rule 4901-1-15(A)(2), Ohio Administrative Code (O.A.C.). The companies filed a memorandum contra OCC's application for review and interlocutory appeal on November 30, 2007.

C. October GCRR Case No. 07-1191-EL-UNC

AEP-Ohio filed an application on November 16, 2007, for an additional generation service rate increase for expenditures incurred in October 2007, Case No. 07-1191-EL-UNC, *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of an Additional Generation Service Rate Increase Pursuant to Their Post-Market Development Period Rate Stabilization Plan* (October GCRR). In the October GCRR application, AEP-Ohio requests an increase of $2,222,074 for CSP and an increase of $679,616 for OP for incurred expenses that are recoverable under Section 3 of the RSP. As part of the October GCRR application, AEP-Ohio filed the direct testimony of company witnesses. AEP-Ohio served a copy of this application on all the parties to September GCRR case. Motions to intervene in this case were filed by IEU-Ohio, OEG, OCC, APAC, and OPAE.

D. November GCRR Case No. 07-1278-EL-UNC

AEP-Ohio filed its most recent application on December 19, 2007, for an additional generation service rate increase for expenditures incurred in November 2007, Case No. 07-1278-EL-UNC, *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of an Additional Generation Service Rate Increase Pursuant to Their Post-Market Development Period Rate Stabilization Plan* (November GCRR). In the November GCRR application, AEP-Ohio requests an increase of $2,723,671 for CSP and an increase of $1,698,925 for OP for incurred expenses that are recoverable under Section 3 of the RSP. The companies' request that the increases in this application be reflected in customer bills issued March 19, 2008, through December 2008. Along with the November GCRR application, AEP-Ohio filed the direct testimony of company witnesses. AEP-Ohio served a copy of the November GCRR application on all the parties to the September GCRR case.

E. TCRR Case No. 07-1156-EL-UNC

As part of their September GCRR application, the companies requested recovery of expenditures incurred as a result of a change in the method by which the companies' locational marginal pricing is determined by its regional transmission organization (RTO), PJM Interconnection. Furthermore, AEP-Ohio requested that, should the Commission determine that it is more appropriate to reflect such locational marginal pricing expenditures in the companies' transmission cost recovery riders (TCRRs), the companies be permitted to adjust the actual over- or under-recovery of the TCRRs to recognize the costs associated with the change in pricing methodology.

On October 31, 2007, the companies filed an application for approval to adjust their respective TCRRs for 2008. See *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company to Adjust Each Company's Transmission Cost Recovery Rider*, Case No. 07-1156-EL-UNC (TCRR case). By finding and order issued December 19, 2007, in the TCRR case, the Commission approved the companies' request to adjust their TCRRs for 2008. However, the Commission denied their request to revise the TCRR rates to reflect increased costs due to the change in the RTO's locational marginal pricing methodology. Instead, the Commission elected to further consider the locational marginal pricing issue as part of the September GCRR case.

F. GCRR Cases and TCRR Case

On January 16, 2008, AEP-Ohio filed a motion in all the pending GCRR cases and the TCRR case to convene a hearing at the Commission's earliest convenience, to facilitate the filing of a stipulation setting forth the terms of a settlement between the parties and the presentation of company testimony. By entry issued January 16, 2008, AEP-Ohio's request to convene a hearing in the pending GCRR cases, and in the companies' TCRR case, was granted.

The hearing in these cases was held on January 17, 2008. The direct testimony of the companies' witnesses filed in each case was admitted into evidence. In the September GCRR application, the direct testimony of Selwyn J. Dias (Company Ex. 1), John M. McManus (Company Ex. 2), Philip J. Nelson (Company Ex. 3), and David M. Roush (Company Ex. 4) was admitted. In the October GCRR case, the testimony of Selwyn J. Dias (Company Ex. 5), John M. McManus (Company Ex. 6), Philip J. Nelson (Company Ex. 7), and David M. Roush (Company Ex. 8) was admitted. In the November GCRR case, the testimony of Selwyn J. Dias (Company Ex. 9), John M. McManus (Company Ex. 10), Philip J. Nelson (Company Ex. 11), and David M. Roush (Company Ex. 12) was admitted. Also admitted into evidence at the hearing was the Joint Stipulation and Recommendation (Joint Ex. 1, including proposed tariffs) addressing all the issues raised in the September, October, and November GCRR cases.

II. EXPENDITURES REQUESTED FOR RECOVERY BY AEP-OHIO

In these GCRR applications, the companies have requested recovery for environmental expenditures associated with the cost of compliance with: the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) adopted by the United States

Environmental Protection Agency (US EPA); a modified National Pollution Discharge Elimination System (NPDES) permit issued pursuant to the Federal Clean Water Act (CW Act); and PJM Interconnection's new locational marginal pricing method. In recognition of the Commission's determination in 07-63, that the companies may recover actual, incurred expenses, AEP-Ohio is also requesting authority to incorporate a monthly adjustment mechanism in the GCRRs.

A. Clean Air Interstate Rule and Clean Air Mercury Rule

The US EPA adopted the CAIR which became effective on July 11, 2005. The CAIR program requires the significant reduction of nitrogen oxide and sulfur dioxide emissions. The reduction of emissions will be a two-phase process for nitrogen oxides and sulfur dioxide. CAIR requires that emissions of nitrogen oxide be reduced by 53 percent from 2003 levels by the year 2009, and further reduced to 61 percent below 2003 levels by the year 2015.[1] The CAIR program also requires that, by the year 2010, sulfur dioxide emissions be reduced by 55 percent from 2003 levels and further reduced to 69 percent below 2003 levels by the year 2015 (Co. Ex. 2 at 3-4; Co. Ex. 6 at 3-4; Co. Ex. 10 3-4).[2]

Similarly, the US EPA adopted the CAMR which became effective July 18, 2005. The CAMR implements a two-phase process for the reduction of mercury emissions. The CAMR seeks to reduce mercury emissions by 20 percent by the year 2010, and a 70 percent reduction by the year 2018, from 2003 levels. Furthermore, the CAMR requires the installation of continuous mercury emissions monitoring systems on all coal-fired units by January 1, 2009 (Co. Ex. 2 at 4; Co. Ex. 6 at 4; Co. Ex. 10 at 4).

In addition to the US EPA's CAIR and CAMR, each state must develop state regulations to institute the CAIR and CAMR program requirements. The state rules must be submitted to and approved by the US EPA. The Ohio Environmental Protection Agency (OEPA) promulgated CAIRs effective as of September 27, 2007, and CAMRs effective as of May 2007 (Co. Ex. 2 at 5; Co. Ex. 6 at 5; Co. Ex. 10 at 5). The companies request recovery of the carrying costs associated with the capital investment for CAIR and CAMR compliance. The companies propose calculating the pre-tax weighted average cost of capital using the same rates for 2006 as approved in 07-63, as well as an adjustment to reflect the Section 199 tax deduction reflected in the case as well (Co. Ex. 3 at 2-3, 5; Co. Ex. 7 at 2; Co. Ex. 11 at 2).

1 In other words, pursuant to CAIR requirements, nitrogen oxide emissions will be reduced by an additional eight percent between 2009 and 2015.

2 In other words, pursuant to CAIR requirements, sulfur dioxide emissions will be reduced by an additional 14 percent between 2009 and 2015.

B. National Pollution Discharge Elimination System Permit

In accordance with the Clean Water Act (CW Act) any discharge of pollutants to waters in the United States requires a permit under the National Pollution Discharge Elimination System (NPDES). Such permits are issued by the US EPA or authorized states pursuant to Section 402 of the CW Act. The companies state that the Mitchell Plant received a water pollution control modification effective May 4, 2007, which included a new end-of-pipe discharge limit of 12 parts per trillion for total mercury. The companies represent that the permit did not include a discharge limit for mercury previously. AEP-Ohio states that compliance with the modified NPDES mercury discharge limit necessitates the installment of additional enhanced mercury removal equipment on the existing flue gas desulfurization wastewater treatment system which must be operational by May 2009. Furthermore, AEP-Ohio states that the company has appealed this permit modification and a hearing was scheduled for November 15, 2007. In the September GCRR application, the companies request recovery of the associated expenditures pending the outcome of the appeal (Co. Ex. 2 at 9-10). Like CAIR and CAMR, the companies request recovery of the carrying costs associated with the capital investment to comply with the modified NPDES permit (Co. Ex. 3 at 2-3, 5).

C. PJM's New Locational Marginal Pricing Method

AEP-Ohio states that, pursuant to the Federal Energy Regulatory Commission (FERC) order issued in Docket No. EL06-55 on May 1, 2006, PJM implemented the locational marginal loss method for allocating transmission line losses as of June 1, 2007. According to AEP-Ohio, prior to June 1, 2007, PJM accounted for transmission line losses by implementing an average loss factor. In other words, transmission losses for the hour were averaged across the transmission load for the hour (average loss method). The locational marginal pricing method factors the transmission losses into the energy price (locational marginal price or LMP) and, therefore, customers near the generation facility are charged prices that reflect lower loss costs than customers that are farther from the generation facility. Under the LMP method, PJM considers the effects of losses in determining which generators to dispatch and, as a result, the actual cost of meeting the total PJM load is reduced (Co. Ex. 4 at 5-6; Co. Ex. 8 at 6-7; Co. Ex. 12 at 6-7).

Where AEP-Ohio had previously reported its load to PJM including an average loss factor, only the load is reported under the new methodology. AEP-Ohio's transmission line losses are settled financially through the marginal loss component of the LMP. Pursuant to the LMP method, the companies now receive financial charges for transmission losses. AEP-Ohio acknowledges that, under the LMP method, it receives a share of PJM's over collection on a load ratio share basis and the companies' share of any over collection redistributed by PJM will be reflected as a credit to total marginal loss cost (Co. Ex. 4 at 6-8; Co. Ex. 8 at 7-8; Co. Ex. 12 at 7-8).

Further, AEP-Ohio requests that, should the Commission determine that it is more appropriate to reflect such locational marginal pricing expenditures in the companies' TCRRs, that the companies be permitted to adjust the actual over- or under-recovery of the TCRR to recognize the costs associated with the change in pricing methodology since June 1, 2007, and that the companies be authorized to immediately file to adjust the going-forward TCRR rates.

D. Summary of Generation Expenditures Requested

Below is a table summarizing the expenditures for which AEP-Ohio requests recovery, the associated revenue requirement, and the percentage additional monthly increase that the companies propose should be applied to customer bills.

	September GCRR		October GCRR		November GCRR	
	CSP	OP	CSP	OP	CSP	OP
Total CAIR/CAMR/ NPDES carrying costs	58,486,505	8,544,193	1,625,456	262,976	1,352,702	432,900
Locational Marginal Losses Price	9,094,855	10,390,116	582,951	455,553	1,354,216	1,363,300
Total Costs	67,581,360	18,934,309	2,208,407	718,529	2,706,918	1,796,200
Jurisdictional Factor	100.0%	94.183%	100.0%	94.183%	100.0%	94.183%
Total Jurisdictional Costs	67,581,360	17,832,900	2,208,407	676,732	2,706,918	1,691,715
2006 uncollectible cost rate	.4209%	.2298%	.4209%	.2298%	.4209%	.2298%
Gross-up for uncollectibles	67,867,012	17,873,974	2,217,741	678,291	2,718,360	1,695,612
2008 Commercial Activity Tax Rate	.0195%	.0195%	.0195%	.0195%	.0195%	.0195%
Gross Up for Commercial Activity Tax	67,999,611	17,908,896	2,222,074	679,616	2,723,671	1,698,925
Less: Rev. Req. from 07-63	32,832,574	5,963,943	--	--	--	--
Additional Rev. Req.	35,167,037	11,944,953	2,222,074	679,616	2,723,671	1,698,925
Projected Base Generation Revenue	939,900,000	1,033,500,000	817,700,000	889,000,000	740,000,000	794,000,000
Additional Monthly Rate	3.74157%	1.15578%	0.27175%	0.07645%	0.36806%	0.21397%

(Co. Ex. 4, DMR Ex. 2 at 1; Co. Ex. 8, DMR Ex. 2 at 1; Co. Ex. 12, DMR Ex. 2 at 1)

III. STIPULATION

At the hearing held in these cases on January 17, 2008, AEP-Ohio submitted a Stipulation and Recommendation (Joint Ex. 1) signed by AEP-Ohio, the staff, OCC, OEG, IEU-Ohio, OHA, APAC, and OPAE which states that all of the issues in the GCRR cases and the TCRR case have been resolved. For purposes of considering the Stipulation submitted in these cases, OCC, OEG, IEU-Ohio, OHA, APAC, and OPAE should be considered parties in these cases. Pursuant to the Stipulation, the parties agree that:

(1) The net cost of the locational marginal pricing losses, as defined in the September GCRR case, should be recovered through the TCRRs, rather than through the GCRRs. Therefore, the proposed GCRRs will be adjusted to reflect the removal of the net costs and the riders in the TCRR case will be adjusted to reflect the inclusion of $78 million in net costs of marginal losses, $38,873,715 for CSP and $39,126,285 for OP. Any over- or under-recovery of the actually incurred costs from June 2007 through December 2008 will be reflected in the 2009 TCRRs and will reflect the carrying charges on any such over- or under-recovery.

(2) The TCRRs approved in the TCRR case will be adjusted to include an $18 million credit associated with net congestion costs, $8,427,549 for CSP and $9,572,451 for OP. Any over- or under-recovery of the TCRR revenue resulting from this imputed credit will be reflected in the 2009 TCRR and will reflect the carrying charges on any such over- or under-recovery.

(3) The net cost of marginal losses included in the 2008 TCRRs in the TCRR case will be included in the determination of whether either CSP or OP exceed the amount of generation rate increase permitted under Section 3 of the RSP. The amount of generation rate increases that will be permissible in 2008 under Section 3 of the RSP for CSP and OP are $89,393,208 and $209,095,566, respectively. The companies will provide the signatory parties a monthly calculation of the net cost of marginal losses, with credits separately identified, and the remaining amount of permissible generation rate increase recoveries.

(4) The remaining portion of the proposed increase to the GCRRs (i.e., the carrying costs associated with the CAIR, CAMR, and NPDES requirements) will be $28,519,993 for CSP and $4,900,481 for OP, which reflects a $10 million reduction in the companies' total request for such costs.

(5) For CSP, the GCRRs and the TCRRs under this Stipulation result in a remaining $21,999,500 of permissible generation rate increases for 2008 under Section 3 of the RSP.

(6) For OP the GCRRs and the TCRRs under this Stipulation result in a remaining $165,068,800 of permissible generation rate increases for 2008 under Section 3 of the RSP.

(7) Once the Stipulation is approved by the Commission, the companies will not make any other filings or collect additional revenues under Section 3 of the RSP related to compliance with CAIR, CAMR, or the NPDES.

Attached to the Stipulation were two sets of tariff pages reflecting the TCRRs and GCRRs for CSP and OP for all customer classes as agreed to in the Stipulation. One set of tariffs reflects the rates to become effective with the beginning of the February 2008 billing cycle. However, the companies have also submitted an alternative set of tariffs in the event the Commission's order is not issued in time for the February 2008 billing cycle. The alternative tariffs have an effective date beginning with the March 2008 billing cycle.

Rule 4901-1-30, O.A.C., authorizes parties to Commission proceedings to enter into a stipulation. Although not binding on the Commission, the terms of such an agreement are accorded substantial weight. *See, Consumers' Counsel v. Pub. Util. Comm.*, 64 Ohio St.3d 123, at 125 (1992), *citing Akron v. Pub. Util. Comm.*, 55 Ohio St.2d 155 (1978). This concept is particularly valid where the stipulation is unopposed by any party and resolves all issues presented in the proceeding in which it is offered.

The standard of review for considering the reasonableness of a stipulation has been discussed in a number of prior Commission proceedings. See, e.g., *Cincinnati Gas & Electric Co.*, Case No. 91-410-EL-AIR (April 14, 1994); *Western Reserve Telephone Co.*, Case No. 93-230-TP-ALT (March 30, 2004); *Ohio Edison Co.*, Case No. 91-698-EL-FOR *et al.* (December 30, 1993); *Cleveland Electric Illum. Co.*, Case No. 88-170-EL-AIR (January 30, 1989); *Restatement of Accounts and Records (Zimmer Plant)*, Case No. 84-1187-EL-UNC (November 26, 1985). The ultimate issue for our consideration is whether the agreement, which embodies considerable time and effort by the signatory parties, is reasonable and should be adopted. In considering the reasonableness of a stipulation, the Commission has used the following criteria:

(a) Is the settlement a product of serious bargaining among capable, knowledgeable parties?

(b) Does the settlement, as a package, benefit ratepayers and the public interest?

(c) Does the settlement package violate any important regulatory principle or practice?

The Ohio Supreme Court has endorsed the Commission's analysis using these criteria to resolve issues in a manner economical to ratepayers and public utilities. *Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.*, 68 Ohio St.3d 559 (1994) (*citing Consumers' Counsel, supra,* at 126). The court stated in that case that the Commission may place substantial weight on the terms of a stipulation, even though the stipulation does not bind the Commission (*Id.*).

The Commission finds that the Stipulation appears to be the product of serious bargaining among capable, knowledgeable parties. The signatory parties represent a wide diversity of interests including the utility, residential consumers, low-income residential consumers, commercial and industrial consumers, and the staff. Moreover, no party opposes the stipulation. Further, we note that the signatory parties routinely participate in complex Commission proceedings and that counsel for the signatory parties have extensive experience practicing before the Commission in utility matters.

We find that the settlement, as a package, benefits ratepayers and the public interest. We conclude that the incurred expenses which AEP-Ohio will be recovering in the GCRRs pursuant to the Stipulation are expenditures which may be recovered in accordance with the RSP case. The Commission finds that the proposed revenue requirements set forth in the Stipulation are appropriately below the four percent cap established in the RSP case. Furthermore, the Commission understands that the companies' transmission expenditures will be audited by the staff to ensure that only appropriate costs are recovered. Therefore, upon review of the Stipulation and the supporting testimony, we conclude that the Stipulation, as a whole, represents a reasonable resolution of the issues presented in these proceedings.

Finally, the Commission finds that the settlement does not violate any important regulatory principles or practices. Accordingly, the Commission concludes that the Stipulation submitted in these cases should be adopted and approved in its entirety.

IV. CONCLUSION

The Commission has reviewed the Stipulation submitted in the GCRR cases and the TCRR case and has determined that it should be approved in its entirety. In light of the resolution of the issues in these cases, the Commission finds that it is not necessary for the attorney examiner to issue a ruling on the interlocutory appeal filed by OCC on November 26, 2007, in the September GCRR case.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) CSP and OP are public utilities and electric light companies as defined in Sections 4905.02 and 4905.03(A)(4), Revised Code.

(2) By order issued January 26, 2005, in the RSP case, the Commission approved AEP-Ohio's RSP application which permits the companies to request limited adjustments to the generation rates provided for in the RSP, as long as the total generation rate increases are not greater than an average of seven percent per year for CSP and 11 percent per year for OP, for the years 2006, 2007, and 2008.

(3) AEP-Ohio filed the September GCRR application on October 24, 2007, the October GCRR application on November 16, 2007, and the November GCRR application on December 19, 2007. In each GCRR application AEP-Ohio requests that the Commission authorize the implementation of the proposed riders to recover additional generation-related revenues in billings through December 2008.

(4) A prehearing conference was held in the September GCRR case on January 3, 2008.

(5) A hearing in the GCRR cases and the TCRR case was held on January 17, 2008.

(6) At the hearing, AEP-Ohio submitted a Stipulation and Recommendation signed by AEP-Ohio, the staff, OCC, OEG, IEU-Ohio, OHA, APAC, and OPAE which states that all of the issues in the GCRR cases and the TCRR case have been resolved.

(7) For purposes of considering the Stipulation submitted in these cases, OCC, OEG, IEU-Ohio, OHA, APAC, and OPAE should be considered parties in these cases.

(8) The Stipulation presented in these proceedings should be adopted in its entirety.

ORDER:

It is, therefore,

ORDERED, That, for purposes of considering the Stipulation submitted in these cases, OCC, OEG, IEU-Ohio, OHA, APAC, and OPAE be considered parties in these cases. It is, further,

ORDERED, That the Stipulation submitted in these proceedings be adopted in its entirety. It is, further,

ORDERED, That the tariffs shall be effective with the February 2008 billing cycle. It is, further,

ORDERED, That AEP-Ohio shall notify all affected customers via a bill message or via a bill insert within 30 days of the effective date of the tariffs. A copy of the customer notice shall be submitted to the Commission's Service Monitoring and Enforcement Department, Reliability and Service Analysis Division, at least 10 days prior to its distribution to customers. It is, further,

ORDERED, That the companies are authorized to file in final form four complete copies of the tariff consistent with this opinion and order. Each company shall file one copy in its TRF docket (or may make such filing electronically as directed in Case No. 06-900-AU-WVR) and one copy in this case docket. The remaining two copies shall be designated for distribution to the Rates and Tariffs, Energy and Water Division of the Commission's Utilities Department. It is, further,

ORDERED, That nothing in this opinion and order shall be binding upon the Commission in any future proceeding or investigation involving the justness or reasonableness of any rate, charge, rule, or regulation. It is, further, ORDERED, That a copy of this opinion and order be served upon each party of record and all other interested persons of record in these proceedings.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Ronda Hartman Fergus

Valerie A. Lemmie

Donald L. Mason

GNS/CMTP/vrm

Entered in the Journal
JAN 30 2008

Reneé J. Jenkins
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission's Promulgation of Rules for Electric Transition Plans and of a Consumer Education Plan, Pursuant to Chapter 4928, Revised Code.	))))	Case No. 99-1141-EL-ORD

SECOND ENTRY ON REHEARING

The Commission finds:

(1) On November 30, 1999, the Commission adopted a number of rules regarding the manner in which electric transition plan applications should be filed and considered by the Commission. At the same time, the Commission established a general plan for existing electric utility companies to educate consumers about electric restructuring, as required by Section 4928.42, Revised Code.

(2) Section 4903.10, Revised Code, states that any party who entered an appearance in the proceeding may apply for rehearing with respect to any matters determined in said proceeding by filing such a request within 30 days after the entry of the order upon the journal of the Commission.

(3) Between December 15 and 23, 1999, the Commission received five applications for rehearing from:

(a) The Neighborhood Environmental Coalition, Western Alliance, and Parkview Areawide Seniors Inc. (hereinafter jointly referred to as Western Alliance);

(b) The American Association of Retired Persons, Appalachian Peoples' Action Coalition, Citizen Power, Citizens Protecting Ohio, Earth Day Coalition, Enron Corp., Greater Cleveland Growth Association, Industrial Energy Users-Ohio, National Federation of Independent Business-Ohio, Ohio Association of Community Action Agencies, Ohio Citizen Action, Ohio Council of Retail Merchants, Ohio Environmental Council, Ohio Grocers Association, Ohio Manufacturers Association, Ohio Meat Industries Association, Ohio Partners for

Affordable Energy, Ohio Petroleum Council, Safe Energy Communication Council, and Sierra Club – Ohio Chapter (hereinafter jointly referred to as the Consumer Education Alliance and referenced, for shorthand purposes, as CEA);

(c) The Ohio Manufacturers' Association, the Industrial Energy Users-Ohio, Ohio Council of Retail Merchants, Ohio Partners for Affordable Energy, Enron Energy Services Inc., Greater Cleveland Growth Association, and CNG (hereinafter referred to as the Coalition for Choice in Electricity and referenced, for shorthand purposes, as CCE);

(d) The Ohio Council of Retail Merchants, which incorporated the arguments contained in the rehearing applications filed by CCE and the CEA; and

(e) The Industrial Energy Users-Ohio, which incorporated the arguments contained in the rehearing applications filed by CCE.

(4) On January 4, 2000, the Commission granted those five applications for rehearing listed above for the limited purpose of allowing the Commission additional time to consider the issues raised in those applications.

(5) On December 29 and 30, 1999, the Commission received in this docket additional applications for rehearing from The Cincinnati Gas & Electric Company (CG&E), Columbus, Southern Power Company, Ohio Power Company,[1] Ohio Partners for Affordable Energy,[2] The Dayton Power and Light Company (DP&L), Ohio Consumers' Counsel (OCC), and FirstEnergy Corp. (FirstEnergy).

(6) On December 30, 1999, January 3 and 7, 2000, memoranda contra various parts of the applications for rehearing were

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1 Ohio Power Company and Columbus Southern Power Company are both subsidiaries of American Electric Power Inc. (AEP). They jointly filed an application for rehearing and they will be referenced as "AEP".

2 The application for rehearing by Ohio Partners for Affordable Energy (Ohio Partners) only incorporated the arguments contained in the rehearing applications filed by CCE and the CEA.

filed by FirstEnergy, AEP, PG&E Corporation (PG&E), OCC, and CCE.

(7) Some of the arguments raised in the applications for rehearing are similar in nature or identical. Therefore, we will group the arguments together as appropriate in order to consider them. We have included headings in bold for ease of reference. Additionally, we wish to make clear that we will refer to those assignments of error raised by CCE and CEA, but it should be understood that we are simultaneously addressing the applications for rehearing filed by the Industrial Energy Users-Ohio, Ohio Council of Retail Merchants, and Ohio Partners. First, we will address the assignments of error related to our conclusions for the consumer education plan.

Consumer Education Plan

(8) Two of Western Alliance's assignments of error allege that the consumer education plan should be modified to: (a) ensure that community-based organizations (CBOs) are able to participate in the consumer education plan, and (b) encourage the utilities to include CBOs in the utilities' individual education plans (including funding for the CBOs). Similarly, CEA argues in its second assignment of error that the Commission should have provided grant funding to CBOs, consumer organizations, trade organizations, and other credible entities. CEA states that the plan is doomed if the utilities seek participation by CBOs, but they cannot participate without funding. CEA also asks the Commission to clarify whether the utilities are permitted to contract with CBOs for consumer education services.

Western Alliance and CEA want the consumer education plan to ensure that CBOs are able to participate in educating the public about electric restructuring, including as participants in the service territory-specific campaigns. The plan we adopted specifically lists partnerships with CBOs as one of the tactics to be employed for the statewide education campaign. In addition, we specifically encouraged the utilities to work with CBOs and to provide CBOs with membership on the service territory-specific advisory groups. We reaffirm those statements. We do, however, clarify that, while the general plan requires that statewide funds not be disbursed through grants, the plan does not address or prohibit the disbursement of some service territory-specific funds through contracts with CBOs to provide services relating to communicating the message of choice. We believe that our education plan emphasizes the value that CBOs can bring to educating the public. In our opinion, the adopted consumer education plan appropriately includes CBOs. We do, however, reserve the right to revisit this issue after one year has passed. We will monitor the level to which CBOs have been utilized by the utilities and make adjustments to the plan as appropriate.

(9) Western Alliance also contends that the consumer education plan should be modified to ensure that environmental interests are "adequately represented in the consumer education plan". In particular, Western Alliance is seeking to ensure that "green energy" is adequately represented. The consumer education plan is designed to promote the choice of electric service in Ohio. It is not intended to promote one form of generation over another, including so-called "green energy". The education plan will focus on raising the awareness of choice among consumers and providing the tools necessary for consumers to make informed decisions about their electric service. We see no need to modify the consumer education plan as requested by Western Alliance. Despite this conclusion, we note that our staff has proposed and we will consider in the near future a rule that will require, outside of the consumer education plan, the dissemination of information to consumers about generation sources, including "green energy". *In the Matter of the Commission's Promulgation of Rules for Minimum Competitive Retail Electric Service Standards Pursuant to Chapter 4928, Revised Code*, Case No. 99-1611-EL-ORD (proposed rule 4901:1-XX-09).

(10) CEA argues, in its first assignment of error, that the Commission should have adopted measurable standards with which to evaluate the performance of the plan. CEA states that, without such measurable standards in the plan, there can be no determination as to whether the Commission has met its responsibility to adopt and order a consumer education plan. FirstEnergy states, in its December 30, 1999 memorandum contra, that provision (F) will provide the baseline and continuing research for objectively measuring customer awareness.

The Commission had a responsibility to adopt and order a consumer education plan. We have done that in this docket. While specific, measurable evaluation standards are indeed critical to the success of the program, we believe that those goals cannot realistically be set until the results of a baseline, statewide research study are available to ourselves and to the statewide advisory group. That study is to take place in the spring of this year and goals will be set thereafter.

(11) Additionally, CEA argues that the Commission erroneously placed sole responsibility and authority for the consumer education plan with the utility industry and, thus, is precluding meaningful participation by the advisory groups. CEA's argument is based upon the plan's creation of the advisory groups, but its failure to require incorporation of the work of the advisory groups. FirstEnergy contends that the plan recognizes that Section 4928.42, Revised Code, places the responsibility for education with the electric utilities and, therefore, CEA is improperly seeking to micromanage the education effort and regulate the dispersion of funds. As explained in FirstEnergy's response, it believes that the adopted role for the advisory groups will avoid the pitfalls of a "governance by committee" approach suggested by CEA.

We intend that the advisory groups formed within the service territories will be comprised of members similar in representation to the statewide advisory group, with emphasis on the inclusion of CBOs among their members. We also intend that the role of the territory specific-advisory groups be similar to that of the statewide advisory group, in that the territory specific-advisory groups will provide input to the messages and dissemination of the message within the service territories while being mindful that the campaign must support the statewide campaign. We believe that the coordination of such efforts is best done by the electric utilities within their own areas and ultimately coordinated by Ohio Electric Utility Institute to ensure consistency of message. We remind CEA that the Commission has ultimate supervision of the program. Given that the advisory groups, including CBOs, are given a specific mission and the Commission has a specific oversight role as does the OCC in consultation, we do not agree with CEA's assessment that the utilities were given "sole responsibility and authority" over the consumer education plan. However, given our conclusions and as noted above, we do reserve the right to revisit the progress of the education program and assess the level of involvement of non-utility stakeholders.

(12) CEA also alleges that the Commission should have required the education plans to include information about energy efficiency improvements, net metering, and aggregation. CEA states that the Commission has not met the requirements of Chapter 4928, Revised Code, because, under the adopted plan, only the utilities must agree upon the messages of the campaign. Additionally, CEA contends that the failure to include information about energy efficiency and net metering violates the goals of the state electric policy. Moreover, CEA argues that the campaigns should educate customers on organizational options under the competitive market (not just rely upon the ability to choose a marketer). FirstEnergy argues in response that the campaign's message should be that consumers have a choice and not include multiple themes.

Section 4928.56, Revised Code, requires the Director of the Ohio Department of Development (ODOD) to establish a consumer education program, which provides information to consumers regarding energy efficiency and energy conservation. We said in our November 30, 1999 order that messages of the campaign would be developed with the assistance of the advisory group and that the ultimate plan would not duplicate the efforts of ODOD, but support them. We, again, conclude that, while net metering and aggregation may be messages of the overall campaign, it is the duty of the advisory group, in conjunction with the Commission, OCC, and advertising/PR firms to determine the specific messages of the campaign. This assignment of error is denied.

(13) CG&E alleges, in its last assignment of error, that the Commission should clarify provision (F) of the consumer education plan. CG&E states that it is unclear whether the Commission contemplates service territory-specific research (done by the utilities or via contract) or statewide research that is detailed so as to provide valuable data for the service territory-specific campaigns.

We clarify that all research conducted for the education campaign will be done as part of the statewide campaign and each utility is not required to conduct education and awareness research individually. The statewide research will be conducted such that statistically accurate service territory conclusions may be drawn, as well as statewide conclusions. This does not, however, preclude other research as ordered by this Commission for the purposes of market monitoring.

Processing Rules

(14) In Western Alliance's first assignment of error, it asks the Commission to affirm that public interest groups and ordinary citizens are not going to be shut out of the transition process. Specifically, Western Alliance asks the Commission to clarify that there will be an opportunity for public hearings and public input in either the rules docket or in specific transition plan dockets.

Western Alliance worries that the general public will not be able to participate in the transition plan process. However, Section 4928.32, Revised Code, specifically allows all persons with a real and substantial interest in a proposed transition plan to file with the Commission their preliminary objections to the plan. Moreover, our adopted rules allow intervention. Thus, the process for the transition plans plainly allows interested groups and ordinary citizens to participate in these proceedings, if they choose. Additionally, public notice of the transition plan filings will be made so that the general public can learn of the filing and learn how to obtain further information about a particular utility's proposed application. Thus, the general public not only can participate in the transition plan proceedings, but will also be provided with basic information from which the public can evaluate whether it wishes to participate in the proceedings. Western Alliance also requests that the Commission clarify that there will be public hearings in either this docket or in the individual transition plan application dockets. Public hearings regarding the transition plans are not mandated by Chapter 4928, Revised Code. Rather, Section 4928.32, Revised Code, states that, for those aspects of the proposed plan that the Commission determines reasonably require a hearing, the Commission shall afford a hearing. Our adopted rules correspond with the discretion granted to the Commission by the legislature. Upon review of the transition plan applications, we will determine whether hearings are reasonably required. Nothing in Western Alliance's application for rehearing convinces us that the processing rules should be clarified or modified on this point. For these reasons, we conclude that Western Alliance's first assignment of error should be denied.

(15) Western Alliance argues in its last assignment of error and OCC argues in its first assignment of error that the Commission should ensure public input by scheduling public hearings throughout the state of Ohio. Western Alliance states that public input is important, particularly on the issues of unbundling and the shopping incentive. OCC states that local hearings will not delay the Commission's decision-making process if they are held during or immediately following the evidentiary hearings. OCC suggests a local hearing be held in at least one city in each utility's service area and that the Commission publish notice of such hearings once each week for two consecutive weeks prior to the local hearing. FirstEnergy states in response that local hearings are not necessary, would have little value, and OCC (and other group representatives) can provide input for the general public without holding local hearings.

We have, in part, discussed Western Alliance's and OCC's concern. We noted above that Chapter 4928, Revised Code, does not mandate that the Commission hold hearings in every transition plan proceeding. Upon review of the transition plan applications, we will determine whether hearings are reasonably required. Moreover, in our November 30, 1999 decision, we noted that, due to the statutory time constraints, we would not establish rules to accommodate certain parties, including a rule for holding local public hearings. We continue to believe that our conclusion was correct. This conclusion is justified because of the large scope of the transition plan applications and the fact that several such cases will be pending before the Commission and be subject to the same statutory time constraint. As noted, we will evaluate whether hearings are reasonably required in the transition plan cases at a later time. For these reasons, we deny Western Alliance's last assignment of error and OCC's first assignment of error.

(16) OCC also alleges (in its second assignment of error) that the Commission erroneously failed to establish a rule precluding the transition plan evidentiary hearings from taking

place simultaneously. OCC believes that the Commission should establish an evidentiary hearing schedule at the outset to avoid simultaneous hearings. OCC states that the Commission should at least order that every effort will be made to avoid simultaneous hearings and, if they do occur simultaneously, every effort will be made to not unduly disadvantage parties who experience difficulties as a result. FirstEnergy states that this issue was already considered by the Commission. Also, FirstEnergy argues that the need for hearings, their scope, and schedule thereof are within the Commission's discretion and there is no need to restrict or interfere with that discretion at this point.

We recognize that some parties will have an interest in a number of the transition plan applications and we noted that we would do our best to alleviate the difficulties that the parties will face because of their involvement in multiple dockets. As we have done in the past, we will take efforts to avoid conflicts between the different dockets. However, we will not modify our conclusion to not establish a rule such as that requested by OCC.

(17) OCC's third assignment of error states that the Commission inappropriately failed to include in the rules the requirement that active spreadsheets be provided to any intervening party who requests them. Likewise, CCE alleges in its first assignment of error that the Commission erred in not incorporating in its rules the requirement, set forth in the finding and order, to provide electronic copies of active spreadsheets. FirstEnergy correctly noted in its memoranda contra that Rule 4901:1-20-04(B) does require that active spreadsheets be provided to parties. OCC and CCE have overlooked the last sentence in Rule 4901:1-20-04.

(18) OCC's fourth assignment of error relates to the settlement conference rule, Rule 4901:1-20-08. OCC argues that the adopted rule should have included the rationale/purpose explained by the Commission in the November 30, 1999 Finding and Order. OCC is concerned that our statements in the order regarding the usefulness of having the settlement conference begin at day 60 (rather than at a later time) conflict with the adopted rule language. Also, OCC again advocates that the settlement conference not be held until day 100. FirstEnergy states that it makes sense to meet and

attempt to narrow the scope of the proceedings as early as possible.

We disagree with OCC's statements. We believe that our rationale for scheduling settlement conferences in these cases is reasonable. Moreover, we believe that there is no need to alter the 60-day deadline. We have not declared that the 60-day settlement conferences to be "preliminary" or that the purpose is solely to organize future meetings. Rather, we are requiring the parties to explore settlement and are doing so at a fairly early stage in these cases. We will not assume that holding a settlement at day 60, rather than at day 100, will be fruitless.

(19) OCC states in its fifth assignment of error that the Commission should not have established the intervenors' prefiling deadline 14 days prior to the start of the hearing. OCC prefers that the prefiling deadline for intervenor testimony be seven days prior to the start of the hearing. OCC contends that the seven-day difference will jeopardize the intervenors' ability to prefile complete testimony. OCC also believes that the utilities will have ample time to prepare for the intervenors' witnesses because those witnesses will not testify at the commencement of the hearing. FirstEnergy argues that the intervenor prefiling deadline will not jeopardize the intervenors' ability to file complete testimony since they have ample time to conduct discovery. Additionally, FirstEnergy points out that OCC's preferred seven-day prefiling deadline exacerbates the utilities' ability to adequately depose intervenor witnesses prior to the start of the hearing.

We considered this issue at the time we established our rules. OCC reiterates prior arguments. We believe that the "14 days prior to the hearing" intervenor deadline is reasonable. Also, we are not absolutely convinced that the intervenor witnesses will testify several weeks after the start of the hearing, as OCC suggests. In the past when we have faced multiple complex proceedings, the order of testimony has not followed a strict schedule of all applicant witnesses followed by all intervenor witnesses. We believe that our past experiences in this regard are likely to occur again. Moreover, we are willing to avoid conflicts between the dockets, as OCC requested above. We cannot assume that all electric utility witnesses will testify prior to any intervenor witnesses under such circumstances. For these reasons, we believe that the intervenor prefiling deadline is appropriate.

(20) DP&L and AEP argue that the time frames for responding to intervention requests, discovery requests, and motions are unreasonably short. CG&E takes issue with the intervention response date (Rule 4901:1-20-10) in its eighth assignment of error. FirstEnergy takes issue with the time frame for serving responses to discovery requests (Rule 4901:1-20-11(A)). DP&L suggests that responses to intervention requests (Rule 4901:1-20-10) should be lengthened from five calendar days to recognize that Saturdays, Sundays, and legal holidays are not working days. AEP suggests five business days. CG&E suggests 10 business days from the date of service. DP&L and AEP also suggest that the time frame for serving responses to discovery requests be lengthened from 10 calendar days to 10 business days. FirstEnergy suggests that the time frame to respond to discovery requests be lengthened to 10 days from actual receipt. AEP seeks to lengthen the time for responding to discovery-related motions as well (Rule 4901:1-20-11(C)). With regard to the discovery rule, CG&E contends that Rule 4901:1-20-11 is unreasonable and/or unlawful. In this regard, CG&E states that all discovery rules, except those regarding expedited discovery, must be submitted to JCARR.

OCC disagrees with all of the electric utilities' arguments about the deadlines for responding to discovery requests, intervention requests, and discovery-related motions. OCC states that a rapid "turn around" is necessary given the statutory time line for resolution of these cases. OCC raises a concern that the additional time requested by the utilities will have a cumulative delaying effect and, therefore, the adopted rules should remain. CCE does not oppose extending the time to file responses to intervention requests, as CG&E suggests. However, CCE opposes lengthening the time frame for responding to discovery requests for the same reasons espoused by OCC. CCE notes that the attorney examiner can address those instances in which just cause is shown that producing responses within the 10 calendar day period may be difficult.

We were required under Section 4928.32(A), Revised Code, to expedite discovery in the transition plan proceedings.

DP&L, CG&E, FirstEnergy, and AEP are unhappy with the time frames we selected. We believe that the five-day and 10-day time frames are acceptable time frames. Quite frankly, any expedited time frames that we would establish would be objectionable from the electric utilities' point of view because they are shorter than what is typically applied and the utilities have all suggested different time frames. We have imposed a 10-day time frame for discovery responses in other proceedings and it has worked. We also find the time frame for responding to intervention requests to be reasonable too. We simply do not believe that the utilities need a longer period of time to determine whether they will respond to an intervention request and actually write the response.

(21) Also, CG&E states that the deadline for filing intervention requests is so late that intervenors could effectively intervene after the cut-off date for conducting written discovery requests. CG&E urges the Commission to revise the rules to prevent such gamesmanship and the resulting prejudice. OCC agrees with CG&E's point. Additionally, OCC states that the written discovery cutoff date should be closer to the commencement of the hearing so that intervenors can serve written discovery requests after any supplemental utility testimony is filed. CG&E's point is accurate, but it is something that also exists in our current procedural rules. Moreover, CG&E and OCC are overlooking the fact that depositions can be taken after the cut-off for written discovery and after the intervention deadline. We believe that the intervention deadline we established is acceptable, despite CG&E's and OCC's statements.

(22) AEP alleges in its third assignment of error that Rule 4901:1-20-12 should acknowledge that protective orders will apply through the pendency of the proceedings, through appeals, plus 60 days, or for a period of 18 months, whichever period is longer. AEP states that the adopted rule could essentially allow a protective order to remain in effect for a very short period of time, if a transition plan order is not appealed. AEP believes that such was not the Commission's intention and requests clarification on this point. AEP's point is accurate. We had intended protective orders for the transition plan proceedings to apply through the pendency of the proceedings, through appeals, plus 60 days, or for a period of 18 months, whichever period is longer. Our rule, however,

was not written as clearly as we would have preferred. We do find, however, that, given the flexibility that exists in Rule 4901:1-20-12, we do not need to modify it, in order for us to carry out our intentions. The individual rulings in the transition plan proceedings, which grant protective orders, can specify that those protective orders will apply through the pendency of the proceedings, through appeals, plus 60 days, or for a period of 18 months, whichever period is longer. For this reason, we deny AEP's third assignment of error, but clarify that protective orders in the transition cases can apply through the pendency of the proceedings, through appeals, plus 60 days, or for a period of 18 months, whichever period is longer.

(23) FirstEnergy takes issue with the period of time associated with the Commission's adequacy review, as set forth in Rule 4901:1-20-14(A). FirstEnergy states that, if the review period is 30 days, it will expire after the time period allowed in Section 4928.31(A), Revised Code, for the filing of timely transition plan applications. FirstEnergy states that the Commission should expressly state that a transition plan initially filed within the 90-day period, but supplemented or refiled pursuant to a Commission ruling after the 90-day period, will be considered timely under Section 4928.31(A), Revised Code.

FirstEnergy's concern existed even without our declaration of a 30-day adequacy review in Rule 4901:1-20-14(A). Chapter 4928, Revised Code, required transition plan filings within a relatively short window of time and, thus, any determinations of substantial inadequacy made after that period of time could raise the question of whether subsequent filings can be considered timely under Section 4928.31(A), Revised Code. For that reason, we do not believe that our rule should be modified. Additionally, we do not believe that any advance declaration of compliance with the time element in Section 4928.31(A), Revised Code, is necessary at this point.

Unbundling Rules

(24) As we understand it, CG&E and FirstEnergy allege (in CG&E's first assignment of error and in FirstEnergy's seventh assignment of error) that the definition of "regulatory asset" in Rule 4901:1-20-03, Appendix A, provision (B)(6),

conflicts with Chapter 4928, Revised Code, because the Commission's rule is more restrictive. As we understand it, CG&E and FirstEnergy contend that Sections 4928.01(A)(26) and 4928.40(A), Revised Code, expressly anticipate recovery of regulatory assets beyond those approved in the last rate case. CG&E suggests that either the last sentence of provision (B)(6) be stricken or the Commission clarify that "the rate recovering regulatory assets to be approved in the transition plan cases is the component of the bundled rate approved within the last rate case to recover regulatory assets." Basically, CG&E does not think that the rule should limit the book balance of regulatory assets that may be recovered.

CCE points out that the second sentence of provision (B)(6) does not impose a limit on the regulatory assets or dollars that may be recovered as CG&E and FirstEnergy claim. Rather, as we understand CCE's view, provision (B)(6) recognizes that the unbundled rate <u>element</u> for regulatory assets must equal the rate reflected in the utility's schedule of rates and charges.

We feel that our rule is appropriate as a minimum filing requirement. For that reason, we do not believe that any modification to provision (B)(6) is needed.

(25) CCE argues in its second assignment of error that the Commission's finding and order may raise a conflict about the application of the five percent reduction described in Rule 4901:1-20-03, Appendix A, provision (C)(1)(c). CCE believes that the Commission should affirm that the production-related portion of rates composes the generation component of rates and that the production-related component (in its entirety) is subject to reductions for residential customers. AEP and FirstEnergy state in their memoranda contra that the Commission did not intend to resolve what should or should not be included in the generation component and that the rules were structured to allow the utilities to file and support their preferred mechanism. For that reason, they argue that there is no conflict between the rule and the Commission's discussion of the rule.

AEP and FirstEnergy have correctly noted that our rule was structured to allow the utilities to file and support what should and should not be included in the generation component. We are unwilling to modify the filing requirement provision as CCE has suggested. CCE (as well as other parties) can question the make-up of the generation component in the context of the individual transition plan proceedings. We will take such argument into consideration at that time.

(26) CCE also argues that the list in Rule 4901:1-20-03, Appendix A, provision (C)(1), of elements functionally related to the generation component is incomplete. In particular, CCE states that some of the ancillary services listed under the transmission component can be production-related or generation-related and their costs should not be allocated to the transmission component. FirstEnergy contends that CCE's argument directly contradicts Section 4928.34(A)(1), Revised Code, since the transmission component equals the Federal Energy Regulatory Commission (FERC) tariff rates and, as such, would not be included in the generation component.

Similarly, CCE alleges that the list in Rule 4901:1-20-03, Appendix A, provision (C)(2), of ancillary services is incomplete because it does not include certain services listed in Section 4928.01(A)(1), Revised Code. FirstEnergy does not think CCE's modification is needed because FirstEnergy could not unbundle these other items since it does not have them, even though they are listed in the legislation.

We find the lists in provisions (C)(1) and (C)(2) to be adequate for purposes of the plan content requirements. CCE is able to pursue in the transition proceedings an argument that additional elements/services should be unbundled and/or that they should be related to the generation versus transmission versus distribution components.

(27) CCE next alleges that the Commission failed in Rule 4901:1-20-03, Appendix A, provision (C)(2), to adequately reflect that refunds determined or approved by FERC must be flowed through to retail electric customers, pursuant to Section 4928.34(A)(1), Revised Code. AEP responded by stating that the rules do not need to repeat the statutory provisions. Additionally, in AEP's view, CCE's assignment of error must be denied because non-switching customers will see an increase in the distribution rate component when there is a decrease in basic transmission rates and, for the

switching customers, refunds are a matter between them and the supplier.

We are not convinced that provision (C)(2) must be modified, despite CCE's allegation. We recognize that the transmission component's charges must include a sliding scale to ensure that FERC refunds are flowed through to retail electric customers, pursuant to Section 4928.34(A)(1), Revised Code. As FirstEnergy noted, we will take steps to ensure that those future refunds, if any, are appropriately handled. For purposes of our filing content requirements, we believe the adopted rule is correct. This allegation of error is denied.

(28) CCE further argues that the Commission erroneously excluded metering service and billing and collection service from the other unbundled components in Rule 4901:1-20-03, Appendix A, provision (C)(4). CCE states that these services may become competitive and should be broken out from general rates so that the market for those services can develop. CCE states that these two services should be designated as unbundled portions of the distribution function. FirstEnergy responds by stating that, pursuant to Section 4928.04, Revised Code, the Commission is not obligated to proceed with these issues until March 31, 2003.

CCE raised this issue in its initial comments. We fully considered this request and decided that the information should be identified. Thus, the electric utilities and other parties are free to raise in the transition proceedings an argument that these two services should be or should not be unbundled portions of the distribution function. Moreover, as we noted before, parties may address the costs of individual meter change outs in order to facilitate aggregation.

(29) CG&E contends in its second assignment of error that Rule 4901:1-20-03, Appendix A, provision (C)(4)(a), must be revised to allow utilities to recover the gross receipts tax (GRT) through April 30, 2002, in order to recover their GRT expenses incurred. CG&E believes that, although the adopted rule relates to filing requirements only, it could conflict with Section 4928.34(A)(6), Revised Code. CCE points out that Section 5747.98, Revised Code, states that the electric utilities are not subject to the excise tax after

payment of the assessment. Therefore, CCE believes the Commission's rule is consistent with the statute.

We are not convinced that provision (C)(4)(a) conflicts with Section 4928.34(A)(6), Revised Code, or that the rule must be modified. We disagree with CG&E's request.

(30) Next, CG&E alleges that the inclusion of an emission fee rider (Rule 4901:1-20-03, Appendix A, provision (C)(4)(d)), is inappropriate because emission fees are included in frozen rates.

We do not agree that there is an error in provision (C)(4)(d). Our rule lists emission fee riders as unbundled components, if applicable. The intent of having emission fee riders unbundled is to comply with Section 4905.31, Revised Code, which specifically requires the termination of the riders once the applicable cost of emission fees has been recovered. Therefore, it is necessary to unbundle this rider from other costs so that the rider can be terminated pursuant to Section 4905.31, Revised Code. *See, In the Matter of the Commission Procedures for the Recovery of Emission Fees*, Case No. 93-1000-EL-EFC, Entry (August 19, 1999).

(31) CCE urges the Commission to modify Rule 4901:1-20-03, Appendix A, provision (C)(5), to recognize that tax changes undertaken by Ohio are not intended to increase rates and that restructuring efforts should be applied to eliminate any increase in the price of electricity. Section 4928.34(A)(6), Revised Code. CG&E, however, seeks to modify Rule 4901:1-20-03, Appendix A, provisions (C)(5) and (D), to allow an adjustment in the capped rate of the total of all unbundled components for additional reasons other than those adopted by the Commission. In particular, CG&E notes that the exceptions should include charges to certified suppliers, material changes authorized by federal law, material changes in tax laws, and changes due to resolution of property tax litigation. CCE agrees with CG&E that material changes in tax laws and changes due to property tax litigation are legitimate ways in which rates may be adjusted and, thus, the Commission's rules should reflect them.

AEP responded to CCE's request to modify provision (C)(5). AEP notes that Chapter 4928, Revised Code, requires the Commission to address the difference between current and new taxes and to avoid placing the burden of that difference upon the electric utility or its shareholders. Given that requirement, AEP states that it is not possible to require the rates to be capped to prevent the pass through of tax changes. Similarly, FirstEnergy argues that CCE's request directly contradicts Section 4928.34(A)(6), Revised Code.

We do not agree that Section 4928.34(A)(6), Revised Code, requires all tax changes to not increase the price of electricity, as CCE has stated. In fact, that provision of the legislation specifically states that tax-related adjustments shall, in certain circumstances, be addressed by the Commission through accounting procedures, refunds, or an annual surcharge or credit to customers. Additionally, taxation rate adjustments shall have a corresponding adjustment to the rate cap for each rate schedule. Chapter 4928, Revised Code, acknowledges that electric rates may increase as a result of tax changes and restructuring, even though the goal may be to eliminate price increases to the extent possible. As for CG&E's suggestion, we do not agree that the minimum unbundling filing requirements for current rates <u>must</u> allow for adjustment of the capped rate for the reasons cited by CG&E. However, we do recognize that Section 4829.34, Revised Code, does allow for certain further adjustment to the capped rate. CG&E can pursue its position in the context of its transition plan proceeding or after a triggering event, but we will not modify the filing requirements on that point.

(32) In CCE's ninth assignment of error, it further argues that the Commission's rules erroneously do not require an unbundling plan to unbundle all of the components listed in Section 4928.01(A)(27), Revised Code. FirstEnergy contends that retail electric service does not necessarily include all of the items listed in Section 4928.01(A)(27), Revised Code; rather, it is the utilities' rates that must be unbundled.

Similar to our conclusion in finding 26 above, we believe that the unbundling rules are adequate for purposes of the minimum plan content requirements. As we have stated previously, CCE (and other parties) can raise specific arguments in the transition plan proceedings for unbundling other components and we will take such arguments under consideration then.

(33) CCE next seeks to have the Commission modify Rule 4901:1-20-03, Appendix A, provision (E), to assure that master-metered customers will receive the benefits of unbundling and competition because the state's electric policy seeks to ensure the competitive supply of retail electric service to all consumers. AEP disagrees with CCE's suggestion because it would require the Commission to extend its jurisdiction beyond what it is authorized.

We are not convinced that the nonexhaustive list of tariff items in provision (E) must be modified to include master-metered service. We have considered CCE's argument, but cannot agree to modify the provision. CCE may pursue this topic in the context of the individual transition proceedings.

(34) In CG&E's fifth assignment of error, it contends that the requirement to meet the FERC's seven-factor test (Rule 4901:1-20-03, Appendix A, provision (F)(2)(g)) is unlawful. CG&E believes that, because Section 4928.34(A)(1), Revised Code, requires the use of the FERC rates, the Commission's adopted rule is an attempt to impermissibly change those rates. CG&E states that the only purpose for the seven-factor test is to reclassify facilities, for which the Commission has no authority. CG&E further contends that it has already accomplished the separation of transmission facilities from distribution facilities when its open access transmission tariff was calculated. Finally, CG&E states that it will have to perform the seven-factor test between 2001 and 2003 and to do so now is an unnecessary and extraordinary expense.

We do not agree with CG&E's position that Rule 4901:1-20-03, Appendix A, provision (F)(2)(g), is unlawful. Nor do we agree that it should be modified. We do note, however, that some of the electric utilities have sought waivers of this requirement in their transition plan applications. We are currently reviewing those requests to waive the filing requirement until a later day.

(35) CCE's tenth assignment of error also concerns the seven-factor test in Rule 4901:1-20-03, Appendix A, provision (F)(2)(g). Like CG&E in the finding above, CCE questions the requirement to apply FERC's seven-factor test. CCE contends that not all FERC rates must satisfy the seven-factor test and, thus, this information will be insufficient. Moreover, CCE alleges that Chapter 4928, Revised Code, requires

a clear demarcation of transmission and distribution facilities, services, and functions to eliminate the negative effects of gaps, seams, and pricing pancakes.

We find here, as we have for several other allegations of error, that our adopted rule is adequate as a minimum filing requirement. CCE's tenth assignment of error is denied.

(36) CCE's last assignment of error related to the unbundling rules concerns the schedule contents in Rule 4901:1-20-03, Appendix A, provisions (F)(2)(k) through (m). CCE does not believe that the contents will provide enough detailed information to verify whether tax changes that are proposed in the unbundling plan will be neutral, as required by Section 4928.34(A)(6), Revised Code.

Our rule is an appropriate minimum filing requirement. We do not accept CCE's contention that further modification is needed.

Corporate Separation Rules

(37) AEP, FirstEnergy, and CG&E argue that the definition of "affiliates" in Rule 4901:1-20-16(B)(1) should be narrowed to apply only to an affiliate engaged in the business of supplying competitive retail electric service or providing a non-electric product or service. Similarly, FirstEnergy alleges that, with the existing definition of "affiliates", the code of conduct will prohibit routine utility interactions, including coordination and centralized support functions. If not more narrowly defined, AEP believes the effect of the definition violates Section 4928.17(A), Revised Code. CG&E agrees that the Commission may audit all affiliates and, therefore, in the alternative, suggests that, while the rule applies to all affiliates, it applies only to information which would convey a competitive advantage to the receiving affiliate. Also, AEP seeks a clarification of the second sentence in the definition of "affiliates" because the Commission's order indicated that it was making no modification to the staff's proposal, but the adopted rule contains the additional sentence.

PG&E argues that the definition is appropriate because the legislation requires all of the utility's affiliates to be structurally separate, whether they provide competitive retail electric service or whether they provide products or services other than retail electric service. Section 4928.17(A), Revised Code. PG&E is less concerned, however, with information sharing between wholly regulated entities, especially for economic efficiency and operational stability. OCC states that the definition of "affiliates" is correct, but the specific rules should be clear so as not to apply corporate separation restrictions to relationships between non-regulated affiliates (except with the cost allocation manual (CAM) requirements). CCE emphasizes that the Commission must have authority to audit all affiliates and have access to the books and records of all affiliates. Otherwise, CCE believes there would be a large loophole for ensuring against anticompetitive behavior.

We had not intended, with our adopted definition of "affiliates", to prohibit all interactions between affiliated entities and electric utilities. Sharing of information and employees between affiliated entities and electric utilities for safety purposes, economic efficiency, and operational stability can be acceptable, if not at the expense of the competitive market or if it does not impede the competitive market. Moreover, we clarify that certain centralized support functions can be permissible sharing among affiliated entities and electric utilities. Specifically, we wish to clarify that the corporate separation rules are intended to require independent work/functions when the failure to maintain independent operations may have the effect of harming customers or unfairly disadvantaging unaffiliated suppliers of competitive retail electric service or nonelectric products or services (such as with sharing that violates the code of conduct provisions). Additionally, we clarify that provision (D)'s use of the term "employees" shall mean employees as defined in Rule 4901:1-20-16(B)(4), excluding officers and directors. Provision (E) allows for certain flexibility upon annual certification to the Commission that there is no sharing of employees. We clarify that such certification as it relates to a lack of shared employees is intended to be a demonstration that there is no prohibited sharing of employees. Finally, we clarify that our adopted definition of "affiliates" was intended to include the second sentence, even though our order may have given a different impression.

(38) AEP's final assignment of error states that the Commission should clarify Rule 4901:1-20-16(B)(4), the definition of "employees". AEP believes that the other provisions in the corporate separation rule will require the utility to maintain job descriptions of consultants and independent contractors, something that is not ordinarily done. Additionally, AEP seeks clarification that the Commission's rule is not intending to impair the ability of outside counsel and consultants to perform their duties. AEP does not object to a provision that would prohibit consultants and independent contractors from being conduits for transferring confidential information.

On January 20, 2000, we modified certain aspects of the corporate separation rules on our own motion. Included in those modifications were changes to some provisions specific to employees who are shared consultants and shared independent contractors. Thus, we believe that nearly all of AEP's concerns in its final assignment of error, have been addressed by the modification. We do emphasize that the corporate separation rules' use of "employees" is not intended to impair outside counsel and consultants from performing their duties. Rather, it is intended to ensure appropriate, pro-competitive behavior in the performance of their duties. Also, while AEP indicated no objection to a provision in the corporate separation rules that prohibits consultants and independent contractors from being information conduits, our adopted rules already contain such prohibitions in the code of conduct section.

(39) CCE seeks clarification as to what exemptions the Commission intends to grant to utilities, as set forth in Rule 4901:1-20-16(E). CCE suggests that any exemptions be addressed on a case-by-case basis and only with a showing of just cause. FirstEnergy states that, if the Commission allows intervention in exemption requests, the endless litigation will destroy any incentive intended by the rule. FirstEnergy urges the Commission to solely determine what exemptions are appropriate. We will consider exemptions at the time that such requests are raised. They will be considered on a case-by-case basis and granted when we find them to be justified and reasonable.

(40) A number of assignments of error relate to the code of conduct provisions in Rule 4901:1-20-16(G)(4). DP&L,

FirstEnergy, and AEP argue that, for several reasons, the Commission erred in making the code of conduct provisions in Rule 4901:1-20-16(G)(4) effective immediately. They argue that the immediate effective date conflicts with Section 4928.17, Revised Code, which requires a corporate separation plan to begin on the starting date of competitive retail electric service (January 1, 2001). DP&L and First-Energy also state that making that portion of the corporate separation rules effective immediately conflicts with the statutory scheme of evaluating the utility's transition plan, including a corporate separation plan, prior to the plan being effective. Furthermore, FirstEnergy contends that the code of conduct provisions cannot be imposed outside of the corporate separation plan approval process. Moreover, DP&L argues that it cannot meet the immediately effective provisions because it has no affiliate engaged in competitive generation services at this time. AEP notes that, if the legislature had intended the code of conduct to become effective earlier than the start of competition, it would have indicated such. AEP alleges also that the existing undue preference or advantage prohibition in Section 4928.17(A)(3), Revised Code, should alleviate Commission concerns over affiliate relationships while the corporate separation plans are under review.

PG&E and OCC argue that the immediate effective date is consistent with Section 4928.17(A)(3), Revised Code, which imposes several obligations upon the electric utilities by January 1, 2000. Also, PG&E points out that the Commission is given wide discretion as to the effective dates of the corporate separation plans. Section 4928.17(C), Revised Code. Similarly, CCE argues that the Commission's authority in this area includes measures necessary to prohibit anticompetitive behavior. A code of conduct effective immediately is needed, in CCE's view, to preclude anticompetitive advantages from occuring to the affiliate prior to January 1, 2001.

We concluded that part of the corporate separation rules needed to be effective immediately in order to prohibit, prior to the start of competitive retail electric service, certain activities from occurring that would be prohibited after the start of competitive retail electric service. Quite simply, we did not want to establish a framework under which the electric utilities could, for example, allow retail electric affiliates access to the electric utility's distribution system prior to the start of competition because such would be prohibited activity soon thereafter. Such gaming is unacceptable and can only diminish the ability of a competitive market to develop, in our view. We found that that type of gaming could be avoided by eliminating its opportunity to exist, namely, making the code of conduct provisions effective immediately. This conclusion carries out the purposes of the Chapter 4928, Revised Code, which we have specifically been instructed to do. *See*, Sections 4928.06(A) and 4928.17(A)(1), Revised Code. We do not believe that the immediately effective provisions preclude an electric utility from proposing a corporate separation plan. Nor do those effective provisions preclude our ability to evaluate a proposed corporate separation plan, which will become effective on the starting date of competitive retail electric service. In fact, we believe that our immediately effective provisions comport with Section 4928.17(A)(3), Revised Code, inasmuch as our provisions specifically restrict the means by which some undue preferences or advantages could occur. In that respect, our administrative rule amplifies Section 4928.17(A)(3), Revised Code, which was effective on January 1, 2000.[3]

(41) CCE argues that the Commission should have adopted a "GENCO Code of Conduct" and that the Commission should have also included three other provisions in its code of conduct that the Commission previously rejected. AEP opposes CCE's general suggestion, as well as its specific recommendations, as being anticompetitive. FirstEnergy questions CCE's premise that competition is harmed by inclusion of the generation affiliated competitor.

We previously considered CCE's concerns in this area. We did not agree with CCE and chose a different code of conduct approach. As for CCE's three other suggested provisions, we stated previously that the adopted rules sufficiently cover the request. We are still not convinced that modifications are necessary.

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3 We also wish to footnote that while we stated, on November 30, 1999, that the code of conduct provisions shall be effective immediately, that date can only be when permitted by law. In this situation, the earliest that the code of conduct provisions could become effective is following review by the Joint Committee on Agency Rule Review. That time period has yet to expire. Thus, we wish to make clear that our code of conduct provisions were not intended to become effective prior to the January 1, 2000 date set forth in Section 4928.17(A)(3), Revised Code.

(42) Moreover, CCE alleges that the Commission improperly refused to extend the code of conduct to non-tariffed products and services. CCE believes that the Commission has broad authority to prevent unfair competitive advantages for utility-affiliate transactions involving competitive products and services, not just tariffed products and services.

CCE's argument was raised and evaluated when several utilities argued that comparable access should be limited to only tariffed products and services. We concluded that the code of conduct should be limited in its application to products and services related to tariffed products and services. Nothing in CCE's application for rehearing convinces us that our earlier conclusion was in error.

(43) FirstEnergy alleges that the Commission's restriction on the use of the electric utility's name and logo in Rule 4901:1-20-16(G)(4)(h) is an unlawful restriction on commercial speech and should be deleted. FirstEnergy contends that the rule does not directly advance a governmental interest. In the alternative, FirstEnergy states that the Commission should clarify that the rule does not prevent FirstEnergy's Ohio operating companies from indicating that they are affiliates, without disclaimers.

PG&E believes that the Commission's rule is narrowly drawn for the purposes of seeking to avoid customer confusion and preventing competitive affiliates from benefiting from a trade brand without a sufficient disclaimer. PG&E points out that California has a similar requirement. OCC also believes that the adopted rule appropriately serves a substantial government interest of avoiding customer confusion, which the General Assembly clearly recognized (given the directives for funding consumer education). OCC raises the concern that use of the same name and logo by the regulated electric utility and unregulated competitive electric service supplier may even thwart consumer education efforts. CCE likewise believes the rule involved is a reasonable balance of permitting joint marketing when consistent with the state policy objectives (i.e., ensuring access to monopoly-provided utility services and mitigating market power). CCE urges the Commission to deny this assignment of error and put FirstEnergy on notice that it may impose additional structural and behavioral remedies when necessary.

On January 20, 2000, we modified provision (G)(4)(h) on our own motion. As a result of this modification, the electric utilities shall address in their transition filings how they plan to ensure against unreasonable sales practices, market deficiencies, and market power. To that end, the electric utilities must detail how they will meet the obligation, particularly as to how it relates to joint marketing activities, joint advertising activities, and the use of the name and logo of the electric utility. Thus, during our consideration of the transition plans, we will evaluate such plans. For this reason, we believe that FirstEnergy's allegation of error has been rendered moot.[4]

(44) FirstEnergy takes issue with Rules 4901:1-20-16(I) and (J)(4)(c). FirstEnergy argues that these two provisions are overly broad because they do not place limitations on affiliate practices solely for the purpose of maintaining separation of the affiliate's business from the business of the utility to prevent unfair competitive advantage. FirstEnergy does not believe that the separation requirements of Chapter 4928, Revised Code, are intended to give a blanket authorization to pry into affiliate transactions that are not related to utility operations.

We do not share FirstEnergy's opinion about Rules 4901:1-20-16(I) and (J)(4)(c). We believe it is appropriate for the Commission and staff to ensure that the corporate separation requirements are being met. One such means is through access to books and records of the electric utility and its affiliates. Moreover, we believe that requiring a CAM, which contains the allocation of costs between the utility and its affiliates, is likewise a vital source of information from which this Commission can ensure that the corporate separation requirements are being met. Nothing in FirstEnergy's application for rehearing convinces us otherwise. We reiterate, however, our prior conclusion that the CAM requirements will be reevaluated as actual experience is obtained.

4 On January 25, 2000, AEP filed an application for rehearing regarding our *sua sponte* modification of provision (G)(4)(h). We will address that pleading in a separate ruling.

(45) FirstEnergy believes that Rule 4901:1-20-16(J) should require that the costs for shared services (to be maintained in the CAMs) be capped at the stand-alone costs for those services. PG&E states that the method for charging costs and transferring assets should be at the higher of market value or fully allocated costs. OCC states in response that the Commission should not modify this rule if FirstEnergy is attempting to be allowed to absorb the costs of shared services (up to the amount it would have paid had it purchased the services on its own).

We do not think that we must modify provision (J) to cap the costs of shared services to be accounted for in the CAMs. We have required that all costs be based upon fully allocated costs, which are the sum of direct costs, plus an appropriate share of indirect costs. We find that acceptable accounting for shared costs. This requirement does not, however, control the ratemaking conclusion for shared services.

(46) OCC and CCE contend that the Commission erred in not permitting interested parties access to the CAMs. They both argue that the Commission's grant of discovery rights during the electric transition plan proceedings will not be helpful thereafter. Also, OCC states that staff monitoring is insufficient because the staff will not pursue subtle signs of anticompetitive behavior. Moreover, OCC believes that the sensitive nature of the information in the CAMs is not reason for precluding consumers not in competition with the affiliate suppliers (and particularly their residential representative, OCC) to have access to the CAMs. FirstEnergy counters by stating that non-access to the CAMs will not preclude complaints. Moreover, FirstEnergy contends that the General Assembly has not intended OCC or other motivated parties to participate in these compliance reviews.

OCC and CCE raised this same argument in their initial comments. We concluded then that the Commission and our staff would maintain exclusive authority for CAM compliance audits and updates. We believe that we and our staff can monitor compliance. Additionally, we do not believe that just allowing access for consumer groups and/or OCC out of the numerous parties interested in the CAMs is appropriate either. However, as FirstEnergy states, non-access to the CAMs will not preclude complaints. Moreover, complaints will not preclude discovery related to

CAM information either. Therefore, the Commission will consider specific discovery requests in the context of particular complaint proceedings. To that extent, we clarify our rule regarding access to the CAMs.

(47) OCC's final assignment of error relates to the biennial audits established in Rule 4901:1-20-16(K). OCC believes that the adopted rule should have required the publication of the staff's results and required the Commission to thoroughly examine the audit information through an open docket. FirstEnergy points out that the General Assembly did not specify that hearings be part of the Commission's review under Section 4928.17, Revised Code.

We considered this question at the time we adopted our corporate separation rules. We will take this into consideration and determine whether to publish audit results at a later time. We again note that we shall reevaluate the CAM requirements as actual experience is obtained.

(48) CG&E takes issue with the prohibitions against certain financial arrangements between utilities and their affiliates in its tenth assignment of error. CG&E states that it could be advantageous or necessary for CG&E to maintain existing indebtedness related to its generation facilities, even if those generation assets were "spun off" to a separate generation affiliate. CG&E contends that a "per se" disallowance should not be adopted. OCC states that the Commission should prohibit any kind of financing by electric utilities for acquisition, ownership, or operation of an affiliate. For those existing financial arrangements, OCC states they should be retired at the earliest practicable time. CCE, however, agrees with the Commission's adopted rule to eliminate financial support, except under limited circumstances.

In raising this assignment of error, CG&E appears to have overlooked the fact that Rule 4901:1-20-16(G)(3), regarding financial arrangements between an electric utility and an affiliate, is not a blanket prohibition. The rule specifically notes that the listed categories of financial arrangements are restricted, <u>except as the Commission may otherwise approve</u>. Thus, not all financial arrangements between electric utilities and their affiliates are per se prohibited as OCC would like. CG&E (and other electric utilities) may attempt to demonstrate that certain arrangements are advantageous or otherwise appropriate and should be permitted. For these reasons, we believe that our rule is appropriate and requires no modification.

Operational Support Rules

(49) CG&E states in its sixth assignment of error that the requirement in Rule 4901:1-20-03, Appendix B, provision (C)(2)(c)(i), to provide day-ahead load forecasts is unreasonable. CG&E worries that suppliers can increase the wholesale price of power for high demand areas, while CG&E's service rates are frozen. CG&E contends that suppliers should perform their own load forecasts. CCE states in response that providing suppliers with day-ahead forecasts does not enable them to increase the wholesale price of power to high demand areas. CCE supports the existing rule.

AEP and FirstEnergy raised concerns with this aspect of the staff's proposal in their initial comments. We concluded that the staff's proposal was appropriate, noting that load forecasts in the aggregate (and if available, by customer class) are an integral element to the reliability and dependability of service. It is for that reason that we found that the operational support plan should address the provision of day-ahead load forecasts. We also noted that we were not requiring the electric utilities to create and provide forecasts for individual certified supplier's load. Although CG&E raises this argument now for the first time, we do not feel that it justifies a modification to the requirements of what the utilities' operational support plan must address. CG&E's sixth assignment of error is denied.

(50) In CG&E's next assignment of error, it alleges that the operational support plan requires utilities to presently establish a bidding process for competitive electric retail service. CG&E contends that Section 4928.14(B), Revised Code, does not require bidding until the end of the market development period and, thus, the rule requirement is premature. CG&E noted that the Commission may have intended this to be a placeholder but, in that case, should expressly note such.

CG&E has misunderstood the nature of the items listed in the "Other Requirements" section of the operational support rules. As we explained in the finding and order (page

29), this provision (including the bidding process) is intended to be a topical listing for project management purposes only. To be certain that this is understood, we reiterate that we do not expect the electric utilities to file, in their transition plan applications, a "game plan" for all of the activities (including the bidding process) in Rule 4901:1-20-03, Appendix B, provision (C)(2)(f). This is because those items may not need attention in the reasonable future. We, however, believe that operational support will have to eventually address a bidding process (as well as the other items in that provision) and it is for that reason that we included the list. We see no error on our part.

(51) CCE seeks clarification as to how the Commission will develop uniform business practices. CCE specifically suggests that the Commission require the taskforce to establish uniform business rules by April 1, 2000, with the Commission reserving the right to decide the issues on its own, if they are not done by that date. FirstEnergy opposes CCE's deadline, stating that there is no need to "cut corners to meet an arbitrary deadline, and then encounter significant problems in January 2001."

At this time, the taskforce has already begun assembling and meeting. Thus, CCE's first concern has been taken care of. As to establishing a specific deadline, we do not feel that it is necessary at this point. We previously noted that, if the taskforce does not timely accomplish its work, we may step in. We affirm that statement, but we are unwilling to adopt an April 1, 2000 deadline. We will monitor the activities of the taskforce and take appropriate steps, when necessary. We consider operational support to be a vital aspect of the development of a competitive market in Ohio and fully intend to ensure that operational support systems will be ready to ensure a successful implementation of the customers' ability to choose generation suppliers.

Transition Charges Rules

(52) Only one party raised any allegations of error with regard to the adopted rules for transition charges. FirstEnergy states the requirement in Rule 4901:1-20-03, Appendix D, provision (B)(1)(b)(iv), to report a deferred fuel balance as part of its transition application is unreasonable because the Commission permitted it to not maintain deferred fuel balances

on its books, as result of the approved rate plans. FirstEnergy contends that it must therefore, create "fictitious information merely to meet a filing requirement that is meaningless relative to the [operating] companies." We see no need to modify our rules in light of FirstEnergy's statements here. FirstEnergy can explain in its transition plan filing why the deferred fuel balance information is not included and seek to justify a waiver with regard to that filing requirement.

(53) FirstEnergy also states that the filing requirements in Rules 4901:1-20-03, Appendix D, provisions (F)(2) through (7), should be modified. FirstEnergy contends that the rules should reflect that, while the information must be filed with the application, the applicant is not sponsoring the materials and may object to the admission and use of the materials during the course of the proceeding. We see no need to modify the rules as FirstEnergy requests. The rules require certain information to be included in the electric utilities' transition plans. Regardless of whether the utility relies upon that information in its proposal, the information shall be filed in accordance with our rules. As with any information for which a party seeks admission, objections may be raised.

Independent Transmission Rules

(54) AEP, CG&E, and FirstEnergy contend that Rule 4901:1-20-17 is unlawful, in particular provision (B)(3). They argue that the rule conflicts with federal law particularly because transmission of electric energy is subject to the exclusive jurisdiction of the FERC and cannot be regulated by administrative rule. They also argue that the rule is contrary to Section 4928.12(E), Revised Code, because the adopted rule goes beyond interim measures necessary and proper to achieve independent, nondiscriminatory operation of, and separate ownership and control of transmission facilities on or after the start of competitive retail electric service. That is to say, Section 4928.12(E) does not grant the Commission interim powers over retail pricing or pancaking. Similarly, AEP and FirstEnergy contend that, contrary to Sections 4928.12(A) and (B), Revised Code, the adopted rule "seeks to force all utilities under the Commission's jurisdiction to be in a single common transmission entity." AEP states that the Commission went too far in prohibiting pancaked rates

when Chapter 4928, Revised Code, sets as its goal the minimization of pancaked transmission rates. Moreover, AEP and FirstEnergy allege that the adopted rule's requirement that interim arrangements be approved by the FERC is prohibited state control of the timing and content of FERC jurisdictional rate filings. CG&E and FirstEnergy both take issue with the rule because it raises several questions and because the term "pooling" is not defined.

OCC and CCE allege that much of the allegations of error are moot, given the Commission's recent modification to the independent transmission rules. OCC also states that FirstEnergy's preemption concern over the obligations for the transmission entity ignores the fact that the Commission has to exercise the power and jurisdiction conveyed by the General Assembly.

The major objection regarding the independent transmission rules is with regard to provision (B)(3). On January 4, 2000, we modified that provision on our own motion. Thus, we believe that nearly all of the concerns specific to that provision have been addressed by virtue of the modification.[5]

As for the other remaining arguments against the revised independent transmission rules, we have considered them and find that they should be rejected.

Shopping Incentive Rules

(55) CCE contends that the Commission improperly rejected its prior argument that the shopping incentive rules should not apply to any affiliates of an incumbent electric utility. CCE still argues that any customers switching from an incumbent to its affiliate should not be included in determination of the percentage of customers switching. In CCE's view, customers who switch from one entry to another within a single corporation will do little to advance the objectives of a robust market. AEP and FirstEnergy argue in their memoranda contra that the 20 percent is not the standard for determining whether there is effective competition, particularly given the tests found in Section

5 On January 21, 2000, AEP filed an application for rehearing of our *sua sponte* modification of Rule 4901:1-20-17(B)(3). We will address that pleading in a separate ruling.

4928.40(B)(2), Revised Code, for terminating the market development period. FirstEnergy adds that, since the corporate separation rules ensure that customers who switch are making a choice that is treated as any other, so too should the switch to an affiliate for purposes of the shopping incentive.

The Commission previously considered CCE's argument and chose not to accept it. We do not believe that CCE has raised anything new which warrants a change in our prior conclusion. CCE's twelfth assignment of error is denied.

(56) FirstEnergy takes issue with the requirement to propose adjustments to the shopping incentive in the first two years of the market development period (Rule 4901:1-20-03, Appendix E, provision (C)). In FirstEnergy's view, the rules improperly focus upon the shopping incentive as an assessment of the competitive market, rather than the effectiveness of marketers and municipal aggregation. FirstEnergy also states that Chapter 4928, Revised Code, does not require the electric utilities to achieve any interim switching levels. PG&E and OCC contend that, since the Commission is required by statute to assure that, at the end of the market development period, there is a 20 percent load switch in each customer class, it stands to reason that the Commission has the discretion to require the electric utilities to include a plan for achieving that mandate.

We do not agree with FirstEnergy. FirstEnergy raised this issue in its initial comments. As we stated before and as CCE noted, the legislation does not preclude midcourse reviews and, in fact, specifically, acknowledges that such reviews may be done by the Commission. Given such flexibility, we chose to adopt a rule that would require the utilities to suggest approaches for such midcourse reviews as part of the shopping incentive portion of the transition plan. This rule "sets the stage" for considering how midcourse reviews should be done. The rule, itself, does not require interim switching levels. Regardless of FirstEnergy's belief that Rule 4901:1-20-03, Appendix E, provision (C), is ill-advised, we find it reasonable and appropriate.

(57) FirstEnergy's last assignment of error states that the Commission improperly invented a new customer class (mercantile commercial and industrial customers) in its

> shopping incentive rules. FirstEnergy states that the effect of the shopping incentives must be judged on the utility's classes of customers and, since a mercantile commercial and industrial customer class does not exist in the tariffs of FirstEnergy's operating companies, the use has no valid purpose.
>
> We clarify that the shopping incentive rules do not preclude reporting by the customer classes (e.g., residential, commercial, and industrial) contained within the tariff of each electric utility.

It is, therefore,

ORDERED, That the applications for rehearing of Western Alliance, CEA, CCE, Ohio Council of Retail Merchants, Industrial Energy Users-Ohio, Ohio Partners, DP&L, and OCC are denied. It is, further,

ORDERED, That the applications for rehearing of CG&E, AEP, and FirstEnergy are denied, except to the limited extent explained in Finding 37. It is, further,

ORDERED, That our Finding and Order of November 30, 1999, is clarified to the extent set forth in Findings 8, 13, 22, 37, 46, 50, 54, and 57 of this Second Entry on Rehearing. It is, further,

ORDERED, That a copy of this Second Entry on Rehearing be served upon all parties and interested persons of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Craig A. Glazer

Judith A. Jones

Donald L. Mason

GLP;geb

Entered in the Journal
JAN 27 2000

A True Copy

Gary E. Vigorito
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Regulation of the Electric Fuel Component Contained Within the Rate Schedules of Ohio Power Company and Related Matters.	)	Case No. 98-101-EL-EFC
In the Matter of the Regulation of the Electric Fuel Component Contained Within the Rate Schedules of Columbus Southern Power Company and Related Matters.	)	Case No. 98-102-EL-EFC

OPINION AND ORDER

The Commission, having considered the testimony filed in these cases, the exhibits presented at a public hearing, and the relevant provisions of the Revised Code and Chapter 4901:1-11, of the Ohio Administrative Code (O.A.C.), issues its Opinion and Order.

APPEARANCES:

F. Mitchell Dutton, and Marvin I. Resnik, American Electric Power Service Corporation, One Riverside Plaza, Columbus, Ohio 43215, on behalf of Ohio Power Company and Columbus Southern Power Company.

Betty D. Montgomery, Attorney General of the State of Ohio, by William L. Wright and Robert A. Abrams, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43215-3793, on behalf of the Staff of the Public Utilities Commission of Ohio.

Robert S. Tongren, Ohio Consumers' Counsel, by Evelyn R. Robinson-McGriff, Colleen L. Mooney, and Ann M. Hotz, Assistant Consumers' Counsel, 77 South High Street, 15th Floor, Columbus, Ohio 43266-0550, on behalf of the residential consumers of Ohio Power Company and Columbus Southern Power Company.

McNees, Wallace & Nurick, by Samuel C. Randazzo, Richard P. Rosenberry, and Kimberly J. Wile, Fifth Third Center, Suite 1700, 21 East State Street, Columbus, Ohio 43215, on behalf of Industrial Energy Users-Ohio.

OPINION:

I. Introduction:

Ohio Power Company (OPCO) and Columbus Southern Power Company (CSP) (collectively Companies) are electric light companies within the meaning of Section 4905.03(A)(4), Revised Code, and public utilities as defined by Section 4905.02, Revised Code. The Companies are also electric utilities within the meaning of Rule 4901:1-11-01(L), O.A.C. The Companies have within their tariffs on file with this Commission schedules which contain a fuel component allowing the Companies to pass on to their customers the acquisition and delivery costs of fuel which the Companies incur in the provision of electric service.

Section 4905.301, Revised Code, provides in pertinent part that:

> The fuel component in schedules of the type required by Section 4905.30 of the Revised Code shall be reviewed at a hearing by the public utilities commission once annually.

By Finding and Order dated March 12, 1998, the Commission initiated proceedings to review both OPCO's and CSP's electric fuel component (EFC).

Pursuant to the requirements of Section 4909.191(C), Revised Code, and Rule 4901:1-11-11(B), O.A.C., "[t]he electric utility shall demonstrate at the hearing on its fuel component that its acquisition and delivery costs were fair, just, and reasonable". At the hearing, the Public Utilities Commission is to consider, to the extent applicable, the following:

(1) The efficiency of the electric utility company's fuel procurement and utilization practices and policies;

(2) The results of the financial audit;

(3) The results of the performance audit;

(4) Compliance by the electric utility with previous Commission performance recommendations; and

(5) Such other factors as the Commission considers appropriate.

Pursuant to Section 4905.66(B)(2), Revised Code, and Rule 4901:1-11-10(B), O.A.C., Deloitte & Touche LLP (Deloitte) conducted a financial audit of the electric fuel components of OPCO and CSP. Deloitte filed its audit report in each of these cases on February 12, 1999 (Commission Ordered Exhs. 1 and 2, respectively). Also pursuant to Section 4905.66(B)(2), Revised Code, and Rule 4901:1-11-10(B), O.A.C., Energy Ventures Analysis, Inc. (EVA) conducted a joint management/performance audit of the fuel related policies and practices of OPCO and CSP. EVA filed its joint audit report in each of these cases on February 16, 1999 (Commission Ordered Exh. 3).

Section 4909.191(C), Revised Code, and Rule 4901:1-11-11(B), O.A.C., require each electric utility to demonstrate at a hearing that its acquisition and delivery costs were fair, just and reasonable. OPCO and CSP filed data pertinent to their respective fuel procurement policies and practices on February 12, 1999, in accordance with Section 4909.191(B), Revised Code, and Rule 4901:1-11-11(D)(1), O.A.C. (Company Exhs. 4, 6, 7, and 9). The Company filed the direct testimony of its witnesses John McManus, John E. Price, Philip J. Nelson, and Stephen D. Baker (Company Exhs. 10 through 13, respectively) on March 2, 1999.

On May 14, 1998, the Office of Consumers' Counsel (OCC) filed a motion to intervene in Case No. 98-101-EL-EFC on behalf of the residential customers of OPCO. The Attorney Examiner granted OCC's motion by Entry dated June 4, 1998. OCC moved to intervene in Case No. 98-102-EL-EFC on September 10, 1998, on behalf of the residential customers of CSP. The Attorney Examiner granted OCC's motion by Entry dated February 3, 1999. OCC filed the direct testimony of its witness Scott J. Rubin on March 11, 1999 (OCC Exh. 1).

On June 15, 1998, Industrial Users-Ohio (IEU-OH) moved to intervene in Case No. 98-101-EL-EFC. The Attorney Examiner granted the motion of IEU-OH by Entry dated July 9, 1998. OCC and IEU-OH both sponsored the testimony of Kevin B. Caldwell filed on March 11, 1999 (IEU-OH Joint Exh. 1).

The Attorney Examiner called the hearing in these cases on March 16, 1999. On that date, the Attorney Examiner took appearances, marked exhibits, and took the testimony of the management/performance audit witness, Emily Medine. The Attorney Examiner then recessed the hearing to March 24, 1999. On March 24, 1999, the Attorney Examiner resumed the hearings, taking the testimony of Raymond W. Strom, a Staff witness, and Philip J. Nelson, a rebuttal witness testifying on behalf of the Companies. The parties waived cross-examination of the remaining witnesses. Each of the parties filed briefs and reply briefs in these cases. OPCO and CSP filed proof that notice of the hearing was published as required by Section 4909.191(A), Revised Code, and Rule 4901:1-11(C), O.A.C. (CSP Exh. 4) on March 24, 1999. Neither Staff nor either of the intervenors has filed an objection to this exhibit.

II. Financial Audits:

Case No. 98-101-EL-EFC and Case No. 98-102-EL-EFC

Deloitte states in its financial audit report in each of these cases that it has examined the EFC rates for each of the Companies for the six-month periods ended May 31, 1998, and November 30, 1998. From its examinations, the Auditor concludes that the costs that each of the Companies charged its customers through the operation of its EFC were in accordance with Chapter 4901:1-11, O.A.C., and that each of the Companies properly applied its EFC rate to its customer bills (Comm. Ord. Exh. 1 at 2).

The Auditor noted that each of these companies exceeded its projected controlled sulfur dioxide emissions for 1997 under Title IV of the Clean Air Act Amendments of 1990 and surrendered emission allowances (EA's) to the United States Environmental Protection Agency (USEPA). OPCO surrendered 65,725 EA's; CSP 14,513. The OPCO EA's had an average unit cost of $17.01; the CSP EA's $28.40. The Auditor reviewed the Company's supporting documentation and noted that the EA's were transferred to USEPA. According to the Auditor, the Companies charged the costs of these EA's to expense, below the line so that the ratepayer will not be charged for this expense. The Auditor stated in its report that it does not appear possible to determine what impact, if any, on the PUCO's jurisdictional customers is related to the surrender of these allowances. We will discuss the Companies' surrender of these EA's to USEPA in more detail below.

Case No. 98-101-EL-EFC – EA Consumption Costs – December 1997 Through November 1998

According to the financial Auditor, OPCO has deferred $5,737,125, which represents the PUCO jurisdictional share of costs associated with consumed allowances for the 12 months ended November 30, 1998. According to the Auditor, the Company plans to offset these deferrals with the respective share of the Ormet gain deferrals and deferred gains from USEPA auctions. The Auditor reports that the Company will include the remainder of the $5,737,125 in reconciliation adjustments in future EFC proceedings.

OCC and IEU-OH argue that to permit OPCO to include these emission allowance consumption costs for the period December 1, 1997 through November 30, 1998 in its EFC calculations would violate the settlement agreement approved by this Commission in Case No. 94-101-EL-EFC et al. (Opinion and Order dated March 23, 1995).

The settlement agreement provides in pertinent part:

> As a related matter, if during the term of the fixed EFC rate established by this agreement, the parties agree and/or the Commission orders the Company to flow back to ratepayers emission allowance proceeds resulting from the Company's emission allowance strategy and activities relative to non-affiliate transactions, including EPA auctions, the fixed EFC rate may be subject to reduction by a flow back of such proceeds.

(Paragraph 14 at page 24.)

Both OCC and IEU-OH contend that during the period of the fixed EFC rate this language prohibits anything but allowance proceeds from sales of EA's to be flowed through the Company's EFC. These parties note that there is no corresponding language providing for an increase in the fixed EFC rate (OCC Brief at 12-14; IEU-OH Reply Brief at 9-10). OCC argues that the Commission decided that EA costs would be treated as fuel costs, *In the Matter of the Commission's Investigation into the Trading and Usage of, and the Accounting for, Emission Allowances by Electric Utilities in Ohio* Case No. 91-2155-EL-COI (Entry dated March 25, 1993), at 2. OCC noted that this was almost two years before the parties entered into the settlement agreement in Case 94-101-EL-EFC et al. OCC concludes that absent a separate provision allowing the Company to recover EA consumption costs from ratepayers for the period of the fixed EFC rate, these costs would be treated as fuel costs. As such, these costs would be subject to the Company's fixed EFC rate (OCC Brief at 12). OCC points to the DP&L EFC proceeding, Case No. 93-105-EL-EFC, decided on November 23, 1994, to show that utilities in Ohio had already begun to pass the proceeds from EA sales back to ratepayers through the EFC rate. OCC notes that the AEP companies did not follow this procedure at the time because AEP was awaiting the approval of the Federal Energy Regulatory Commission for an AEP system-wide emission allowance agreement (*Id.* at 13-14).

OPCO argues that the EA consumption cost offset to transaction gains did not cause the Company's EFC rate to exceed the fixed rate. Regardless, the Company argues that the offset is consistent with the language. OPCO keys in on the language "proceeds resulting from the Company's emission allowance strategy and activities relative to non-affiliate transactions" to argue that one must include the cost of consumed allowances in determining the "proceeds". The Company further argues that even if the above cited provision does prohibit consideration of EA consumption costs in determining OPCO's "proceeds resulting from the Company's emission allowance strategy and activities", paragraph 3 of the settlement agreement would permit the consumption cost offset. Paragraph 3, at page 18, provides:

> Notwithstanding the "EFC Rate" portion of this Settlement Agreement, the Signatory Parties reserve the right to seek changes, up or down, to the fixed EFC rate for any changes in costs resulting from new

programs imposed by Federal or State government or changes in the tax laws imposed by the Federal or State government, which costs cannot be recovered other than through EFC rates pursuant to Ohio statutes and Commission regulations.

The Company argues that at the time the Settlement Agreement was docketed (February 28, 1995), the Commission had yet to determine how OPCO's EA consumption costs would be recovered. Finally, OPCO argues that the Commission did not amend its EFC rules to provide for the recovery of EA consumption costs until January 16, 1997, in Case No. 94-1792-EL-ORD, well after the date the Settlement Agreement was docketed. According to OPCO, these amended rules created a mechanism for recovery of costs, "which costs cannot be recovered other than through EFC rates pursuant to Ohio statutes and Commission regulations".

OPCO distinguished the facts of DP&L, Case No. 93-105-EL-EFC, supra, from the facts of this case on the basis that, in DP&L, the Commission did not deal with EA consumption costs, but with proceeds from EA sales. Similarly, OPCO dismisses OCC's arguments regarding the guidelines this Commission adopted in the EA Investigation, Case No. 91-2155-EL-COI, supra, because those guidelines pertained to market-based activities, not consumption (Companies Reply Brief at 3-6).

Commission Staff agrees with the Company that the EA consumption costs in question can be recovered independent of Company's fixed EFC rate (Post Hearing Brief at 37). Staff argues that the following provision of the Settlement Agreement permits such recovery:

> For the four-year period of January 1, 1995 to December 31, 1998, OPCO shall retain the jurisdictional share of SO_2 allowance credits, on a ten-year levelized basis, arising from the sale of allowances to OPCO's affiliated Companies. Such allowance credits, on a ten-year levelized basis, shall be adjusted as actual information becomes known. The Signatory Parties reserve for future resolution the issue of the appropriate ratemaking treatment of SO_2 allowance credits or charges arising from the sale and/or purchase of allowances to/from any OPCO non-affiliate company, including EPA auctions.
>
> (Paragraph 4, at 18-19)

The language used in paragraphs 4 and 14, set forth above, does not indicate that the parties contemplated that consumption costs would not be subject to the stipulated EFC rate period. The references in both paragraphs, directly or indirectly, indicate that the parties were discussing sales not consumption. The use of the word "proceeds" in paragraph 14 refers to the difference between costs and the amount one receives as a result of selling something. In paragraph 4, the parties explicitly used the phrase "arising from sales". Thus, neither provision would permit the Company to recover the consumption costs the Company incurred during the period covered by the fixed EFC over and above the fixed EFC rate. It is our finding that these costs cannot be netted and then recovered during the period of the fixed EFC rate. Nor is the Commission persuaded that the treatment of EA consumption costs constitutes a change in costs resulting from a new program imposed by the federal or state government as contemplated by paragraph 3 of the settlement agreement. The EA's arise out of provisions of the Clean Air Act Amendments of 1990. The Commission guidelines relating to the trading and usage of EA's were adopted in 1993. It should have been clear to the Company that it would be using (consuming) EA's as a result of generating electricity during the period of the fixed EFC. It should also have been clear to the Company, even if the Commission had not made the decision in a case involving an AEP company, that costs related to EA's were to be treated as fuel costs. If the parties had wanted to treat these EA consumption costs differently from the fixed EFC rate, then they should have included such a provision in the settlement agreement. They did not. As argued by OCC and IEU-OH, these costs should be treated the same as fuel costs. As such these costs are subject to the cap on the Company's EFC rate in effect at the time and cannot be separately recovered.

III. Management/Performance Audits:

EVA filed its *Management/Performance Audit of the Fuel-Related Policies and Practices of Columbus Southern Power Company and Ohio Power Company* (Cases No. 98-101-EL-EFC and 98-102-EL-EFC) (Comm. Ord. Exh. 3) on February 16, 1999. EVA reviewed the fuel procurement policies and practices of OPCO and CSP for the 12-month period ending November 30, 1998. OPCO and CSP are both wholly owned subsidiaries of American Electric Power, Inc. (AEP). American Electric Power Service Corporation (AEPSC) handles the fuel procurement for both companies.

OPCO's fuel costs were set for regulatory purposes by the settlement agreement that this Commission adopted in Case No. 94-101-EL-EFC. Our Opinion and Order in that case established a fixed EFC rate for OPCO to be in effect for three and a half years, from June 1, 1995 through November 30, 1998. The period of the fixed EFC rate ended with the end of the audit period.

Coal Purchases and Production

EVA reports that OPCO purchased 18.7 million tons of coal during the audit period and CSP purchased 4.8 million tons. According to the Auditor, the average coal prices that CSP experienced during this audit period remained about the same as the average coal prices CSP experienced during the prior audit period. EVA observed that the reduction in the average contract and spot prices CSP encountered during this audit period were offset by an increase in the contract percentage. According to the Auditor, OPCO did not fare as well. The Auditor reports that the slight increase in OPCO's spot-purchases and the lower spot prices did not offset the rather substantial increase in affiliate coal costs and a modest increase in contract coal prices.

The Auditor specifically reviewed the affiliate operations of both CSP and OPCO. CSP operates the Conesville Coal Preparation Plant (CCPP) on a leaseback basis. OPCO operates three mining complexes, Meigs, Muskingum, and Windsor.

EVA found that, during the audit period, CCPP production costs, at $4.48/ton on a clean coal basis, were $0.33/ton higher than CSP experienced in 1997. According to the Auditor, the primary reason for the increased costs was a decrease in production which increased the fixed costs on a cost/ton basis.

The Auditor reported that OPCO produced 9.0 million tons of coal during the current audit period from its three affiliate mine complexes. EVA notes that this figure is lower than the 9.8 million tons produced at these mine complexes in 1997. AEP attributes the decline in production to poor geology at the Meigs mine. The figures reported by the Auditor indicate that production at the Muskingum mine was flat for the period, while production at the Windsor mine increased by .3 million tons to 1.9 million tons from 1.6 million tons for the prior period. According to the audit report, the price of coal/ton from both the Meigs and Muskingum mines to OPCO generating units increased significantly from the last audit period. EVA attributes the cost increase of Meigs coal from $34.47/ton in the prior audit to $43.17/ton in the current audit to poor geology which increased the mine's reject rate, reduced its labor productivity, and lowered its overall production level. The Muskingum mine suffered some flooding during the spring which reduced productivity at the mine. EVA states, however, that the increase in the costs of coal from the Muskingum mine is principally due to the decision to close the Muskingum mine in October 1999. The decision to close this mine resulted in the establishment of shutdown liabilities that were recorded in accordance with generally accepted accounting principles (i.e., over the final year of operation). The improved performance at the Windsor mine was due to higher productivity which increased the number of tons over which to spread the fixed costs and lower third-party sales.

Environmental Compliance

The Auditor found that, as January 1, 2000, and the start of Phase II of the SO_2 and NO_X control programs get closer, Title IV of the 1990 Amendments to the Clean

Air Act continues to dominate AEP's environmental activities. During the audit period, the Auditor reports that AEP completed a draft of its Acid Rain Compliance Program Update. This update addresses AEP's compliance with both SO_2 and NO_X Title IV requirements.

Historically, AEP had an arrangement with a broker for the purchase and sale of EA's. The exclusivity of this arrangement ended with a renegotiation of the arrangement during the last audit period. The original agreement with the broker has expired. During the audit period AEP did not purchase or sell any allowances through a broker. According to the audit report, AEP will not seek recovery of any fees it paid to the broker.

EVA reports that the responsibility for procurement and sale of EA's is currently in the Power Marketing and Trading Organization of AEPSC (Trading Group). A Risk Management Committee, made up of the Chairman and CEO of AEP, the Executive Vice-President Financial Services, and the President of AEP Energy Services, decides AEP's trading strategy. The Auditor reports that since this group took responsibility for buying and selling EA's in March 1998, there has been considerable activity. During the audit period, AEP sold approximately 250,000 EA's while purchasing 350,000 EA's. The average price reported for the 100,000 EA gain was, according to EVA, considerably lower than the average market price for EA's in 1998. According to the audit report, AEP's accounting procedures regarding EA's follows FERC accounting rules.

System Operation and Power Exchange

AEP's unit commitment decisions are based on minimization of total operating costs including fuel, variable operating and maintenance costs, and emission costs subject to system operating considerations, such as turn-down times, voltage reliability, jointly owned unit requirements, and specified unit minimum loads. AEP unit commitments are first determined by annual maintenance scheduling.

Power Sales Management

During the audit period, EVA reports, power sales for AEP were conducted by the Trading Group. The traders sell power based on average fuel costs. The traders are permitted to sell power at replacement coal costs only during times when system generation cannot be sold at system average costs. Sales of power at replacement coal costs to power marketers are referred to as Coal Conversion Sales. In a Coal Conversion Sale, power marketers are responsible for the sale of the power to an end-user and for the replacement of the coal burned to generate the power. The Auditor reports that off-system sales and purchases have increased significantly since the commencement of trading activities.

Audit Recommendations

As a result of its review of the fuel-related policies and practices of CSP and OPCO, the management/performance auditor made a number of recommendations:

(A) Market Price of Muskingum and Windsor Coal

Pursuant to the settlement agreement adopted by this Commission in our Opinion and Order in Case No. 94-101-EL-EFC et al., the Commission determined that:

> Commencing with the December 1998 billing cycle, if OPCO's Muskingum Mine or Windsor Mine are still operating as affiliates of OPCO, OPCO shall be permitted to accumulate deferrals, during that period of operation, for a period of two years from the beginning of that billing cycle, for recovery under the Gavin cap established in the Stipulation and Recommendation in Case No. 92-01-EL-EFC, [1] any Operating Losses resulting from application of the Commission-approved EFC rates for that period, which EFC rates shall be based, as it relates to the Muskingum and Windsor Mines, on the applicable statutes and Commission regulations then in effect, for comparable quality coal at market prices. (Emphasis supplied.)

(Settlement Agreement at 19.)

EVA recommended that, for the audit period December 1, 1998 to November 30, 1999, the market price for Muskingum coal be 88.5 cents/MMbtu delivered to the Muskingum plant and the market price for Windsor coal be 80.8 cents/MMbtu delivered to the Cardinal plant. EVA further recommends that these prices be revised for the audit period December 1, 1999 to November 30, 2000 (Comm. Ord. Exh. 3 at 1-16). EVA notes that affiliate mine prices did not affect ratepayer costs during the audit period as the rates during the audit period were governed by the Settlement Agreement

1 Pursuant to this Stipulation and Recommendation, the cost of coal burned at the Gavin Station was capped at 157.5cents per MMbtu, subject to quarterly escalation based on certain specified cost factors, for a period of 15 years beginning December 1, 1994. Pursuant to paragraph 3 of the Stipulation and Recommendation, OPC is permitted to recoup, among other things, unrecovered fuel costs incurred by Ohio Power at the Gavin Station under the cap to the extent that the Company is able to achieve in a given month a cost of coal burned at the Gavin Station less than the cap. The application of the Gavin cap was expanded pursuant to the Settlement Agreement adopted by this Commission in Case No. 94-101-EL-EFC to include a number of items in addition to those unrecovered items provided for in paragraph 3 of the Stipulation and Recommendation in Case No. 92-01-EL-EFC.

adopted by this Commission in Case No. 94-101-EL-EFC. However, as EVA points out, affiliate costs do affect the amount of money OPCO can expect to recover under the Gavin cap and, therefore, the duration of the Gavin cap (*Id.* at 8).

OPCO objects to the Auditor's recommendation. OPCO contends that the price of these coals should be the price of "comparable quality coal at market prices," not an adjusted price to determine the relative worth of bids for dissimilar coal (Companies Initial Brief at 6). The Company further argued in favor of its own recommended market price that EVA's approach was defective in that there have not been any offers of like quality coal for Muskingum River Units 1-4 at EVA's derived market price.

Staff, OCC, and IEU-OH would have us adopt the Auditor's recommended price for both Windsor and Muskingum coal. The parties argue that the prices recommended by EVA are reasonable. In support of this argument, the parties point to the testimony of Kevin Cardwell, a witness jointly sponsored by OCC and IEU-OH, who testified that that OPCO sold Windsor coal during the audit period for prices well below those the Company advocates in these proceedings, prices even less than those advocated by EVA (OCC/IEU-OH Joint Exh. 1 at 10-13). EVA states in its audit that the AEP proposed price of 87.79 cents/MMbtu for coal from the Windsor mine and 105.92 cents/MMbtu for coal from the Muskingum mine were arrived at by reference to bids that AEP received for raw coal with characteristics similar to washed Muskingum coal. According to the Auditor, AEP chose this bid not because it was the lowest evaluated cost offer, but because the coal quality was the most like Muskingum coal quality (Comm. Ord. Exh. 3 at 2-9).

EVA, Staff, OCC, and IEU-OH define the market price for comparable quality coal to be a price based upon the most competitive bid on a quality adjusted basis, not just the lowest bid for a fixed quality (*Id.*). This means that companies buying coal should evaluate the bid price based upon such things as ash and sulfur content. According to the Auditor, AEP, as reflected in that Company's *Coal Procurement Procedures Manual,* evaluates coal on an adjusted delivered cost basis in cents per MMbtu. EVA points out that AEP adjusted the bids it received in response to its solicitations of February, May, and July 1998 for their sulfur and ash content. According to EVA, AEP, pursuant to its written procedures, bases its sulfur adjustment on the Canter Fitzgerald Market Price Index (*Id.* at 2-10).

The methods for determining the market price of comparable quality coal used by OPCO and EVA are similar except that EVA adjusts the bid to reflect the sulfur penalty. EVA notes that there is a "sulfur penalty" experienced by AEP due to emission allowance consumption. The Auditor illustrates this penalty by the use of the following example:

> [I]f two coals have the same cents per MMbtu delivered price but one coal has an SO_2 content of 7.0 pounds per MMbtu and the other coal

> has an SO_2 content of 3.5 pounds per MMbtu, the higher sulfur coal will consume twice as many Emission Allowances (EA) as the lower sulfur coal. At $200 per EA, the difference would be worth $8.00 per ton.

(Comm. Ord. Exh. 3, footnote 11, at 2-11.)

We believe that not to make such an adjustment is per se unreasonable. The company should not be permitted to, in effect, charge its customers for compliance coal when the company is required to consume EA's to burn coal. Having found the method used by EVA to determine the market price of comparable coal to be reasonable, we also find the values EVA arrived at for the market prices of Windsor and Muskingum coals to be reasonable.

(B) Treatment of Surrendered Emission Allowances

Title IV of the 1990 Clean Air Act (CAA) regulates emissions of SO_2 and NO_X from coal-fired utility boilers. EVA notes that the 1990 CAA Amendments continue to dominate AEP environmental activities. Pursuant to these amendments AEP submitted and this Commission approved an environmental compliance plan (Case No. 92-790-EL-ECP, Opinion and Order [initial application] dated November 25, 1992; Case No. 94-1181-EL-ECP, Opinion and Order [two-year review] dated March 25, 1995). The CAA includes, among other things, the "Phase I Extension Program" which provides incentives for electric utilities to maximize emissions controls. As part of this program, Congress created a pool of emission allowances for allocation to units which were part of the Phase I Extension Plan. Pursuant to a compliance plan, generating units could be designated as either "control" or "transfer" units. The former is the plant on which the scrubber technology is actually installed; the latter is one whose compliance is linked to the control unit. Over-compliance at the control unit could be "transferred" to designated transfer units to meet the emission limits set for those transfer units. The key point of AEP's strategy to comply with the CAA for its Ohio generation was the installation of scrubbers at the Gavin plant. Gavin's two 1300 MW units were designated as control units; while Cardinal Unit 1, Muskingum Units 1-4, Conesville 3, and Picway were designated as transfer units.

As required by its Phase I Extension Plan, AEP submitted projections of emission and utilization levels for each Phase I transfer unit, which projections became the upward limit on the level of emissions for that unit. According to John McManus, Manager of Environmental Strategy and Planning for AEPSC, actual emission levels during Phase I have differed significantly from those projected by AEP for almost all of AEP's Phase I Extension plan units. For the years 1997 and 1998, emissions from AEP Phase I Extension Plan units exceeded the Extension Plan levels (Companies' Exh. 10 at 5). Mr. McManus testified that the primary reason for the Companies exceeding of the

Extension Plan emission levels was higher than projected utilization levels, as opposed to higher than projected SO_2 emission rates (*Id.*).

EVA and Staff are particularly concerned that AEP did not become aware that it would exceed the Extension Plan emission levels until mid-1997. Even then, EVA reports the Companies did little to minimize the costs. In its audit report, EVA lists a number of actions that AEP could have taken to lessen the costs. EVA's list of possible actions include limiting off-system sales from the subject plants, altering or switching fuel supplies to the affected units, and limiting unit utilization (Comm. Ord. Exh. 3 at 5-10 and 5-11). The Auditor noted in its report that the number of EA's the Companies were required to surrender would have been substantially less had AEP not sold substantial amounts of power off-system. The audit report indicates that 49,006 EA's were consumed from traditional off-system sales and 82,372 EA's were consumed from coal conversion sales (*Id.* at 5-12). According to EVA, the only change that AEP indicated it made in 1998 was to more closely monitor emission levels from the transfer units (*Id.*).

As a result of exceeding the Extension Plan emission levels, the USEPA required AEP to forfeit 65,725 EA's on behalf of OPCO and 14,513 EA's on behalf of CSP, a total of 80,238 EA's. This forfeiture is in addition to requiring AEP to relinquish an EA for each ton of SO_2 actually emitted from its Phase I units, thus, in effect, doubling the cost in EA's of each ton of SO_2 emissions in excess of the Extension Plan emission levels.

The issue, at this point, is how to treat the 80,238 EA's relinquished by the Company for exceeding Extension Plan levels. EVA and IEU-OH characterize these EA's as a penalty which AEP may not recover through its EFC pursuant to Rule 4901:1-11-04(H)(2), O.A.C. This rule requires that costs associated with penalties for non-compliance with Title IV of the Clean Air Act Amendments of 1990 be excluded from the EFC.

The Companies argue, pursuant to EPA guidance contained in an EPA response to comments document dated October 26, 1992, that exceeding the emission limitations is not a violation of the Act, but failing to provide allowances for the deduction to account for the exceeding of the limitations would be a violation (Company Exh 10 at 6; Companies Brief at 17). The Companies state, however, that they are not seeking recovery for the 80,238 EA's forfeited to the EPA (Companies' Brief at 17). OPCO and CSP have recorded the costs of these EA's below the line and have not included them as an expense recoverable through the EFC (Companies' Brief at 17). According to the Companies, the question of whether the required forfeiture is a penalty or an operational cost is moot for purposes of this case.

The resolution of the issue does not end here, however. EVA, Staff, OCC, and IEU-OH argue that EFC customers have been harmed even though they are not bearing the direct cost for the EA's being relinquished. The EA's in question had an average cost of $17.01 for OPCO and $28.40 for CSP (Companies' Exh. 4 at 6; Companies' Exh.

7 at 6). The record indicates that during the audit period, AEP purchased EA's on the open market. These purchases added to the average cost of the EA's in the Companies' inventories. At the end of the audit period the average cost of an EA was $31.84 for OPCO and $56.35 for CSP (*Id.*). At the end of 1998, the value of an EA purchased to replace one of the relinquished EA's, according to EVA, approached $200.00. Had the Companies not been required to return 80,238 EA's to USEPA, EVA, Staff, OCC, and IEU-OH contend that OPCO and CSP would not have needed the additional, more costly EA's.

EVA recommends that the surrender of 80,238 1998 EA's be viewed as a sale of allowances during the current audit period and that the difference between the book cost of the surrendered allowances and the market value of those allowances flow through the reconciliation adjustment. EVA also recommended that the surrender of the 1999 and, if necessary, 2000 allowances should be similarly treated in the year in which the surrender is required. Staff, OCC, and IEU-OH agree with the recommendation of the auditor that the surrender of these EA's to the EPA be treated as a sale, the proceeds of which should be passed through the EFC to the Companies' ratepayers.

EVA further recommends that AEP immediately evaluate alternatives to minimize or eliminate the surrender of year 2000 allowances and that this plan be filed with this Commission as part of each of the companies mid-year filing.

In their brief, the Companies argue that the surrender of the EA's to EPA does not constitute a sale of EA's. The Companies characterize the analogy of a "sale" as a fiction tied to the notion that EFC customers have some sort of ownership right to the EA's. OPCO and CSP cite the testimony of their witness, Philip J. Nelson, Senior Rate Consultant in the Energy Pricing and Regulatory Services Department of AEPSC, for the proposition that ratepayers have no more paid for the buildup of an allowance bank through base rates and the EFC than they have paid for any other company asset. Mr. Nelson further testified that rate making has never been premised on the notion of particular dollars paid in rates being attributable to particular assets, let alone that ratepayers acquire a quasi-ownership interest in an asset (Companies' Exh. 12 at 11).

There is no question that EFC customers have been harmed by the forfeiture of these EA's. Accordingly, we agree that remedial action is necessary. The Companies are obligated to provide service to their customers at reasonable rates consistent with, among other considerations, safety, the reliability of the system, and the continuity of service over time. The manner in which the Companies squandered these 80,238 EA's has done nothing to further the provision of electric service at reasonable costs to the customers of these utilities. The standard the Commission is to apply in its review in an EFC case is "fair, just, and reasonable." It is neither fair, just, nor reasonable that the customers of these utilities bear the burden of higher rates for actions described by the Auditor as imprudent.

The use of the analogy of a "sale" is appealing in that those who indirectly paid for the EA's through rates would get immediate compensation for the surrender of these EA's to the EPA. However, as noted by the Companies, there was no sale. If we adopted the sale analogy as recommended by EVA, Staff, OCC, and IEU-OH, the current EFC customers of both Companies would receive a windfall. Current EFC customers may not be the ones who have been harmed by the utilities' inaction. The customers who will be harmed are those would be EFC customers when those EA's would have been used. They are the ones who will pay higher rates because of the surrender of these EA's to the EPA. Treating the surrender as a sale is one way to resolve the issue before us. However, we believe the better resolution is for the to reprice 80,238 of the highest cost EA's that the Companies purchased during the audit period to the weighted average value of the EA's surrendered to the USEPA during the audit period. To the extent that the number of EA's the Companies purchased during the audit period are insufficient to replace all of those surrendered to USEPA, the Companies should purchase the difference on the open market. The Companies should also add these EA's to the Companies' inventories at the weighted average value of those EA's the Companies surrendered to USEPA. It is the Commission's intent that the Companies respective inventories reflect the weighted average value each would have had but for the surrender of the 80,238 EA's to USEPA.

EVA's other recommendations, that AEP immediately evaluate alternatives to minimize or eliminate the surrender of year 2000 allowances and that this plan be filed with this Commission as part of each of the Companies' mid-year filing, are appropriate, under the circumstances, and will be adopted.

(C) Treatment of EA's Consumed in Off-system Sales

EVA reports that during the audit period the companies engaged in off-system sales. These sales caused the utilities to consume additional EA's as well as additional fuel. As in any sale, AEP's profit is the difference between the price of the electricity and the cost to the utility to generate that electricity. EVA's concern is that the size of the actual profit from the sale is misleading. AEP prices the EA's used in the sale at market even though the average cost of the EA's withdrawn from inventory is significantly lower. According to the Auditor, AEP calculated that the difference between the market value of these allowances and the book cost of these allowances was $9.7 million dollars. EVA considers this profit to be the unintended consequence of emission allowance accounting procedures and a windfall to the utility. EVA recommends that OPCO's and CSP's shares of the $9.7 million dollars (adjusted for any double counting of penalties) be treated as an audit period gain on the sale of the EA's and, as such, should be passed through the reconciliation adjustment of the EFC mechanism to the respective company's EFC ratepayers (Comm. Exh. 3 at 5-14).

OCC and IEU-OH join in this recommendation. Commission Staff joins in the recommendation as it applies to "profits" due solely to emission allowance accounting procedures for sales labeled as coal conversion sales but not for traditional third-party off-system sales which are not part of that program.

The Companies argue that the benefits associated with these off-system sales, i.e., the revenue realization net of expenses such as fuel and EA's, flow to rate payers because those revenues reduce base rates and the frequency that utilities seek increases in those base rates (Companies' Brief at 14). The Companies contend that, consistent with the rate base benefits associated with off-system sales, fuel and EA costs associated with off-system sales are excluded pursuant to Rules 4901:1-11-04(F)(2), O.A.C., and 4901:1-11-04(H)(3), O.A.C., from the calculation of jurisdictional fuel expense (*Id.*).

IEU-OH argues that this whole issue could be eliminated if AEP were required to purchase EA's used to support off-system sales in the market, thus sparing the low cost EA's currently in inventory for generating electricity for EFC ratepayers (IEU-OH Brief at 7). Given, however, that the matter is at issue in this case, IEU-OH joins EVA and OCC in characterizing these off-system sales as a sale of electricity <u>and</u> EA's. OCC states that, pursuant to the AEP system Interim Allowance Agreement, OPCO and CSP receive cash from these sales which reflects the current market value of the allowances used to produce the electricity. The net proceeds of what OCC and IEU-OH characterize as "the allowance sale" are allocated among AEP operating companies in precisely the same manner as if the allowances had been sold. The parties note the testimony of Philip J. Nelson, that the AEP accounting system does not, in fact, treat allowances consumed in off-system sales as a sale of these allowances but as allowances consumed in the generation of electricity. Both OCC and IEU-OH argue that it is this very accounting practice that masks the injury to the EFC ratepayer. The parties argue that if allowances consumed in off-system sales were treated as a sale of those allowances, EFC ratepayers would receive their share of the sale proceeds through the EFC rate (OCC Brief at 9-11; IEU-OH Brief 8-11).

Commission Staff supports the position of OCC and IEU-OH as it applies to third-party sales pursuant to the Companies' Coal Conversion Program. In theory, under the Coal Conversion Program, power marketers buying electricity from OPCO or CSP furnish their own coal and EA's. As it works, however, the selling utility generally supplies both the coal and the EA's. Staff observes that, pursuant to the program, the power marketer makes the coal inventory "whole" by assuring the replacement of comparable coal without affecting the weighted average inventory cost. According to Staff, this is not true in the case of EA's used to generate the electricity. Staff, citing the testimony of Stephen D. Baker, Manager of Regulatory Affairs in the Fuel Supply Department of AEPSC, notes that one of the premises of the Coal Conversion Program is that coal conversion sales will have no adverse consequences for EFC ratepayers (Staff Brief at 34-35, Co. Exh. 13 at 14-15).

Staff supports the Companies' position with regard to what Staff terms as "traditional third-party off-system sales." These sales have been included at some level in developing a utility's base rates and have not, as noted by Staff, historically been included in Commission EFC proceedings (*Id.*).

The Companies argue, contrary to the arguments of Commission Staff, that there is no difference between third-party off-system sales made pursuant to the Coal Conversion Program and so-called "traditional" third-party off-system sales (Company Reply Brief at 14).

Costs, fuel costs and EA costs, associated with third-party off-system sales, are at some level considered in the ratemaking process. Thus, as argued by the Companies, these costs are excluded from costs included in the EFC rate pursuant to Commission rule. The Coal Conversion Program is different. That program, as noted by Mr. Baker, is not supposed to have adverse impacts on EFC jurisdictional customers. That is one of the defenses the Companies employ to argue against proposals that the Commission eliminate the program. The Commission understands that the Companies often supply both the fuel and the EA's to support these sales. However, as noted by Staff, the power marketer makes the EFC jurisdictional customers whole by assuring the replacement of comparable coal without affecting the average weighted inventory cost. We expect the same thing to happen with regard to the cost of EA's to provide this service. The Companies should reprice the highest cost EA's purchased during the audit period, the number to equal the number of EA's involved in sales made pursuant to the Companies' Coal Conversion Program, to the average weighted value of the EA's consumed in making those coal conversion sales. To the extent that the number of EA's the Companies purchased during the audit period are insufficient to replace all of those EA's consumed in making these coal conversion sales, the Companies should purchase the difference on the open market. The Companies should also add these EA's to the Companies' inventories at the weighted average value of those EA's consumed in making coal conversion sales during the audit period. It is the Commission's intent that the Companies respective inventories reflect the weighted average value each would have had but for these coal conversion sales.

Commission Staff notes that OPCO consumed 73,852 EA's to provide coal conversion services during the prior audit period. The Commission stated the following in its Opinion and Order, at page 17, in Case No. 94-101-EL-EFC et al.:

> If fuel-related activities undertaken during the period of the fixed EFC rate, or through November 30, 2000 as applicable to the Muskingum or Windsor mines, affect fuel costs after that time, the resulting effects will be evaluated on an ongoing basis from and after November 30, 1998 (November 30, 2000, if applicable), and considered in Commission decisions regarding future EFC rates.

In Staff's assessment the premature depletion of the allowance bank is such a "fuel-related activit[y] undertaken during the period of the fixed EFC rate, or through November 30, 2000 as applicable to the Muskingum or Windsor mines, affect fuel costs after that time."

The Companies consider it to be inappropriate to impose remedies in this case related to prior audit period activities. The Companies note that Staff failed to make a similar recommendation for the EFC of CSP, even though CSP also consumed EA's in the prior period for coal conversion sales. The Companies also argue that Staff has misinterpreted the cited portion of our Opinion and Order in Case No. 94-101-EL-EFC, et al., *supra*. According to the Companies, the language upon which Staff relies was never intended to leave EA issues open for three years. OPCO states that the strongest indicator that Staff has misinterpreted the above cited provision is that neither OCC nor IEU-OH has argued for this additional relief. The Company contends that the purpose of the language cited by Staff was intended to refer to fuel procurement activities undertaken during the fixed EFC period which would have continuing effects after that period (Companies' Reply Brief at 15-17).

There is insufficient evidence of record for the Commission to issue a finding regarding this issue. It is not clear to this Commission, given the nature of EFC proceedings during the period of the fixed EFC rate, that consideration of this issue is barred as an event occurring during a prior audit period. There is a question of how much effect those EA's consumed in coal conversion sales during the period of the fixed EFC had on the weighted average value of EA's in OPCO's inventory after the expiration of the period in which the Company's EFC rate was fixed. Finally, there is the question of interpretation to be accorded the provision cited by Staff. The Commission will defer this issue for decision until OPCO's next EFC hearing. The Commission suggests that the parties, pursuant to the settlement agreement at page 33, engage in a good faith attempt to resolve the issue as to the intended interpretation of the above cited provision prior to the Company's next EFC hearing.

(D) Phase II Compliance Strategy

EVA recommends as part of its audit that AEP reconsider elements of its phase II compliance strategy. The Auditor recommends that AEP:

(1) Consider a broader range of coals, including coal from the Powder River Basin.

(2) Revise its EA price forecast.

(3) Reconsider the likely timing of new regulations which could reduce the forecast of EA prices.

(4) Consider some innovative financing strategies for technological solutions in order to reduce the uncertainty created by changing environmental regulations.

The Companies note that except for these suggestions, EVA concluded that "AEP's compliance plan is generally thorough and well-conceived" (Comm. Ord. Exh. 3 at. 5-2). The Companies acknowledge that since the time the Phase II compliance plan was completed in the spring of 1998, the market price of EA's has increased significantly. The Companies state that they intend to review the compliance plan in light of these changing market conditions (Companies' Exh. 10 at 9; Companies' Brief at 29).

Because the Companies have agreed to implement EVA's recommendation, there is no need for a Commission directive in this regard. The auditor chosen to conduct the next management/performance audit for OPCO and/or CSP should review this matter and include its evaluation in its report to the Commission.

(E) AEP should reconsider its sales of coal conversion services

As noted above, power marketers in a coal conversion sale are required to replace the coal consumed with the AEP Fuel Supply Department acting as overseer. In practice, the management/performance Auditor found that AEP actually replaces the coal and bills the power marketer for it. EVA notes that AEP monitors the process via two different reports. The Coal Conversion Replacement Status Report compares actual versus projected replacement coal costs and quality; the Coal Conversion Service Report documents by plant the computed coal consumption by power marketers (Comm. Ord. Exh. 3 at 3-13).

According to its audit report, EVA has a number of concerns regarding the Companies' Coal Conversion Programs. The first area of concern relates to how the Companies' insure that the replacement coal is equal to or superior to the coal that was consumed in the coal conversion sale at the same or lower price. While EVA describes the Companies' procedures in this regard as "somewhat crude (and not documented)," the Auditor notes that the Companies' have demonstrated to its satisfaction that the replacement coal to date has been of comparable quality and price (*Id.* at 3-15).

The Auditor's second area of concern relates to the sequence in which AEP purchases spot coal. AEP indicated to the Auditor that spot coal is purchased first for the system, then for the Coal Conversion Program. It is the Auditor's view that this practice should lead to the in-system and traditional off-system load receiving the lowest price spot coal. However, EVA notes, that there are many months in which the coal purchased for coal conversion sales has a lower price than other coal (*Id.*).

EVA's final concern regarding the Companies' Coal Conversion Programs relates to the administrative costs of the program. EVA reports that the AEP Fuel Supply Department takes no fee for performing this service for power marketers, lumping the costs for this service together with all the other costs it incurs in procuring coal for the AEP system. It is EVA's opinion that, as the Companies' shareholders receive the benefit of the Coal Conversion Program, the shareholders should be paying the program's administrative costs (*Id.* at 3-18—3-19). OCC and IEU-OH share the Auditor's concern (OCC Brief at 26-29; IEU-OH Brief at 17-19). OCC would have this Commission ban all such coal conversion sales; IEU-OH recommends that the Companies consider terminating their coal conversion activities (*Id.*). IEU-OH would further require the Companies to provide an affirmative demonstration that the conversion sales produce a positive benefit for EFC customers (IEU-OH Brief at 18).

The Companies' argue, in support of the Coal Conversion Program, that EVA, as noted above, is satisfied that the replacement coal has, to date, been of comparable quality and price. The Companies point out, in reference to the concern that in some months replacement coal appears cheaper than spot coal purchased for system customers and traditional off-system sales, that the value of the coal, on a quality adjusted basis, is the same for both sets of customers. The Companies state that the coal used for the coal conversion sales is often purchased from the same coal suppliers, from the same seams, from the same mine, located in the same Ohio county. Even so, the Companies explain, particular shipments of coal may vary in Btu, ash, or sulfur content. To the extent that one shipment of coal has a lower Btu content or a higher ash and/or sulfur content than another shipment, the price/ton will vary between the shipments. The value of the shipments, however, is the same on a quality adjusted basis. The Companies dismiss the question of administrative costs as irrelevant since the recovery of such costs are considered in base rate proceedings not EFC proceedings. Further, the Companies argue that, in OPCO's case, enlarging the number of third-party affiliate coal sales benefits jurisdictional customers (Companies Initial Brief at 25-27).

It appears that there is currently no issue before us concerning whether the quality of the replacement coal is comparable to the quality of the spot market coal purchased to serve system customers or traditional off-system sales customers. The Commission is confident that a review by the next auditor chosen to conduct the management/performance audit for these Companies will easily determine whether the apparent difference in price between coal bought for the Coal Conversion Program and the coal bought to serve system customers or traditional off-system sales customers is comparable on a quality adjusted basis. The management/performance auditor should include the results of its review along with its conclusions and any recommendations it may have regarding this issue in its report to the Commission. Finally, as the Companies argue, the question of administrative costs of the coal conversion program is irrelevant to these proceedings, the administrative costs of coal procurement having been considered in the Companies' respective base rate cases.

(F) Manual Dispatch/Economic Dispatch

EVA recommends that the appropriate entity in AEP's Power Generation group prepare a monthly report for distribution to senior management on the extent to which CSP and OPCO generating assets have been operated on manual dispatch. The Report should quantify the emission allowances consumed by these units. EVA further recommends that AEP's Power Generation group regularly review the decision to place units on manual dispatch in the context of current emission allowance prices and penalties where appropriate.

The Company suggests that the auditor, in the case of the above recommendations, believes manual dispatch excludes economic dispatch. According to the Companies the decision to control a unit manually or automatically is independent of the decision to run a unit off of economic dispatch. The Company concedes that units not on economic dispatch are controlled manually; but they state that the converse is not true (Companies Initial Brief at 27-28).

From the audit report, it is not clear that the Auditor was confused, as the Companies contend. The Auditor, in making this recommendation, expresses concern over the inaction of the Companies in regard to the increases in cost per MMbtu experienced at Muskingum Units 1-4 during the first 11 months of 1998. According to the Auditor, "it is hard to imagine how Muskingum #4 would dispatch at all with fuel and emission costs in excess of $44 per MWH." The audit report indicates that the cost of EA's required to generate electricity at Muskingum #4 after exceeding emission standards, $14/MWH, was a significant factor in the overall high cost of generation. According to EVA, the Companies gave the Auditor no indication that the decision to continue to generate electricity at Muskingum under the circumstances had been reviewed in the context of higher EA prices.

In this Opinion and Order, we have already dealt with the results of the Companies' inaction as it relates to having exceeded emission standards. The fact that the Companies will be required to replace any EA's they are required to surrender to USEPA for exceeding emission standards at the average cost of the EA's surrendered should be an incentive for the Companies to be more attentive to this issue. In light of this decision, we will not adopt the Auditor's recommendation at this time.

Other Issues

(A) The cost of affiliate coal subsequent to November 30, 1998

Subdivision V, Section 5 of the Settlement Agreement approved by this Commission in Case No. 94-101-EL-EFC et al., entitled *Operating Losses after 1998*, reads in part as follows:

> Commencing with the December 1998 billing cycle, if OPCO's Muskingum Mine or Windsor Mine are still operating as affiliates of OPCO, OPCO shall be permitted to accumulate deferrals, during that period of operation, for a period of two years from the beginning of that billing cycle, for recovery under the Gavin cap established in the Stipulation and Recommendation in Case No. 92-01-EL-EFC, any Operating Losses resulting from application of the Commission-approved EFC rates for that period, which EFC rates shall be based, as it relates to the Muskingum and Windsor Mines, on the applicable statutes and Commission regulations then in effect, for comparable quality coal at market prices. Subsequent to November 30, 1998, OPCO agrees to waive any claim of preemption or lack of Commission jurisdiction to determine an EFC rate as if the cost of coal from the Muskingum and Windsor Mines were at market prices for comparable quality coals. (Emphasis supplied.)

The Muskingum and Windsor mines were operating as affiliates of OPCO subsequent to November 30, 1998. Thus, the provision underlined above is operable. OPCO reads this provision to mean that deliveries of coal from these mines after November 30, 1998, are to be repriced at market (Company Initial Brief at 8). Staff and OCC argue that all coal at these mines, whenever delivered, burned after November 30, 1998, must be repriced to the market price (Staff Brief at 10; OCC Brief at 23). IEU-OH argues that for the purposes of calculating the EFC rate to be applied subsequent to December 1, 1998, affiliate coal from the Windsor and Muskingum Mines must be valued at the market price (IEU-OH Brief at 14). IEU-OH argues that the provision in question does not use the term "reprice". It is IEU-OH's position that it is irrelevant when the coal was mined; the provision requires that all Windsor and Muskingum coal be valued at market for the purpose of calculating OPCO's EFC rate (*Id.*).

We agree with IEU-OH's position in this regard. The provision relates only to the question of determining an EFC rate for OPCO subsequent to November 30, 1998. It is clear from the wording of the provision that for this narrow purpose the Commission is to use one value for Windsor coal and one value for Muskingum coal burned subsequent to November 30, 1998, and that value is the market price of comparable coal. We point out that this provision does not speak to any other purpose for which OPCO might wish to value this coal. For this reason, we believe the distinction drawn by IEU-OH is important. For the method to be used to determine the market price of comparable quality coal see our discussion above.

(B) Purchased Power Costs for June, 1998

CSP has included in its proposed EFC rate in this case a reconciliation adjustment reflecting 100 percent of the cost of the power it purchased during the week of June 22, 1998. Similarly, OPCO has included an amount reflecting 100 percent of the cost of the power it purchased during the same week in its deferred fuel account as an operating loss for future recovery since that Company cannot currently recover these costs pursuant to the fixed EFC rate contained in the settlement agreement this Commission adopted in Case No. 94-101-EL-EFC. It was during the week of June 22, 1998, that there were severe electricity supply constraints affecting the Midwest power market, which caused prices for available power to increase substantially from the norm.[2] Commission Staff, OCC, and IEU-OH have all objected to the recovery of these costs through the EFC.

Staff requests that the Commission remove $1.265 million from OPCO's deferred fuel account to preclude OPCO from recovering under the Gavin rate cap costs not related to the fuel portion of power purchased during the week in question. Staff also recommends that the Commission direct CSP to include a negative $0.611 million in its Reconciliation Adjustment (RA) at the generation level for the same reason. It is Staff's position that the Companies have failed to carry their burden of proof regarding the recovery of the excessive fuel costs the Companies claim are associated with purchased power for the week of June 22, 1998. Staff argues that the excess of the costs of the power purchased during that week represents a premium associated with opportunistic pricing in a supply constrained market rather than truly capturing the fuel costs associated with producing the purchased power. Staff determined the amounts by taking the magnitude of the average of the actual purchased power costs incurred by the Companies for June 1998, as provided by AEP, and evaluated the level of these costs against normal projected purchased power costs for the period July-November 1998, data also provided by AEP (Staff Brief at 15-19). OCC and IEU-OH agree with Staff's assessment and recommendation (OCC Brief at 14-17; IEU-OH Brief at 15-17).

While the Companies' proposed EFC rates contains an amount reflecting 100 percent recovery or deferral of actual June 1998 purchased power costs, the Companies, on brief, only argue that the fuel-related portion of purchased power costs are recoverable through the EFC, citing Rule 4901: 1-11-04(D)(1), O.A.C.:

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2 The electricity supply constraints experienced by Ohio's regulated electric utilities during the week of June 22, 1998, was the subject of this Commission's report to the Ohio General Assembly, *Ohio's Electric Market, What Happened and Why.*

(C) Includable purchased power costs

(1) Includable purchased power costs other than economic power.

> ... [T]he "includable purchased power costs" are the actual and identifiable acquisition and delivery costs for the fuel utilized in the generation of power purchased by the electric utility during the base period. The acquisition and delivery costs shall include the amounts billed as costs for system losses incurred by the seller in delivering the power purchased, but shall not include the amounts billed as capacity or demand costs nor the costs of any gross receipts tax or other revenue based tax occasioned by fuel revenues.

The Companies state that historically the seller disclosed the fuel costs of the power it sold. However, as reported by the financial Auditor, the general evolution and expansion of the competitive power markets has resulted in purchases based on a total price, particularly when the seller is a broker or other third party (Companies' Brief at 22; Comm. Ord. Exh. 1 at 11; Comm. Ord. Exh. 2 at 6). The financial Auditor observed that when the Companies encounter a situation where the price for the power purchase is not itemized, they have historically allocated 80 percent of the purchase price to fuel (*Id.*). The Companies state, however, that they are not claiming that 80 percent of the purchased power costs for that power purchased during the week of June 22, 1998, were fuel related.

The Companies contend that the Staff adjustment based upon a comparison of actual June purchases to a projected average of July-November 1998 is unreasonable. The Companies argue that Staff's adjustment incorrectly assumes that there is no relationship between increasing purchased power costs and the fuel related portion of those purchases. The Companies note that all utilities dispatch their generation based on least cost principles. They argue that as generating capacity shortages develop, the units dispatched have increasingly higher fuel costs. The Companies state that during the shoulder months, such as the period July-November 1998 used by Staff in its calculations, fuel-related generating costs associated with base-load, coal-fired units would be around the level of one or two cents per kWh. The Companies state that when capacity becomes tighter, as during a peak month like June, utilities will dispatch generating units run on natural gas, propane, or fuel oil at fuel costs which can exceed six cents/kWh (Company Initial Brief at 21-25).

Our rules permit 100 percent recovery of the money an electric utility spends on purchased power only in the case of purchases of economy power; that is not the case before us. Nor does the Commission believe that the 80 percent rule of thumb is applicable in this case. Eighty percent may be representative of the fuel cost for power purchased at X/kWh. It is not likely, however, that at 10X/kWh the fuel costs will increase ten times to maintain the 80 percent relationship. As argued by Staff, much of the increase in price for purchased power during the week in question was not fuel-related, but "represents a premium associated with opportunistic pricing in a supply constrained market."

Having said this, we agree with the Companies that, consistent with our rules, they are permitted to recover through the EFC, as in the case of CSP, or on a deferred basis, as in the case of OPCO, the fuel costs associated with this purchased power. We also agree with the Companies that there is a probability that some of the power purchased during the week in question may have been generated with more costly fuels. Staff's calculations, as alleged by the Companies, may not be representative of the fuel costs associated with power purchased during the month of June. Therefore, we will direct the Companies, in consultation with Commission Staff, to recalculate the fuel portion of the power purchased during the week of June 22, 1998, using data normalized for a typical last week in June or, if that is not practicable, normalized data for a typical month of June, to determine a more representative fuel cost associated with the purchase of a kWh and to multiply that figure by the number of kWh purchased during the week of June 22, 1998. CSP should revise its proposed EFC and OPCO should revise the amount in its deferred fuel account for power purchased during the week in question to be consistent with this Opinion and Order.

(D) Mid-Year EFC Rate

The EFC rate currently being charged by OPCO, 1.475 cents per kWh, is that rate recommended by the parties in a settlement agreement in the mid-year, non-audit phase of this case which this Commission adopted in its Opinion and Order dated November 19, 1998. The 1.475 cents per kWh was agreed to by the parties solely for the purpose of settling that phase of this case. Pursuant to the settlement agreement, the Commission is to determine the appropriate mid-year EFC rate as part of the audit phase of the proceeding. The settlement also provided that the difference between the rate recommended for settlement purposes in the mid-year phase of these proceedings and the actual rate determined by the Commission in the audit phase of the proceedings to have been the appropriate mid-year EFC rate will be reflected for collection or refund through the EFC rate to become effective in June 1999. In agreeing to the settlement, each of the parties reserved its right to raise in this phase of the proceedings any issues it could have raised in the mid-year phase.

OPCO raised two issues in this hearing which could have affected the mid-year EFC rate had they been resolved at the time. The first issue, the proper market price to be used for coal from the Muskingum and Windsor mines, we have already discussed.

The second issue concerns the request of the Company that it be permitted to revise it proposed EFC rate to include the forecasted EA's consumption expense OPCO inadvertently omitted from its mid-year filing. The EA's consumption costs at issue are those that the Company would incur after the period of the fixed EFC rate.

Philip J. Nelson, a witness for OPCO, testified that the Company inadvertently failed to include EA's consumption costs of $1,302,000 in calculating the fuel cost (FC) component of its mid-year EFC (Companies Exh. 12 at 5). He further testified that the effect of correcting the error is to increase the FC and, therefore, the EFC by 0.00966 cents per kWh (*Id.*).

None of the parties object to the Company revising its EFC rates to include these costs. To the extent that the $1,302,000 does not include the costs of EA's surrendered to the USEPA or used in coal conversion sales, OPCO's request to include these costs in its EFC rate to become effective in June 1999 is reasonable and should be approved.

(E) Motion to Strike

On May 6, 1999, counsel for the Companies filed a motion to strike certain portions of the reply brief filed by OCC. Specifically, the Companies are concerned with that portion of the reply brief dealing with a request made by OCC that the Commission take administrative notice of the results of the USEPA's 1999 emission allowance auction (page 12, the first and second paragraphs; page 14, the last three sentences; and Attachment one). The Companies are concerned that, if the Commission grants OCC's request, the Companies will lose their due process right to explain and/or rebut the matters contained in OCC's reply brief.

OCC contends in its memorandum contra that the Companies have not sought to explain and/or rebut attachment one to its reply brief. Attachment One contains the matter to which the Companies object. Further, OCC argues the Companies' motion is overly broad, seeking to exclude information not directly related to the USEPA auction. Finally, OCC argues that the Commission should not strike when the material presented in the brief is merely meant to persuade the Commission to a point of view or merely supports OCC's legal and policy arguments.

The Commission has reviewed the material in question and will grant the motion to strike. By including the material in its reply brief, OCC failed to give the Companies adequate time in which to explain and/or rebut the material to which the Company objects. Though we are granting the Companies' motion to strike, we do agree with OCC that the motion is overly broad. As suggested by OCC we will strike only that material contained in Attachment 1 to OCC's reply brief and any direct references in OCC's reply brief to the material contained in that attachment.

CONCLUSION:

The Commission's resolution of a number of the issues discussed in this Opinion and Order will require the Companies to recalculate various components of their proposed EFC rates. The Companies should file their respective proposed EFC rates, as recalculated, with the Commission by the close of business on June 1, 1999. The Companies' EFC rates, as recalculated, should become effective with the first billing cycle of June 1999 and remain in effect until otherwise ordered by this Commission.

Except as discussed in this Opinion and Order, we find that companies have demonstrated in these proceedings, as required by Section 4909.191(C), Revised Code, and Rule 4901:1-11-11(B), O.A.C., that their respective acquisition and delivery costs of fuel for the audit period are fair, just, and reasonable.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) Ohio Power Company and Columbus Southern Power Company are electric light companies as defined by Section 4905.03(A)(4), Revised Code, and public utilities as defined by Section 4905.02, Revised Code. The Companies are also electric utilities within the meaning of Rule 4901:1-11-01(L), O.A.C.

(2) Section 4905.301, Revised Code, requires this Commission to review the fuel component contained in schedules of the type required to be filed pursuant to Section 4905.30, Revised Code, at a hearing held at least once annually.

(3) Ohio Power Company and Columbus Southern Power Company have filed schedules with the Commission pursuant to Section 4905.30, Revised Code, which contain a fuel component.

(4) By Entry dated November 5, 1998, the Commission initiated these proceedings to review the electric fuel component contained in the filed schedules of Ohio Power Company and Columbus Southern Power Company and related matters.

(5) The Commission conducted two days of public hearings in these cases beginning on March 16, 1999 and concluding on March 24, 1999 at its offices at 180 East Broad Street, Columbus, Ohio.

(6) Ohio Power Company and Columbus Southern Power Company filed proof that notice of the hearing was published as required by Section 4909.191(A), Revised Code, and Rule 4901:1-11-11(C), O.A.C.

(7) Ohio Power Company and Columbus Southern Power Company submitted all facts, data, and other information pertinent to their respective electric fuel components at least 30 days prior to the hearing as required by Section 4909.191(A), Revised Code, and Rule 4901:1-11-11(D)(1), O.A.C.

(8) This Commission, as required by Section 4905.66(B)(2), Revised Code, and Rule 4901:1-11-09(B), O.A.C., caused Deloitte & Touche to conduct a financial audit of each of the Companies' fuel components and Energy Ventures Analysis, Inc. to conduct a management/performance audit of the Companies' fuel procurement and utilization policies and practices. Deloitte filed its report in each of these cases on February 12, 1999; EVA filed a unified management/performance audit of the fuel-related policies and practices of the Companies on February 16, 1999.

(9) Ohio Power Company's emission allowance consumption costs for the 12 months ended November 30, 1998, are subject to the Company's fixed EFC rate in effect at the time and cannot be separately recovered.

(10) The definition of "market price of comparable quality coal" as used to determine the market price for Muskingum and Windsor coals should be based upon the most competitive bid on a quality adjusted basis, not just the lowest bid for a fixed quality.

(11) As determined by the management performance auditor, the market price of Muskingum Coal is 88.5 cents/MMbtu and the market price of Windsor coal is 80.8 cents/MMbtu.

(12) Under the facts of this case, Ohio Power Company and Columbus Southern Power Company were imprudent in exceeding the sulfur dioxide emission levels established pursuant to the Clean Air Act Amendments of 1990.

(13) The Companies should reprice 80,238 of the highest cost EA's that the Companies purchased during the audit period to the weighted average value of the EA's surrendered to the USEPA during the audit period. To the extent that the number of EA's the Companies purchased during the audit period are insufficient to replace all of those surrendered to USEPA, the Companies should purchase the difference on the open market. The Companies should also add these EA's to the Companies' inventories at the weighted average value of those EA's the Companies surrendered to USEPA.

(14) AEP should evaluate alternatives to minimize or eliminate the surrender of year 2000 allowances and file its plan to accomplish this goal with this Commission as part of each of the Companies' mid-year EFC filings.

(15) It is not reasonable for the Companies to consume EA's with a low average cost from their respective inventories of EA's in generating electricity for Coal Conversion Sales.

(16) The Companies should reprice the highest cost EA's purchased during the audit period, the number to equal the number of EA's involved in sales made pursuant to the Companies' Coal Conversion Program, to the average weighted value of the EA's consumed in making those coal conversion sales. To the extent that the number of EA's the Companies purchased during the audit period are insufficient to replace all of those EA's consumed in making these coal conversion sales, the Companies should purchase the difference on the open market. The Companies should also add these EA's to the Companies' inventories at the weighted average value of those EA's consumed in making coal conversion sales during the audit period. The Commission is deferring a similar issue, affecting only OPCO and involving the prior audit period, to the Company's next EFC audit proceeding.

(17) Subdivision V, Section 5 of the Settlement Agreement adopted by this Commission in Case No. 94-101-EL-EFC et al., entitled *Operating Losses after 1998*, requires that affiliate coal, subsequent to November 30, 1998, be valued at market for purposes of calculating Ohio Power Company's EFC rate.

(18) The Companies may recover the fuel costs associated with the power they purchased during the week of June 22, 1998. The Companies, in consultation with Commission Staff, should recalculate the fuel cost portion of the power they purchased during the week of June 22, 1998, as discussed in this Opinion and Order.

(19) Ohio Power Company may include in the calculation of its EFC rate the forecasted EA consumption expense it inadvertently failed to include in its mid-year EFC filing to the extent that the $1,302,000 does not include the costs of EA's surrendered to the USEPA or used in coal conversion sales.

(20) The Companies' motion to strike portions of OCC's Reply brief is granted in part and denied in part as discussed in this Opinion and Order.

(21) Except as discussed in this Opinion and Order, the Companies have demonstrated in these proceedings, as required by Section 4909.191(C), Revised Code, and Rule 4901:1-11-11(B), that their respective acquisition and delivery costs of fuel for the audit period are fair, just, and reasonable.

ORDER:

It is, therefore,

ORDERED, That Ohio Power Company and Columbus Southern Power Company recalculate their respective EFC rates as discussed above and file their EFC tariffs containing the recalculated EFC rates with the Commission by the close of business on June 1, 1999. The recalculated EFC rates for each of the Companies shall become effective beginning with the first billing cycle of June 1999 and remain in effect until otherwise ordered by this Commission. It is, further,

ORDERED, Ohio Power Company, Columbus Southern Power Company, and each of the auditors chosen for each of the companies' next EFC audit proceedings comply with the terms of this Opinion and Order. It is, further, ORDERED, That a copy of this Opinion and Order be served upon each party of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Ronda Hartman Fergus

Craig A. Glazer

Judith A. Jones

Donald L. Mason

SJD/vrh

Entered in the Journal
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Gary E. Vigorito
Secretary

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Re San Diego Gas and Electric Company
Decision 95-11-031
Application 93-06-055

California Public Utilities Commission
November 8, 1995

ORDER denying rehearing of Decision 94-09-040 (56 CPUC 2d 45), in which the commission had authorized a gas and electric utility to abandon its steam heating service but had rejected its request to charge its electric customers for decommissioning costs, remaining capital costs, and common plant costs associated with its steam business. Commission reiterates that policy issues, and not just accounting principles, were significant factors in its decision, so that it was appropriate to treat abandoned or retired facilities differently from sold facilities.

P.U.R. Headnote and Classification

1.
ACCOUNTING

s14 - Abandoned or retired property - Standard practices - Property as being from separate company division - Steam heating service.
Ca.P.U.C. 1995
[CAL.] In theory, since the abandonment or retirement of facilities has the same result as the sale of facilities (namely disposal of property), it would appear logical to treat associated decommissioning or common costs in the same manner; however, where a utility is disposing of property that was used solely in operations by a separate division, more than mere standard accounting practices come into play; accordingly, where a gas and electric utility was authorized to abandon its steam service operations, it was not allowed to recoup steam-related decommissioning costs, remaining capital costs, and common plant costs from its electric customers, since the facilities at issue had never been used in electric service operations.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

2.
APPORTIONMENT

s24 - Expenses - Of electric and heating service - Abandonment of steam service - Allocation of associated costs - Shielding of electric customers.
Ca.P.U.C. 1995
[CAL.] The commission affirmed that, although a gas and electric utility had been authorized to formally abandon its steam heating business, it could not charge its electric customers for any decommissioning costs, remaining capital costs, and common plant costs associated with such abandonment, since its electric and steam heating services had been totally separate and independent.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

3.
EXPENSES

s51 - Expenses and losses of other departments - Electric versus heating services - Abandonment of steam service - Allocation of associated costs - Shielding of electric customers.
Ca.P.U.C. 1995
[CAL.] Although again finding it reasonable for a gas and electric utility to abandon its steam heating business, the commission deemed it unreasonable for the utility to allocate steam-related decommissioning costs, remaining capital costs, and common plant costs to electric ratepayers, since the electric and steam services had been operated as totally separate and independent departments.

Re San Diego Gas and Electric Company

P.U.R. Headnote and Classification

4.
ORDERS

s1 - Precedential value - Consistency - Ability to depart from past decisions.
Ca.P.U.C. 1995
[CAL.] Although the commission strives to maintain consistency on similar issues from one proceeding to the next, there is no law prohibiting the commission from departing or deviating from a prior order if the facts and circumstances of another case so dictate; the commission is concerned with preserving consistency overall, but it need not adhere rigidly to a particular practice if policy considerations necessitate a change.

Re San Diego Gas and Electric Company

BY THE COMMISSION:

*1 *ORDER DENYING REHEARING OF DECISION 94-09-040*

An application for rehearing of Decision (D.)94-09-040 was filed by San Diego Gas and Electric Company (SDG&E). In D. 94-09-04 we authorized SDG&E to discontinue steam service activities and denied the company's request to charge its electrical corporation customers for decommissioning costs and remaining capital costs related to the steam business. In addition we denied SDG&E's request to reallocate certain common Operation and Maintenance and common plant costs to its gas and electric customers.

SDG&E alleges that rehearing should be granted because the decision misapplies Commission precedent, ignores the Commission's own accounting standards and basic accounting principles, and inappropriately addresses issues that are outside the scope of SDG&E's Application 93-06-055. (Application for Rehearing, p. 1.) No party filed a response to the application for rehearing. We will discuss each of SDG&E's arguments below.

[1-4] SDG&E argues that the decision relies upon D.93-06-038, (*Re Pacific Gas and Electric Company* (1993) 49 Cal.P.U.C. 2d 568), and that in doing so misapplies Commission precedent. SDG&E asserts that misapplication of Commission precedent is legal error. (Application for Rehearing, pp. 3-4.) In D.93-06-038 the Commission approved the request of Pacific Gas and Electric Company (PG&E) to sell its San Francisco steam service to a new utility provider. PG&E sold its steam system at a net capital loss, but did not seek to have its electric customers make up the difference. SDG&E argues that it is legal error for the Commission to rely upon D.93-06-038 because that case involved a sale of PG&E's steam system, while SDG&E does not propose to sell anything, but instead proposes to retire old unused facilities. (Application for Rehearing, p. 4.) SDG&E is incorrect in its assertion that the instant decision relies upon D.93-06-038. In D.94-09-040 we make reference to D.93-06-038 to put SDG&E's application in historical context. The decision contains an analysis of the facts of the SDG&E application and states that SDG&E's request to have unrecovered steam equipment costs and decommissioning costs absorbed by electric customers is rejected for two reasons. First, it is unknown whether in the long term SDG&E will experience net losses or gains from the discontinuance of steam service. Second, even if the cessation of steam service would result in net costs to the company, we conclude that it is inappropriate to charge those costs to electric customers. (D.94-09-040, pp. 4-7 (slip op.).)

Assuming arguendo that the reasoning of D.94-09-040 did rely on D.93-06-038, SDG&E's argument overlooks the fact that the Commission is not bound by prior Commission decisions. This issue is discussed at some length in *Re Pacific Gas and Electric Company*, 30 Cal.P.U.C. 2d 189, 223-225 (modified by D.88-12-083, unpublished.) Accordingly, it is not legal error for the Commission to deviate from the reasoning in a prior decision. While we find no inconsistency between D.93-06-038 and the decision at issue, such incon-

sistency would not in itself be evidence of legal error. The California Supreme Court addressed this during the era of the Railroad Commission of the State of California. The court observed as follows:
*2 'The departure by the Commission from its own precedent or its failure to observe a rule ordinarily respected by it is made the subject of criticism, but our reply is that this is not a matter under the control of this court. We do not perceive that such a matter either tends to show that the Commission had not regularly pursued its authority, or that said departure violated any right of the petitioner guaranteed by the state or federal constitution. Circumstances peculiar to a given situation may justify such a departure. ' *Postal Telegraph-Cable Company v. Railroad Commission of the State of California* (1925) 197 Cal. 426,436.

We find no legal error has been shown.

We also find no merit to SDG&E's argument that there is legal error because the decision ignores basic accounting principles and the Commission's own standard practices. Applicant argues that it is 'retiring' its steam facilities, not selling them, and that therefore termination of steam operations should receive the same accounting treatment as retirement of other plant. SDG&E asserts that the decision ignores standard accounting principles for the retirement of plant as well as the Commission's Standard Practice U-4. (Application for Rehearing, pp. 4-5.) SDG&E's argument overlooks the policy reasons underlying the determination that SDG&E's electric customers should not be charged for the remaining steam system capital and decommissioning costs. The issue before the Commission is not simply an accounting one. In the decision we conclude that it would be inappropriate as a policy matter to charge SDG&E's electric customers with the costs of terminating steam service, an operation that for purposes of ratemaking has been treated as a separate utility from gas and electric operations. We note here, as we have previously observed, that ratemaking drives accounting, and not vice versa. *Re Southern California Gas Company* [D.90-11-031] (1990) 38 Cal.P.U.C.2d 166,191. With regard to the allegation that the decision does not follow the Commission's Standard Practice U-4, we do not agree that standard practice is applicable to the facts before us. Furthermore, it is not legal error for the Commission to deviate from its own precedent or a rule ordinarily followed by it where circumstances justify such a departure.*Postal Telegraph-Cable Company v. Railroad Commission of the State of California* , *supra.*

SDG&E's argument that the decision's discussion of Administrative and General (A&G) expenses is erroneous and ignores sound accounting principles also must be rejected. (Application for Rehearing, p. 6.) The decision found that SDG&E did not provide evidence that supported its assertion that common O&M expenses cannot be charged to specific activities, and are not reduced even if the entire steam department is eliminated. (D.94-09-040, pp. 9-10 (slip op.).) Upon review we find that SDG&E did not meet its burden of proof on this issue. SDG&E claims that the decision ignores sound accounting practice, but does not allege what practice it believes is controlling. We conclude that the resolution of this issue is dictated not by accounting practices but by a failure of the evidence. SDG&E has failed to provide a breakdown of the A&G costs that it seeks to transfer to gas and electric rates. In the absence of evidence we do not find it credible to assume that there will be no reduction whatsoever in the A&G expenses previously assigned to steam rates, as a result of terminating steam service. We find no legal or factual error.

*3 Finally, SDG&E argues that the decision improperly considers the disposition of the Station B property because the ultimate disposition of Station B is not before the Commission at this time. (Application for Rehearing, p. 7.) We find no legal error in the decision's reference to Station B. The decision notes that there is no evidence that in the long term SDG&E will experience a loss from the discontinuance of steam service. In this context the

decision notes that SDG&E has no current plans for the disposition of Station B, which occupies a city block near the waterfront of downtown San Diego. (D.94-09-040, p. 5 (slip op.).) The SDG&E application itself makes reference to Station B and indicates that steam production facilities are located there. (A.93-06-055, pp. 1-2.) Applicant's decision not to include Station B treatment in its application does not preclude us from considering the fact that some portion of Station B value might be attributable to the Steam Department. In carrying out its mandate under Public Utilities Code Section 451 to set just and reasonable rates, it is appropriate for the Commission to consider all relevant facts. SDG&E's argument is further flawed because the decision does not reach any conclusion regarding the disposition of Station B or the portion of its value that should be attributed to the Steam Department. The decision states:
'...even if the cessation of steam service would result in net costs to the company, it is inappropriate to charge these costs to electric customers. ' (D.94-09-040, p. 5 (slip op.).)

SDG&E's argument is without merit.

No further discussion is required of SDG&E's allegations of error. Accordingly, upon reviewing each and every allegation of error raised by SDG&E we conclude that sufficient grounds for rehearing of Decision 94-09-040 have not been shown.

Therefore, IT IS ORDERED:

That the application for rehearing of Decision 94-09-040 filed by San Diego Gas and Electric Company is denied.

This order is effective today.

Dated November 8, 1995 at San Francisco, California.

DANIEL Wm. FESSLER

President

P. GREGORY CONLON

JESSIE J. KNIGHT, JR.

HENRY M. DUQUE

JOSIAH L. NEEPER

Commissioners

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Re Ohio Power Company
Case No.93-01-EL-EFC

Ohio Public Utilities Commission
May 26, 1993

Before Commissioners: Craig A. Glazer Chairman J. Michael Biddison Jolynn Barry Butler Richard M. Fanelly David W. Johnson

*1 Case No. 93-01-EL-EFC

In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedule of Ohio Power Company and Related Matters.

OPINION AND ORDER

BY THE COMMISSION:

The Commission, having reviewed the testimony and exhibits presented at the public hearings, relevant portions of the Revised Code and Administrative Code, and being fully advised, issues its Opinion and Order.

APPEARANCES:

Messrs. Richard Cohen, Ohio Power Company, 301 Cleveland Avenue, S.W., Canton, Ohio 44701, and Marvin I. Resnik, American Electric Power Service Corporation, One Riverside Plaza, Columbus, Ohio 43215, on behalf of Ohio Power Company.

Mr. Lee Fisher, Attorney General for the state of Ohio, James B. Gainer, Section Chief, by Messrs. Thomas W. McNamee and William L. Wright, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43266-0573, on behalf of the staff of the Public Utilities Commission of Ohio.

Mr. William A. Spratley, Consumers' Counsel, by Mr. Thomas C. Kawalec, Ms. Ann Hotz, and Mr. Barry Cohen, Associate Consumers' Counsel, 77 South High Street, Columbus, Ohio 43266-0550, on behalf of the residential customers of Ohio Power Company.

Emens, Kegler, Brown, Hill & Ritter Co., by Mr. Richard P. Rosenberry, Mr. Samuel C. Randazzo, and Ms. Denise C. Clayton, 65 East State Street, Suite 1800, Columbus, Ohio 43215-4294, on behalf of Anheuser-Busch Companies, Inc., B.P. Oil Company, LTV Steel Company, Owens-Corning Fiberglas Corporation, Owens-Illinois, Inc., Republic Engineered Steels, Inc., The Timken Company (Industrial Energy Consumers).

OPINION:

I. *Introduction*

Ohio Power Company (Ohio Power) is an electric light company under Section 4905.03 (A) (4), Revised Code, and is, therefore, a public utility subject to the ongoing jurisdiction and supervision of this Commission pursuant to Sections 4905.02, 4905.04, 4905.05, and 4905.06, Revised Code. Ohio Power is also an electric utility within the meaning of Rule 4901:1-11-01(L), Ohio Administrative Code (O.A.C.).Section 4905.301, Revised Code, requires the Commission to review each electric utility's electric fuel component (EFC) at a hearing annually or at a lesser interval of time as ordered by the Commission. By entry issued July 23, 1992, the Commission initiated this proceeding to review Ohio Power's EFC and related matters.

In addition to the hearing requirements set forth in Section 4905.301, Revised Code, the Commission is required by Section 4905.66 (B) (2), Revised Code, to conduct or cause to be conducted, at least annually, an audit of the fuel-related policies and practices of each electric utility. Rule 4901:1-11-10, O.A.C., provides that each electric utility shall be subject to a management/performance (m/p) audit and a financial audit of its fuel-related policies and practices. Rule 4901:1-11-10 (B) (1), O.A.C., requires the Commission to conduct the m/p audit or cause this audit to be conducted by a qualified independent auditing firm selected by the Commission, and Rule 4901:1-11-10 (B) (2), O.A.C., requires the Commission to conduct the financial audit or cause this audit to be conducted by a qualified independent auditing firm selected by the electric utility. Rules 4901:1-11-10 (B) (1) and 4901:1-11-10 (B) (2), O.A.C., require the electric utility to bear the cost of the audits. By Finding and Order dated July 23, 1992, the Commission determined that both the financial and m/p audits of Ohio Power would be conducted in conjunction with the instant proceeding. Ernst & Young conducted the company's financial audit and Arthur D. Little, Inc., conducted the m/p audit. On February 12, 1993, the m/p and financial audit reports were submitted in accordance with Rule 4901:1-11-10 (D), O.A.C., and the Commission Entry of November 5, 1991. The scope of the respective audits was defined by Rule 4901:1-11-10 (C), O.A.C., and the Commission's combined Opinion and Order in *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedule of Ohio Power Company and Related Matters*, Case Nos. 92-01-EL-EFC and 92-101-EL-EFC (November 25, 1992) (1992 EFC proceedings).

*2 Section 4909.191 (A), Revised Code, requires each electric utility to file proof at the time of its EFC hearings that notice of the proceedings was published in accordance with that statute. Additionally, Rule 4901:1-11-11, O.A.C., requires that the same hearing notice be published once between 15 and 30 days prior to the hearing date. Ohio Power caused the required publications to be made (Ohio Power Exs. 1, 2).

Section 4909.191 (C), Revised Code, requires the Commission at each EFC hearing to consider, to the extent applicable, the efficiency of the electric utility's fuel procurement policies and practices, the results of the financial and the m/p audits, and the company's compliance with previous performance recommendations. Rule 4901:1-11-11 (B) (5), O.A.C., additionally requires the Commission to determine the EFC rate to be charged by the company during the next current period. Section 4909.191 (C), Revised Code, and Rule 4901:1-11-11 (B), O.A.C., require each electric utility to demonstrate at its EFC hearings that its acquisition and delivery costs were fair, just, and reasonable. Ohio Power filed data pertinent to its fuel procurement policies and practices in accordance with Section 4909.191 (B), Revised Code, and Rule 4901:1-11-11 (D) (1), O.A.C. The direct testimony of the company's witnesses was filed in accordance with the Commission's November 5, 1992 entry.

The Office of Consumers' Counsel (OCC) and the Industrial Energy Consumers (IEC) were granted intervention in these proceedings. A hearing in this matter commenced on March 16, 1993 and continued on March 17, 19, 25, 31, and April 5, 1993. At the hearing, Mr. Paul W. Daley and Charles A. Oberlin testified on behalf of the company. Mr. Tom Meike testified as a representative of the financial auditor and Mr. Glenn G. Whatley testified as a representative of the m/p auditor. IEC sponsored the testimony of Messrs. Lane Kollen and William J. Barta and called Messrs. Charles A. Ebetino and Gregory S. Campbell of Ohio Power as if on cross-examination. The parties filed their briefs on April 15, 1993 and reply briefs on April 26, 1993.

II. *The EFC Financial Audit*

On February 14, 1992, Ernst & Young filed with the Commission its EFC Financial Performance Audit (Comm. Ord. Ex. 1). The financial auditor reviewed Ohio Power's calculation of the EFC rate in the review period (December 1, 1991 to November 30, 1992). The scope of the review included, *inter alia*, the processing of fuel receipt and consumption transactions, processing of energy purchase and sale transactions, calculation of the EFC rate, procedures for processing fuel data, review of quality and quantity specifications, and the reporting of fuel acquisition and delivery. Based upon its review, the auditor concluded the following:

1) the method of computing the EFC was consistent in the review period and consistent with Chapter 4901:1-11, O.A.C.; 2) the heat rate, freight receipts, invoices, and purchasing procedures were properly and consistently applied when computing the EFC in the sample month; 3) no exceptions were identified in the accounting procedures in the test period; and 4) the EFC rate reported to the Commission was properly applied to customer bills during the fuel clause review period.

*3 In addition, the auditor reviewed the impact of two Commission approved EFC stipulations during the audit period. In *In the Matter of the Electric Fuel Component Contained Within the Rate Schedule of Ohio Power Company and Related Matters*, Case No. 90-01-EL-EFC, the Commission approved a stipulation in which the parties agreed that the cost of Ohio Power's affiliate coal purchases on a weighted-average basis shall be repriced, for EFC purposes, at $1.75 per million British thermal units (MBtu), free on board (FOB) plant. Moreover, the stipulation stated that:

In order to recognize any remaining influence which arises from the $1.75/MBtu limitation upon affiliate coal delivered during the three audit years, the company's calculation of the cost of fuel consumed during the six-month period immediately following the conclusion of the 1991 audit year will be based upon a blend of fuel inventories as of November 30, 1991 which reflect affiliate coal deliveries made during the relevant audit years priced at $1.75/MBtu, and affiliate coal deliveries made after that period at actual cost.

Id. at 17.

Ernst & Young found that Ohio Power's calculation of a credit related to the pricing and consumption of coal at $1.75/MBtu to be reasonable, except with regard to the removal of the influence of Ohio Power-generated, off-system sales. Ernst & Young recommended a more appropriate methodology to reprice the off-system sales [FN1] and found that the reconciliation adjustment (RA) should be increased by $2,565 (Comm. Ord. Ex. 1 at II-7).

In the 1992 EFC proceedings, the Commission approved a stipulation in which the signatory parties agreed that, for all coal burned at the Gavin, Muskingum, Mitchell, and Cardinal (Units 1 and 2) plants from December 1, 1991 to November 30, 1994, Ohio Power shall use the predetermined price of 164 ¢ /MBtu. Ohio Power included an addition to the RA, which reflects the predetermined price of coal burned at the four plants from December 1, 1991 to November 30, 1992. Ernst & Young reviewed this addition to the RA and found Ohio Power's methodology and calculation to be reasonable, except with regard to the removal of the influence of off-system sales. Ernst & Young recommended a more appropriate methodology [FN2] and found that the RA should be reduced by $31,421 (Comm. Ord. Ex. 1 at II-8, II-9).

As a result of both suggestions for repricing off-system sales, Ernst & Young recommends that the RA of the EFC rate be increased by $2,565 and reduced by $31,421, for a net reduction of $28,856. Ohio Power indicated that it will use the financial auditor's methodologies for repricing off-system sales and that it accepts the adjustment to the RA (Tr. II, 150).

III. *The EFC Management and Performance Audit*

Arthur D. Little, Inc. (Little) conducted the m/p audit of the fuel procurement policies and practices of Ohio Power (Comm. Ord. Ex. 2). [FN3] This review covered the audit period of December 1, 1991 to November 30, 1992. In addition to the general objectives set forth in the Commission's Request for Proposal, the m/p auditor reviewed:

*4 1) the management and operation of Ohio Power's affiliate coal mines; 2) the effort of Ohio Power to purchase the maximum amount of Ohio produced coal; 3) Ohio Power's efforts to implement recommendations from last year's m/p audit which were ordered by the Commission; 4) the cost allocation of the research and development unit at the Tidd plant; 5) the sale of the Martinka Mine; and 6) fuel procurement issues related to Ohio Power's Clean Air Act compliance plan.

A. *Affiliate Operations and Coal Procurement*

As part of its audit, Little reviewed Ohio Power's operations at its affiliate mines. During the audit period, Ohio Power owned three coal mining operations. They are: the Southern Ohio Coal Company (SOCCO), the Central Ohio Coal Company (COCCO), and the Windsor Coal Company (Windsor). SOCCO operates the Meigs Mine, which sends its coal to Ohio Power's Gavin plant, and operated, prior to its sale, the Martinka Mine, which sent its coal to Ohio Power's Mitchell plant. COCCO operates the Muskingum Mine and sends its coal to the Muskingum River plant. Windsor operates the Windsor Mine and sends its coal to the Cardinal plant. As of July 1, 1992, the Martinka Mine was sold to Peabody Development Company (Peabody) and its new affiliate, Martinka Coal Company (MCC). By separate contract, Ohio Power has arranged for a 20-1/2 year contract for coal from Peabody (Comm. Ord. Ex. 2, at 26).

Ohio Power is required to demonstrate that its acquisition and delivery costs for fuel to generate electricity are fair, just, and reasonable. In defining "acquisition cost", Section 4905.01 (F), Revised Code, states in part that affiliate coal included in the EFC rate shall not exceed a price that is reasonable when compared to the average cost per MBtu of similar quality coal purchased from all independent like mining operations under similar term contracts during the period. In addition, pursuant to Section 4905.67 (B), Revised Code, the Commission is required annually to determine whether the acquisition cost of fuel supplied to the electric utility by an affiliate company represents a sales price that produces a return on the affiliate company's actual investment base that is fair and reasonable.

During the current audit period, the cost differential between affiliate and contract coal prices decreased from 24.07 ¢ /MBtu in the last audit year to 21.25 ¢ /MBtu in the current audit period (Comm. Ord. Ex. 1 at Ex. III-6; Co. Ex. 3 at Ex. 6). Looking at the same time periods, the average delivered price of affiliate coal dropped from 175.22 ¢ /MBtu to 164.66 ¢ /MBtu (Comm. Ord. Ex. 1 at Ex. III-4, III-5; Co. Ex. 3 at Ex. 5). The drop in the differential between affiliate and non-affiliate coal prices is due to increased production and shipments, reductions in staff at COCCO and the Meigs Mine, renegotiation of the Marietta contract, expiration of the Glenn Brooke contract, reconfiguration of the Meigs Mine operations, and the sale of the Martinka Mine (Comm. Ord. Ex. 1 at III-10).

*5 Little found that fuel procurement, affiliate mine management, fuel utilization, and power dispatching were conducted with reasonable care (Comm. Ord. Ex. 2, at 2). Little reviewed Ohio Power's contract profile and noted the Donaldson contract was purchased by Arch Coal Sales Company, a replacement agreement was developed, and the Sands Hill contract was signed. However, Little stated that these matters should be reviewed in next year's audit because these events occurred outside the audit period (*Id.* at 29, 35).[FN4] Also, Little reviewed AEPSC's coal pile inventory procedure, noting several "fairly significant recurring deviations between physical and book inventory"(*Id.* at 50). Those deviations should also be reviewed in more detail during the next audit (*Id.*).

However, Little made several recommendations with regard to Ohio Power's affiliate operations and coal procurement. Little noticed that, since it last audited Ohio Power in 1987, Ohio Power had reduced costs at its Meigs Mine by increasing longwall productivity and restructuring the mine. Although, Little praised the improvements at the

Meigs Mine, it stated that the operation and productivity of continuous mining sections can be improved and that the mining plan for the "C" block of Meigs Mine Number 31 was not well planned (*Id* . at 6, 39-40). Similarly, Little noticed that Ohio Power had improved productivity at its Muskingum Mine. However, Little suggested: (1) reviewing the risk management and labor training programs and (2) re-examining the economics of moving the raw coal loading point (*Id.* at 6, 38). Furthermore, Little recommended that Ohio Power's quality assurance/ quality control program include blend samples to ensure unbiased results and that Ohio Power review ways to implement a "blind" ticket system for coal samples which would match the identity of vendors during coal analysis (*Id.* at 8, 49-50). Finally, Little reviewed Ohio Power's plan to reduce coal inventories, in accordance with the latest stipulation. Little found that the plan has merit (Comm. Ord. Ex. 2, at 42).

Ohio Power has stated that it agrees with Little's recommendation that operation and productivity of continuous mining sections can be improved at the Meigs Mine and will devise a plan (Tr. II, 123, 133-4). Furthermore, Ohio Power has reviewed and revised its mining plan for the "C" block of Meigs Mine Number 31 (*Id.*). Finally, Ohio Power states that it is not opposed to the auditor's recommendation for a "blind ticket system" (Ohio Power Reply Brief at 3 n.1).

Staff believes that all the recommendations of the m/p auditor are reasonable and should be adopted by the Commission (Staff Brief at 17-8). Staff also states that it believes Ohio Power's fuel procurement efforts are reasonable, including the coal inventory reduction plan (*Id.* at 6). IEC stated that the differential between affiliate and non-affiliate coal prices remains substantial and, clearly, affiliate coal "represents no bargain" for the ratepayers (IEC Reply Brief at 29). Also, IEC stated that, although the coal inventory reduction plan may reduce inventories, the plan will limit purchases of spot coal for the most part and, thereby, reduce Ohio Power's ability to achieve lower *actual* fuel costs, accelerate Meigs Mine cost recovery, and reduce Meigs Mine coal costs (*Id.* at 23).

***6** The Commission has in the past consistently looked at coal costs between the Ohio Power's affiliate and non-affiliate supplies when determining the reasonableness of affiliate coal. Such a comparison recognizes the unique position occupied by Ohio Power, relative to other Ohio regulated electric utilities, as a large purchaser of coal from affiliate mines. We find this approach reasonable and in accordance with the Rule 4901:1-11-10, Appendix D and E, O.A.C. The price differential between non-affiliate and affiliate coal supplies continues to decline as can be seen by the 1.1 percent decrease in the differential for the current audit period from the differential in the prior audit period (Co. Ex. 3, at 21).

Sections 4905.69 and 4905.301, Revised Code, are intended to foster efficient fuel procurement and utilization practices through the EFC mechanism. Pursuant to these statutes, the Commission has been granted considerable authority to encourage efficient fuel procurement practices and fuel cost minimization. See *Consumers' Counsel v. Pub. Util. Comm.* (1979), 56 Ohio St. 2d 78 and *Consumers' Counsel v. Pub. Util. Comm.* (1992), 63 Ohio St. 3d 531.The Commission finds that Ohio Power's affiliate coal costs, including acquisition and delivery costs, are fair, just, and reasonable. [FN5] Productivity at each of Ohio Power's affiliate mines reached record highs in 1992 (Ohio Power Ex. 3, at 6).

Moreover, the weighted average delivered cost of coal from Ohio Power affiliates during the audit period (164.7 ¢ /MBtu) was just slightly above the price stipulated in the 1992 EFC proceedings (164 ¢ /MBtu) and the overall weighted average delivered cost of fuel during the audit period was 154.73 ¢ / MBtu, well below the stipulated price (Comm. Ord. Ex. 2, at 5). The Commission also finds that Ohio Power's plan to reduce coal inventories is reasonable.

However, the Commission finds that Little's recommendations are reasonable and should be adopted. Therefore, Ohio Power should devise a plan for improving operation and productivity of continuous mining sections at the Meigs Mine, review its risk management and labor training programs at the Muskingum Mine, re-examine the economics of moving the Muskingum Mine raw coal loading point, include blend samples in the quality assurance/quality control program, and implement a "blind ticket" system during coal analysis.

During next year's audit, the m/p auditor should review Ohio Power's revised plan for mining the "C" block of the Meigs Mine Number 31. Additionally, the m/p auditor should review the buyout of the Donaldson contract, the replacement agreement, the Sands Hill contract, and the "fairly significant recurring deviations between physical and book inventory" in the pile inventory procedure, noted by Little. The m/p auditor should also inquire why FSD determined to exceed its contract commitment policy when it entered into the sands Hill contract.

B. *Tidd Project*

The Tidd project involves a technology that is designed to enable the burning of high sulfur Ohio coal in a way that is economically and environmentally superior to conventional coal-fired boilers that use separate scrubbers. The project is being conducted at the company's Tidd generating plant. Costs for the project are included within the Ohio Coal Research and Development (OCRD) component, which is part of the company's EFC rate. In Ohio Power's EFC proceeding in Case No. 88-01-EL-EFC, the Commission determined that it was appropriate for OCRD costs to be allocated over total company sales, rather than just sales to EFC customers. However, modifications of the Commission's EFC rules would be required before this could be implemented. To date, the Commission has not amended its rules. In the Ohio Power's EFC review in Case No. 91-101-EL-EFC, OCC and IEC urged the Commission to follow through on its decision in the earlier EFC proceeding. However, the company and the Commission staff recommended that the Commission reverse its earlier decision. In Case No. 91-101-EL-EFC, the Commission decided that more information was needed which was not in the record when the Commission originally made its decision. The Commission directed the financial auditor for the 1992 EFC proceedings to determine: (1) the percentage of Tidd-generated kWh used by EFC and non-EFC customers and (2) the costs of the Tidd project allocable to EFC and non-EFC customer, based on total company sales and how much of these costs would flow through the AEP system operating agreement and off-system sales (also referred to as AEP system sales).

*7 The financial auditor for the 1992 EFC proceedings' audit, Deloitte & Touche (D&T), reviewed those matters and found that, because the Tidd plant is operated as needed for testing purposes and cannot be relied upon to meet load requirements, the plant is not operated like a commercial plant and is not dispatched as part of the AEP system. D&T found that it was not appropriate, or possible, to allocate Tidd's generation between EFC and non-EFC customers under methods used for commercially available plants. However, the auditor did a mathematical calculation based upon the overall ration of energy used by EFC and non-EFC customers of the company during the audit period December 1, 1990 to November 30, 1991. The results of the calculation, showed that 54 percent, or $5,052,216, of the costs would be attributable to EFC customers and 46 percent, or $4,303,739, would be attributable to non-EFC customers during the audit period (Comm. Ord. Ex. 2, at 27 in the 1992 EFC proceedings). D&T calculated total costs of the Tidd project through November 30, 1991 to be $162,549,000, with $46,779,000 remaining to be incurred (*Id.* at 26). D&T also reviewed the AEP system operating agreement and determined that the Tidd plant does not qualify for inclusion under the agreement and, therefore, the energy and costs of the plant could not be allocated among the pool members or allocated for off-system sales. Because of the Tidd plant's experimental nature, it was not available to be dispatched based on its variable cost and could not be relied on by the AEP pool manager to supply power and energy for the AEP system for any significant length of time (*Id.* at 23). D&T also found that the Tidd plant was never truly an incremental cost for an off-system sale since the plant was never dispatched to meet the load requirements of an off-system sale (*Id.* at 24).

In the 1992 EFC proceedings, the Commission determined that, although D&T undertook a review of the AEP system operating agreement and made a cost allocation, more information was needed to further review this matter. Specifically, the Commission requested more information regarding the following:

1) the potential recoverability of Tidd costs under the existing terms of Ohio Power's wholesale power contracts; 2) the feasibility of Ohio Power amending its contracts to allow for recovery of these costs; 3) potential amendments to the AEP operating agreement to allow recovery of these costs; 4) the Federal Energy Regulatory Commission's (FERC) precedent with regard to recovery of Department of Energy approved clean coal projects; and 5) the treatment of the revenues received from the sale of electricity generated from Tidd.

In the current proceeding, Little reviewed the matters requested by the Commission. Little felt that, to answer most of the questions above, it was necessary to determine if Tidd is dispatched (Comm. Ord. Ex. 2, at 19). Little concluded that Tidd is not dispatched by the AEP pool manager (*Id.*). Instead, the plant manager of Tidd operates the unit in accordance with the experimental plan provided by AEP mechanical engineering (*Id.*). The auditor concluded that because the dispatcher is not assigning generation to Tidd, its output is not dispatched (Comm. Ord. Ex. 2, at 19). The auditor's recommended that the Commission continue its current method of allocating costs of Tidd to EFC customers (*Id.* at 26).

***8** Little reviewed Ohio Power's interchange and wholesale power agreements (*Id.* at 20). It determined that because the Tidd plant is not dispatched, none of Tidd's cost can be charged to non-jurisdictional customers unless the interchange agreements were modified (*Id.*). Little believes that it is unlikely that AEP could craft an interchange agreement that would pass on Tidd's costs and that would be accepted by FERC without a significant departure from existing FERC precedents. Further, the auditor concluded that Tidd's capacity costs are not recoverable under the terms of existing wholesale power contract. However, Ohio Power could file a wholesale rate case at FERC to seek recovery of Tidd's capacity costs. With regard to Tidd energy costs, the auditor concluded that, depending upon an interpretation of FERC's rules, these costs may be recoverable under the terms of existing wholesale power contracts (*Id.* at 20). However, the auditor noted that it is unclear whether FERC would accept an amendment to Ohio Power's wholesale power agreements which attempts to charge customers with Tidd's operating costs. Little also noted that, regardless of FERC's view of Tidd costs, interchange customers and wholesale power purchasers currently face market conditions favorable to them and would be unlikely to pay added charges for Tidd to purchase power from AEP.

Based on the existing language of the AEP Operating Agreement and behavior patterns shown in prior attempts to amend that agreement, the auditor found that the AEP Operating Agreement would have to be amended to accommodate the inclusion of Tidd costs (*Id.* at 24). The auditor believes this process of amending the agreement could potentially expose Ohio Power jurisdictional customers to risks that are larger than the potential benefits (*Id* .). The auditor points out that opening the AEP operational agreement to modification may provide other state commissions with the occasion to request other modifications that may not be favorable to Ohio Power, such as the manner in which capacity differences are handled (*Id.* at 24). The auditor also stated that there does not appear to be any

FERC precedent on recovery of Department of Energy approved clean coal projects (*Id.* at 24, 25).

In its review of the treatment of revenues from Tidd, Little found that Ohio Power books OCRD revenue and revenue derived from the sale of Tidd's energy based upon amounts that approximate its collections from customers for those activities (*Id.* at 25). OCRD revenue is booked at approximately one mill per kWh, an amount identical to the estimated expenses and revenue from energy generated at Tidd is booked at the EFC rate (*Id.*). The auditor found the company's approach for both OCRD and energy revenues to be reasonable (*Id.*).

Little recommends that the Commission continue the current approach of allocating the costs of Tidd to EFC customers (*Id.* at 26). According to the auditor, to seek a broader sharing would only expose Ohio Power to litigation and potentially draw the Commission into negotiations to protect the interests of Ohio ratepayers (*Id.*).

***9** IEC and OCC do not agree with the auditor's recommendation. They believe that Tidd's cost should be recovered from Ohio Power's non-jurisdictional customers and other AEP operating companies, as well as from the company's Ohio jurisdictional EFC customers. IEC argues that, while Tidd may not be dispatched as regularly as a commercially available plant, it still produces generation that can be allocated between EFC and non-EFC customers. IEC argues that there are opportunities available for spreading Tidd's costs among those that use its generation and benefit from the knowledge gained from the project. IEC contends that the auditor recognized that the wholesale power agreements appear to allow for the inclusion of Tidd's energy costs and FERC might accept inclusion of Tidd's cost and AEP's wholesale charges for demand (IEC Brief at 57). Further, IEC points out that AEP's interconnection agreement could be amended to recover Tidd's costs. IEC also does not believe that Ohio Power will lose sales in the wholesale market if Ohio Power is the low-cost producer of energy that it claims it is. IEC also points out that the research and development of the Tidd plant, although it has taken place in Ohio Power's service territory, will benefit other AEP system operating companies (*Id.* at 57 n. 32). IEC requests that the Commission direct Ohio Power to calculate the OCRD cost over the total AEP system sales or over total company sales using the percentage established by the auditor (*Id.* at 58). IEC recommends that the Commission cap Ohio Power's Tidd cost recovery from EFC customers at 54 percent of total OCRD costs, exclusive of amounts associated with loans and grants (*Id.* and IEC Reply Brief at 28).

OCC argues that, whether or not Ohio Power has difficulty passing through fairly allocated costs of the Tidd plant to non-EFC customers, the Commission should not permit the company to pass these costs solely to Ohio Power EFC customers (OCC Brief at 50. Further, OCC states that whether or not costs are recoverable in competitive markets should not dictate discriminatory recovery from, or subsidization by, EFC customers (*Id.*). OCC agrees with IEC that the record does support the position that the wholesale market place is so competitive that the addition of Tidd costs would significantly affect Ohio Power's or AEP's wholesale prices (OCC Reply Brief at 4). Based on Ohio Power revenues from total sales from resales transactions during 1991 contained on FERC Form No. 1, OCC contends that Tidd cost which should be allocated to non-EFC customers would comprise only approximately .95 percent, or 1.4 percent if capacity costs are excluded (*Id.* at 3-4). OCC believe this small amount would not substantially influence Ohio Power's competitive position (*Id.*). Further, OCC believes that FERC has a solid policy of passing through the cost of research and development projects to the broadest base of ratepayers possible and, therefore, amendments of wholesale agreements to pass through Tidd costs would not likely invoke contested litigation at FERC (*Id.* at 5-7).

***10** OCC also argues that the auditor did not perform a sufficient independent investigation as to whether or not the AEP interconnection agreement would permit the pass-through of Tidd costs and whether the Tidd plant is under the direction of the AEP pool manager to be dispatched (OCC Brief at 10). OCC believes that the auditor's conclusion, that an attempted amendment of the AEP interconnection agreement would lead to litigation at FERC that would ultimately have a negative impact on Ohio's ratepayers, is not supported by the record (*Id* . at 11).

Ohio Power and the staff support the auditor's recommendation. The company states that it is properly allocating Tidd costs in accordance with the Commission's rules (Ohio Power Brief at 25). It is Ohio Power's position that the Tidd plant does not qualify for inclusion under the AEP interconnection agreement, and its energy and costs cannot be allocated among the pool members or allocated for AEP system sales. Ohio Power argues that system sales costs are derived from the incremental out-of-pocket costs of the generation which is specifically dispatched for the sale (Ohio Power Reply Brief at 16 n.18). Ohio Power states that, because of the nature of the Tidd's operation, it is never dispatched to meet the load requirements of a system sale (*Id.* at 17). Therefore, Ohio Power believes that, since the Tidd plant is never truly an incremental cost for a system sale, it should not be allocated as a system sales cost (*Id.*).

The staff believes that the Tidd's operation on a experimental basis does not make the plant dispatchable (Staff Brief at 14). Tidd generation is placed onto the system grid to demonstrate the experimental technology and not to sell power to a particular customer (*Id.*). The staff believes that existing generation capacity levels, economic conditions, and mild weather are factors that, when coupled with recently-enacted National Energy Policy Act's open access provisions, serve to make interchange and wholesale markets highly competitive and would render Ohio Power's recovery of Tidd costs from wholesale customers an uncertain venture at best (*Id.* at 14-5). The staff also argues that because Tidd is not normally expected to meet load, an amendment to the AEP interconnection agreement would be required to designate Tidd generation as "primary member capacity" (*Id.* at 15). Such an amendment would require several layers of approval, including that of AEP operating companies, FERC, and the state commissions of the affected states (*Id.*). Further, the change in the allocation of Tidd costs proposed by OCC and IEC would create a regulatory environment that blunts, rather than fosters the development of increased, environmentally sound uses for Ohio coal (*Id.* at 15-6). Such an allocation would also be ill-advised because it may retard further development of research and development programs that are vital to Ohio's economy (*Id* .).

Much of the auditor's recommendation hinges upon its belief that the AEP operating agreement would need to be modified and accepted by FERC, both of which would be difficult. The Commission finds that the auditor failed to recognize that the interconnection agreements will, in any event, be renegotiated as a result of the Clean Air Act. Accordingly, the Commission will review the allocation of the costs of the Tidd Project as part of the renegotiation of the AEP operating agreement.

C. *Sale of the Martinka Mine and the Peabody Contract*

***11** From late 1991 to early 1992, Ohio Power and SOCCO (through AEPSC's FSD) invited several vendors to submit combined bids for the purchase of the Martinka Mine and a coal supply contract. FSD did inform the bidders of the maximum price which it would consider for an accompanying coal supply agreement (Tr. III, 38-9). Ultimately, four companies submitted bids, three of which FSD considered competitive enough to seriously consider (IEC Ex. 5). Those three bids were made by Peabody, Arch Mining Company, and Robert E. Murray Coal Company (Murray) (*Id.*). FSD conducted several studies, which analyzed the purchase bids and the contract bids, and conducted detailed negotiations with the three bidders (*Id.*;Tr. III, 26-7, 108-9). In late spring 1992, Ohio Power and SOCCO decided to accept the Peabody bid.

On July 1, 1992, SOCCO sold the Martinka Mine to Peabody and MCC (Comm. Ord. Ex. 2, at 26).[FN6] In Ohio Power's final accounting, as filed with the Securities and Exchange Commission, the sale of the mine yielded an after-tax loss of approximately $111,000 (Comm. Ord. Ex. 2, at 27). At the same time SOCCO sold the Martinka Mine, Ohio Power entered into a new long-term coal supply agreement with Peabody (*Id.*). This contract provides for the delivery of coal, which complies with both the Phase I and Phase II requirements of the 1990 amendments to the Clean Air Act, to the Mitchell Generating Station (*Id.*). The coal deliveries commenced in July 1992 and will continue until December 2012, with an option to extend the contract up to an additional 60 months (*Id.*). The contract is a base price plus escalation contract, with the prices ranging from 147.8 ¢ /MBtu to 150.3 ¢ / MBtu (Ohio Power Ex. 3R, at 9). The annual tonnage requirement for most of the term of the contract is 2,500,000 tons (Comm. Ord. Ex. 1 at III-5; Tr. V, 67-8). The delivery schedule varies to take into account the inventory levels at the Mitchell plant and to permit the inventory to burn down (Tr. III, 57). Also, the contract permits Ohio Power to increase or decrease the base quantity of coal by 13 percent after 1994 (Tr. III, 64-5; Tr. V, 68). The contract has an estimated present value of $200 to $300 million, depending upon the value of sulphur dioxide emission allowances and the discount rate (Comm. Ord. Ex. 2, at 27).

Peabody agreed to deliver coal from the Martinka Mine (now known as the Tygart Mine) to the Mitchell plant through August 1994 (Comm. Ord. Ex. 2, at 26; Tr. III, 62-3). Thereafter, Peabody will deliver coal, which will comply with Ohio Power's Clean Air Act compliance plan, from other Peabody holdings or from other properties to the Mitchell plant (*Id.*;Tr. II, 128-9). Also, Peabody assumed reclamation liabilities, water treatment liabilities, ultimate mine closure costs, and all post-sale operating costs (Comm. Ord. Ex. 2, at 26). The contract also contained minimum quantity requirements and a liquidated damages clause. Ohio Power avoided significant shut-down costs (estimated at $147 million) by coupling the sale of the Martinka Mine with a coal supply contract (Tr. III, 46; IEC Ex. 9).

***12** The Commission directed the m/p auditor to review the appropriateness of the divestiture of the Martinka Mine and the Peabody coal contract. Little reviewed the sale agreement, new supply contract, and FSD's economic evaluation of the "integrated transaction". Little also conducted interviews of AEPSC FSD personnel (Tr. II, 27-31, 33-4). Little concluded that the sale of the Martinka Mine was essentially a break-even transaction and that the sale and new contract were "prudent because [Ohio Power] has reduced the expected future cost of coal delivered to the Mitchell Plant" (Comm. Ord. Ex. 2, at 4; Tr. I, 112). Furthermore, Little noted that the cost savings of the new contract will accrue to the benefit of the Ohio Power ratepayers and stockholders because it will bring Ohio Power's weighted average cost of fuel down, allow Ohio Power to amortize the investment in the Meigs Mine, and, when the fixed cost of coal expires, the saving will flow to the ratepayer through lower expected cost (*Id.* at 4, 27; Tr. II, 46-7). Also, Little stated that it felt that FSD's action in providing a maximum price to the bidders was not out of the ordinary and was helpful to the bidders so that they understood that FSD wanted a market-based price for the coal (Tr. II, 84, 86). Moreover, Little concluded that the Peabody offer was the lowest cost offer (Tr. II, 57). Little stated that Ohio Power had a reasonable assessment of what the market price of coal to the Mitchell plant would be (Tr. II, 61-2). On cross-examination by OCC, Little stated that it had no reservations regarding the sale of the Martinka Mine (Tr. I, 118).

IEC does not dispute that the Peabody bid was the best of the three bids (Tr. V, 38). Rather, IEC questions the thoroughness of the auditor's review of the integrated transaction, as well as the transaction's reasonableness. IEC claims that the m/p auditor performed little substantive analysis and "regurgitated" the analysis used by FSD to find the transaction prudent (IEC Brief at 2). IEC argues that the FSD analysis only compared the Peabody proposal to continued purchases of coal from the Martinka Mine (rather than evaluating for the least-cost fuel purchasing option) and, in such a scenario, any reduction in coal costs to the Mitchell plant would appear prudent (*Id.* at 2-3; IEC Reply Brief at 7). Furthermore, IEC points to several reasons why the integrated transaction is unreasonable. Those reasons can be summarized as follows:

1) the cost of coal under the Peabody contract is excessive; 2) the coal contract perpetuates a fuel-sourcing strategy that has limited Ohio Power's ability to access spot coal purchases for years; 3) the divestiture was not properly accounted; 4) the contract has a substantial take-or-pay requirement for Ohio Power, in the form of liquidated damages; and 5) the integrated transaction is a risk and cost-shifting strategy used by Ohio Power to avoid regulatory review of the prudence and reasonableness of shutdown costs for the Martinka Mine.

***13** IEC points to several factors to substantiate its claim that the cost of coal under the contract is excessive. First, FSD's announcement of the maximum price it would accept tended to set a price floor and price ceiling for the bids (IEC Brief at 12; IEC Ex. 6; Tr. V, 55). Second, the coal contract includes an amount above the market price for coal in order to induce Peabody to purchase the Martinka Mine and allow the Martinka costs to be shifted into the Peabody contract (IEC Brief at 16, 19, 30; IEC Ex. 2A, at 8). IEC supports this claim with evidence that no one was interested in purchasing the Martinka Mine on a stand-alone basis (Tr. I, 112; Tr. II, 36-8; Tr. III, 53). Third, the contract requires delivery of river coal which Peabody will purchase from third parties and resell to Ohio Power at an agreed price. Although the contract does not indicate the amount Peabody will pay for the coal, Peabody's last bid illustrated that the cost was much lower than that which Peabody will charge Ohio Power, resulting in a revenue stream of $36 million over approximately seven years (IEC Brief at 18). Fourth, market prices for delivery of similar coal to the Mitchell plant are much lower. A 1991 bid by Arch for low-sulphur coal to the Gavin plant, which was similar in the quality of coal for the Mitchell plant, was almost 10 ¢ /MBtu less that Arch's bid in the integrated transaction, even after considering transportation and penalty adjustments (IEC Brief at 27).

In substantiating the claim that the Peabody contract perpetuates a fuel source strategy which limits spot market purchases, IEC points to the "relatively high" minimum tonnage requirements compared to the projected burn requirements for the Mitchell plant and the "relatively high" liquidated damages (IEC Brief at 20; IEC Ex. 2A, at 7). As a result, IEC states that Ohio Power will not come close to its 80-85 percent contract/15-20 percent spot purchases objectives in the first ten years of the Peabody contract (IEC Brief at 20; Tr. II, 74). Therefore, IEC argues that the ratepayers are in almost the same position that existed when the Martinka Mine supplied the Mitchell plant, albeit at a somewhat lower price (IEC Reply Brief at 3).

With regard to IEC's claims that the accounting for the sale of the Martinka assets and liabilities was improper, IEC presented the expert testimony of William J. Barta and alleged five errors. First, IEC argues that the divestiture should have been recorded as a disposal of a segment of a business, pursuant to Accounting Principles Board Opinion No. 30 (APBO 30) (IEC Brief at 37; IEC Ex. 1A, at 8-11). If APBO 30 had been followed, a significant gain would have been realized (IEC Ex. 1A, at 12). Second, Mr. Barta states that the journal entry of an accrual to recognize the settlement of the Tygart tunnel dispute overstated the liability because Ohio Power did not discount the settlement payments (IEC Ex. 1A, at 14). Third, several entries (those which recognize payment of prorated property taxes and accruals for layoff benefits and allowances for

United Mine Workers Association (UMWA) and non-UMWA Martinka employees) reflect a catch-up of expenses due to under-accruals in prior reporting periods (IEC Ex. 1A, at 15; Tr. IV, 27). Mr. Barta claims that these expenses were part of the mine's normal business activities and should have been recognized as operating costs in prior reporting periods and included in the overall costs rebilled to Ohio Power (*Id.*). Mr. Barta states that it was inappropriate to make a catch-up accrual entry for these expenses at the date of closing and, thereby, reduce the gain realized on the sale (IEC Ex. 1A, at 15).

***14** Fourth, the discharge of several obligations by Peabody (reclamation liabilities, water treatment liabilities, workers' compensation claims, post retirement medical benefits and other employee-related liabilities) were not recognized, but should have been (*Id.*). Mr. Barta states that the reclamation and water treatment liabilities should have been recognized as normal operating business activities, the costs of which should have been recovered through monthly accruals and rebilled to Ohio Power (*Id.* at 16). The discharge of the future liabilities should have been recognized as a contribution to the gain of the disposition of property and a reduction in outstanding liabilities (*Id.* at 16). Finally, Mr. Barta argues that Ohio Power's proposed treatment of the interest income associated with the sale (to offset the revenue requirement of Cove North) is improper (*Id.* at 21). The Cove North property has been reclassified as non-utility property (*Id.*). Mr. Barta states that, since the ratepayers have provided a return on and of capital on the Martinka assets through the EFC, they should be permitted to share in the interest income (*Id.* at 22). Mr. Barta recommended that a portion of the interest income be applied as a direct reduction to the monthly charges in the EFC, rather than off-setting on-going, non-utility costs (*Id.*).

IEC witness Mr. Kollen testified that, in his opinion, any gain recognized from the sale should be shared with the customers because past, present, and future affiliate coal costs are too high (Tr. V, 41-2). IEC suggested several regulatory options to the Commission, including:

1) a levelized EFC disallowance of the full Martinka Mine buy-out cost, ranging from $13.7 million to $16.1 million; FN7 2) reprice the Peabody coal purchases down by 10 ¢ /MBtu (based upon the 1991 Arch bid), thereby increasing the differential between the actual cost of fuel and the stipulated price cap, allowing additional recovery of the Meigs investment, and reducing the future cost of coal from the Meigs Mine; 3) a deferral of the Martinka Mine contract buy-out cost into Account 186 for later review in a rate base proceeding and reduce the recoverable Peabody coal contract costs to a reasonable level by excluding the annual premium for the Martinka Mine acquisition; 4) accelerate recovery of deferred fuel and Meigs Mine investment costs under the stipulation in the 1992 proceedings, by repricing the Peabody costs for EFC purposes, to reflect the exclusion of the costs shifted to the Peabody contract; 5) use some measure of gain that could have been recorded based upon the computations discussed by Mr. Barta or the excess of proceeds over the fair market value of the assets on a levelized basis to reduce recoverable fuel costs; and 6) use the imputed interest income from the sale of the mine to reduce recoverable fuel costs.

(IEC Brief at 49-50; IEC Reply Brief at 3; IEC Ex. 2A, at 18-9). IEC favors the first option listed above (IEC Brief at 51).

***15** OCC argues that the certainty and finality of the integrated transaction are questionable because it is unclear whether the integrated transaction was the sole method by which the Martinka Mine could be sold and because the financial auditor did not independently test the sale accounting entries (OCC Brief at 15-6). OCC states that IEC witness Kollen's position is flawed because he assumed all shut-down costs are included in the excessive portion of the coal contract price (OCC Reply Brief at 9). Moreover, OCC states that the Clean Air Act eliminated the sole source for the Martinka Mine coal and decreased the value of the mine, thus weakening any imprudence argument against Ohio Power (*Id.*). OCC agrees with IEC that whether the coal contract was excessive must be based upon a review of the reasonable market price for the types of coal purchased under the contract (*Id.* at 10). However, OCC finds that the data, upon which IEC relied to determine that the market prices, was outdated (*Id.*). OCC recommends that the Commission require Ohio Power to notify the Commission and the parties to this proceeding of any modification in future accounting for this transaction because of the complexity of the integrated transaction, the uncertainty in the record, and the difficulty of applying accounting principles to data that lack finality (OCC Brief at 16; OCC Reply Brief at 10).

Staff concurs with the m/p auditor's findings and stated that:

The Martinka "integrated" transaction represents a "win-win" for the Company and its ratepayers, by relieving [Ohio Power] of significant shut-down liabilities (for which it might otherwise seek recovery from EFC ratepayers), while lowering the costs of fuel for the Mitchell plant and ensuring timely compliance with Federal [Clean Air Act] emission limitations. The execution of the Peabody contract has enabled [Ohio Power] to solidify its compliance plans for Mitchell and ensure long-term supply reliability.

Staff Brief at 12.

Moreover, staff believes the evidence demonstrates that the price sought by FSD was consistent with the range of prices Ohio Power received in early 1991 for low sulphur coal suitable for use at the Gavin plant and that the Peabody contract price is reasonable (*Id.* at 8, 10). Also, staff noted that Ohio Power secured coal, which complies with the Clean Air Act, over the long-term from a reliable coal vendor before the market for such coal tightens (Staff Reply Brief at 4). Staff stated that IEC's witnesses lacked experience in coal markets, coal contracts, and coal mine valuation, thereby undermining the credibility and value of their testimony (*Id.* at 9). Specifically, staff argues that APBO 30 is not applicable to this transaction (*Id.* at 11). Staff also noted that the financial auditor felt that APBO 30 was inapplicable to the asset sale (Tr. VI, 8). Finally, staff argues that the record lacks sufficient information for the Commission to find that a gain should result from the asset sale because IEC presented no evidence of the dollar amount of the gain (Staff Brief at 12). Because staff concurred with the accounting treatment made by Ohio Power for the Martinka divestiture, staff specifically expressed no opinion with regard to the proper regulatory treatment that should be accorded any gain that might result from the sale or with regard to the applicability of Commission precedent (Staff Brief at 6 n.2). Accordingly, staff finds that the integrated transaction will benefit Ohio Power ratepayers and urges the Commission to so find (*Id.*).

***16** Ohio Power contends that the sale of the Martinka Mine and the Peabody contract were reasonable and prudent actions on its part (Ohio Power Brief at 2). Ohio Power points out that the IEC witnesses assumed that because the sale and coal contract were integrated, that the price paid for the Martinka assets could not have been representative of its fair market value (Tr. IV, 39-40). Ohio Power argues that IEC's witnesses initiated their analyses by assuming their ultimate conclusion and that the Commission should not rely upon such circular reasoning (Ohio Power Brief at 6).

Ohio Power countered IEC's claim that the cost of coal under the Peabody contract is excessive with evidence that it did a market price analysis and compared the Peabody coal price with the 1991 bids Ohio Power received for comparable coal (IEC Ex. 5; Tr. III, 27). Also, Ohio Power witness Paul Daley adjusted the 1991 bids for time, transportation costs, transportation penalties, and contract length (Ohio Power Ex. 3R, at 7-9). As a result, Mr. Daley found the market price to range from 147.2 to 150 ¢ /MBtu, while the price range under the Peabody contract is 147.8 to 150.3 ¢ /MBtu (*Id.* at 9).

Also, Ohio Power presented evidence that the mine may have particular value to Peabody because ownership of the mine enhanced the value of Peabody's ownership in the Guffey reserves, adjacent to the mine (Ohio Power Ex. 3R, at 4). Ohio Power also noted that Peabody can market Martinka coal to cogeneration projects, industrial customers, the export market, and the metallurgical markets (*Id.*). Ohio Power attempted to refute IEC's claim that FSD's maximum price for coal set a price floor and price ceiling with Mr. Kollen's acknowledgement that it was not an uncommon practice in his consulting business for various entities to indicate the amount of money they intend to spend (Tr. V, 55). Next, Ohio Power argues that Peabody clearly preferred to deliver coal only from its own mines, as opposed to third-party coal, to the Mitchell plant. However, some of that coal was unsuitable for the Mitchell plant, so Peabody offered to deliver some coal which was purchased from third parties (Tr. III, 98, 104; Tr. II, 138-140). Nevertheless, the third-party repriced coal accounts for a small portion of the total coal volume under the Peabody contract (Tr. III, 136, 139). Finally, Ohio Power states that IEC's suggestion that Ohio Power should have shut down the Martinka Mine, rather than integrate the asset sale with a coal purchase contract, makes no sense (Ohio Power Brief at 21). Mr. Ebetino stated that he suggested an integrated transaction to FSD management personnel on the belief that it would produce the best economics for ratepayers and Ohio Power and that the results show that an integrated transaction was the best, rather than shutting down the mine as IEC suggests (Tr. III, 45-6).

With regard to the accounting issues raised by OCC, Ohio Power does not believe that the accounting lacks finality or that any issues need to remain open. Furthermore, Ohio Power does not agree with any of the alleged errors raised by Mr. Barta. First, Ohio Power notes that APBO 30 does not apply to the sale of the mine because SOCCO was still in the mining industry and because records of the Martinka assets and operations which were sold were not separately maintained (Ohio Power Brief at 8-10; Ohio Power Ex. 12, at 3-5; Tr. VI, 16). Second, the accrual entry recognizing the Tygart tunnel dispute settlement did not overstate the liability. Mr. Campbell stated that, if the tunnel settlement had been discounted at the same rate as sale price of the Martinka Mine, as suggested by Mr. Barta, the total discount would have been $168,000 before taxes (Ohio Power Ex. 12, at 12). Mr. Campbell stated that this discount amount is immaterial in relation to the entire transaction and, therefore, no adjustment to the accounting entry is warranted (*Id.*). Third, Ohio Power states that the entries reflecting payment of taxes, layoff benefits, and UMWA and non-UMWA allowances all accrued as a result of the sale. Therefore, the entries are not catch-ups from under-accruals in prior reporting periods (*Id.* at 12-14; Tr. VI, 37-9).

***17** Fourth, Ohio Power contends that there is no accounting entry to record the assumption of liabilities by Peabody of reclamation, water treatment, and ultimate mine closure costs because current accounting rules and coal industry accounting practices do not require accrual of these costs (Ohio Power Ex. 12, at 6; Tr. VI, 25-6). Moreover, an alternative accounting treatment which recognizes any gain by the assumption of liabilities by Peabody would have no effect on the net income of the sale transaction because it would have been offset, dollar-for-dollar, by accruing the previously unrecognized costs (*Id.*). Also, Ohio Power states that liability for workers' compensation claims, all post-retirement medical benefits, and other employee related liabilities was not entirely assumed by Peabody (Ohio Power Ex. 12, at 15). Mr. Campbell testified that SOCCO is generally responsible for workers' compensation claims related to injuries which occurred before July 1, 1992 and SOCCO is still responsible for all of its retired employees' continuing post-retirement medical benefits (*Id.*). Finally, Ohio Power argues that, even if the sale would result in a gain, that gain would not be shared with the customer; the gain would go to the stockholders (Ohio Power Brief at 14). If the Commission determines that that contract price was unreasonable, Ohio Power recommends that the cost recovery level be adjusted (*Id.* at 15).

Therefore, Ohio Power states that the integrated transaction was prudent, the sale and contract prices are reasonable, there should not be any disallowance, and the Commission should not adopt any "regulatory options" suggested by IEC (Ohio Power Brief at 22; Ohio Power Ex. 3R, at 10).

IEC and Ohio Power do agree, however, that the Peabody coal contract must be reviewed, pursuant to Section 4909.191 (C), Revised Code, under the standard of "fair, just, and reasonable", rather than pursuant to Section 4905.01 (F), Revised Code, under which the price of affiliate coal must be reasonable when compared to the average cost per MBtu of similar quality contract coal (IEC Brief at 7; Ohio Power Reply Brief at 7). Ohio Power argues that, the Commission has previously rules, in the context of determining the reasonableness of affiliate coal, that:

[if] the total cost is reasonable then no investigation into the individual components which comprise that cost is warranted, unless the total cost includes payments for violations of laws or agency regulations, such as fines and penalties for violations of mine health and safety laws.

Ohio Power Company, Case No. 80-242-EL-FAC (March 11, 1981). See, also, *Indiana Michigan Municipal Distributors Association and City of Auburn, Indiana v. Indiana Michigan Power Company* , 62 FERC 62,237 (March 2, 1993). Ohio Power states the Commission should find, based upon the record in this matter, that the Peabody coal cost is at a fair market level and, therefore, is fair, just, and reasonable.

***18** Before addressing the matters raised by the parties on this issue, the Commission would first like to commend Ohio Power for its actions to divest its Martinka Mine. The Commission believes that appropriate divestiture can benefit Ohio Power ratepayers and Ohio Power. Nevertheless, the Commission must examine all aspects of the integrated transaction.[FN8]

The Commission finds that the record lacks sufficient evidence to determine the reasonableness of the price of coal under the Peabody contract when compared to a range of market prices for similar quality coal that could be delivered to and utilized at the Mitchell plant. If the price of coal under the Peabody contract is reasonable when compared to market prices, then no further investigation of the contract is needed, at least with respect to the Peabody price element as a successor to the Martinka contract price.

The company's efforts to substantiate the reasonableness of the Peabody price by comparison to the 1991 low sulphur fuel bids, modified as necessary for use at the Mitchell plant, were contradicted in a number of important respects by IEC, which in turn cited evidence of a Peabody "premium" between $5 million (10 ¢ /MBtu) to over $16 million (30 ¢ / MBtu) per year. Whether any premium exists in the Peabody contract needs further substantiation by reference to the above stated market price standard. If this additional evidence concludes there is a premium, the evidence should also estimate its size in a considerably narrower range than the threefold range of IEC. Moreover, it may not be sufficient, notwithstanding the stated position of the auditor and Ohio Power, for Ohio Power to demonstrate only that the Peabody contract price is better than the Martinka contract price. This is not, however, an issue that the Commission needs to address if the Peabody price satisfies the market price standard. If the Peabody price does not satisfy the market price standard, the parties should be prepared to address this additional issue at hearing and on brief. We believe that all aspects of the price issue should be addressed by the m/p auditor for the 1994 spring EFC proceeding.

The Commission also notes that the coal contract between Ohio Power and its affiliate, SOCCO, does not have a clause which permits Ohio Power to terminate the contract in the event that changes in the laws or regulations would make coal from the Martinka Mine unusable at the Mitchell plant. Without such a clause the risk of changes in the law seems to be placed upon Ohio Power, and perhaps also upon its customers, as a result of application of certain unavoidable legal mandates. If it is determined that the Peabody contract price includes a premium related to the Martinka sale, further review is required with regard to such "changes in the law/environmental" clauses. The Commission believes that this issue should also be addressed by the m/p auditor for the 1994 spring EFC case.

Specifically, the auditor should determine:

***19** 1) a range of fair market prices for coal of similar quality to that which was purchased by Ohio Power in the Peabody contract at the time the Peabody contract was entered into. This market analysis should be made to determine the price of coal without being integrated with a mine purchase agreement; 2) the industry standard with regard to inclusion of "changes in the law/environmental" clauses in long-term, high sulphur coal purchase transactions between non-affiliated entities; 3) what circumstances or considerations affecting long-term, high sulphur coal purchase transactions between non-affiliated parties usually determine which party, the seller or the buyer, is vested with the consequential risks and costs of "changes in the law/environmental" requirements; 4) the reasonableness of the ration between contract vs. spot purchases with the Peabody contract in place; 5) transportation options available to Ohio Power at the Mitchell plant during the life of the Peabody contract; 6) the purpose and reasonableness of the apparently unusual liquidated damages clause of the Peabody contract; and 7) Ohio Power's flexibility, during the life of the Peabody contract, to respond to changing conditions.

Any party to the 1994 spring EFC proceeding may provide evidence as to the fair market price for coal of similar quality to the Peabody contract coal. Accordingly, the Commission will refrain from determining the reasonableness of the sale of the Martinka Mine and the Peabody contract in this proceeding and will review these matters in Ohio Power's 1994 spring EFC proceeding. The record from this case should be incorporated into the record in the next case.

D. *Clean Air Act Compliance and Fuel Procurement Issues*

The Commission directed the m/p auditor to review fuel procurement issues related to Ohio Power's Clean Air Act compliance plan, which the Commission approved on November 25, 1992. [FN9] Little noted that Ohio Power (through AEPSC FSD) is taking steps to ensure a timely compliance with the Clean Air Act requirements. Little identified several issues, which it felt should be addressed in next year's audit. Those issues are:

1) a decision concerning where responsibility will rest within AEPSC concerning emission allowance trading; 2) steps to have Cardinal Unit 1 available for fuel switching; [FN10] 3) any conclusions AEPSC may reach regarding the capabilities of the Westinghouse Dispatch Program to perform environmental dispatch; and 4) any conclusions AEPSC may reach regarding the importance of emission allowances in the terms of interchange and other bulk power market activities.

(Comm. Ord. Ex. 2, at 18).

The Commission staff agrees with the m/p auditor that the above issues should be reviewed in next year's audit and recommends that the Commission direct the next m/p auditor to review such issues (Staff Brief at 19). IEC states that Ohio Power has taken no steps toward having Cardinal Unit 1 available for fuel switching in Phase I and that the Commission should advise Ohio Power that the "Commission 'says what it means and means what it says,' namely that AEP should fuel-switch Cardinal 1 in Phase I" (IEC Reply Brief at 25; Tr. II, 68).

***20** The Commission agrees that the issues raised by the m/p auditor regarding compliance with the Clean Air Act should be addressed in next year's audit. In the 1992 ECP proceeding, the Commission stated that Ohio Power "should take steps to have Cardinal Unit 1 available for fuel switching in Phase I, considering the low cost nature of such a compliance action" (Opinion and Order at 32). In the Entry on Rehearing, the Commission also stated that it would review Ohio Power's ongoing implementation efforts through the two-year review mechanism, as well as in EFC cases. Moreover, the Commission stated that, in subsequent fuel cases, it expected Ohio Power:

to demonstrate a reduced revenue requirement at least equal to the total revenue requirement benefit identified in this case resulting from a Cardinal fuel switch, which affects both fuel costs and the bank of SO2 allowances.

Id., Entry on Rehearing at 5 n.1. There has been no review or evidence presented by the auditor or the parties in this proceeding regarding fuel-switching Cardinal Unit 1. The Commission finds that the auditor and the staff should evaluate Ohio Power's efforts regarding Cardinal Unit 1 in next year's EFC case.

V. *The EFC Rate*

The EFC rate will cover the six-month current period of June 1, 1993 through November 30, 1993. The EFC rate will consist of a fuel component calculated pursuant to Rule 4901:1-14-04, O.A.C., a reconciliation adjustment (RA) calculated pursuant to Rule 4901:1-11-06, O.A.C., a system loss adjustment (SLA) calculated pursuant to Rule 4901:1-11-07, O.A.C., and an Ohio coal research and development component.

The EFC rate proposed by the company has been derived from five months of projected data and one month of actual data for the six-month base period of December 1, 1992 through May 31, 1993, and pursuant to the stipulation approved by the Commission in the 1992 EFC proceedings. The EFC rate proposed by Ohio Power is used by the company to compute the fuel charges rendered to jurisdictional customers during the six-month current period of June 1, 1993 through November 30, 1993. Based on the actual and projected data, the company has calculated a fuel component of 1.639980 ¢ /kWh; an RA rate of 0.060703 ¢ / kWh, which included a reconciliation of $1,465,757 in accordance with the 1992 EFC proceedings, [FN11] a reconciliation of ($28,856) recommended by the financial auditor, and an SLA of (0.045728) ¢ /kWh, using a 12-month rolling average of losses method (Company Ex. 4, at 6-8). Ohio Power states that, since the entire record from the hearing in the 1992 EFC proceedings has been incorporated into this record (Tr. VI, 121) and the Commission found, based upon that record, the stipulation to be reasonable, the Commission should find the effects of the stipulation on the EFC continue to be reasonable (Ohio Power Brief at 23-4). IEC contends that the stipulation is unlawful and unreasonable and has appealed the Commission's adoption of the stipulation. Instead of relitigating those issues in this proceeding, the record was incorporated into the record in this proceeding and IEC reserved its right to address those issues if the Ohio Supreme Court remands the 1992 EFC proceedings' order (IEC Brief at 59).

***21** In addition to the rate components above, the company has included in its calculations of the EFC rate a .1 ¢ /kWh for the recovery of OCRD costs (*Id* . at 6-7). Based upon the above, the company has calculated an EFC rate of 1.754955 ¢ /kWh (*Id.* at 9). The Commission finds that Ohio Power's proposed EFC rate should be adopted, subject to the Commission's subsequent determination of the allocation of the costs of the Tidd Project and the reasonableness of the sale of the Martinka Mine and the Peabody contract. [FN12] Ohio Power should file the EFC tariff rider setting forth the 1.754955 ¢ /kWh rate no later than May 28, 1993. The tariff rider should become effective with the company's June 1993 billing cycle and remain in effect until otherwise ordered by the Commission.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

1) Ohio Power is an electric light company within the meaning of Section 4905.03(A) (4), Revised Code, and as such, is a public utility subject to the jurisdiction and supervision of the Commission. Ohio Power is also an electric utility within the meaning of Rule 4901:1-11-01(L), O.A.C. 2) Section 4905.301, Revised Code, requires the Commission to review each electric utility's EFC at a hearing at least annually. By entries issued November 5, 1991 and July 23, 1992, the Commission initiated these proceedings to review Ohio Power's EFC and related matters. 3) Notice of this proceeding was published in accordance with the requirements of Section 4909.191 (A), Revised Code, and Rule 4901:1-11-11 (C), O.A.C. 4) The financial and m/p audits were performed in compliance with Section 4905.66 (B), Revised Code, and the provisions of Rule 4901:1-11-10, O.A.C. 5) The financial auditor found that, subject to a $28,856 reduction in the RA, Ohio Power's EFC rate was properly calculated and properly applied to customers' bills. 6) The m/p auditor found that fuel procurement, affiliate mine management, fuel utilization, and power dispatching were conducted with reasonable care. Also, the m/p auditor recommended that the Commission continue the current approach for allocating the costs of the Tidd project. Finally, the m/p auditor found the sale of the Martinka Mine and the accompanying Peabody coal contract to be prudent. 7) The next financial and m/p auditors should review those matters set forth in this Opinion and Order. 8) The EFC rate for the period June 1, 1993 through November 30, 1993 should be 1.754955 ¢ /kWh, subject to the Commission's subsequent determination of the allocation of the costs of the Tidd Project and the reasonableness of the sale of the Martinka Mine and the Peabody contract.

ORDER:

It is, therefore,

ORDERED, That the financial and m/p auditors for the company's next EFC audit review those matters set forth in this Opinion and Order. It is, further,

ORDERED, That the EFC rate to be charged by Ohio Power during the six-month period beginning June 1, 1993 be 1.754955 ¢ /kWh. It is, further,

ORDERED, That Ohio Power file its EFC tariff rider incorporating the EFC rate for the next current period no later than May 28, 1993. It is, further,

***22** ORDERED, That the EFC rider become effective with the company's June 1993 billing cycle and remain in effect until otherwise ordered by the Commission. It is, further,

ORDERED, That a copy of this Opinion and Order be served upon all parties of record.

FOOTNOTES

FN1. Ernst & Young recommended that the following methodology be used to reprice off-system sales: (1) define the numerical relationship between the average fuel cost per month at each of the four plants subject to the stipulation and the fuel cost for each month of Ohio Power-generated, off-system sales from each of the plants and (2) condition the incremental adjustment with the numerical relationship and add this fact to the original off-system sale cost.

FN2. Ernst & Young recommends the following methodology: (1) develop a numerical relationship between the average fuel cost (cents per kilowatt-hour (¢ /kWh) for each month and each plant and the fuel cost for each month of off-system sales, (2) using the relationship, condition the existing heat rate (developed from the plant-specific monthly MBtu and generation information) to develop a heat rate for the specific Ohio Power-generated, off-system sales, (3) apply the off-system sales heat rate to the generation levels for each of the plant-specific, off-system sales figure to determine MBtus, and (4) reprice these MBtus at 164 ¢ /MBtu.

FN3. Ohio Power is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). Another AEP subsidiary, American Electric Power Service Corporation (AEPSC), acts as fuel agent for Ohio Power. Fuel procurement is handled by AEPSC's Fuel Supply Department (FSD).

FN4. Little indicated that, with the Sands Hill contract, Ohio Power is beyond its contract versus spot purchases ratio and that Little will question FSD management as to why it determined to exceed its contract commitment policy (Comm. Ord. Ex. 2, at 35).

FN5. The Commission previously accepted a stipulation in the 1992 EFC proceedings which set the EFC rate at 164 ¢ /MBtu. IEC did not reargue its objections to the stipulation which were thoroughly considered in that case and which is now before the Ohio Supreme Court. The Commission reaffirms the reasonableness of that stipulation in this proceeding.

FN6. Peabody purchased all assets, except for the Cove North land and its mineral rights (Comm. Ord. Ex. 2, at 26; Tr. III, 54, 56).

FN7. Mr. Kollen measured the Martinka buy-out cost in two ways: (1) the calculation of liquidated damages ($13.7 million) and (2) the shutdown cost of $147 million, amortized on a levelized basis, at an assumed cost of capital of ten percent to Peabody ($16.1 million) (IEC Ex. 2A, at 17).

FN8. As discussed *infra*, appropriate divestiture of AEP's other mines not covered by the stipulation in the 1992 EFC proceedings could lead to lower fuel costs and the end of protracted litigation, while still protecting the interests of AEP's shareholders and maintaining the use of Ohio coal. We expect AEP to continue pursuing this path while we review the Martinka transaction in the next EFC case.

FN9. See, *In the Matter of the Application of Ohio Power Company for Approval of an Environmental Compliance Plan Pursuant to Chapter 4913, Revised Code*, Case No. 92-790-EL-ECP (1992 ECP proceeding).

FN10. Little indicated that it is can review this issue in next year's audit, but it is not clear whether AEPSC management can make a decision with respect to Cardinal Unit 1 or whether the Commission must first approve any actions.

FN11. The weighted average delivered cost of fuel during the audit period was 154.73 ¢ /MBtu (Comm. Ord. Ex. 2, at 5).

FN12. The Commission notes that although the subsequent determination on the sale of the Martinka Mine and the Peabody contract will not have an affect on the EFC rate set in this proceeding due to the stipulated price of coal burned at Mitchell, such a determination could affect the acceleration of recovery of the Ohio Proportionate Jurisdiction Share of Meigs affiliate mining operations' investment and related liabilities and direct closure-related costs.

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Re Trading and Usage of the Accounting Treatment for Emissions Allowances by Electric
Case No. 91-2155-EL-COI

Ohio Public Utilities Commission
May 13, 1993

Before Glazer, chairman, and Biddison, Butler, Fanelly, and Johnson, commissioners.

BY THE COMMISSION:

ENTRY ON APPLICATION FOR REHEARING

***1** THE COMMISSION FINDS:

1) In an Entry in this case dated March 25, 1993, this Commission adopted and issued guidelines relating to the subject of emission allowance trading and usage.

2) On April 23, 1993, the Industrial Energy Users-Ohio and the Ohio Manufacturers' Association (Collectively IEU-OMA) and the Office of Consumers' Counsel (OCC) filed applications for rehearing. Each of these applications will be discussed below.

3) On May 3, 1993, Ohio Edison Company and The Dayton Power & Light Company (DP&L) filed memoranda contra the applications for rehearing.

4) IEU-OMA allege that the Commission erred:

a) by not stating and discussing its support for the conclusions that the guidelines would " . . . encourage, as much as possible, the timely emergence of a viable allowance trading market", thereby violating Section 4903.09, Revised Code.

b) in failing to disclose the facts relied upon and the reasoning followed in concluding that generic action is warranted in this proceeding, again violating Section 4903.09, Revised Code.

c) by failing to identify the source of its authority to issue the guidelines and the effect of such guidelines.

d) by failing to address the filed comments concerning the proposed use of the Commission's EFC mechanism for emission allowance cost recovery.

e) by allowing the recovery of emission allowance costs through the EFC mechanism though the Commission understood emission allowances are "non-fuel" items.

f) in adopting guideline 4, to the extent that this guideline permits recovery of emission allowance costs through the EFC mechanism in plain violation of statutory requirements.

5) In its application for rehearing OCC alleges that the Commission erred in two instances:

a) by authorizing the recovery of costs relating to emission allowance trading through the EFC mechanism, and

b) by permitting the accrual of carrying charges on banked allowances.

6) We have reviewed the allegations of error contained in each of the applications for rehearing and find that they lack merit. Contrary to allegations made by both IEU-OMA (allegations of error 4e and f) and OCC (allegation of error 5a), this Commission has statutory authority to permit the pass through of the costs under discussion. These costs are, as stated by the Commission in our March 25, 1993, Entry, acquisition and delivery costs of fuel. FN1 As DP&L notes in it memorandum contra, in theory, at least, the market has factored the value of the allowances into the price of coal, i.e., "the premium for lower sulfur coal should equate to the

cost of high sulfur coal plus the cost of the allowances necessary to burn the high sulfur coal in compliance with the Clean Air Act Amendments of 1990 (CAA)." (at page 4). Thus, as viewed by the Commission and argued by DP&L, the allowances are integral to the burning of high sulfur coal in compliance with the CAA. Regardless, pursuant to Section 4905.301, Revised Code:

*2 Nothing in this section shall preclude the use of a fuel component that creates positive efficiency incentives for minimizing the costs of electric service.

We believe that positive efficiency incentives include the recovery of costs associated with allowance trading through the EFC mechanism. The guidelines are designed to provide the utility the positive incentive of timely recovery of costs. Further, the guidelines assure efficiency through the review conducted in the individual utility's Environmental Compliance Plan and Integrated Resource Plan proceedings to determine whether the purchase of allowances is the least cost approach to environmental compliance. Further, timely recovery serves to reduce the carrying costs and transaction costs of allowance trading and utilization. Finally, the timely recovery of costs serves as an incentive to the utility to act in the ratepayers' interests. Prior to the utility's recovery of the costs associated with allowance trading, however, the Commission will conduct what is, in effect, a prudence review of the utility's operations through the EFC audit and hearing process to determine that the utility is purchasing allowances pursuant to its already approved IRP or ECP.

The Commission is also unpersuaded by IEU-OMA's allegations of error 4c and d. The Commission is of the opinion that the source of our authority is obvious, i.e. Sections 4905.01 and 4905.301, Revised Code, and cases such as *Consumers' Counsel v. Pub. Util. Comm.*, 63 O. St. 3rd 531 (1992) and *Consumers' Counsel v. Pub. Util. Comm.*, 56 O. St. 2nd 319 (1978). It is not required, as implied by IEU-OMA, that we address each and every comment to a Commission proposal.

IEU-OMA's allegations of error 4a and b are inapt. It was clear to the Commission early on in these proceedings that the biggest impediment to the development of a viable allowance trading market was regulatory uncertainty. The purpose of the guidelines was to establish that certainty required so that utilities under the Commission's jurisdiction could proceed with emissions allowance trading. As was noted in our March 25, 1993 Entry, these are guidelines, not rules. We have established a safe haven. Rules would require a utility to act in a certain way. Guidelines permit utilities to act in a certain way with confidence as to what the procedure to be employed is and the criteria to be used in judging the utility's performance are. Guidelines, in that they are not rules, permit a utility to propose a different procedure or set of criteria.

Finally, OCC contends that it is error to permit carrying charges in the case of trading allowances when we do not permit this treatment in the case of coal. OCC states that "[b]ecause the Commission considers allowance costs to be acquisition and delivery costs of fuel, it is inconsistent for the Commission to treat allowance costs more favorably than coal costs." We intend to treat allowance costs in the same manner as we treat coal costs on an ongoing basis. The authorization of carrying charges is a recognition that these allowance costs are in the first instance a shareholder expenditure, an expenditure on which the shareholder requires a return if the guidelines are not to serve as a disincentive for the utility to enter the emissions trading market. The Commission will treat allowance costs like coal costs after the first rate case for each utility in which these costs are considered.

*3 7) For the reasons set forth in Finding 6, above, the applications of IEU-OMA and OCC for a rehearing, filed in this case on April 23, 1993, should be denied.

It is, therefore,

ORDERED, That the applications of IEU-OMA and OCC for a rehearing filed in this case on April 23, 1993 be denied. It is, further,

ORDERED, That a copy of this Entry be served upon each electric light company under the jurisdiction of this Commission, upon anyone who has filed comments in this case, and upon any other person or entity interested in these proceedings.

FOOTNOTES

FN1 IEU-OMA cite in support of their argument that the Federal Energy Regulatory Commission (FERC) has determined that these costs are not fuel costs for FERC accounting purpose. We reviewed this issue and found that, while interesting, the FERC's determination is not helpful in the matter of cost recovery. FERC's intent was "to provide useful financial and statistical information to users of a utility's financial statements by establishing uniform accounting and reporting requirements for allowance transactions. The [FERC] rule is 'rate neutral' in that the prescribed accounting reflects the economic effects of whatever ratemaking treatment is granted. The rule does not dictate or favor one particular rate treatment over another."Adopting FERC's rules without adapting them to Ohio's circumstances would be to have the accounting rules determine the method of recovery. This is not the function of accounting. Accounting should follow the determination not drive it. While FERC has issued accounting rules, it is up to the states to determine the method of cost recovery. This Commission has done so. We are now reviewing the FERC's accounting rules to determine if they can be adapted to our circumstances.

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4901:1-35-03 Filing and contents of applications.

Each electric utility in this state filing an application for a standard service offer (SSO) in the form of an electric security plan (ESP), a market-rate offer (MRO), or both, shall comply with the requirements set forth in this rule.

(A) SSO applications shall be case captioned as (XX-XXX-EL-SSO). Twenty copies plus an original of the application shall be filed. The application must include a complete set of direct testimony of the electric utility personnel or other expert witnesses. This testimony shall be in question and answer format and shall be in support of the electric utility's proposed application. This testimony shall fully support all schedules and significant issues identified by the electric utility.

(B) An SSO application that contains a proposal for an MRO shall comply with the requirements set forth below.

(1) The following electric utility requirements are to be demonstrated in a separate section of the standard service offer SSO application proposing a market-rate offer MRO:

(a) The electric utility shall establish one of the following: that it, or its transmission affiliate, belongs to at least one regional transmission organization (RTO) that has been approved by the federal energy regulatory commission; or, if the electric utility or its transmission affiliate does not belong to an RTO, then the electric utility shall demonstrate that alternative conditions exist with regard to the transmission system, which include non-pancaked rates, open access by generation suppliers, and full interconnection with the distribution grid.

(b) The electric utility shall establish one of the following: its RTO retains an independent market-monitor function and has the ability to identify any potential for a market participant or the electric utility to exercise market power in any energy, capacity, and/or ancillary service markets by virtue of access to the RTO and the market participant's data and personnel and has the ability to effectively mitigate the conduct of the market participants so as to prevent or preclude the exercise of such market power by any market participant or the electric utility; or the electric utility shall demonstrate that an equivalent function exists which can monitor, identify, and mitigate conduct associated with the exercise of such market power.

(c) The electric utility shall demonstrate that an independent and reliable source of electricity pricing information for any energy product or service necessary for a winning bidder to fulfill the contractual obligations resulting from the competitive bidding process (CBP) is publicly available. The information may be offered through a pay subscription service, but the pay subscription service shall be available under standard pricing, terms, and conditions to any person requesting a subscription. The published information shall be representative of prices and changes in prices in the electric utility's electricity market, and shall identify pricing of on-peak and off-peak energy products that represent contracts for delivery, encompassing a time frame beginning at least two years from the date of the publication. The published information shall be updated on at least a monthly basis.

(2) Prior to establishing an MRO under division (A) of section 4928.142 of the Revised Code, an electric utility shall file a plan for a CBP with the commission. The electric utility shall provide justification of its proposed CBP plan, considering alternative possible methods of procurement. Each CBP plan that is to be used to establish an MRO shall include the following:

(a) A complete description of the CBP plan and testimony explaining and supporting each aspect of the CBP plan. The description shall include a discussion of any relationship between the wholesale procurement process and the retail rate design that may be proposed in the CBP plan. The description shall include a discussion of alternative methods of procurement that were considered and the rationale for selection of the CBP plan being presented. The description shall also include an explanation of every proposed non-avoidable charge, if any, and why the charge is proposed to be non -avoidable.

(b) Pro forma financial projections of the effect of the CBP plan's implementation, including implementation of division (D) of section 4928.142 of the Revised Code, upon generation, transmission, and distribution of the electric utility, for the duration of the CBP plan.

(c) Projected generation, transmission, and distribution rate impacts by customer class and rate schedules for the duration of the CBP plan. The electric utility shall clearly indicate how projected bid clearing prices used for this purpose were derived.

(d) Detailed descriptions of how the CBP plan ensures an open, fair, and transparent competitive solicitation that is consistent with and advances the policy of this state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code.

(e) Detailed descriptions of the customer load(s) to be served by the winning bidder(s), and any known factors that may affect such customer loads. The descriptions shall include, but not be limited to, load subdivisions defined for bidding purposes, load and rate class descriptions, customer load profiles that include historical hourly load data for each load and rate class for at least the two most recent years, applicable tariffs, historical shopping data, and plans for meeting targets pertaining to load reductions, energy efficiency, renewable energy, advanced energy, and advanced energy technologies. If customers will be served pursuant to time-differentiated or dynamic pricing, the descriptions shall include a summary of available data regarding the price elasticity of the load. Any fixed load provides to be served by winning bidder(s) shall be described.

(f) Detailed descriptions of the generation and related services that are to be provided by the winning bidder(s). The descriptions shall include, at a minimum, capacity, energy, transmission, ancillary and resource adequacy services, and the term during which generation and related services are to be provided. The descriptions shall clearly indicate which services are to be provided by the winning bidder(s) and which services are to be provided by the electric utility.

(g) Draft copies of all forms, contracts, or agreements that must be executed during or upon completion of the CBP.

(h) A clear description of the proposed methodology by which all bids would be evaluated, in sufficient detail so that bidders and other observers can ascertain the evaluated result of any bids or potential bids.

(i) The CBP plan shall include a discussion of time-differentiated pricing, dynamic retail pricing, and other alternative retail rate options that were considered in the development of the CBP plan. A clear description of the rate structure ultimately chosen by the electric utility, the electric utility's rationale for selection of the chosen rate structure, and the methodology by which the electric utility proposes to convert the winning bid(s) to retail rates of the electric utility shall be included in the CBP plan.

(j) The first application for a market rate offer by an electric utility that, as of July 31, 2008, directly owned, in whole or in part, operating electric generation facilities that had been used and useful in this state shall include a description of the electric utility's proposed blending of the CBP rates for the first five years of the market rate offer pursuant to division (D) of section 4928.142 of the Revised Code. The proposed blending shall show the generation service price(s) that will be blended with the CBP determined rates, and any descriptions, formulas, and/or tables necessary to show how the blending will be accomplished. The proposed blending shall show all adjustments, to be made on a quarterly basis, included in the generation service price(s) that the electric utility proposes for changes in costs of fuel, purchased power, portfolio requirements, and environmental compliance incurred during the blending period. The electric utility shall provide its best current estimate of anticipated adjustment amounts for the duration of the blending period, and compare the projected adjusted generation service prices under the CBP plan to the projected adjusted generation service prices under its proposed electric security plan.

(k) The electric utility's application to establish a CBP shall include such information as necessary to demonstrate whether or not, as of July 31, 2008, the electric utility directly owned, in whole or in part, operating electric generation facilities that had been used and useful in the state of Ohio.

(l) The CBP plan shall provide for funding of a consultant that may be selected by the commission to assess and report to the commission on the design of the solicitation, the oversight of the bidding process, the clarity of the product definition, the fairness, openness, and transparency of the solicitation and bidding process, the market factors that could affect the solicitation, and other relevant criteria as directed by the commission. Recovery of the cost of such consultant(s) may be included by the electric utility in its CBP plan.

(m) The CBP plan shall include a discussion of generation service procurement options that were considered in development of the CBP plan, including but not limited to, portfolio approaches, staggered procurement, forward procurement, electric utility participation in day-ahead and/or real-time balancing markets, and spot market purchases and sales. The CBP plan shall also include the rationale for selection of any or all of the procurement options.

(n) The electric utility shall show, as a part of its CBP plan, any relationship between the CBP plan and the electric utility's plans to comply with alternative energy portfolio requirements of section 4928.64 of the Revised Code, and energy efficiency requirements and peak demand reduction requirements of section 4928.66 of the Revised Code. The initial filing of a CBP plan shall include a detailed account of how the plan is consistent with and advances the policy of this state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code. Following the initial filing, subsequent filings shall include a discussion of how the state policy continues to be advanced by the plan.

(o) An explanation of known and anticipated obstacles that may create difficulties or barriers for the adoption of the proposed bidding process.

(3) The electric utility shall provide a description of its corporate separation plan, adopted pursuant to section 4928.17 of the Revised Code, including but not limited to, the current status of the corporate separation plan, a detailed list of all waivers previously issued by the commission to the electric utility regarding its corporate separation plan, and a timeline of any anticipated revisions or amendments to its current corporate separation plan on file with the commission pursuant to Chapter 4901:1-37 of the Administrative Code.

(4) A description of how the electric utility proposes to address governmental aggregation programs and implementation of divisions (I) and (K) of section 4928.20 of the Revised Code.

(C) An SSO application that contains a proposal for an ESP shall comply with the requirements set forth below.

(1) A complete description of the ESP and testimony explaining and supporting each aspect of the ESP.

(2) Pro forma financial projections of the effect of the ESP's implementation upon the electric utility for the duration of the ESP, together with testimony and work papers sufficient to provide an understanding of the assumptions made and methodologies used in deriving the pro forma projections.

(3) Projected rate impacts by customer class/rate schedules for the duration of the ESP, including post -ESP impacts of deferrals, if any.

(4) The electric utility shall provide a description of its corporate separation plan, adopted pursuant to section 4928.17 of the Revised Code, including, but not limited to, the current status of the corporate separation plan, a detailed list of all waivers previously issued by the commission to the electric utility regarding its corporate separation plan, and a timeline of any anticipated revisions or amendments to its current corporate separation plan on file with the commission pursuant to Chapter 4901:1-37 of the Administrative Code.

(5) Division (A)(3) of section 4928.31 of the Revised Code required each electric utility to file an operational support plan as a part of its electric transition plan. Each electric utility shall provide a statement as to whether its operational support plan has been implemented and whether there are any outstanding problems with the implementation.

(6) A description of how the electric utility proposes to address governmental aggregation programs and implementation of divisions (I), (J), and (K) of section 4928.20 of the Revised Code.

(7) A description of the effect on large-scale governmental aggregation of any unavoidable generation charge proposed to be established in the ESP.

(8) The initial filing for an ESP shall include a detailed account of how the ESP is consistent with and advances the policy of this state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code. Following the initial filing, subsequent filings shall include how the state policy is advanced by the ESP.

(9) Specific information

Division (B)(2) of section 4928.143 of the Revised Code authorizes the provision or inclusion in an ESP of a number of features or mechanisms. To the extent that an electric utility includes any of these features in its ESP, it shall file the corresponding information in its application.

(a) Division (B)(2)(a) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for the automatic recovery of fuel, purchased power, and certain other specified costs. An application including such provisions shall include, at a minimum, the information described below:

(i) The type of cost the electric utility is seeking recovery for under division (B)(2) of section 4928.143 of the Revised Code including a summary and detailed description of such cost. The description shall include the plant(s) that the cost pertains to as well as a narrative pertaining to the electric utility's procurement policies and procedures regarding such cost.

(ii) The electric utility shall include in the application any benefits available to the electric utility as a result of or in connection with such costs including but not limited to profits from emission allowance sales and profits from resold coal contracts.

(iii) The specific means by which these costs will be recovered by the electric utility. In this specification, the electric utility must clearly distinguish whether these costs are to be recovered from all distribution customers or only from the customers taking service under the ESP.

(iv) A complete set of work papers supporting the cost must be filed with the application. Work papers must include, but are not limited to, all pertinent documents prepared by the electric utility for the application and a narrative and other support of assumptions made in completing the work papers.

(b) Divisions (B)(2)(b) and (B)(2)(c) of section 4928.143 of the Revised Code, authorize an electric utility to include unavoidable surcharges for construction, generation, or environmental expenditures for electric generation facilities owned or operated by the electric utility. Any plan which seeks to impose surcharge under these provisions shall include the following sections, as appropriate:

(i) The application must include a description of the projected costs of the proposed facility. The need for the proposed facility must have already been reviewed and determined by the commission through an integrated resource planning process filed pursuant to rule 4901:5-5-05 of the Administrative Code.

(ii) The application must also include a proposed process, subject to modification and approval by the commission, for the competitive bidding of the construction of the facility unless the commission has previously approved a process for competitive bidding, which would be applicable to that specific facility.

(iii) An application which provides for the recovery of a reasonable allowance for construction work in progress shall include a detailed description of the actual costs as of a date certain for which the applicant seeks recovery, a detailed description of the impact upon rates of the proposed surcharge, and a demonstration that such a construction work in progress allowance is consistent with the applicable limitations of division (A) of section 4909.15 of the Revised Code.

(iv) An application which provides recovery of a surcharge for an electric generation facility shall include a detailed description of the actual costs, as of a date certain, for which the applicant seeks recovery and a detailed description of the impact upon rates of the proposed surcharge.

(v) An application which provides for recovery of a surcharge for an electric generation facility shall include the proposed terms for the capacity, energy, and associated rates for the life of the facility.

(c) Division (B)(2)(d) of section 4928.143 of the Revised Code authorizes an electric utility to include terms, conditions, or charges related to retail shopping by customers. Any application which includes such terms, conditions or charges, shall include, at a minimum, the following information:

(i) A listing of all components of the ESP which would have the effect of preventing, limiting, inhibiting, or promoting customer shopping for retail electric generation service. Such components would include, but are not limited to, terms and conditions relating to shopping or to returning to the standard service offer and any unavoidable charges. For each such component, an explanation of the component and a descriptive rationale and, to the extent possible, a quantitative justification shall be provided.

(ii) A description and quantification or estimation of any charges, other than those associated with generation expansion or environmental investment under divisions (B)(2)(b) and (B)(2)(c) of section 4928.143 of the Revised Code, which will be deferred for future recovery, together with the carrying costs, amortization periods, and avoidability of such charges.

(iii) A listing, description, and quantitative justification of any unavoidable charges for standby, back-up, or supplemental power.

(d) Division (B)(2)(e) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for automatic increases or decreases in any component of the standard service offer price. Pursuant to this authority, if the ESP proposes automatic increases or decreases to be implemented during the life of the plan for any component of the standard service offer, other than those covered by division (B)(2)(a) of section 4928.143 of the Revised Code, the electric utility must provide in its application a description of the component, the proposed means for changing the component, and the proposed means for verifying the reasonableness of the change.

(e) Division (B)(2)(f) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for the securitization of authorized phase-in recovery of the standard service offer price. If a phase-in deferred asset is proposed to be securitized, the electric utility shall provide, at the time of an application for securitization, a description of the securitization instrument and an accounting of that securitization, including the deferred cash flow due to the phase-in, carrying charges, and the incremental cost of the securitization. The electric utility will also describe any efforts to minimize the incremental cost of the securitization. The electric utility shall provide all documentation associated with securitization, including but not limited to, a summary sheet of terms and conditions. The electric utility shall also provide a comparison of costs associated with securitization with the costs associated with other forms of financing to demonstrate that securitization is the least cost strategy.

(f) Division (B)(2)(g) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions relating to transmission and other specified related services. Moreover, division (A)(2) of section 4928.05 of the Revised Code states that, notwithstanding Chapters 4905. and 4909. of the Revised Code, commission authority under this chapter shall include the authority to provide for the recovery, through a reconcilable rider on an electric distribution utility's distribution rates, of all transmission and transmission-related costs (net of transmission related revenues), including ancillary and net congestion costs, imposed on or charged to the utility by the federal energy regulatory commission or a regional transmission organization, independent transmission operator, or similar organization approved by the federal energy regulatory commission.

Any utility which seeks to create or modify its transmission cost recovery rider in its ESP shall file the rider in accordance with the requirements delineated in Chapter 4901:1-36 of the Administrative Code.

(g) Division (B)(2)(h) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for alternative regulation mechanisms or programs, including infrastructure and modernization incentives, relating to distribution service as part of an ESP. While a number of mechanisms may be combined within a plan, for each specific mechanism or program, the electric utility shall provide a detailed description, with supporting data and information, to allow appropriate evaluation of each proposal, including how the proposal addresses any cost savings to the electric utility, avoids duplicative cost recovery, and aligns electric utility and consumer interests. In general, and to the extent applicable, the electric utility shall also include, for each separate mechanism or program, quantification of the estimated impact on rates over the term of any proposed modernization plan. Any application for an infrastructure modernization plan shall include the following specific requirements:

(i) A description of the infrastructure modernization plan, including but not limited to, the electric utility's existing infrastructure, its existing asset management system and related capabilities, the type of technology and reason chosen, the portion of service territory affected, the percentage of customers directly impacted (non-rate impact), and the implementation schedule by geographic location and/or type of activity. A description of any communication infrastructure included in the infrastructure modernization plan and any metering, distribution automation, or other applications that may be supported by this communication infrastructure also shall be included.

(ii) A description of the benefits of the infrastructure modernization plan (in total and by activity or type), including but not limited to the following as they may apply to the plan: the impacts on current reliability, the number of circuits impacted, the number of customers impacted, the timing of impacts, whether the impact is on the frequency or duration of outages, whether the infrastructure modernization plan addresses primary outage causes, what problems are addressed by the infrastructure modernization plan, the resulting dollar savings and additional costs, the activities affected and related accounts, the timing of savings, other customer benefits, and societal benefits. Through metrics and milestones, the infrastructure modernization plan shall include a description of how the performance and outcomes of the plan will be measured.

(iii) A detailed description of the costs of the infrastructure modernization plan, including a breakdown of capital costs and operating and maintenance expenses net of any related savings, the revenue requirement, including recovery of stranded investment related to replacement of un-depreciated plant with new technology, the impact on customer bills, service disruptions associated with plan implementation, and description of (and dollar value of) equipment being made obsolescent by the plan and reason for early plant retirement. The infrastructure modernization plan shall also include a description of efforts made to mitigate such stranded investment.

(iv) A detailed description of any proposed cost recovery mechanism, including the components of any regulatory asset created by the infrastructure modernization plan, the reporting structure and schedule, and the proposed process for approval of cost recovery and increase in rates.

(v) A detailed explanation of how the infrastructure modernization plan aligns customer and electric utility reliability and power quality expectations by customer class.

(h) Division (B)(2)(i) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for economic development, job retention, and energy efficiency programs. Pursuant to this section, the electric utility shall provide a complete description of the proposal, together with cost-benefit analysis or other quantitative justification, and quantification of the program's projected impact on rates.

(10) Additional required information

Divisions (E) and (F) of section 4928.143 of the Revised Code provide for tests of the ESP with respect to significantly excessive earnings. Division (E) of section 4928.143 of the Revised Code is applicable only if an ESP has a term exceeding three years, and would require an earnings determination to be made in the fourth year. Division (F) of section 4928.143 of the Revised Code applies to any ESP and examines earnings after each year. In each case, the burden of proof for demonstrating that the return on equity is not significantly excessive is borne by the electric utility.

(a) For the annual review pursuant to division (F) of section 4928.143 of the Revised Code, the electric utility shall provide testimony and analysis demonstrating the return on equity that was earned during the year and the returns on equity earned during the same period by publicly traded companies that face comparable business and financial risks as the electric utility. In addition, the electric utility shall provide the following information:

(i) The federal energy regulatory commission form 1 (FERC form 1) in its entirety for the annual period under review. The electric utility may seek protection of any confidential or proprietary data if necessary. If the FERC form 1 is not available, the electric utility shall provide balance sheet and income statement information of at least the level of detail as required by FERC form 1.

(ii) The latest securities and exchange commission form 10-K in its entirety. The electric utility may seek protection of any confidential or proprietary data if necessary.

(iii) Capital budget requirements for future committed investments in Ohio for each annual period remaining in the ESP.

(b) For demonstration under division (E) of section 4928.143 of the Revised Code, the electric utility shall also provide, in addition to the requirements under division (F) of section 4928.143 of the Revised Code, calculations of its projected return on equity for each remaining year of the ESP. The electric utility shall support these calculations by providing projected balance sheet and income statement information for the remainder of the ESP, together with testimony and work papers detailing the methodologies, adjustments, and assumptions used in making these projections.

(D) The first application for an SSO filed after the effective date of section 4928.141 of the Revised Code by each electric utility shall include an ESP and shall be filed at least one hundred fifty days before the electric utility proposes to have such SSO in effect. The first application may also include a proposal for an MRO. First applications that are filed with the commission prior to the initial effective date of this rule and that are determined by the commission to be not in substantive compliance with this rule shall be amended or refiled at the direction of the commission. The commission shall endeavor to make a determination on an amended or refiled ESP application, which substantively conforms to the requirements of this rule, within one hundred fifty days of the filing of the amended or refiled application.

(E) Subsequent applications for an SSO may include an ESP and/or MRO; however, an ESP may not be proposed once the electric utility has implemented an MRO approved by the commission.

(F) The SSO application shall include a section demonstrating that its current corporate separation plan is in compliance with section 4928.17 of the Revised Code, Chapter 4901:1-37 of the Administrative Code, and consistent with the policy of the state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code. If any waivers of the corporate separation plan have been granted and are to be continued, the applicant shall justify the continued need for those waivers.

(G) A complete set of work papers must be filed with the application. Work papers must include, but are not limited to, all pertinent documents prepared by the electric utility for the application and a narrative or other support of assumptions made in the work papers. Work papers shall be marked, organized, and indexed according to schedules to which they relate. Data contained in the work papers should be footnoted so as to identify the source document used.

(H) All schedules, tariff sheets, and work papers prepared by, or at the direction of, the electric utility for the application and included in the application must be available in spreadsheet, word processing, or an electronic non-image-based format, with formulas intact, compatible with personal computers. The electronic form does not have to be filed with the application but must be made available within two business days to staff and any intervening party that requests it.

Replaces: 4901:1-35-03

Effective: 05/07/2009

R.C. 119.032 review dates: 09/30/2013

Promulgated Under: 111.15

Statutory Authority: 4928.06, 4928.141

Rule Amplifies: 4928.14, 4928.141, 4928.142, 4928.143

Prior Effective Dates: 5/27/04

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FILE

EXHIBIT NO._________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets	)	Case No. 08- 917-EL-~~UNC~~ SSO
and	)	
In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan	)	Case No. 08- 918-EL-~~UNC~~ SSO

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

Filed: July 31, 2008

component of Account 501 fuel. Purchased power was limited to the fuel component of "economic" purchased power. This definition is used to calculate the cost to the internal customer (Net Energy Cost or NEC). Without going into great detail, the EFC followed the FERC fuel clause definition and limited the items in the fuel clause to the narrow NEC definition of fuel. For instance fuel handling, (Account 152) which clears to Account 501 (fuel) was not includible. Likewise purchased power demand charges or capacity payments were not includible. The EFC did, however, include certain environmental items such as emission allowance consumption expense, and gains on the sale of allowances and research and development expenditures for new clean coal technology.

Q. ARE THE COMPANIES PROPOSING TO REESTABLISH THAT EFC METHODOLOGY?

A. No. S.B. 221 provides for a broader cost-based adjustment that includes all prudently incurred fuel, purchased power, and environmental components in an ESP. The Companies believe that it is reasonable and efficient to include all these components in a single cost recovery mechanism rather than have separate clauses for each. The costs the Companies are proposing to include are variable costs directly related to energy produced or purchased to serve the internal load customer. The Companies are not proposing to include the capital carrying costs on environmental capital in the FAC. Company witness Mr. Baker addresses the recovery of those capital carrying costs in his testimony.

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data is a reasonable, albeit conservative, method of establishing the other FAC components for the base period.

FORECAST OF FAC COSTS

Q. ARE COSTS THAT THE COMPANIES ARE SEEKING TO RECOVER IN THE FAC EXPECTED TO BE HIGHER THAN THE ADJUSTED FUEL COMPONENT OF THE COMPANIES' MOST RECENT SSO RATES DEVELOPED AS DESCRIBED ABOVE?

A. Yes. The Companies expect fuel and environmental costs to be substantially higher than the fuel rates in our most recent SSO. Recent prices for fuel have increased dramatically. Since the Companies have much of their fuel supply under contracts they have some protection from the increases. Unfortunately, however, as they expire lower cost contracts are being replaced by much higher cost contracts. Also, environmental variable costs continue to increase. While allowance expense for the Companies has come down in recent years due to the addition of environmental controls, the operating expenses (consumables) of the environmental controls at the generating plants are climbing rapidly. Since the FAC will include emission allowance costs, as well as the gains from the sale of allowances, the benefits of the lower allowance requirements associated with environmental controls will be reflected in the customers' rates.

Q. HOW DID THE COMPANIES CALCULATE THE FAC CHARGE THEY ARE PROPOSING IN THIS PROCEEDING?

A. The Companies have projected 2009 costs for the NEC, those environmental items in the prior EFC, and the additional cost items to be included in the FAC. These costs were assigned to internal load and off-system uses, as explained below in more detail. The NEC off-system uses include off-system sales to non-AEP entities as well as to other AEP operating companies. For example OPCO's sales of energy to CSP though the FERC-approved AEP Interconnection Agreement (AEP Pool) is an off-system use for OPCO. The total FAC costs less those assigned off-system, results in the costs for the internal load. The internal load costs, determined for each Company, are divided by the internal load MWh to develop a 2009 rate. The same methodology was used to establish the FAC rate in the most recent SSO.

ALLOCATION FACTORS

Q. HOW ARE THE ALLOCATION FACTORS DEVELOPED TO ASSIGN THE COSTS TO INTERNAL LOAD?

A. Off-system Sales (OSS) of energy to non-AEP companies for the NEC component of fuel cost is determined by a stacking of the Companies' generation resources and an assignment of the highest cost resources to OSS on an hour-by-hour basis. An exception to this is purchases made specifically for internal load such as the renewable purchases required under S.B. 221. For those costs not assigned directly by the NEC, I have used a ratio developed from the NEC MWh data to assign energy related costs between internal load and off-system uses or I directly assign the cost to either internal load or OSS. I developed this MWh data for the base period using 1999 Net Energy Requirement (NER) reports and for 2009 using forecast NER data.

Q. WHAT ITEMS ARE DIRECTLY ASSIGNED TO INTERNAL LOAD OR OSS?

FILE

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for the Approval of its Electric Security Plan; and Amendment to Its Corporate Separation Plan; and the Sale or Transfer of Certain Generation Assets	)	Case No: 08-917-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan and an Amendment to its Corporate Separation Plan	)	Case No. 08-918-EL-SSO

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S INITIAL POST-HEARING BRIEF

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Exhibit PJN-1(Rev.), line 36 (for CSP) and at Exhibit PJN-4, line 37 (for OPCo)). Second, Mr. Roush calculated a cents-per-kWh rate for CSP's PAR, which Mr. Nelson added to the base period FAC for CSP.[14] (Companies' Ex. 7, p. 10 and at Exhibit PJN-1 (Rev.), line 37). Third, for OPCo, Mr. Nelson used the frozen 1999 EFC rate net of the component for Gavin Cap and mine investment/closing cost recovery that had been identified and transferred to OPCo's RAC in the ETP case. (Companies' Ex. 7, p. 10 and at Exhibits PJN-7 and PJN-4, line 10). Because the RAC expired, it was appropriate to reduce OPCo's base period FAC rate by the amount of the Gavin Cap and mine investment shutdown cost recovery component that was in OPCo's 1999 EFC rate.

The frozen 1999 EFC rates and the 1999 data for the other FAC components, coupled with the adjustments that Mr. Nelson made to reflect the rate changes since the Companies' ETP cases, properly identify the current baseline FAC rate for fuel, purchased power and environmental variable expenses within the most recent SSO for each Company. (*Id.*, at 10, Exhibits PJN-1 and PJN-4). In addition, by properly identifying the FAC rate components of the Companies' current SSOs, they have also identified the appropriate non-FAC base generation components of the current SSOs.

In sum, the Companies' approach to identifying the existing FAC rates within their current SSOs starts with their actual 1999 EFC rates in effect at the time of the unbundling required by their ETP cases. After expanding those 1999 EFC rates to reflect the same 1999 level of costs associated with the additional expense categories of the FAC, the Companies conservatively reflected the impact of subsequent actual rate

[14] Including CSP's PAR as an element of its base-period FAC (which results in a lower non-FAC base rate), is appropriate only if the Companies proposal to include slice-of-system power purchases in the FAC is also adopted since the slice-of-system power purchases are intended, in part, to replace power purchased to supply CSP's load after acquiring the Monongahela Power's Ohio service territory.

changes that have occurred. It is a straight-forward and accurate method for identifying the existing FAC rates within the Companies' current SSOs. As a result, by subtraction, it also provides a straight-forward and accurate method for establishing the non-FAC components of their current SSOs.

Mr. Nelson explained that recommendations to use estimates of recent fuel costs as the fuel rate components of the Companies' current SSO rates should not be accepted, because they lead to arbitrary results. (Companies' Ex. 7B, pp. 2-5). First, Mr. Nelson noted that the purpose of identifying the FAC rate within the current SSO is to establish the non-FAC or base SSO in current rates. This is done by subtracting from the current total SSO the current FAC component. Using fuel costs, rather than fuel rates, to determine the FAC baseline rate results in the non-FAC portion of the generation rates floating with whatever assumption is made regarding FAC costs. (*Id.*, at 2). In short, use of FAC costs in a manner such as OCC witness Smith recommends (OCC Ex. 10, pp 12-14) would be subjective and arbitrary.

In addition, Mr. Nelson stated that 2008 is shaping up to be one of the most volatile years in decades for the Companies' fuel costs. Determining the non-FAC base SSO by subtracting from the total SSO fuel costs from such a volatile period would be inappropriate. Mr. Nelson further explained that use of 2008 cost data would require resolution of protracted disputes about out-of-period adjustments that impact the 2008 data. (Companies' Ex. 7B, p. 3).

Mr. Nelson also addressed the Staff's version of a cost-based approach to determining the FAC components of the Companies' current SSOs. Staff Witness Cahaan recommends using 2007 fuel costs with a 3% escalation for CSP and a 7%

escalation for OPCo. (Staff Ex. 10, pp. 3–4). Staff's approach suffers from the same basic flaw, in that it seeks to unbundle both the FAC and the base non-FAC rate components of existing rates based on an arbitrary measure of costs. While it does at least avoid the practical infeasibility of OCC witness Smith's recommendation to use 2008 costs, it does not avoid the subjective and arbitrary characteristic of using a cost-based approach.

Mr. Nelson also refuted the rationale that Mr. Cahaan offered for using a cost-based approach for unbundling rates, that since the Companies earned good returns in 2007 and might do so in 2008, they would *not* be harmed by a cost approach. Mr. Nelson stated that the cost-based approach and the rationale Mr. Cahaan offers in support of it effectively applies an earnings test, based on results from the RSP period, when no earnings test is applicable. He noted that such an approach also applies an earnings test prospectively, in effect to the Companies' ESP at the outset of the plan, when no such earnings test is permitted by S.B. 221. (Companies' Ex. 7B, p. 4).

c. Operation of the FAC Mechanism

Companies' witness Roush explained how the Companies' proposed FAC mechanism will operate at pages. (Companies' Ex. 7, pp. 13-13). Based on the projected 2009 FAC costs and internal load values that Mr. Nelson provided, Mr. Roush calculated 2009 FAC rates by service voltage.[15] He reviewed the impact on customers of including the full incremental costs in the FAC rate in conjunction with the other rate increases that

[15] The 2009 forecast of costs for the fuel, purchased power, and environmental expenditures that the Companies propose to recover through their FAC mechanism are contained in Exhibits PJN-2 (CSP) and PJN-5 (OPCo) to Mr. Nelson's Direct Testimony, Companies' Ex. 7. These costs were assigned to internal load and off-system uses, in the manner that Mr. Nelson described in detail, at pages 12 – 14 of his Direct Testimony. The internal load costs projected for 2009, determined for each Company, are divided by the projected 2009 internal load to develop a 2009 rate. (*Id.*, at 12).

CERTIFICATE OF SERVICE

I hereby certify that a copy of this *Appendix to Second Merit Brief of Appellee/Cross-Appellant Industrial Energy Users-Ohio,* was sent by ordinary U.S. mail, postage prepaid, to the parties listed below this 2nd day of January, 2013.

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