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REPORT OF THE MANAGEMENT/PERFORMANCE AND FINANCIAL AUDITS OF THE FAC OF THE COLUMBUS SOUTHERN POWER COMPANY AND THE OHIO POWER COMPANY

Case No. 09-0872-EL-FAC

May 14, 2010

Prepared for:
Public Utilities Commission of Ohio
180 East Broad Street
Columbus, OH 43215-3793

Prepared by:

Energy Ventures Analysis, Inc.
1901 N. Moore Street, Suite 1200
Arlington, VA 22209-1706
(703) 276-8900

Larkin & Associates PLLC
15728 Farmington Road
Livonia, MI 48154
(734) 522-3420

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INTRODUCTION

Under Senate Bill 221, the Columbus Southern Power Company ("CSP") and the Ohio Power Company ("OPCO") (jointly "AEP Ohio" or the "Companies") filed applications for approval of an electric security plan ("ESP") which includes a fuel adjustment clause ("FAC") mechanism under which the Companies can recover 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. Pursuant to Senate Bill 221, CSP and OPCO filed applications with the Public Utilities Commission of Ohio ("PUCO") for approval of ESP's on July 31, 2008 (Case Nos. 08-917/918-EL-SSO). The PUCO approved the establishment of fuel adjustment clauses ("FAC") for CSP and OPCO in its Opinion and Order dated March 18, 2009 and affirmed in its Entry on Rehearing dated July 23, 2009.

The PUCO established an annual audit to approve appropriateness of the accounting of the FAC costs and the prudency of decisions made. Energy Ventures Analysis, Inc. ("EVA") and its subcontractor, Larkin & Associates PLLC ("Larkin"), were selected by the PUCO to perform the management/performance and financial[1] audits, respectively for up to three years. The initial audit covers the January through December 2009 period. The second audit will cover the period January through December 2010; the third audit will cover the period January through December 2011.

[1] This part of the review has in prior reports been referred to as the "Financial Audit", a term which could be misleading because the work does not involve an audit of financial statements, but rather is an attestation engagement involving verification of AEP-Ohio's FAC filings that is conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants, and using guidance set forth in former Chapter 4901:1-11 and related appendices of the Ohio Administrative Code relating to "Uniform Financial Audit Program Standards and Specifications for the Electric Fuel Component."

Background On The FAC

The FAC is the Fuel Adjustment Clause, and is the mechanism that is being used to recover prudently incurred fuel, purchased power, and other miscellaneous expenses. The FAC includes the following:

- Account 501 (Fuel) – the cost of fuel and transportation for generating electricity.
- Account 502 (Steam Expenses) – the cost of material and expenses used in the production of steam including the cost of chemicals used in environmental controls.
- Account 509 (Allowances) – the cost of emission allowances related to emissions of sulfur dioxide (SO_2) and nitrous oxide (NOx).
- Account 518 (Nuclear Fuel Expense) – the amortized cost of the nuclear fuel assemblies which is not relevant at this time for CSP or OP.
- Account 547 (Non-Steam Fuel) – the cost of fuel used in non-steam applications such as simple cycle gas peaking plants.
- Account 555 (Purchased Power) – the cost of purchased electricity including both energy and demand or capacity charges.
- Account 507 (Rents) – the costs associated with purchase contracts or unit power sales that have to be recorded as a lease per accounting rules.
- Account 557 (Other Expenses) – the cost of renewable energy credits (REC's) to meet the renewable requirements of S.B. 221.
- Accounts 411.8 and 411.9 (Gains and Losses from Disposition of Allowance) – the gains or losses from the sale of allowances.
- Other Accounts – the costs associated with items allowed to be recovered under the FAC not included in the above.

In its initial application for an ESP, AEP Ohio proposed mitigating the rate impact of any FAC increases on its customers by phasing in the new ESP rates by deferring a portion of the annual incremental FAC costs during the three-year ESP period ending December 31, 2011. Specifically, AEP Ohio proposed that the amount of incremental FAC costs to be recovered from customers would be such that total bill increases would not be more than 15 percent during each year of the ESP. However, in its Opinion and Order dated March 18, 2009, the PUCO modified AEP Ohio's proposal to mitigate the rate impact on customers by limiting the phase-in of any FAC cost increases on a total bill basis by the percentages shown in Exhibit 1-1.

Exhibit 1-1. Annual Percentage Increase Caps On FAC Costs

Company	2009	2010	2011
CSP	7	6	6
OPCO	8	7	8

CSP has 17 different FAC rates and OPCO has 23 different FAC rates. The PUCO stated that the collection of any deferrals, including carrying costs that are remaining at the end of the ESP "shall occur from 2012 through 2018 as necessary to recover the actual fuel expenses incurred plus carrying costs."[2]

Audit Of The FAC

This audit direction was to follow the general guidance provided for this work in former Appendix D and Appendix E to Chapter 4901:1-11, Ohio Administrative Code (O.A.C.). In addition, the initial audit should include the actual cost for the Rider FAC for the months January 1, 2009 through December 31, 2009. Such audit should follow the guidelines in Section L of Appendix D and Section M of Appendix E to former Chapter 4901:1-11, O.A.C.

Audit Approach

EVA and Larkin conducted this audit through a combination of document review, interrogatories, site visits and interviews. EVA and Larkin visited the Conesville Coal Preparation Plant ("CCPP") and the Conesville power plant on March 4th, 2009. EVA and/or Larkin conducted interviews with the individuals in the positions listed in Exhibit 1-2 mostly during the week of March 1st, 2009.

As this is the first audit of the FAC, there are no follow-up from prior audit directives.

[2] See PUCO's Opinion and Order dated March 18, 2009 at page 23.

Exhibit 1-2. List Of Interviews

Topic	Department	Participants
Internal Audits	Audit Services	Rod Burnham, Rich Mueller, Tim Dooley
Fuel Supply	FEL	Greg Keenan, Jim Henry, Jason Rusk, Jeff Dial, Jerry Lybarger, Mike DeBord, Deepak Raval
Environmental Compliance	Multiple	Eric James, Jerry Lybarger, John McManus, Karen Anderson, Tim Dooley, Brian Rupp
Purchased Power	Commercial Operations & Others	David Kulha, Phil Nelson, Matt Nollenberger, Mark Leskowitz, Time Dooley
Renewables	Commercial Operations & Others	Jay Godfrey, Matt Nollenberger, Tim Dooley
FAC Filings	AEP Ohio Regulatory & Others	Andrea Moore, Phil Nelson, Tim Dooley
AEP River Operations	River Operations & Others	Darlene Norris, Jeff Rieger, Bob Blocker, Phil Nelson, Tom Palumbo, Carolyn Minkler, Jerry Lybarger, Tim Dooley, Deepak Raval
Natural Gas Agreements	FEL & Others	Nita Spracklen, Jim Henry, Jerry Lybarger, Phil Nelson, Tim Dooley, Deepak Raval
Accounting/Financial	Fuel Accounting	Fran Armatas, Tim Dooley
Conesville Prep Plant	CCPC Plant Management	Greg Stiltner, Timothy Mathis, Jerry Lybarger
Conesville Power Plant	Conesville Plant Management	Mark Borman, Earl Duck, Angela Larrick, Deepak Raval

Major Management Audit Findings

1. AEP Ohio's fleet is largely coal-based and coal procurement costs are by far the largest component of the FAC. Since mid-2007, the coal industry has demonstrated unprecedented volatility which has resulted in utility fuel procurement personnel facing enormous challenges. From mid-2007 until the third quarter of 2008, a global coal supply/demand imbalance increased the demand for and price of U.S. coals. Utilities focused on obtaining both the coal under contract as well as acquiring coal to fill open positions. AEPSC did an exceptional job during this period particularly with those suppliers that faced financial hardship. Since the third quarter of 2008, electricity demand has declined as a result of the severe economic recession. Coal-fired generation has declined disproportionately as it has been affected both by the overall economic decline and by natural gas displacement of coal generation in many markets due to the low natural gas prices. As a result, many utilities ended up with more coal under contract than they needed. After spending more than a year focused on acquiring coal, utilities switched their focus to managing the surplus. Utilities did so through some combination of contract deferrals, contract buyouts, higher inventories, remote storage, and forced burn. AEPSC also did an outstanding job managing its excess volumes. In part because of the fair treatment it has

historically provided its suppliers, many of AEP's suppliers were willing to defer shipments at no cost. In addition, AEPSC chose to allow stockpiles to increase rather than pay for reduced shipments which should benefit ratepayers in the long term. AEP Ohio's coal costs in 2009 were comparable to the coal procurement costs of other utilities nearby.

2. As predicted by AEP, at the end of the first year of the FAC there is a large under-recovery. The under-recovery amounts (subject to adjustment) total \$37.5 million for CSP and \$297.6 million for OPCO. While there are many components to the under-recovery, two coal contract events alone help to explain more than half of OPCO's under-recovery.[3] The decision to increase the contract price under the two [redacted] contracts by \$[redacted] per ton in 2009 increased fuel expense for OPCO by over \$[redacted] million and the 2007 buy-out of the [redacted] contract for [redacted] resulted in an increase of over [redacted] in 2009 fuel expense over the contracted prices. The [redacted] surcharge was a well considered decision in a difficult time. EVA concurs that while expensive, an insolvency of OPCO's [redacted] supplier would have been more expensive. The 2007 buy-out of the [redacted] contract was a Settlement Agreement arising out of a contract dispute. A hindsight review of such a Settlement Agreement is always difficult because its merits need to be considered at the time it was accomplished. The Settlement Agreement was effectively a buyout of the [redacted] contract after 2008. Shipments under the [redacted] contract would have continued through the ESP period. AEP received [redacted] and the [redacted] Reserve as part of the Settlement Agreement. The [redacted] Reserve is a Pittsburgh seam reserve that AEP has booked as an un-regulated asset in 2008 when there was no effective distinction between regulated and un-regulated.

3. AEPSC's fuel procurement operation is run in a professional manner using the leading industry practices in acquiring coal and transportation.

   a. AEPSC uses a portfolio strategy to purchase coals such that its market exposure at any one time is limited and there is reasonable diversification of its suppliers and supply sources.

   b. AEPSC purchases most of its coal through competitive solicitations. AEPSC evaluates procurement decisions on a quality-adjusted basis. AEPSC documents all procurement decisions in a manner that provides the analysis and rationale for each.

   c. AEPSC uses active management of its coal supply to match deliveries and burn where possible.

   AEPSC is in the process of revising its fuel procurement manual to guide its practices.

4. AEP Ohio has an increased and significant appetite for higher sulfur coals following the retrofit of scrubbers on Cardinal 1, Conesville 4, and Mitchell. When combined with the already scrubbed Gavin and Conesville 5&6 units, annual demand could

[3] The ESP limits annual FAC increases to fixed percentage increases that are reasonable in the context of the portfolio strategy AEPSC employs. While it is hard to tie the under-recovery to specific events, the extraordinary increases as a result of a renegotiation with one supplier and a contract buyout help to explain the large under-recovery.

approach 20 million tons per year. The high risk of its Northern Appalachian coal supply was made clear in 2008 when three producers required additional financial support to maintain their solvency. In order to insure a long-term reliable supply at competitive prices, AEPSC may need to look to the Illinois Basin. AEPSC has recognized this and entered into one contract in part to further evaluate the potential for Illinois Basin coal.

5. The scrubber retrofit AEP chose for Cardinal 1 (as well as Muskingum River 5 and other non-AEP Ohio plants) utilizes the jet bubbling reactor technology. AEP has encountered unexpected operating results with this technology which it has determined are a result of fundamental design deficiencies and that "inferior and/or inappropriate materials were selected for the internal fiberglass components." AEP is in discussions with the equipment manufacturer to repair the scrubbers and may pursue legal remedies if AEP cannot resolve these issues with Black & Veatch.

6. The conversion of the [redacted] coal supply agreement, a major source of supply for the Conesville station, from an agreement to buy raw coal to an agreement to buy washed coal will significantly reduce the need for washed coal from the Conesville Coal Preparation Plant. Further, plans to close Conesville 3 in 2012 will reduce overall coal consumption at the Conesville station. The preparation plant at Conesville may not be economic as a result.

7. AEP Ohio achieved its 2009 alternative energy obligations with a reduced solar obligation approved by the PUCO. The obligations were met through a combination of purchased non-solar renewable energy credits ("REC") from wind and landfill gas projects, purchased solar RECs, solar installations on two AEP Ohio service centers, and wind from two purchase power agreements ("PPA"). AEP Ohio entered into three 20-year PPAs in 2009: two for wind and one for solar. The power prices under all three agreements are high compared to current power prices although competitive with current market prices for renewable power. The agreements provide for no market reopeners or early outs thereby obligating AEP Ohio to these high rates for 20 years. AEPSC's strategy is to continue to examine all options including self build options.

8. The quarterly FAC filings were made in a timely manner and contained sufficient documentation to support the numbers included therein. The back-up documentation was less well organized making the audit trail more difficult.

9. AEPSC was notably well-prepared and responsive to the auditors in this first FAC review. AEPSC was extremely responsive to all data requests.

Management Audit Recommendations

1. 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.

2. The decline in coal demand in 2009 was unprecedented but could be the start of a new era in which coal becomes the swing fuel. AEPSC may need to reconsider new coal procurement strategies to avoid over-commitments in the future.

3. EVA recommends that the next management/performance auditor review the Cardinal 1 scrubber situation and determine what if any FAC costs are due to this situation.

4. AEPSC should undertake a study to determine whether there is an economic justification for continuing to operate the Conesville Coal Preparation Plant. The study should be completed in time for it to be reviewed in the next management/ performance audit.

5. AEPSC should finalize its update of its policies and procedures manual to reflect current business practices. The update should be completed in time for it to be reviewed in the next management/performance audit.

6. 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 for same.

Financial Audit Recommendations

1. The FAC workbooks that were provided in the response to LA-1-47 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 that were derived from other sources (e.g., the Monthly Purchase Summary Reports). In addition, these explanations should also apply to issues such as timing differences and/or prior period adjustments. AEP Ohio agrees, and has proposed to include in the monthly FAC workbooks the monthly purchased power reconciliations similar to that provided in the response to LA-4-11.

2. CSP and OPCO should include the reconciliation of the fuel and purchased power accounts that have been designated as includable FAC costs similar to LA-4-11 with the monthly FAC workbooks, with appropriate color coding, to facilitate a clear audit trail.

3. April 2009 was selected as the month for additional detailed testing. LA-1-37 requested copies of invoices and paid cash vouchers or cash receipts for purchases of power recorded in April 2009 that are included in the FAC filings. Larkin was unable to trace most of the information provided to the FAC workbooks (provided in LA-1-47) for that test month. The Companies should provide a better audit trail for tracing such costs in the next audit period. AEP Ohio agrees, and has proposed to include in the monthly FAC workbooks the monthly purchased power reconciliations similar to that provided in the response to LA-4-11.

4. The response to LA-1-39 indicated that during the period January through December 2009, four of AEP Ohio's power plants were designated as "must run" units by PJM for reliability and voltage control reasons during a number of hours. Unless it has

already been presented in another forum, the PUCO may want to have AEP Ohio explain further how the "must run" generating unit designations are affecting the costs that are recoverable in the FAC.

5. The response to LA-2-1(b) indicated that hourly or 24-hour dispatch cost information is not readily available from AEP Ohio's systems. In addition, Off-System Sales detailed cost information related to forced outages is not readily available, nor is it used for any internal business purposes or in existing reports. AEP Ohio should update and/or modify its systems in order to better track the AEP East Fleet system stack information.

6. River Transportation Division ("RTD") should respond to the following prior to the next audit and have the results available for the next auditor to review:

   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 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). AEP agrees that a correction is necessary for this.

   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 2010 true up and credited to the operating companies in August 2010. OPCO'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. OPCO, RTD and the 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. OPCO 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.

Audit Outline

The outline of the remainder of this report is as follows:

- Section 2 Fuel Procurement Audit
- Section 3 Conesville Coal Preparation Plant Audit
- Section 4 Environmental Audit
- Section 5 Performance Audit
- Section 6 Alternative Energy Standards Audit
- Section 7 Financial Audit

2

FUEL PROCUREMENT AUDIT

Background On Columbus Southern Power And Ohio Power

Columbus Southern Power and Ohio Power are both wholly-owned subsidiaries of American Electric Power (AEP). Fuel procurement for both companies is handled by American Electric Power Service Corporation (AEPSC). AEPSC is also responsible for fuel procurement for AEP's other utility subsidiaries and is agent for Ohio Valley Electric Corporation in which AEP owns the largest share and Cardinal Operating in which Ohio Power owns Unit 1. AEP's adoption of centralized fuel procurement was designed to minimize system-wide fuel procurement costs.

The plants operated by CSP and OPCO are listed in Exhibit 2-1 along with 2009 performance metrics. With the exception of Conesville 4, these plants are owned in their entirety by their respective companies.

Conesville 4 is one of four CCD[1] plants in which CSP has an ownership position. The other three plants which CSP does not operate are Zimmer (operated by Duke Energy Ohio), Beckjord #6 Unit 6 (operated by Duke Energy Ohio), and Stuart Plant (operated by Dayton Power & Light). CSP recovers through the FAC its allowed costs associated

[1] CCD refers to Cinergy, Columbus Southern Power, and Dayton Power & Light.

Exhibit 2-1. Columbus Southern Power And Ohio Power Plants

Utility Plant	State	Fuel	Year First Unit In Service	FGD	Operating Capacity (MW)	Net Generation (MWh)	Capacity Factor (%)	Coal Burn (Tons)	Gas Burn (mcf)
Columbus Southern Power					3,152	9,788,362		4,343,298	2,451,788
Conesville	OH	Coal	1957	#4,5, 6	1,695	9,156,196	61.5	4,169,889	-
Picway	OH	Coal	1955	No	100	329,338	37.5	173,409	-
Darby	OH	NG	2001		507	25,693	0.6	-	310,129
Waterford Energy Facility	OH	NG	2003		850	277,135	3.7	-	2,141,659
Ohio Power					6,281	44,114,563		17,592,780	
Gen J M Gavin	OH	Coal	1974	Yes	2,640	21,102,131	91.0	8,503,170	-
Muskingum River	OH	Coal	1953	#5 Planned	1,425	9,127,024	72.9	3,528,464	-
Kammer	WV	Coal	1958	No	630	3,115,279	56.3	1,388,035	-
Mitchell (WV)	WV	Coal	1971	Yes	1,560	10,638,648	77.6	4,173,111	-
Racine	OH	Water	1982		26	131,481	57.6	-	-
Total					9,433	53,902,925		21,936,078	2,451,788

with its ownership share of all four plants. CSP also recovers its purchased power costs for the Lawrenceburg plant which is owned by an affiliate, AEP Generating Co. ("AEG"). In March 2007, CSP and AEG entered into a [redacted]-year agreement for the entire output of Lawrenceburg and pays for capacity, depreciation, fuel, and other operating costs. AEPSC buys the fuel for Lawrenceburg.

OPCO owns Cardinal #1 in its entirety (which along with Cardinal #2 and #3 is operated by Cardinal Operating) and shares of Amos and Sporn Units 2, 4, and 5. OPCO recovers through the FAC its fuel costs associated with its ownership share of these plants.

The fuel supply arrangements for CSP and OPCO consist of commercial purchases comprised of long-term, short-term, and spot purchases. CSP owns and operates the Conesville Coal Preparation Plant ("CCPP") which is owned and operated by Conesville Coal Preparation Company, a wholly-owned subsidiary. The CCPP was built in the mid 1980s to provide more flexibility to AEPSC in its coal procurement for the Conesville station.

Coal procurement performance during the audit period is summarized on Exhibit 2-2.[2] In 2009, AEP Ohio had a high level of contract purchases. Spot coal purchase prices were over 50 percent higher than contract purchase prices.

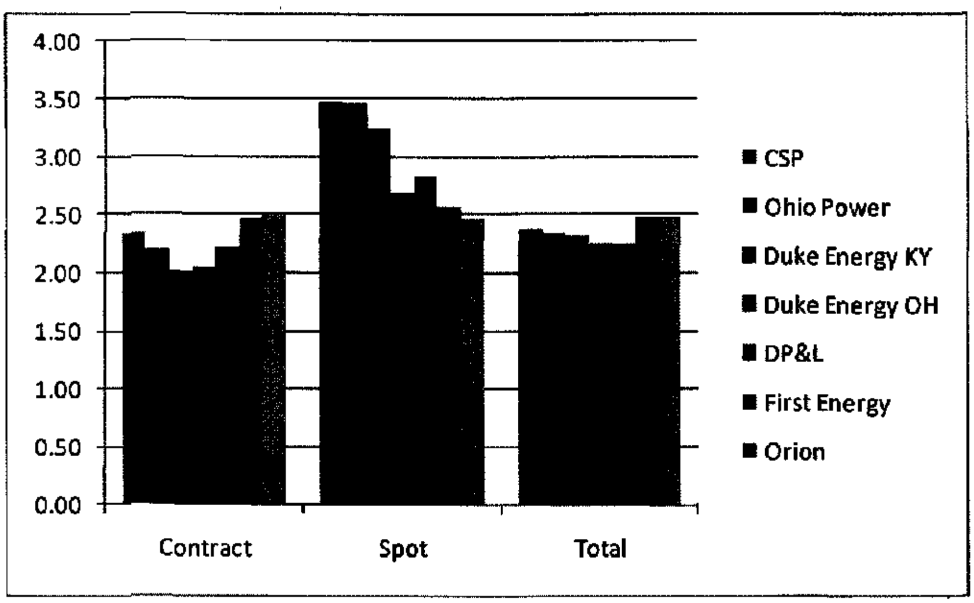
[2] The contract purchases for Conesville in this chart are based upon the tons and cost of the clean coal received from CCPP.

Exhibit 2-2. AEP Ohio Coal Purchases, 2009

[redacted]

AEP Ohio's coal costs compare favorably with the coal purchase expenses of nearby utilities as shown in Exhibit 2-3[3]. While the utilities vary with respect to average spot and contract purchase prices, they are remarkably similar with respect to average costs. This comparison is not dispositive with regard to performance as the utilities vary with respect to quality requirements and transportation.

Exhibit 2-3. Average Price of Coal Purchases, 2009 ($/MMBtu)



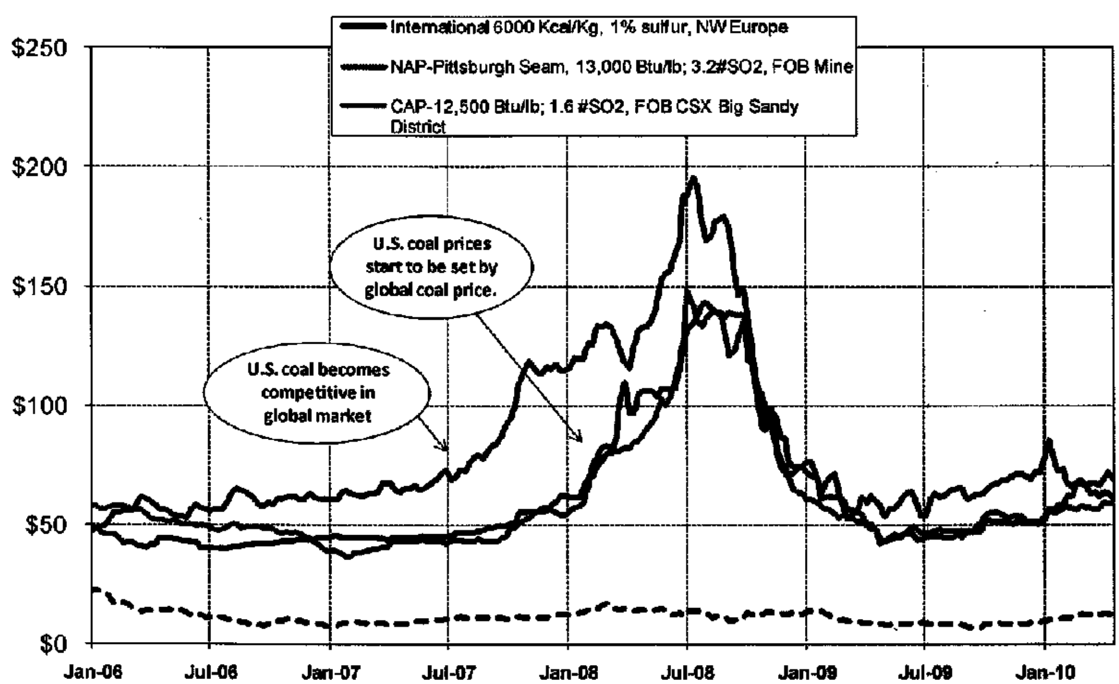
Source: AEPSC for CSP and OP; FERC Form 923 for others (11 months of 2009).

[3] The data come from the utility's Form 923 filings to the Energy Information Administration (EIA). EIA defines contract as purchases for one year or more and spot as everything else.

State Of The Coal Market

No discussion of coal procurement in 2009 is complete without a discussion of the dramatic changes to the world coal market since mid-2007 and the impact of these changes on the U.S. coal market and coal procurement issues. Between mid-2007 and mid-2008, global coal prices tripled. During this period, U.S. coals became competitive in the global marketplace. By the end of 2007, global coal prices began to set the price for U.S. coal. A global economic recession that became pronounced in the third quarter of 2008 resulted in a collapse of both global and U.S. coal prices. Exhibit 2-4 is a graphical display of prompt coal prices for three major U.S. supply regions and steam coal delivered to northwest Europe, Prompt prices are the prices paid today for coal delivered in 90 days.

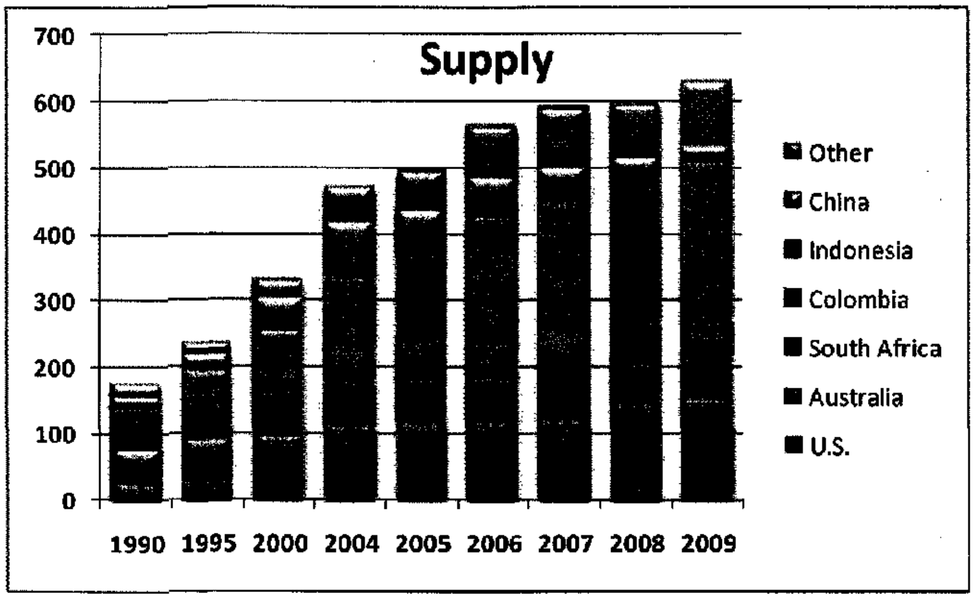
Exhibit 2-4. Historical Prompt Coal Prices (USD/Ton)



Factors Behind Price Increase

Between 2000 and 2008, the volume of steam coal traded in the global seaborne coal market increased by over 200 million metric tons. The increase was due to strong growth in coal demand, primarily in Asia. For most of this period, the increase in supply from Indonesia, Australia, and elsewhere kept up with the growth in demand. (Exhibit 2-5) In 2007, however, an imbalance developed with demand growth outpacing supply growth, creating pressure on the market and causing prices to increase. Global coal prices increased primarily in response to this shortfall. U.S. coal prices increased when U.S. coals became competitive in the global market.

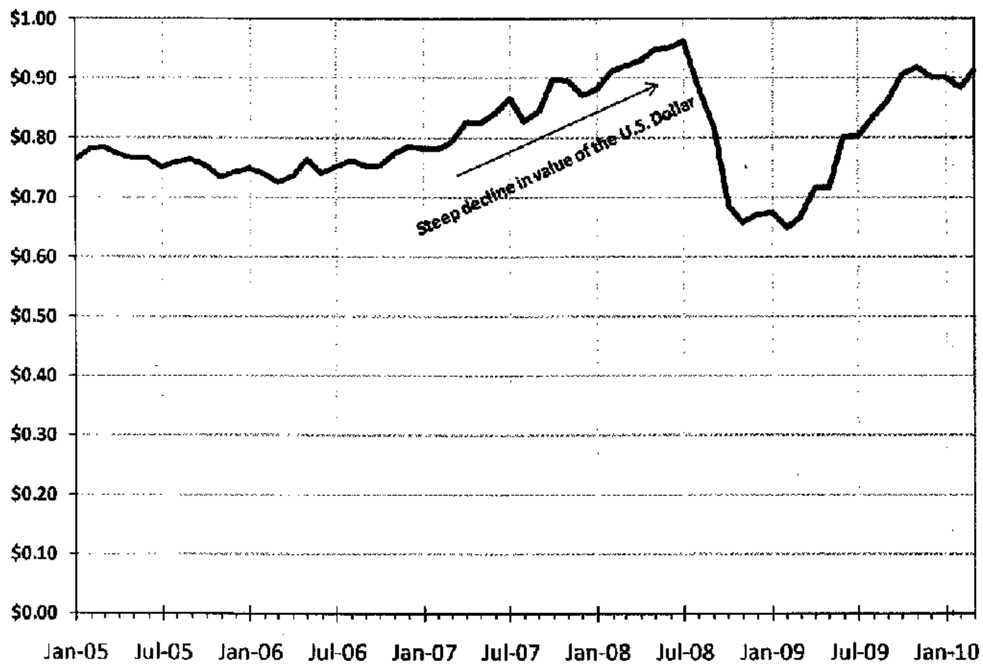
Exhibit 2-5. Seaborne Coal Trade
(Million Metric Tons)



Several factors in addition to the global coal supply/demand imbalance also contributed to the increase in global coal prices. The other major factors included the declining value of the U.S. dollar, increasing freight rates, and several regional supply problems.

The declining value of the U.S. dollar affected coal prices because global coal trade is U.S. dollar denominated. With the U.S. only a minor player in the global coal market, the pricing of coal from the major exporting countries is adjusted to reflect the relative value of the U.S. dollar. With Australia being the largest global exporter of coal, the relationship between the U.S. dollar and the Australian dollar is particularly important. (Exhibit 2-6) The U.S. dollar weakened considerably between mid-2007 and mid-2008. The weaker the U.S. dollar in relation to the Australian dollar, the higher coal prices have to be for Australian producers to realize the same value.

Exhibit 2-6. U.S. Dollars to One Australian Dollar



Higher freight rates are important because coal prices are settled at key market hubs. Therefore, the price contains a freight component. Commodity prices are important because of the relationship between commodity prices and coal prices in the global market. There were several regional supply issues which also affected prices such as heavy rain-induced flooding in Australia and Indonesia and brownouts in South Africa. While generally unpredictable, there are often regional disruptions which affect the coal supply/demand balance.

The rapid change in the market resulted in consumer concerns about being able to buy sufficient coal supplies to meet their requirements in 2009, particularly in the context of mixed supplier performance under lower-priced legacy contracts. As a result, the market tightened further as consumers looked to lock in their supplies for 2009 early in the context of supplier performance issues.

Global Economic Recession

A major global economic recession took hold beginning in the second half of 2008 which ultimately resulted in a steep drop in both coal demand and price. In the U.S., the drop in demand was significant as lower electricity demand reduced coal-fired generation, low natural gas prices resulted in some displacement of coal-fired generation by natural gas-fired generation, lower steel production reduced metallurgical coal demand, and lower global coal prices reduced the competitiveness of U.S. coals in the export market. U.S. coal production ultimately declined by 120 million tons in 2009 as producers shut in or curtailed coal production capacity as they lost market.

The impact of the economy was felt not only in lower electricity demand but in increased availability of natural gas. Displacement of coal generation by natural gas generation was a new and unanticipated market development, because historically natural gas-fired units operated primarily as intermediate-to-peaking units when coal was unavailable because the gas units were more expensive to run than coal units due to the higher price of natural gas. This was not the case in much of 2009 as natural gas prices had plummeted due to a large gas surplus. The surplus was due to several factors. On the demand side, there was a large decline due to the economic recession. On the supply side, there was a surge in domestic production due to the restoration of all Gulf capacity curtailed as a result of Hurricanes Gustav and Ike, record drilling, and the industry's focus on unconventional sources, in particular, the gas shales. As natural gas prices fell, natural gas became more competitive with coal for electricity generation.

The dual affects of the economic recession and the availability of low priced natural gas can be seen in U.S. electricity generation data. Exhibit 2-7 provides generation by fuel type for 2009 versus 2008. Total generation declined 4.0 percent; coal generation declined 11.1 percent; natural gas generation increased 4.2 percent.

Exhibit 2-7. U.S. Net Generation by Energy Source

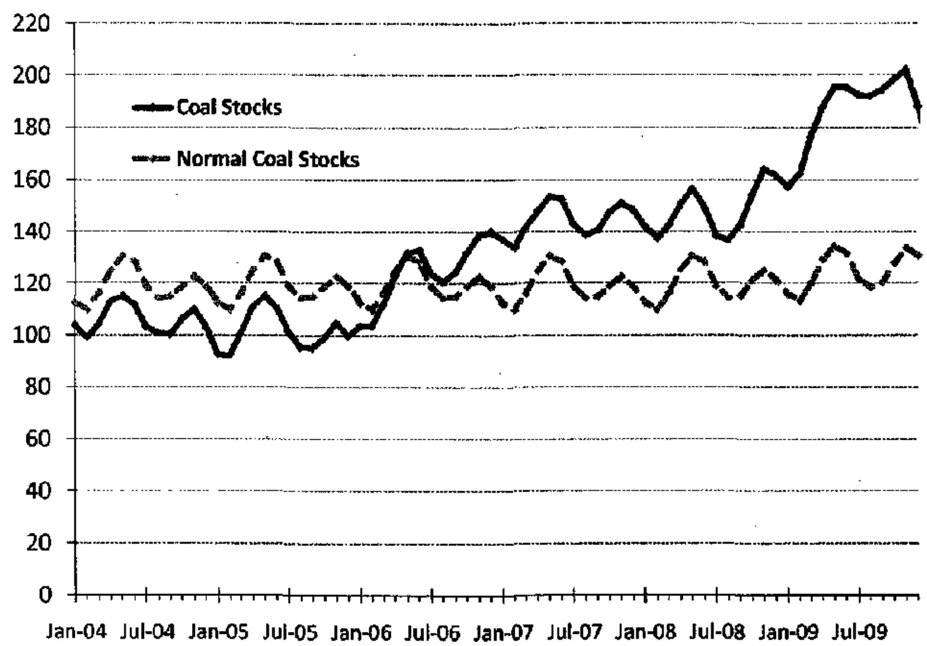
Period	Coal	Oil	Pet Coke	Natural Gas	Nuclear	Hydro	Other Renewables	Pumped Storage	Other	Total
Generation (000 MWH)										
2008	1,985,801	31,917	14,325	882,981	806,208	254,831	126,212	-6,288	23,399	4,119,388
2009	1,764,486	25,792	13,035	920,378	798,745	272,131	141,115	-4,346	21,776	3,953,111
Share of Generation										
2008	48%	1%	0%	21%	20%	6%	3%	0%	1%	100%
2009	45%	1%	0%	23%	20%	7%	4%	0%	1%	100%
2009 vs. 2008										
Annual Change	-11.1%	-19.2%	-9.0%	4.2%	-0.9%	6.8%	11.8%	30.9%	-6.9%	-4.0%

Sources: Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, Form EIA-9:

The decline in global coal demand was accompanied by a decline in coal prices. As shown above, coal prices plummeted in the fourth quarter of 2008 as demand disappeared. The low prompt prices are somewhat misleading as there was low liquidity in the market. Utilities had generally over-purchased coal in the context of reduced demand and were not out in the market for coal. U.S. producers were not making new sales in the global market as the global prices had fallen to levels below the operating costs for many U.S. producers absent the transportation to even the terminal. In other words, very little coal traded at these low prices.

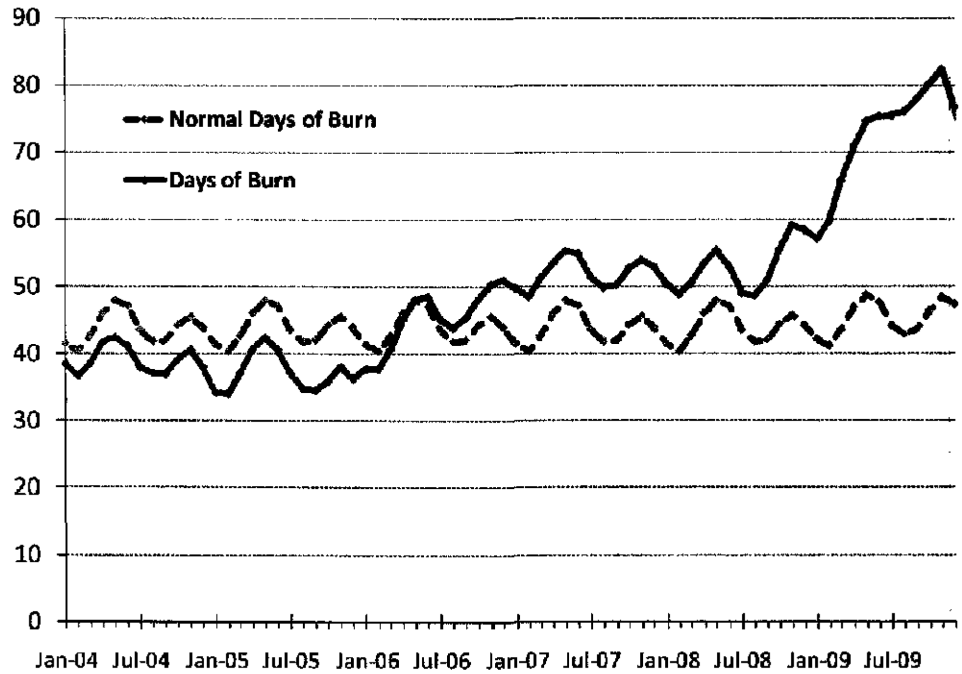
The disconnect between purchases and burn resulted in significant increases in consumer stockpiles through November 2009, at which point utility stockpiles were over 60 million tons above normal. (Exhibit 2-8)

Exhibit 2-8. Actual Versus Normal Utility Stockpiles (Million Tons)



The 60 million ton increase in stocks meant that utilities on average had over 80 days of coal burn in their stockpiles. (Exhibit 2-9) At reduced burns, the numbers of days was even higher. To manage inventories, utilities were forced to employ multiply strategies including deferral of contract tons, buying out of contract tons, using off-site storage to accommodate purchases, and in some cases forced burning of coal.

Exhibit 2-9. Actual Versus Normal Utility Stockpiles (Days of Burn)

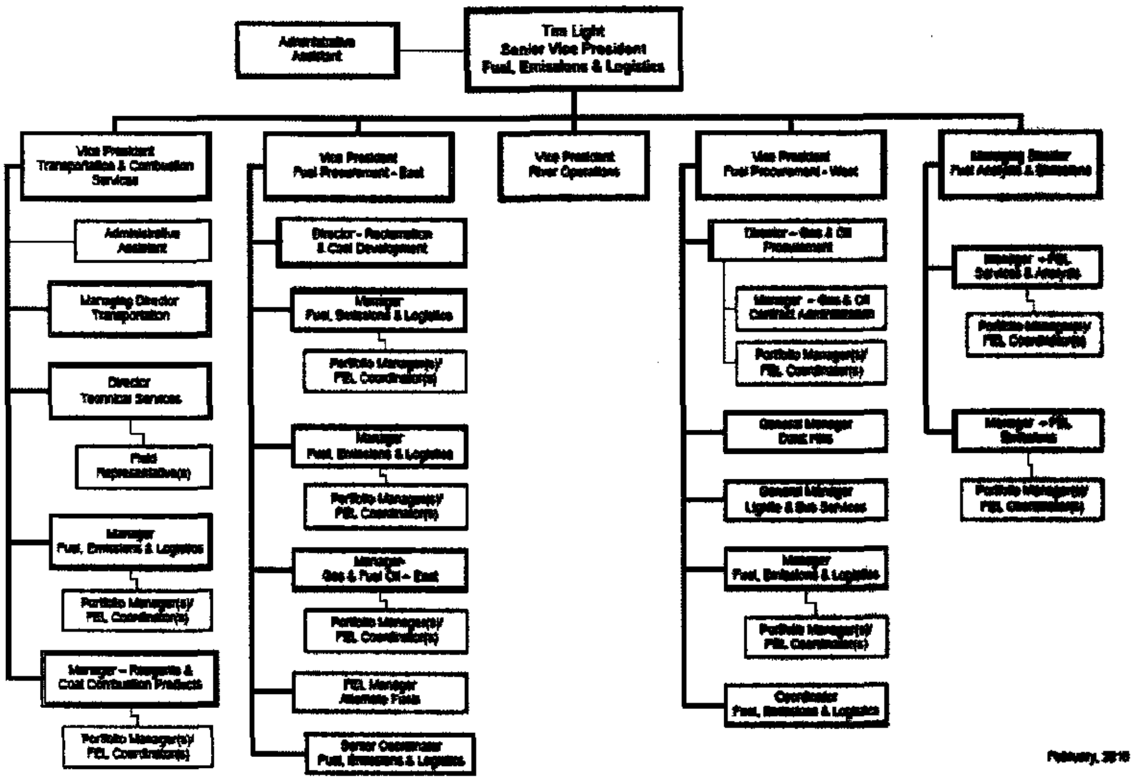


In 2008, utilities had great challenges in insuring adequate coal supply to meet demand. In 2009, utilities had great challenges in managing coal commitments in the midst of a collapsing market. The challenges faced in both years were somewhat in unchartered territory.

Management And Organization

Responsibility for fuel and emission allowance procurement lies with the Senior Vice President Fuel Emissions and Logistics ("FEL"). As shown in Exhibit 2-10, the Senior Vice President has six direct reports, several of which have some involvement in fuel procurement issues for AEP Ohio. The ones most directly involved with AEP Ohio are the Vice President Fuel Procurement East and the Vice President Transportation and Combustion. FEL personnel interact with other AEP personnel on a routine basis.

Exhibit 2-10. Organization Chart For Fuel, Emissions And Logistics



Policies And Procedures

AEPSC is operating under a September 2004 revision to its Coal Procurement Policy although AEPSC indicated an update was underway. The basic policy is "to assure secure, flexible and competitively priced fuel supplies and transportation to meet generation requirements, recognizing the dynamic nature of fuel markets, environmental standards and regulatory requirements."

EVA filed testimony on behalf of the Consumer Advocate Division of the West Virginia Public Service Commission in 2006 and 2007 related to this policies and procedures manual.[4] EVA noted that the manual provides general information on AEPSC organization and procurement procedures and policies but lacks the specifics that are a desirable component of any manual. In both 2006 and 2007, EVA recommended that

[4] 2006 ENEC Filing of Appalachian Power Company and Wheeling Power Company; 2007 ENEC Filing of Appalachian Power Company and Wheeling Power Company.

AEPSC make a number of modifications to the manual. AEPSC indicates that it close to completing a revision.

EVA recommends that the next management/performance audit review the revised manual. EVA hopes that the revised manual will include the following:

a. Specific portfolio targets for each utility system,

b. Specific obligations to use competitive solicitations *except* in unique circumstances with such unique circumstances to be well documented,

c. Specific factors that will be used to evaluate bids received under competitive solicitations,

d. Procedures to be implemented in response to supplier declarations of *force majeure*,

e. Policy related to the use of physical and financial hedges,

f. Procedures that will insure that the procurements for each utility are not compromised by procurements for the other affiliate utilities,

g. Procedures related to the coal inventory process, and

h. Code of conduct requirements for procurement personnel.

Inventory Management

The Coal Procurement Policy states that the "primary obligation of the System and each Operating Company shall be to ensure the availability of a continuous, reliable flow of electricity to the consumer. Consequently, any decision affecting the coal inventory shall be made in light of AEP's primary obligation." The Coal Procurement Policy references targets established in September 2003. As part of this audit, AEPSC provided 2009 targets which are summarized in Exhibit 2-11. The target inventories range between 25 and 35 days of burn on a full load basis. The target winter inventories are generally (but not always) five days higher.

During 2009, as shown on Exhibit 2-12, stocks at the AEP Ohio plants increased substantially and exceeded target levels at all plants. By the end of 2009, the inventory situation at Mitchell and Muskingum River had greatly improved.

[redacted]

In Exhibit 2-12, CSP and OPCO inventory levels are compared, respectively, to actual and normal industry levels based upon EVA's proprietary stockpile report.[5] The CSP inventories are compared to just Northern Appalachian inventories as all the coal purchased for CSP is from Northern Appalachia. The OPCO inventories are compared to eastern utility inventories which consist of multiple coal types. CSP inventories were high but consistent with other utilities. OPCO inventories ran above industry levels.

AEPSC indicated that while it tried to manage its inventory levels, it did not wage a full campaign to bring them under control. AEPSC provided several reasons for this approach. First, AEPSC tried to defer shipments at no cost. AEPSC achieved some success in this regard, ultimately deferring 2.5 to 3.0 million tons of AEP Ohio commitments. AEPSC credits its success with its prior fair treatment of its suppliers. Second, AEPSC did not want cause extreme financial distress to its coal suppliers, several of which depend upon AEP for the lion's share of their business. A major curtailment in shipments could affect their solvency which in turn might jeopardize

[5] EVA publishes the COALCAST Stockpile Data Report on a monthly basis which provides indicative utility inventory levels by coal type on a real time basis.

Exhibit 2-12. Inventory Levels At AEP Ohio Plants (Tons)

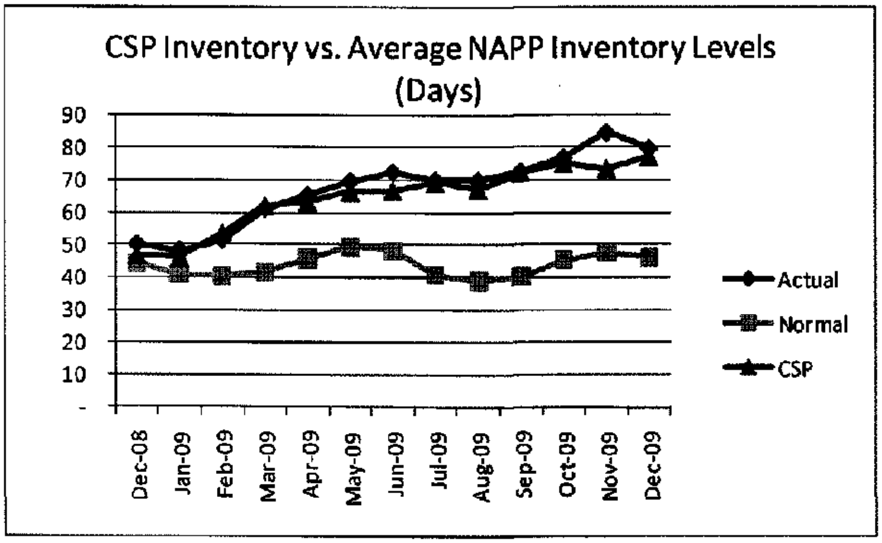
[redacted]

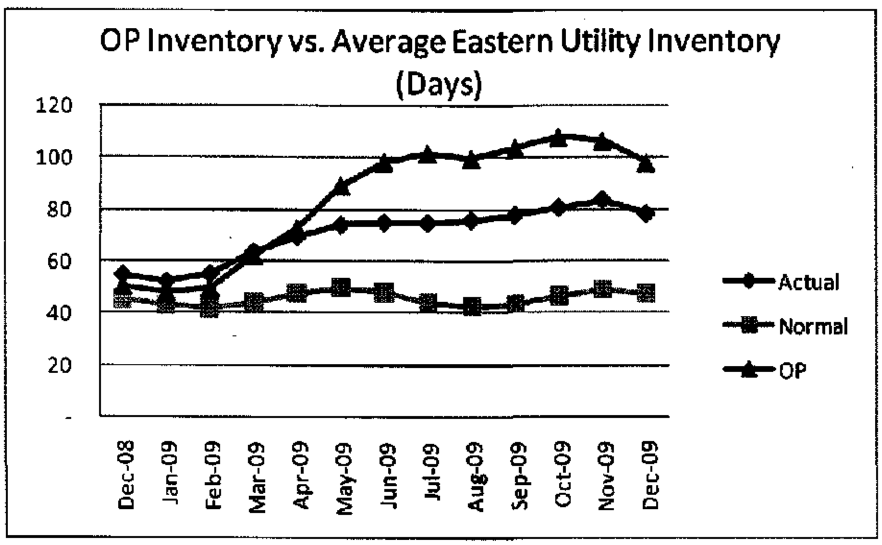
[redacted]

[redacted]

[redacted]

Exhibit 2-13. CSP And OPCO Inventory Days Versus Industry





current coal supply agreements and future coal availability. Third, AEPSC did not want to lose its low priced tons given its market view that prices would eventually bounce back. AEPSC believed that if it could manage the higher stocks, it would benefit from the supply. EVA concurs that AEPSC's strategy is likely to provide benefits for the reasons outlined above.

Physical Inventory

During the era of full regulation, the PUCO mandated semi-annual physical inventory surveys and only allowed book adjustments if the surveys produced sequential errors in the same direction. Further, the adjustments were limited to 50 percent of the difference up to six percent. AEP now conducts its physical inventory survey and adjustments according to AEP System Accounting Bulletin No. 4 which provides for full adjustments to be made following each survey. The AEP System Accounting Bulletin No. 4 also requires that a variance of plus or minus two percent be investigated. An annual audit of the coal pile inventories is conducted by Internal Audit.[6]

The physical inventory survey adjustments at AEP Ohio-operated plants are summarized in Exhibit 2-14. The adjustments are compared to the end of month inventory at the plant. Where the physical inventories were provided by unit, they were aggregated for this table. The shaded lines indicate a variance of more than two percent from the pile. The adjustments are also shown as a percent of burn.

Exhibit 2-14. Physical Inventory Survey Adjustments

Plant	Survey Month	EOM Month Inventory	Tonnage Adjustment	% of Pile	2009 Burn	Inventory as % of Burn
Gavin	Mar-09	1,078,146	58,097	5.4%	8,503,170	0.7%
Gavin	Dec-09	2,222,984	(50,064)	-2.3%	8,503,170	-0.6%
Mitchell	Mar-09	388,611	49,279	12.7%	4,173,111	1.2%
Mitchell	Sep-09	915,593	(4,059)	-0.4%	4,173,111	-0.1%
Kammer	Apr-09	485,369	39,882	8.2%	1,402,967	2.8%
Kammer	Sep-09	496,888	7,910	1.6%	1,402,967	0.6%
Muskingum River	Apr-09	383,720	16,299	4.2%	3,528,464	0.5%
Cardinal 1	Jun-09	534,065	25,575	4.8%	4,225,414	0.6%
Cardinal 1	Dec-09	358,806	(12,125)	-3.4%	4,225,414	-0.3%
Picway	Jun-09	124,953	10,152	8.1%		
Picway	Dec-09	135,683	3,496	2.6%		
Conesville	Dec-09	686,592	(1,917)	-0.3%	2,109,401	-0.1%

Source: EVA 1-36 and Form 1 Data

While the two percent threshold may be too low, most of the adjustments are more than double that amount. EVA is specifically concerned about the Mitchell station which has been the source of at least one prior large adjustment.

Internal Audits

AEPSC has an active internal audit function which regularly audits components of fuel procurement. According to the internal auditors, each year they take the entire universe of audit areas and rank them based upon several factors such as dollar value, history of

[6] Internal Audit conducts the annual review to reduce the workload of the outside auditors. The annual review is conducted per agreed upon procedures.

prior problems, and when the last audit was conducted. The internal auditors indicate they conduct approximately [redacted] audits per year, most of which are financial audits. Audits findings are ranked by risk. Anything determined to be medium or high risk requires follow-up.

The internal audits conducted in the fuel area are summarized in Section 7. Two recent audits demonstrate to EVA the value the internal audit function can play. [redacted] In May 2009, internal audit completed a review of SO_2 cost recovery adjustments. The addition of scrubbers has resulted in many coal supply agreements containing a sulfur adjustment based upon scrubber operating costs rather than emission allowance prices. Hence, the provision has become increasingly important and FEL indicated such a review would not only be desirable but extremely helpful with the construction and implementation of the contract provisions.

Coal Procurement

AEPSC annually purchases about 75 million tons of coal on behalf of AEP Ohio, Appalachian Power, Indiana Michigan Power, Kentucky Power, Public Service of Oklahoma and Southwestern Electric Power and the utilities it is agent for: Ohio Valley Electric and Cardinal Operating. Coal is purchased from virtually every coal supply region and under multiple types of arrangements. AEP has been in and out of the coal business several times. Currently, its mining activities are limited to lignite operations in Texas. AEP still operates the Conesville Coal Preparation Plant in Ohio.

Coal Solicitation

AEPSC monitors its coal position overall and by plant and supplier through an internally developed model which monitors actual and target inventory levels, actual and projected burn, and spot and contract commitments. This tool helps determine when coal purchases should be made. When a need is identified, AEPSC typically buys through a formal solicitation. A request-for-proposal ("RFP") is issued, generally by AEPSC without naming which plants require coals. The RFP requests bids for a wide range of coals and give bidders the option to bid for spot and/or multi-year contract business.

The results from the RFP process help to determine whether to buy coal on a spot or contract basis and for what term.

AEPSC also buys coal through direct negotiation with suppliers, telephone solicitations, and over-the-counter. Direct negotiations with buyers are unusual but at least one of Ohio Power's current contracts was a product of direct negotiation during the period of heightened tightness in the market. Telephone solicitations are conducted when there is an immediate and generally unexpected need. Over-the-counter is used for spot coal commodity type purchases, e.g., 8,800 Btu per pound Powder River Basin coal.

AEPSC conducted two solicitations in 2009. In April, AEPSC conducted its "normal" broad solicitation, asking for bids for spot and contracts for a wide range of coal types. In December, the RFP indicated the coal was solely for lower sulfur coal. AEPSC indicated the reason for the limited RFP in December was a concern that the "normal" solicitation would imply to the market a need for coal at the same time AEPSC was working hard to manage its long contract position.

Regardless of the manner in which coal is procured, a written justification is prepared for every coal procurement. The justification includes why the procurement is being made (generally one or more screens from the model described above), how the specific procurement came about, and the economic justification for the decision. These memos are well written, comprehensive documents that provide good contemporaneous support for the procurement even though most are dated subsequent to the actual transaction.

Without there being a specific portfolio target identified, there appears to be a general desire to have a portfolio of procurements such that market exposure at any one time is limited and there is a diversification of supply and suppliers.

Procurement Administration

AEP Ohio switched from its [redacted] system to the [redacted] in May 2009. Plant personnel enter the fuel receipts information into [redacted] which contains the terms and conditions associated with fuel contracts. The system monitors contract performance and creates payment requests based upon the quantity and quality of coal received and the contract terms and conditions. The payment requests are then run through the [redacted].

Spot Coal Procurements

During the audit period, AEP Ohio purchased spot coal from 18 different suppliers under 26 purchase orders. The spot purchases are listed by supplier and purchase order number in Exhibit 2-15. The spot purchases range from individual shipments to up to a full year of coal supply. Relatively little spot coal was purchased for 2009 due to the decline in demand. The average cost of this coal was relatively high compared to the contract purchases as much of the coal was purchased prior to the downturn in the market.

Exhibit 2-15. Spot Coal Agreements

[redacted]

Contract Procurements

This section of the audit report reviews the contract coal procurements for AEP Ohio. As discussed above, the last two plus years have been among the most challenging in the industry. During the first year (i.e., Q307 to Q308), an extremely tight coal market required that utilities focus on obtaining both their contracted and open volumes at reasonable prices. During the second year (i.e., starting in Q408), utilities focused on managing contract volumes under collapsing plant demand. These unusual times required utilities such as AEPSC to think beyond traditional procurement strategies.

Contract procurements are reviewed in this section following a discussion of several significant contract events that occurred during this volatile period. The first contract event was the buy-out of the long-term coal supply agreement for [redacted]. The second contract event or more accurately events were the non-traditional contract modifications that were made with [redacted] to address their financial distress.

An indication of AEPSC's success in its contract management for the AEP Ohio fleet is that there are no legal disputes regarding coal supply agreements for CSP or OPCO.

[redacted] *Contract Buyout*

In [redacted] Ohio Power Company entered into a [redacted] coal supply agreement for the [redacted].[7] A concern at that time was whether the price being paid to [redacted] under the coal purchase agreement was a market price, i.e., not a subsidy to [redacted] for [redacted] [redacted]. EVA concluded in the audit it conducted at that time that the price paid to [redacted] was within the range of market. The PUCO ordered that subsequent management/performance audits review how the price paid to [redacted] compared with market. EVA believes that this comparison continued until the beginning of the Market Development period.

By mid-2007, the price under [redacted] contract was significantly below market. The FOB mine price for the coal was below [redacted] per ton; the market price for this coal was over $100 per ton. A dispute over the contract arose that the parties elected to resolve through a Settlement Agreement and Mutual Release ("Settlement Agreement") which was signed December 27, 2007. The Settlement Agreement provided for the following, all of which occurred:

- [redacted] and AEPSC to enter into a new agreement, [redacted], for the supply of Central Appalachian coal;

[7] EVA was the management/performance auditor when that transaction was reviewed.

- [redacted] and AEPSC to amend [redacted] to terminate at the end of 2008;
- [redacted] to transfer to AEPSC or its designated affiliate certain mineral and real property interests in [redacted]; and
- [redacted] shall pay AEPSC [redacted].

Subsequently, AEPSC agreed to a buy out of the balance of an additional [redacted] tons of the remaining 2008 [redacted] contract tonnage for a total cash payment of $[redacted] or about $[redacted] per ton. The buy-out agreement ([redacted]) provided for a payment of [redacted] on December 15, 2008 and payments of $[redacted] on January 15, 2009 and every three months thereafter through 2009.

The buy-out, while negotiated in 2007 and booked prior to the ESP period, is essentially for tons that would have been shipped during the period of the ESP. As a result of the buy-out, OPCO ratepayers are paying significantly more for coal. This situation is somewhat unique given that OPCO fuel costs were not regulated during the period when the buyout occurred or the benefits booked yet the value was realized from coal that should have been delivered during the ESP period. In order to match revenues and costs, EVA believes the PUCO should consider whether it would be appropriate to credit the [redacted] and the [redacted] Reserve against OPCO's FAC under-recovery. The value of the [redacted] Reserve is not clear. AEPSC booked the value of the reserve at $[redacted] million in 2008. AEPSC believes the reserve contains [redacted] million tons of clean recoverable coal with a typical washed quality of [redacted] Btu per pound and [redacted] pound SO_2 per MMBtu. AEPSC commissioned [redacted] to perform a mine study for the [redacted] Reserve. The report entitled [redacted] Mine Feasibility Study [redacted] Coal Seam [redacted] Project Area was published April 2009. [redacted] confirmed the feasibility of developing a [redacted] mine that would "provide AEP with a strategic future coal supply." Using [redacted] price forecast, the value of the reserve on a net present value basis using an [redacted] percent discount rate would be $[redacted] million.[8]

[redacted]

[redacted]

[redacted]

As noted above, EVA recognizes this situation is somewhat unique. Further, EVA does not mean to suggest any motivation on the part of AEPSC to transfer value from ratepayers in 2009 to 2011 to an earlier date. It is clear that [redacted] initiated the Settlement Agreement because the contract price was well below market. That being said, the contract was an OPCO asset and the value associated with it would have flowed to OPCO ratepayers through the ESP period had there not been an early contract termination. Further, the difference between the price of the replacement coal and the contract price is one factor behind the large OPCO FAC under-recovery. Equity suggests that the PUCO consider whether some of the realized value should be credited against the under-recovery.

[redacted] *Contract Support*

AEPSC is a party to two long-term contracts with [redacted] subsidiaries. In [redacted], Cardinal Operating entered into [redacted]-year agreement with [redacted] for deliveries starting in 2008. In [redacted], OPCO entered into a 10-year agreement with [redacted]. Both agreements provide for delivery of coal to [redacted] and consequently involve [redacted]. Collectively, these agreements could have provided between [redacted] and [redacted] million tons per year in 2009. Both of these contracts had competitive prices at the time they were executed. By the second half of 2007, the contract prices were significantly below market.

Starting in February 2008, AEPSC received formal requests from [redacted] for immediate and on-going financial assistance in order to avoid breaching certain financial covenants under its loan agreements. [redacted] requested similar assistance from other customers as well. In June 2008, Ohio Power agreed to assist [redacted] by awarding it a [redacted]

AEPSC also agreed to provide on-going financial assistance in 2009 through a $[redacted] per ton increase in coal sold under the two agreements. The $[redacted] increase was not subject to adjustment and was deposited into a deposit control account which could be accessed only for the repayment of debt service. Finally, AEPSC retained the unilateral right as to whether the $[redacted] per ton increase would continue into 2010 and 2011.

AEPSC did not make this concession lightly. The steps undertaken by AEPSC included the following:

- An in-depth review of [redacted]'s lending agreements by AEPSC and outside counsel.
- An in-depth review of [redacted]'s pro forma financial statements.
- Independent modeling of [redacted]'s costs.
- Review by an AEP Professional Mining Engineer of [redacted] mine costs.
- Confirmation of participation by other utilities.
- Analysis of the cost associated with a [redacted] bankruptcy.

The due diligence conducted by AEPSC confirmed that absent financial assistance, [redacted] would effectively be insolvent. If [redacted] were forced into bankruptcy, the below market contracts would most surely be rejected which would require AEPSC to pay a "market price" for the same coal. Throughout most of the period, the market price was in excess of the contract price plus $[redacted] per ton. Further any replacement contracts would have locked in a price increase.

During 2009, [redacted] was able to [redacted]. As a consequence, AEPSC did not exercise its right to continue making these payments and the prices under the contracts in 2010 were not increased by the $[redacted] per ton. The year-on-year difference assuming comparable tonnage would be about $[redacted].[9]

EVA reviewed the justification for the amendments in the [redacted] contracts which provided for these payments and concurs that this decision was in the best

[9] [redacted].

interest of AEP Ohio ratepayers and commends AEPSC for its efforts. That being said, these contracts have many years to go. All efforts should be made to manage the counter-party risk.

[redacted] Contract Support

In 2008, [redacted] advised AEPSC that it was losing money under its contract and if no relief was provided it would not meet its financial covenants. During this period, coal prices had increased sharply and coal suppliers with legacy contracts were suffering as the higher prices had led to significant production cost increases. [redacted] provided access to its financial records which allowed AEPSC to confirm its financial difficulties. AEPSC also confirmed that the cost to replace the [redacted] coal would be significant.

AEPSC agreed to a two-prong financial support package for [redacted]. AEPSC agreed to [redacted] in September 2008 in order for [redacted] to be in compliance with its financial covenants. [redacted] agreed to repay AEPSC by deducting [redacted] tons beginning in 2009. AEPSC also agreed to increase the base price for all coal [redacted] per ton effective January 1, 2009. Additionally, the contract was amended to provide AEPSC with the right to extend the contract for two-three year periods after the scheduled [redacted] expiration at the agreed upon market price less [redacted] per ton. The base tonnage during the extension period would be [redacted] million tons per year through [redacted] million tons per year thereafter.

As with [redacted], AEPSC's actions were carefully considered and economically evaluated. AEPSC recognized both the history of the long and successful relationship with [redacted] and the importance of retaining [redacted] as a supplier [redacted]. EVA commends AEPSC for its actions regarding [redacted].

Contract Review

AEPSC is a party to a number of long-term coal supply agreements. During 2009, AEP Ohio received coal under 18 contracts although shipments under three of the contracts were carry-over tons from a prior period. Shipments by contract and supplier and listed in Exhibit 2-16.

[redacted]

Several suppliers have multiple contracts. The two largest suppliers in 2009 were [redacted] Combined [redacted] and [redacted] accounted for more than [redacted] percent of AEP Ohio's 2009 purchases, as shown in Exhibit 2-17. [redacted]

[redacted]

The key provisions of the 15 agreements are summarized in Exhibit 2-18.

Performance in 2009 under each of the long-term supply agreements is described below along with a summary of monthly shipments by plant. On the shipment tables, a shaded square indicates if the ash, SO_2/MMBtu, or Btu/lb are not compliant with the contracted half-monthly or monthly specification. [10]

[redacted]

[redacted]

[redacted]

In [redacted], AEPSC identified a large open coal position at [redacted] and [redacted]. Given these units were either scrubbed or being retrofit with scrubbers, they could accept higher sulfur coals. At the time, AEPSC had only two term contracts for high sulfur coal: one with [redacted] and the other with [redacted], an affiliate of [redacted]. [redacted] was selected following an RFP process in March [redacted].

The [redacted] contract is for [redacted] years. The first two years are at an annual rate of [redacted]; the rest is at the annual rate [redacted]. AEPSC also has a first right of refusal to additional production, a most favored nations clause, and the [redacted]

[10] Moisture excursions are not noted.

Shipments under the [redacted] Contract in 2009 are summarized in Exhibit 2-19. [redacted] The average quality was consistent with the contracted specifications although there were several months in which the Btu and ash contents were non-compliant.

Exhibit 2-19. Shipments Under [redacted] Contract

[redacted]

[redacted]

In [redacted] following the successful scrubber retrofits of the [redacted] stations, AEPSC determined the optimal coal blend for this station. To implement its strategy, AEPSC entered into several coal supply agreements in [redacted] including the one with [redacted] for lower sulfur coal. The agreement is for [redacted], starting in [redacted], for [redacted] tons per year. The contract has been amended to alter delivery logistics in a manner that either provided value to or was neutral to Ohio Power.

Shipments under the [redacted] Agreement in 2009 are summarized in Exhibit 2-20. Performance has been good with respect to tonnage and ash. SO_2 has been off in three months and at or above suspension limits in two of those months. Per the contract, the price for each shipment of coal having an SO_2 value greater than [redacted] pounds per MMBtu was reduced by [redacted] per ton. In two months of 2009, the average Btu was slightly below the half-month specification but well within the contractual minimums.

Exhibit 2-20. Shipments Under [redacted] Agreement

[redacted]

[redacted]

The initial [redacted] contract was signed in [redacted] for [redacted] per month of [redacted] coal for [redacted] that would be [redacted]. The initial contract ran through [redacted]. Subsequent amendments increased the volume to [redacted] tons per month and extended the contract, such that its current expiration date is [redacted]. In addition, [redacted] coal once its [redacted] is fully operational. However, at Buyer's option and if for at least a six month period, AEPSC can request only [redacted] tons of [redacted] coal and the balance [redacted]

Shipments under the [redacted] Agreement in 2009 are summarized in Exhibit 2-21. The first shipment of [redacted] coal was in [redacted]. Most of the coal shipped in [redacted]. The [redacted] coal consistently did not meet the contracted quality specifications. The [redacted] coal spec increased the contracted Btu/pound to 11,700 and decreased the ash to 9.0 percent. The initial shipments suggest this is an achievable quality.

Exhibit 2-21. Shipments Under [redacted] Agreement

[redacted]

Amendment [redacted] to the [redacted] Agreement also provided for the deferral of what is referred to as the "1/1/09 thru 3/31/09 Quantity Shortfall" and the delay in the delivery of [redacted] tons per month on contract quantity during the April 1, 2009 through December 31, 2009 period. AEPSC agreed to make a [redacted] per ton prepayment for the shortfall tons which will effectively be repaid when the coal is delivered ratably in later years.

The economic analysis of the [redacted] demonstrated a positive net present value to Conesville compared to the alternative of carrying higher stocks. The analysis did not include any risk associated with not ultimately receiving the tons which is always a risk of pre-payment.

[redacted] (07-[redacted]0021)

In [redacted], AEPSC determined a need for coal for [redacted]. The operating and environmental requirements dictate a mid sulfur, low ash fusion coal. The contract with [redacted] is one of three contracts for this product. The contract is for [redacted] years at [redacted] tons per year. The coal under this contract is shipped from the [redacted] mine which was [redacted]. The contract was not [redacted], retained the obligation to perform.

Shipments under this [redacted] contract are listed in Exhibit 2-22. Shipments were significantly below contract levels and the average SO_2 level was above the contracted half-month quality in most months and at suspendable levels in two months. AEPSC plans to complete the contract in [redacted].

Exhibit 2-22. Shipments Under [redacted] 07-10-07-902 Agreement

[redacted]

[redacted] [07-[redacted]-900]

[redacted] The new agreement provided for firm tons and prices for 2009 and 2010 and provided a unilateral option for OPCO for up to [redacted] tons in 2011 at a predetermined price. The agreement also imposed some good faith obligations for the parties to negotiate for 1.25 million tons in [redacted].

Shipments under the [redacted] 07-[redacted]-900 Agreement are summarized in Exhibit 2-23. Peabody shipped the full contract tonnage. However, most of the coal went to the [redacted] station, not [redacted]. In no months was the coal quality consistent with the contracted specifications.

[redacted]

In [redacted], AEPSC entered into a two year agreement with [redacted] for Powder River Basin coal given an expectation that [redacted] would burn a blend with [redacted] Powder River Basin coal. AEPSC subsequently decided that the required investment to

Exhibit 2-23. Shipments Under [redacted] 07-15-07-900 Agreement

[redacted]

achieve the [redacted] was not appropriate at this time given the uncertainty regarding new air regulations and the marginal role the [redacted] plant is playing. The current plan is to burn a blend with [redacted] Powder River Basin coal. As a result, AEPSC has excess Powder River Basin coal under contract. The excess coal is being diverted to [redacted].

Shipments under this [redacted] agreement in 2009 are summarized in Exhibit 2-24. The coal is shipped via the Cook Coal Terminal. The summary shows only the receipts at OPCO plants. The shortfall is overstated as about another 150,000 tons were either at Cook or in transit. The plan is to make up the shortfall in 2010. The delivered Btu content of the coal is consistently below the contracted specification.

[redacted] [07-[redacted]-900]

In [redacted], AEPSC and [redacted] entered into a complex contract for high volumes of [redacted] sulfur coal for an extended period. The contract is complex in part because of its sourcing/quality and in part because of its pricing. The coal is supposed to be from [redacted] mines. There are multiple quality specifications,

Exhibit 2-24 Shipments Under [redacted] Agreement [redacted]

[redacted]

some of which vary by year. Part of the coal comprises the [redacted] sulfur portion of the [redacted] coal blend and is delivered [redacted]. The pricing is complex because prices for segments get reset starting for 2009 which also affect annual tonnage nomination options. In addition to the five plus pages of the contract devoted to the Contract Price and Annual Tonnage Determination, the contract also includes by reference an Electronic Reopener Price Calculation Model which is provided on a compact disc attachment.

Interestingly, in 2008 when the price for the [redacted] volumes was to be reset for the years 2009 through 2012, the parties agreed to modify the procedures in the agreement and reprice the full [redacted] tons only for 2009. They agreed to reprice [redacted] tons for 2010 and 2011 leaving the balance to be repriced in 2009. In 2009, another [redacted] tons of 2010 and 2011 coal was repriced but the parties elected to defer the repricing of [redacted] tons of 2012 coal until 2010.

Amendment [redacted] included the 2009 repricing discussed above and provided for a deferral of [redacted] contract shipments until [redacted], a portion of which ([redacted] tons) will be shipped out of [redacted]. The deferred tonnage was also repriced.

Shipments under the [redacted] Agreement are summarized in Exhibit 2-25. Because the coal was shipped out of [redacted], the specifications were less stringent.

Exhibit 2-25. Shipments Under [redacted] Agreement 07-[redacted]-900

[redacted]

[redacted] (07-[redacted]-900)

In mid-[redacted], AEPSC determined a need for coal for [redacted]. For operating and environmental reasons, the units need a [redacted] sulfur, [redacted] fusion coal. AEPSC entered into a two-year contract with [redacted] for [redacted] tons per year for 2008 and 2009.

Shipments under this agreement are summarized in Exhibit 2-26. In only three of the 12 months was the coal compliant with the monthly specifications in the agreement and the annual averages were above the contracted specifications. Further, in at least one month (March 2009) [redacted] triggered the Buyer's right to suspend shipments This kind of consistent non-performance is a problem for a supplier such as [redacted] which has [redacted] to [redacted] its coal quality.

[redacted]

As noted above, in [redacted], AEPSC determined a need for coal for [redacted]. Given the boiler design and air emission limits, a [redacted] sulfur, [redacted] fusion coal is needed. The contract for [redacted] coal was one of three signed at about the same time.

Exhibit 2-26. Shipments Under [redacted] Agreement 07-[redacted]-901

[redacted]

Shipments under the [redacted]rces agreement in 2009 are summarized in Exhibit 2-27. In mid 2009 when it became clear that the projected burn would for [redacted] would not materialize, AEPSC amended the contract to defer 60,000 tons of 2009 deliveries until the second and third quarter of 2010 at the same price and under the same terms. The coal quality was generally in compliance with the contract specifications.

Exhibit 2-27. Shipments Under [redacted] Agreement

[redacted]

[redacted]

In [redacted] following the successful [redacted] of the [redacted] stations, AEPSC determined the [redacted] for this [redacted]. To implement its strategy, AEPSC entered into several coal supply agreements in [redacted] including the one with [redacted] for [redacted] sulfur coal. The agreement is for [redacted] years, starting in [redacted]. The first two years are at [redacted] tons per year; the last year at [redacted] tons.

Shipments under the [redacted] Contract in 2009 are summarized in Exhibit 2-28. [redacted] delivered the contract tons and met the SO_2 limits in each month. In four out the 12 months, [redacted] was non-compliant with the monthly guaranteed Btu but was well above the suspension limit.

Exhibit 2-28. Shipments Under [redacted] Agreement

[redacted]

[redacted]

In [redacted], Cardinal Operating and [redacted] entered into a [redacted]-year agreement for the supply of [redacted] tons per year to the [redacted] plant. In addition, the agreement gives [redacted] the right of first refusal on any tonnage sold from the mine to third parties and an exclusive option to purchase any or all of the production in excess of [redacted] tons each year provide such option is exercised no later than six months prior to the commencement of the next year. The mine is located on reserves [redacted].

Shipments in 2009 under the [redacted] Agreement are summarized in Exhibit 2-29. As discussed above, the price for coal shipped under this agreement in 2009 was $[redacted] per ton above the contract price. Due to reduced burn, in May 2009 the parties agreed to reduce 2009 tonnage by 200,000 tons and thereby reduced the option tonnage to [redacted] tons. The 2009 prices include the [redacted] which will not continue in 2010. Most of the shipments met the quality specifications.

Exhibit 2-29. Shipments Under [redacted] Agreement

[redacted]

[redacted]

The [redacted] contract with [redacted] was signed in [redacted] and provided for [redacted] tons of Specification A coal and [redacted] tons per year of Specification B coal through [redacted] with [redacted] one-year extension options for AEPSC. With 18 months notice, AEPSC could elect to require [redacted] to [redacted] the coal and deliver [redacted] tons per year of Specification C in lieu of Specification A coal. The specifications are described in Exhibit 2-30.

[redacted]

	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Subsequent amendments increased the term and prices. In [redacted], AEPSC amended the contract to increase volumes to [redacted] with an option to extend to [redacted]. As explained above, under the amended agreement, the potential term now runs to [redacted] with pricing in [redacted] and later at the agreed upon market price less a discount.

Shipments under the [redacted] Agreement in 2009 are summarized in Exhibit 2-31. The coal [redacted] was consistently higher in ash and lower in Btu than contracted.

Exhibit 2-31. Shipments Under [redacted] Agreement

[redacted]

[redacted] approached AEPSC in January [redacted] about using West Kentucky coal at several of its scrubbed plants traditionally supplied by Northern Appalachia coal. The timing was good as prices for Northern Appalachian coals had risen to all time highs. A technical review approved the coal for testing. Given expected [redacted] sulfur coal positions at [redacted], [redacted], and [redacted], AEPSC decided to proceed. AEPSC negotiated about a three year contract for [redacted] given the tight market at that time. As appropriate for a new source, the contract provided an out for AEPSC if it determined "in its sole discretion" that the [redacted] coal was not suitable.

Shipments under the [redacted] contract in 2009 are summarized in Exhibit 2-32. Other than a few months in which the Btu content was slightly below the contracted level, the quality of coal has been good.

Exhibit 2-32. Shipments Under The [redacted] Contract, 2009

[redacted]

According to AEPSC, the jury is still out with respect to the use of Illinois Basin coals in the AEP Ohio units. AEPSC recognizes the value this alternate supply region could provide in terms of competition to Northern Appalachia and indicated it is looking to expand the testing of Illinois Basin coals within the AEP fleet.

[redacted]

A long time source of supply to [redacted] has been the [redacted] mine[11]. [redacted]. In [redacted], the mine was sold to [redacted] and became part of a company currently known as [redacted]. The [redacted] contract is effectively a contract which is [redacted] the [redacted] coal to [redacted]. At the end of [redacted], [redacted] [redacted]

[11] The mine has been operated by different owners and under different names.

[redacted] closed on its purchase of [redacted] which included [redacted] mine in [redacted].

While CSP is the named buyer, relatively little of the coal as shown in Exhibit 2-33 moved to [redacted] in 2009 as CSP receives adequate supply from [redacted] and [redacted]. All shipments have been non-compliant with respect to ash. In many months, the monthly suspension level has been reached. Given the relatively high Btu content of the coal and the relative cost of the coal under the [redacted] agreement, AEPSC is making a sound decision not to force the ash issue.

Exhibit 2-33. Shipments Under [redacted] Agreement

[redacted]

EVA questions the need for and value of [redacted] in this situation as it unquestionably adds costs to the Seller and Buyer. AEPSC indicated that it was not [redacted]. EVA believes that AEPSC should be able to avoid the use of [redacted] in any future contracts for this coal through its procurement practices.

[redacted]

The current [redacted] contract was entered into in late [redacted]. Contract volume for 2009 was increased in mid-2008; the term was extended in mid-2009 with the deferral of some 2009 tons; and the tons and prices were modified in early 2010. This coal is purchased primarily for [redacted] has become a swing plant for OPCO making requirements both variable and uncertain. As a result, [redacted] shipments are directed to other plants if not needed at [redacted]. As shown in Exhibit 2-34, [redacted] was directed to [redacted] and [redacted] in 2009.

Exhibit 2-34. Shipments Under [redacted] Contract

[redacted]

The [redacted] met the SO_2 contract requirements on a regular basis. [redacted] missed the guaranteed monthly Btu specification in five out of the 12 months, although it was always above the 12,800 suspension limit. The ash maximum was exceeded during one month.

Transportation Review

Coal is generally offered to AEPSC FOB barge or FOB railcar and it is the responsibility of AEPSC to arrange for transportation. The only exception is truck coal which is sold FOB plant. Barge transportation is exclusively handled by AEP River Operations. River Operations is a wholly-owned affiliate operating within FEL. AEPSC is a party to multiple rail contracts under which the rail coal is delivered.

During the tight period in the market, AEPSC believes that its customers received extraordinary benefits from River Operations as the railroads were more focused on export business. AEPSC believes that a major reason it was able to maintain sufficient shipments to its plants was that it switched some rail movements to barge. The rates charged by River Operations are based upon costs and the returns and the allowed returns. The Financial Audit provides a full discussion of the associated accounting.

The rail contracts are summarized on Exhibit 2-35. AEPSC owns 1500 railcars and leases another 7500 which it uses as appropriate. Very little of the [redacted] movements use railroad owned cars.

Exhibit 2-35. Rail Contracts

[redacted]

There were no major issues with the railroads during 2009. The Burlington Northern's efforts to require dust controls on trains moving on the Joint Line out of the Powder River Basin would increase rail costs if the Burlington Northern is successful as the [redacted]. The issue is currently before the Surface Transportation Board. AEPSC is involved with industry groups looking at the viable alternatives for compliance: compaction or chemicals. AEPSC believes the costs will be under $0.50 per ton.

Other Fuel Procurement

AEPSC also acquires natural gas for AEP Ohio. The gas is for Darby and Waterford. Gas purchases in 2009 are summarized on Exhibit 2-36. Current strategy has been to buy gas [redacted]. AEPSC has multiple NAESB[12] agreements in place which serve as the basis for the purchases. If capacity factors

[12] North American Energy Standards Board

increase, AEPSC's strategy would be to [redacted].

Exhibit 2-36. Natural Gas Purchases

[redacted]

AEPSC also purchases fuel oil. In 2009, AEPSC used it fuel purchases to explore financial hedging strategies including what role they may ultimately play with respect to coal procurement.

Financial hedging of oil and natural gas is relatively common given the liquidity of these indexes. Subject to developing acceptable risk guidelines, such hedging is an appropriate strategy for reducing price volatility. The problem with using financial hedging for coal is that relatively little AEP Ohio coal is of the type that matches the traded indexes, i.e., NYMEX and PRB. Therefore, any financial hedging using the traded indexes would be what is referred to as a dirty hedge.

Further development of financial hedging strategies for coal is appropriate given the likelihood of continued price volatility. Prior to the implementation of any financial hedging program for coal, a protocol must be developed which defines trading parameters.

3

CONESVILLE COAL PREPARATION PLANT

Plant Description And Operation

The Conesville Coal Preparation Plant (CCPP) was built in the early 1980's to wash local, high-sulfur, raw coal for Conesville Units 1-4 which at that time was subject to a 5.66 pound SO_2 per MMBtu emission limit. Since that time, Units 1 and 2 have been retired, and Unit 4 has been retrofit with a scrubber.

CCPP has a rated capacity to wash 1,000 raw tons of coal per hour, but typically runs around 850 raw tons per hour. The preparation plant consists of three primary washing circuits, each set up to wash a certain size material:

1. The **jig circuit** washes the 6" by 3/8" raw coal and is operated to work at an effective specific gravity of 1.6-1.65. The typical quality of the refuse from the jig circuit is 83 percent ash and 1,174 Btu/lb. The jig circuit produces about 55 percent of the clean coal.

2. The **heavy media cyclone circuit** washes the 3/8" by 28 mesh raw coal with two 26" heavy media cyclones operating at 1.47-1.48 specific gravity. The typical quality of the refuse from the heavy media cyclone is 76-77 percent ash and 1,088 Btu/lb. The heavy media cyclone circuit produces about 40 percent of the clean coal.

3. The **flotation cells** wash the minus 28 mesh raw coal, but this circuit has been idled for years. The plant is currently screening the minus 28 mesh material at 100 mesh. The 28 to 100 mesh material is dried with centrifuges and sent to the clean coal conveyor. The minus 100 mesh material is dried with filter presses and sent to the refuse pile. The 28 to 100 mesh material produces about five percent of the clean coal.

CCPP operates Monday through Thursday, two 10-hour shifts per day. The day shift runs from 6 AM to 4 PM; the second shift performs maintenance on the plant from 4 PM to 2 AM. The plant is operated with 28 employees, 19 of which are UMWA hourly employees and nine are salary employees.

The raw coal handling facilities at the preparation plant site includes a truck dump, primary crusher to minus 6", raw coal pile with the ability to keep the two coals separate with a radial stacker, and an underground reclaim belt capable of blending the different raw coals. The clean coal handling facilities include a radial stacker with an underground reclaim conveyor that ships the coal directly to the Conesville power plant. A picture of the coal handling facilities at CCPP is shown in Exhibit 3-1. The picture was taken from the top of the preparation plant.

Exhibit 3-1. Coal Handling Facilities At CCPP

The refuse from CCPP is all dry refuse, i.e., no slurry ponds are used for the fine coal refuse. The fine refuse is dried with filter presses that reduce the moisture content of the fine refuse to about 30 percent. The fine refuse is blended with the coarse refuse and trucked to the refuse disposal area. The company reports it has sufficient permitted refuse area to last for 28 to 30 years at current operating rates.

CCPP currently washes raw coals from two different suppliers. In 2009, [redacted] supplied about 70 percent of the raw coal from an [redacted] mine with [redacted] percent ash and [redacted] percent sulfur. [redacted] supplies the other 30 percent from [redacted] mines with an average quality of about [redacted] percent ash and [redacted] percent sulfur. Also the [redacted] [redacted].

Operating Performance

The operating performance of the CCPP from 2006 to 2009 is shown in Exhibit 3-2. The utilization of the CCPP was down about 25 percent from 2008 because of the demand for coal-fired generation in 2009. In 2009, the CCPP received 1,895,1110 raw tons and produced 1,514,425 clean tons. The tonnage yield in 2009 was 79.9 percent, down slightly from the levels in the prior years. The Btu per pound of the clean coal was 11,553 , also down from prior years.

Exhibit 3-2. CCPP Operating Performance From 2006 To 2009

	2006	2007	2008	2009
Raw Tons	2,102,618	2,269,245	2,494,887	1,895,110
Clean Tons	1,718,352	1,843,571	2,013,091	1,514,425
Yield %	81.7%	81.2%	80.7%	79.9%
Btu/lb	11,795	11,745	11,636	11,553

The Btu yield for the CCPP was 92.3 percent in 2009. The Btu yield is the percentage of the Btu's in the raw coal that are recovered in the clean coal. The remaining 7.7 percent of the Btu's in the raw coal were thrown away in the refuse material.

As shown in Exhibit 3-3, the CCPP removes 40-50 percent of the ash depending on the ash content in the raw coal, and removes about 30 percent of the sulfur.

Operating Cost

The operating costs of the CCPP per clean and raw ton from 2006 to 2009 are shown respectively in Exhibits 3-4 and 3-5. In 2009, the total cost of the CCPP was [redacted] per clean ton. This was a [redacted] per clean ton increase (15 percent) from [redacted] per clean ton cost in 2008. The major reason for the increase in 2009 was the impact of washing fewer tons. The CCPP washed 1.5 million tons of clean coal in 2009, down 25 percent from the 2.0 million tons washed in 2008. This drove up the benefit, maintenance, power, and other costs that are largely fixed on a total dollar basis.

REDACTED VERSION

Exhibit 3-3. Raw And Clean Coal Ash And Sulfur Quality

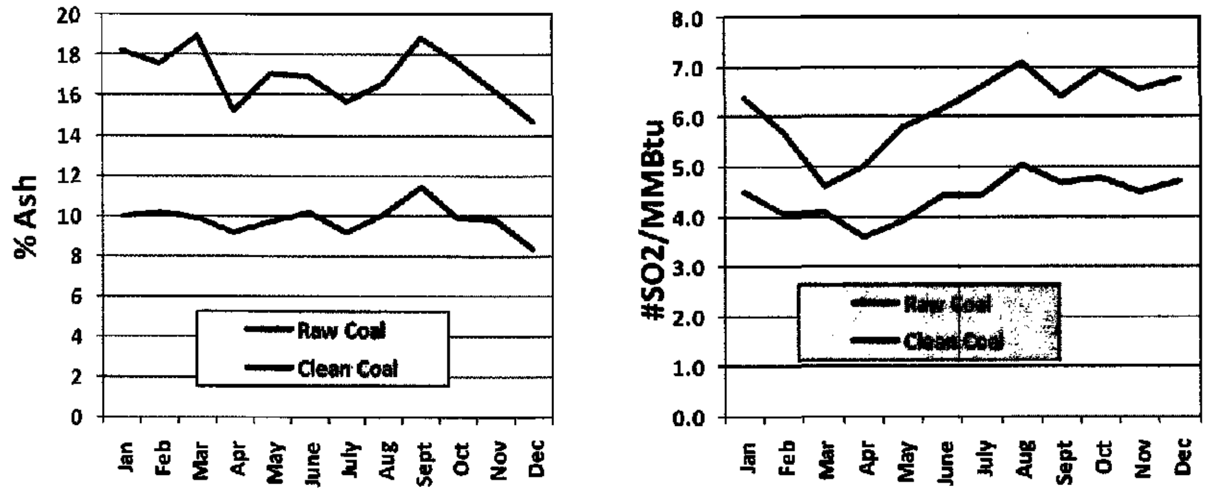


Exhibit 3-4. CCPP Clean Coal Operating Costs, 2006 to 2009

[redacted]

Exhibit 3-5. CCPP Raw Coal Operating Costs, 2006 To 2009

[redacted]

Labor costs are the largest portion of the operating cost of the CCPP. In 2009, labor costs were [redacted] per clean ton, of which [redacted] per ton was direct wages and salaries, [redacted] per ton for benefits excluding other post-employment benefits (OPEB), and [redacted] per ton for the OPEB. The other major operating costs in 2009 were [redacted] per clean ton for outside services, [redacted] per clean ton for maintenance, [redacted] per clean ton for power, and [redacted] per clean ton for supplies.

On a raw coal basis, the total cost of the CCPP was [redacted] per raw ton in 2009, up [redacted] per raw ton from [redacted] per raw ton in 2008. The raw tons washed at CCPP were down to 1.9 million tons in 2009 from 2.5 million tons in 2008. Like the clean coal costs, labor costs are the largest portion of the operating cost of the CCPP with [redacted] per raw ton in 2009, of which [redacted] per raw ton was direct wages and salaries, [redacted] per ton for benefits excluding other post-employment benefits (OPEB), and [redacted] per ton for the OPEB. The other major operating costs in 2009 were [redacted] per raw ton for outside services, [redacted] per raw ton for maintenance, [redacted] per raw ton for power, and [redacted] per raw ton for supplies.

Capital Costs

The CCPP capital costs were very low in 2009 at [redacted]. The two largest expenses were [redacted] for an on-line ash analyzer and [redacted] for monitoring wells. The on-line ash analyzer was installed on the clean coal belt as the clean coal leaves the plant. The justification for this expense was that Conesville Unit 4 requires a coal with an ash content less than 10 percent and without the analyzer the ash content of the clean coal from the plant was not known until about four days later. The delay in information made it difficult for CCPP to adjust the operation of the CCPP to improve the performance of the plant. CCPP estimated that the on-line ash analyzer would improve the yield of the prep plant by one percentage point, i.e., from 80 to 81 percent yield. Assuming 1.6 million raw tons in 2010, the one percentage point yield improvement would produce an extra 16,000 tons of clean coal. At an assumed value of $48.50 per ton, the total savings would be $776,000 per year. Using an estimated cost of $85,000 (it actually was [redacted]), the payback was estimated to be 1.3 months.

The on-line ash analyzer was put into operation in December 2009/January 2010 so the performance data are not yet available to confirm the assumptions used in the justification. EVA believes that the value of the on-line ash analyzer may have been over-stated, but was probably still economic to install. The yield of the CCPP is unlikely to improve by one percentage point while producing the same quality clean coal. The true value from a fuel cost perspective is the impact on the Btu yield which will likely by less than one percentage point. However even if the on-line ash analyzer can improve the Btu yield by just 0.1 percentage point, then the payback would have been 13 months and the purchase of the ash analyzer would have still been economic.

Also, the analysis did not include any benefit due to lower ash that may result from lower maintenance cost for the Unit 4 boiler. Presumably the assumption was the average ash content would not change, but that the fluctuations in ash would be significantly reduced. However, it is reasonable to expect that the average ash content will decline if the plant changes the operation of the jig and heavy media circuits when the ash content begins to exceed 10 percent.

The capital expenses for the monitoring wells was for four wells associated with the use of a project to place FGD and fly ash from the Conesville power plant in an abandoned mine under an Abandoned Mine Land project. This cost is not directly associated with the CCPP and is an expense for the benefit of the powerplant and the disposal of its FGD and fly ash material.

Impact Of Throughput On Operating Costs

The operating cost of the CCPP is affected by the amount of coal washed. The estimated operating cost of the CCPP at different utilization levels is shown in Exhibit 3-6. The blue line represents the total operating cost of the CCPP and ranges from [redacted] perclean ton at 2.0 million clean tons washed to [redacted] per clean ton at 500,000 clean tons

[redacted]

[redacted]

washed. The red line excludes costs that are sunk (i.e., are incurred whether or not the plant is operated or not) and represents the variable cash cost of operating the CCPP. The sunk costs estimate assumed that 80% of the OPEB benefits, and 100% of the ARO closing cost accrual and depreciation are sunk.

The operating costs excluding sunk costs should be used when evaluating whether to operate the CCPP or not. For example, CSP used a CCPP washing cost of [redacted] per clean ton to evaluate the [redacted] contract renegotiation. Based on EVA's estimate, the operating cost would be lower than [redacted] per clean ton if the CCPP washed more than 750,000 clean tons, or higher than [redacted]/ton if the CCPP washed less than 750,000 clean tons.

EVA recommends that AEPSC perform a detailed analysis of the variable/incremental operating cost of the CCPP at various levels that would cover the possible operating levels of the preparation plant in the context of expected reduced volumes due to the [redacted] coal and the expected retirement of Conesville 3. The labor cost portion of this operating cost analysis should reflect the likely staffing and operating schedule for the various operating levels. This cost analysis should also separate the sunk costs from the variable/incremental cost of operating the plant. For example, CSP is obligated for a portion of the OPEB benefits for retired workers and existing obligations for active workers whether or not the CCPP is operated. This and any other sunk costs, and any non-cash costs such as the ARO closing cost accrual and depreciation, should be excluded for the variable/incremental operating cost estimate.

4

ENVIRONMENTAL AUDIT

Environmental Requirements

AEP Ohio coal plants are subject to air emission regulations through both state and federal programs. The only units equipped with flue gas desulfurization equipment when built were the Conesville 5 & 6 units. Since then Gavin, Mitchell, Cardinal 1 and Conesville 4 have been retrofitted with scrubbers.[1] As shown in Exhibit 4-1, the only remaining unit for which a scrubber is planned is Muskingum 5 in 2015. With the exception of Conesville 5&6, all of the scrubbed units and Muskingum 5 are equipped with selective catalytic reduction (SCR) for NOx control. AEP plans to retrofit Conesville 5&6 with SCRs in 2015. There are currently no plans to scrub or retrofit SCRs on Conesville 3, Kammer, Muskingum 1-4, and Picway.

Exhibit 4-1. Status Of Environmental Retrofits On AEP Ohio Units

	Cardinal	Conesville				Gavin		Kammer			Mitchell		Muskingum River					Picway
	1	3	4	5	6	1	2	1	2	3	1	2	1	2	3	4	5	5
SCR	X		X	2015	2015	X	X				X	X					X	
FGD	X		X	X	X	X	X				X	X					2015	

Note: X means installed; shading means not planned

The technology AEP chose for the scrubber retrofit on Cardinal 1 (as well as Muskingum River 5 and other non-AEP Ohio plants) utilizes the jet bubbling reactor technology.

[1] The scrubber retrofit on Cardinal 1

AEP has encountered unexpected operating results with this technology which it has determined are a result of fundamental design deficiencies and that "inferior and/or inappropriate materials were selected for the internal fiberglass components." AEP has reported in its most recent 10-K filing that it is in discussions with Black & Veatch, the equipment manufacturer, to repair the scrubbers and may pursue legal remedies if AEP cannot resolve these issues with Black & Veatch. EVA recommends that the next management/performance auditor review the Cardinal 1 scrubber situation and determine what if any FAC costs are due to this situation.

Under the current regulatory regime, AEP must forfeit an SO_2, seasonal NOx, and annual NOx emission allowance for each ton of SO_2, seasonal NOx, and annual NOx its units emit. The prices of emission allowances have been very volatile. As a result of significant technology retrofits, uncertainty regarding future emission allowance markets, and, in 2009, reduced generation, allowance prices have fallen considerably.

AEP has a stated policy with respect to emission allowance management. The policy acknowledges AEP's responsibility to have sufficient allowances to support generation. Only if it is determined that AEP has surplus allowances will the disposition of allowances be considered. AEP Ohio is a party to the Interim Allowance Agreement which provides the framework for the allocation of SO_2 purchases and sales among the AEP companies. Season and Annual NOx are managed separately for CSP and OP.

Emission Banks

The emission banks for AEP Ohio as of the start and end of the audit period are summarized in Exhibit 4-2. With the uncertainty over future value and the large drop in emissions in 2009, the market for allowances has essentially dried up. During 2009, the only recorded sales related to the March auction of allowances[2], some true ups/power sales-related, and emission re-allocations pursuant to the Interim Allowance Agreement and the Gavin reallocation.

[2] The EPA withholds 2.8 percent of the emission allocations each year and sells them in an auction. Auction proceeds are then distributed to the utilities.

Exhibit 4-2. Status Of Emission Allowance Banks

	Columbus Southern Power				Ohio Power			
	Balances as of 12/31/2008		Balances as of 12/31/2009		Balances as of 12/31/2008		Balances as of 12/31/2009	
	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars
SO2								
Current	151,636	$17,485,593	190,219	$25,028,207	342,831	$10,603,779	384,833	$8,917,715
Non-Current	1,804,575	$16,303,007	1,789,912	$14,539,865	6,786,046	$20,826,342	6,766,542	$18,353,956
SO2 Total	1,956,211	$33,788,600	1,980,131	$39,568,072	7,128,877	$31,430,121	7,151,375	$27,271,671
Seasonal NOx								
Current	3,159	$2,683,896	7,779	$979,795	18,093	$658,594	25,513	$335,256
Non-Current	1,060	$0	18,348	$0	71,115	$0	56,892	$0
Seas. NOx Total	4,219	$2,683,896	26,127	$979,795	89,208	$658,594	82,405	$335,256
Annual NOx								
Current	410	$0	13,400	$564,342	33,906	$0	44,126	$0
Non-Current	2,050	$0	45,260	$0	186,030	$0	148,824	$0
Annual NOx Total	2,460	$0	58,660	$564,342	219,936	$0	192,950	$0

Source: LA 1-50

AEP Ohio's consumption of emission allowances in 2009 is summarized in Exhibit 4-3 based upon ownership shares. Muskingum River was the largest emitter of SO_2, while Conesville was the largest emitter of seasonal and annual NOx reflecting the lack of a scrubber on Muskingum 5 and the lack of SCRs on Conesville 5 & 6, respectively.

Forecast Of Consumption Of Emission Allowances

AEP's current forecast of SO_2 emission allowance consumption through 2014 is summarized on Exhibit 4-4. Beginning in 2012, AEP assumes that two allowances must be forfeited for each ton of SO_2 emitted. The forecast is compared to 2009 emissions.

The biggest change from 2009 is with respect to Stuart because of the scrubber retrofit. OPCO emission allowance consumption is expected to increase in 2010 with higher generation. Assuming the forfeiture policy remains the same under the revamped CAIR, AEP OH has adequate SO_2 allowances in its bank for 30 years (assuming the scrubber retrofit of Muskingum River 5 proceeds as planned). While AEPSC is not actively marketing SO_2 allowances, it indicated that it would consider a sale if there was market interest.

Exhibit 4-3. Allowance Consumption During Audit Period (Tons)

		SO2	Seasonal NOx	Annual NOx
CSP	Beckjord 6	2,384	185	505
	Conesville	19,542	3,505	9,216
	Darby	-	3	-
	Dresden	-	-	-
	Lawrenceburg	1	27	-
	Picway	2,229	292	359
	Stuart	16,415	786	2,106
	Waterford	-	28	-
	Zimmer	3,885	386	976
CSP TOTAL		**44,456**	**5,212**	**13,162**
OP	Amos 3	2,053	564	1,222
	Cardinal 1	2,679	184	564
	Gavin	26,373	2,697	6,905
	Kammer	16,763	1,281	3,266
	Mitchell	3,171	852	2,245
	Muskingum River	98,067	2,434	7,801
	Sport 2, 4, 5	11,230	818	2,772
OP TOTAL		**160,336**	**8,830**	**24,775**
AEP OHIO TOTAL		**204,792**	**14,042**	**37,937**

Exhibit 4-4. Forecast Of SO_2 Emission Allowance Consumption (1,000 Tons)

[redacted]

AEP's current forecast of seasonal and annual NOx emissions is provided on Exhibit 4-5. As with SO_2, emissions vary with technology and plant utilization.

Exhibit 4-5. Forecast Of Seasonal And Annual NOx Emission Allowance Consumption (1,000 Tons)

[redacted]

AEP OH companies also have a surplus of NOx emissions. AEPSC indicated that it did not believe the surplus will ever be utilized for compliance and that it was looking to monetize the surplus. AEPSC uses a variety of brokers (e.g., Climate Futures Exchange, ICAP, and Evolution Markets) for the sale.

Future Environmental Requirements

There is considerable uncertainty regarding future environmental regulations. In December 2009, the EPA issued a finding that greenhouse gas emissions "cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare". This "endangerment" finding under Section 202(a) of the Clean Air Act (CAA) requires that EPA promulgate standards to control such greenhouse gases (GHG) as air pollutants. EPA had already started the process with regulations requiring GHG emission monitoring and reporting.

Regulations for controlling GHG emissions are particularly challenging as there are no "significance" thresholds for GHG emissions in the CAA. To address the "significance" issue, EPA proposed regulations to limit the number of sources that would be subject to GHG regulation by established a trigger set by annual emissions. The "Tailoring Rule" proposed September 30, 2009 established 25,000 tons per year of carbon dioxide equivalent emissions as the trigger. It is not clear that EPA has the authority under the CAA to set thresholds different from those stated in the CAA and many predict the "Tailoring Rule" would not survive a legal challenge.

The schedule for GHG regulations started with New Light-Duty Vehicles. Regulations were proposed in September 2009 and are expected to be finalized in early 2010. EPA is expected to follow with regulations for all categories of new emissions (new facilities or modifications) that result in emissions above the threshold amount. These sources will be required to install best available control technology (BACT) although it is not at all clear what is BACT for CO_2. Absent legislation prohibiting EPA from proceeding, a court ruling that overturns EPA's endangerment finding, and/or new legislation defining a carbon control program, the EPA is expected to proceed.

EPA also has multiple new clean air rules in the offing including replacements for the Clean Air Mercury Rule ("CAMR") which was vacated by the courts in 2008 and the Clear Air Interstate Rule ("CAIR") which was also vacated by the courts in 2008 but reinstated later the same year pending the replacement rule. The EPA is reviewing the National Ambient Air Quality Standards ("NAAQS") for six criteria pollutants to determine the current levels sufficiently protect health (primary standard) and welfare (secondary standard). While a review every five years is required by the CAA, the EPA has consistently failed to perform such reviews. Any changes to NAAQS could require states to revisit their State Implementation Plans. Any changes to air pollution results could affect what pollution control equipment is required to continue to operate. With the exception of Conesville 3, AEP has not announced plans to retire its small coal units. Any program which requires pollution control retrofits could accelerate retirement plans. Another likely change in the new regulations will be the elimination of regional trading which will also affect compliance strategies and the value of emission allowances.

As part of its responses to auditor data requests, AEP Ohio provided a summary of its greenhouse gas ("GHG") emission reduction strategy. AEP Ohio indicated its strategy contains the following elements:

- Active participation in discussions around federal climate policy,
- Active participation in the Chicago Climate Exchange and the International Emissions Trading Association,
- Compliance with renewable energy and efficiency targets included in S.B. 221,
- Consideration of efficiency improvements in its generating fleet which will reduce CO2 emissions,
- Exploration of carbon capture and storage options for possible application to AEP Ohio plants,
- Exploration of lower CO2 emitting generating sources, and
- Investigation of emission offset credits as a compliance option.

.This summary is consistent with the 2009 AEP-East Integrated Resource Plan published in July 2009.

Environmental Reagent Costs

The cost of environmental reagents is recovered in the FAC. Reagent costs have increased with the addition of scrubbers at [redacted], Conesville, and [redacted] and SCRs. A schedule of reagent requirements by plant is provided in Exhibit 4-6.

Exhibit 4-6. Reagent Requirements By Plant

	Lime	Limestone	Hydrated Lime	Trona	Urea
Conesville 4		X	X	X	X
Conesville 5/6	X				X
Cardinal		X	X	X	X
Mitchell		X	X	X	X
Gavin	X			X	X
Muskingum River					X

The Gavin and Conesville 5&6 scrubbers use lime: the other (newer) scrubbers use limestone. The use of limestone scrubbers has reduced the relative cost of scrubbing as limestone is significantly lower in cost than lime. There are multiple suppliers of limestone and good long-term availability. AEPSC uses hydrated lime for water treatment with the limestone scrubbers. Lime availability for the lime scrubbers is a concern.

The trona is used for SO3 mitigation. The largest trona deposit is in the Green River Basin in Wyoming. The trona is difficult and expensive to transport because it must be kept dry and away from heat.

Urea is required by the SCRs. The urea is imported from Qatar. Pricing is based upon the world market price for this commodity. The material is delivered by vessel to New Orleans and moved in covered barges to Ohio.

The consumable contracts in place during 2009 are summarized in Exhibit 4-7. There was enough flexibility in the lime and limestone contracts that AEPSC did not incur penalties for reduced shipments in 2009. AEPSC did incur some liquidated damages in its trona contract. The urea contract volume is tied to burn.

Exhibit 4-7. Consumable Contracts

[redacted]

5

POWER PLANT PERFORMANCE

Benchmarking

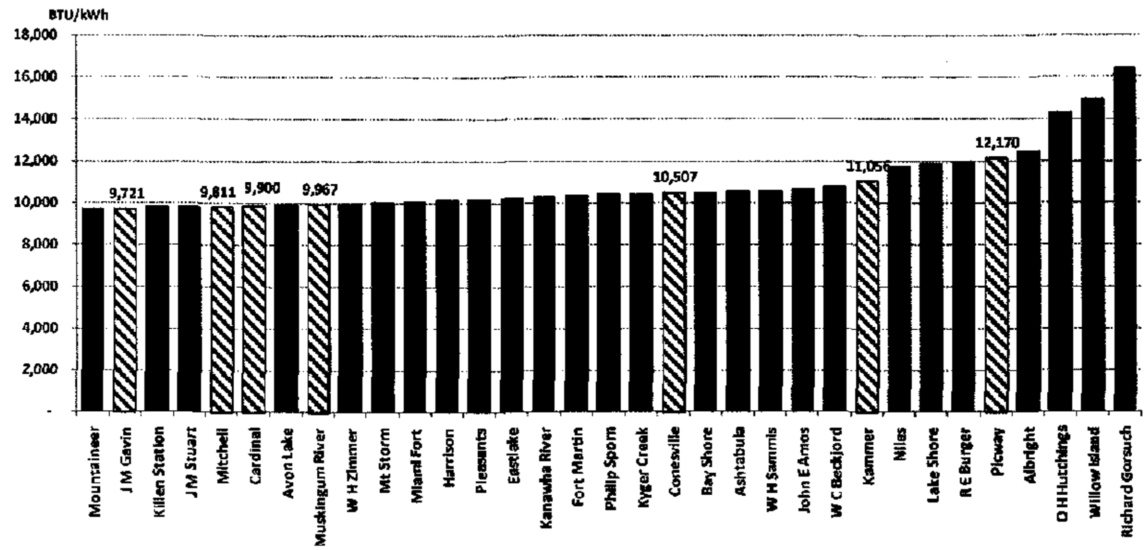
AEP Ohio operates seven coal-fired power plants. AEP Ohio's performance with respect to these power plants can be measured by comparison with other coal-fired power plants in Ohio and West Virginia. Two measures are used to demonstrate performance: heat rate and capacity factor. Heat rate is the Btu's consumed per kilowatt-hour generated. Capacity factor is the megawatt-hours generated over total potential generation.

The heat rates for the AEP Ohio plants compared to the heat rates for the other coal-fired plants in Ohio and West Virginia is provided for 2009 in Exhibit 5-1. The data used to generate these figures are from the Department of Energy, FERC, and EPA.[1] The AEP Ohio plants are highlighted. In 2009, Gavin had the second best heat rate out of the group and four of AEP Ohio's plants were in the top 10.

The capacity factors for the same units for 2009 are provided in Exhibit 5-2. Gavin had the highest capacity factor while the three other plants with decent heat rates all had greater than a 60 percent capacity factor. Not surprisingly there is a general correlation

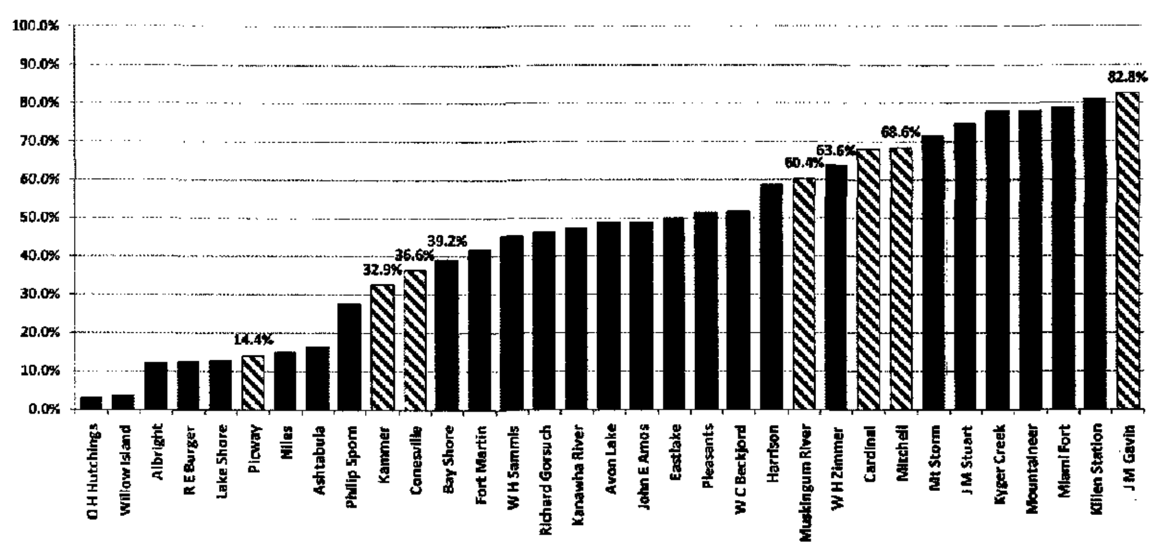
[1] All of the data (AEP and other plants) come from 2009 EIA-923 except Picway. Picway data come from FERC Form 1 (net generation) and EPA CEMS data (heat input).

Exhibit 5-1. Coal-Fired Power Plant Heat Rates 2009



between heat rate and capacity factor. Conesville suffered in 2009 due to a major boiler overhaul and the scrubber tie in on Unit 4. Conesville 4 had the lowest availability of the AEP Ohio units.[2]

Exhibit 5-2. Coal-Fired Power Plant Capacity Factors 2009

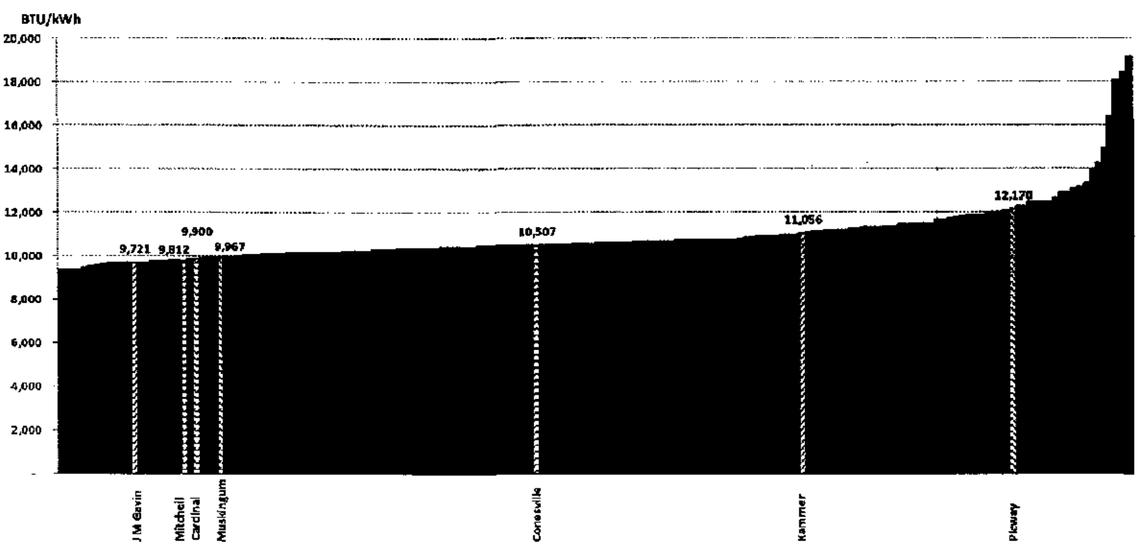


[2] EVA 1-38.

The AEP Ohio plants are also benchmarked against the coal-fired PJM plants. AEP Ohio as a member of PJM gets dispatched by PJM. Therefore, the competitiveness of the AEP Ohio within PJM determines their utilization subject to transmission adders.

Exhibit 5-3 provides the heat rates for all PJM coal-fired plants in 2009. Four AEP Ohio plants fall in the top quartile. While Conesville fell in the middle in 2009, the extended outage on Conesville 4 makes it an atypical year.

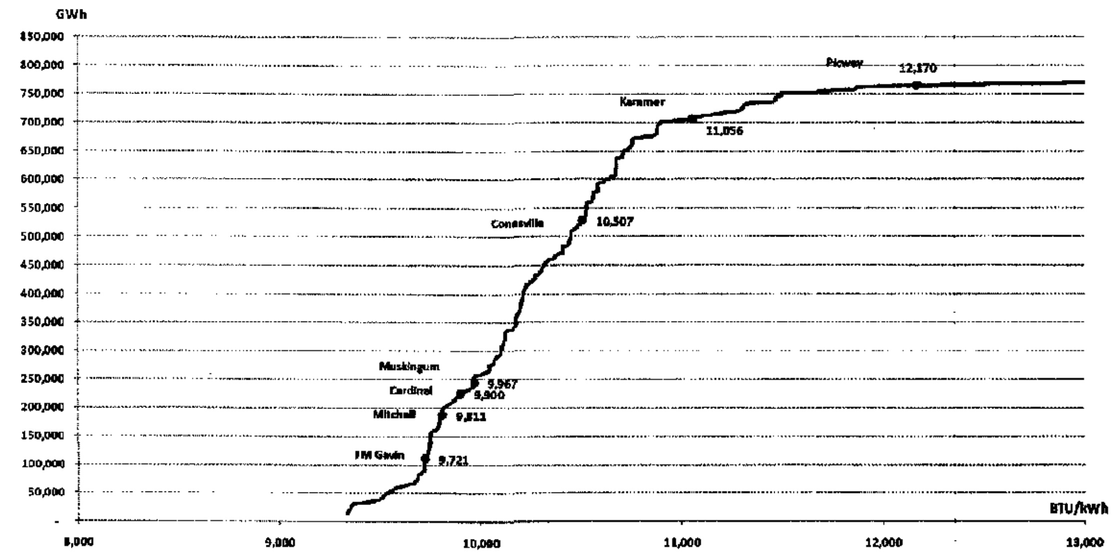
Exhibit 5-3. PJM Coal-Fired Power Plant Heat Rates 2009



The relative heat rate rankings for the AEP Ohio units with respect to total generation are provided on Exhibit 5-4 for 2009. This graph is a better measure of the competitiveness of the AEP Ohio units than the simple unit comparisons which do not capture plant size.

In this presentation, the same four units are on the lower part of the curve. The biggest difference between the presentations is with respect to Kammer. Within the PJM system, Kammer is clearly a marginal unit at least based upon its 2009 performance.

Exhibit 5-4. PJM Coal-Fired Power Plant Cumulative Generation By Heat Rate 2009



Findings

Four of the AEP units have good heat rates and high capacity factors compared to both the coal-fired utility plants in Ohio and West Virginia and the PJM coal-fired utility plants. With respect to fuel procurement, this means that there should a higher level of certainty surrounding the coal requirements for Gavin, [redacted], [redacted], and [redacted] than for the other units.

6

ALTERNATIVE ENERGY SOURCES

Requirements

S.B. 221 included an Alternative Energy Portfolio Standard (O.R.C. 4928.64-65) which requires 25 percent of all kilowatt hours of electricity sold by electric distribution utilities and electric services companies to retail electric consumers under their standard service offers to be obtained by "alternative energy sources" by 2025. Alternative energy sources are defined as "advanced energy resources" and "renewable energy resources" that satisfy the applicable placed in-service requirement. Alternative energy sources can also include new and existing customer-sited advanced and renewable energy resources that the customer commits to integrate into the utility's demand-response, energy efficiency, or peak demand reduction programs. Examples include a resource that has the effect of improving the relationship between real and reactive power; a resource that makes efficient use of waste heat; storage technology that allows customers to modify their demand or load and usage characteristics; and any advanced renewable energy resource that can be utilized effectively. The final rules implementing the Alternative Energy Portfolio Standard were not issued until December 10, 2009.

At least half of the alternative energy requirement must be satisfied from "renewable energy sources" which must include solar. The percentage required by year is provided on Exhibit 6-1. The other requirement is that at least 50 percent of the renewable energy must come from in-state facilities and the balance must come from facilities that can deliver into the state. Technologies that qualify under the renewable category include: solar, wind, hydroelectric, geothermal, waste derived fuel, biomass, biologically derive methane gas, wood waste, fuel cells, and storage facilities.

Exhibit 6-1. Renewable Energy Benchmark Requirements

Year	Renewable Energy Resource	Minimum Solar
2009	0.25%	0.004%
2010	0.50%	0.01%
2011	1.00%	0.03%
2012	1.50%	0.06%
2013	2.00%	0.09%
2014	2.50%	0.12%
2015	3.50%	0.15%
2016	4.50%	0.18%
2017	5.50%	0.22%
2018	6.50%	0.26%
2019	7.50%	0.30%
2020	8.50%	0.34%
2021	9.50%	0.38%
2022	10.50%	0.42%
2023	11.50%	0.46%
2024	12.50%	0.50%

The remaining up to half of the alternative energy requirement can come from "advanced energy resources." Technologies which would qualify include: any method or device which would increase electricity output without an increase in carbon emissions; a distributed generation system consisting of customer cogeneration and thermal output; clean coal technology which limits emissions of carbon; advanced nuclear technology; fuel cells; and demand side management and energy efficiency improvements. Unlike the renewables, there are no interim requirements, simply a cumulative 25 percent requirement by 2025.

To ensure compliance with the alternative energy standards, utilities are required to file an annual report which details its performance. If the utility has failed to meet its requirements in any year and such under-compliance is deemed to have been avoidable, the utility will be assessed a monetary penalty referred to as the "alternative compliance payment ("ACP"). The non-solar ACP is initially set at $45 per MWh and will be adjusted annually by the PUCO according to changes in the Consumer Price Index. The solar ACP is initially set at $450 per MWh. In 2010 and 2011, the solar ACP is reduced to $400per MWh and then gets reduced by $50 every two years thereafter until it hits $50 per MWh in 2024. ACPs are deposited into the Ohio Advanced Energy Fund which provides funding for renewable and energy efficient projects within the state. ACPs are not recoverable through the FAC.

Utilities can obtain relief from certain requirements and avoid paying the ACP. A utility does not have to comply if it demonstrates that compliance with the portfolio standard is "reasonably expected" to increase generating costs by three percent or more. In addition, a utility can obtain relief through the force majeure provisions which state that the PUCO has the ability to waive compliance if the utility can demonstrate there were insufficient renewable energy products in the market place.

2009 Alternative Energy Status And Compliance Reports

In Case No. 08-888-EL-ORD, the PUCO approved Rules for the Alternative Energy Portfolio Standard for electric utilities. The Rules require each utility to file an annual report by April 15th of each year. CSP and OPCO both complied with this requirement; a summary of each report is contained in this section. The Rules also require the filling of an annual Alternative Energy Portfolio Compliance Plan by April 15th which details plans for compliance with the future benchmarks. The Companies submitted a joint compliance plan which is also summarized below.

Columbus Southern Power Compliance Report

CSP actual versus benchmark performance is summarized in Exhibit 6-2. CSP met its non-solar benchmark through in-state REC purchases and through an out-of-state power purchase of wind. AEP Ohio filed and received a force majeure-related reduction in the solar requirement on behalf of both CSP and OP. As a result, CSP considers itself to have been compliant with both the non-solar renewable requirement and revised solar requirement in 2009.

Exhibit 6-2. CSP 2009 Alternative Energy Compliance Report

	Non-Solar		Solar	
	In State	Additional	In State	Additional
Actual MWH	24,526	24,526	68	-
Benchmark	>=24,526	49,052 minus In State	>=399*	798 minus In State*

* CSP received a force majeure for compliance with solar benchmark in 2009.

As part of the compliance report, CSP provided information on the source of the solar and non-solar RECs. The primary source of the solar RECs was the Athens Service Center. The non-solar RECs were split between landfill gas and wind. Fowler Ridge II energy started to be received in November 2009.

Ohio Power Compliance Report

OPCO actual versus benchmark performance is summarized in Exhibit 6-3. OPCO met its non-solar benchmark through in-state REC purchases and through an out-of-state power purchase of wind and REC purchases. AEP Ohio filed and received a force majeure-related reduction in the solar requirement on behalf of both CSP and OP. As a result, OPCO was compliant with both the non-solar renewable requirement and revised solar requirement in 2009.

Exhibit 6-3. OPCO 2009 Alternative Energy Compliance Report

	Non-Solar		Solar	
	In State	Additional	In State	Additional
Actual MWH	31,621	31,621	95	-
Benchmark	>=31,621	63,242 minus In State	>=514*	1,028 minus In State*

* OP received a force majeure for compliance with solar benchmark in 2009.

As part of the compliance report, OPCO provided information on the source of the solar and non-solar RECs. The primary source of the solar RECs was the Newark Service Center. The non-solar RECs were split between landfill gas and wind. Fowler Ridge II energy started to be received in April 2009.

Alternative Energy Portfolio Compliance Plan

The Alternative Energy Portfolio Compliance Plan was filed on a timely basis. The Compliance Plan provides the current estimates of the benchmarks based upon forecast generation.

The compliance plan itself is general and simply states that the Companies have developed a 10-year strategy for compliance. The only details provided with respect to non-solar compliance are that the Companies have purchased some In-State RECs and the Companies will be receiving RECs as part of its power purchase agreements for the Fowler Ridge II wind farm in Indiana. The only details provided with respect to solar requirements compliance are that it will be partially achieved by AEP Ohio's two 70kW solar facilities at its service centers in Athens and Newark and a 10.1 MW power purchase with Wyandot Solar LLC.

The Companies indicate that its general methodology is to identify renewable options and then rank them based upon a levelized cost. The renewable options that have been fully evaluated include: biomass co-firing at coal plants, wind, solar, incremental hydro, landfill gas with micro-turbine, geothermal and distributed generation. The Companies indicated in the Compliance Plan a preference for satisfying its requirements through power purchase agreements with RECs or REC purchases rather than owning the physical assets because of its limited expertise with these types of projects and because of capital limitations.

In 2009, AEP issued an RFP on behalf of all of its operating companies for 1,100 MW of renewable resources. According to AEP, the responses included a "number of proposed wind projects in Ohio that had relatively attractive prices".

In the Compliance Plan, AEP Ohio identified some near-term concerns about complying with the in state non-solar requirements. AEP Ohio is concerned that some projects will not receive timely state certification. The current REC market is very thin and illiquid resulting in very high prices for the available RECs.

Responsibilities For Compliance With The Alternative Energy Standards

According to AEP, the responsibilities for meeting the alternative energy standards are divided among multiple departments. With respect to evaluating compliance options, the

Resource Planning and Operational Analysis department which is responsible for developing the integrated resource plan for AEP-East determines the best compliance options. The Resource Planning and Operational Analysis department uses the Strategist optimization model to evaluate capacity additions. With respect to implementing the strategy, the responsibilities are split according to the resource. The renewables are the responsibility of the Renewable Energy department within Commercial Operations. AEP Ohio Customer Services Alternative Energy Resources department is responsible for customer-sited renewable energy resource distributed generation. The Fuel Procurement group within FEL is responsible for the acquisition of the biomass that will be blended with coal at existing power plants. The Emissions group within FEL is responsible for the market purchases of the RECs.

Accounting For RECs

AEPSC indicates that at least initially it intends to follow the same or similar policies and procedures for purchasing, selling, and accounting of RECs as it does for emission allowance. The Company currently uses the PJM Environmental Information Services Generation Attribute Tracking System (GATS) to document and track RECs. AEPSC indicated if it moves into a position of excess RECs it may move to a different inventory situation.

Activities in 2009

AEPSC as agent for AEP Ohio issued two RFPs (7/15/09 and 12/3/09) for RECs and one supplemental RFP for solar (1/9/09). AEPSC on behalf of all AEP affiliates issued an RFP for renewable energy (6/1/09).

AEP Ohio entered into three contracts in 2009. In February 2009, CSP and OPCO each entered into 50 MW agreements with Fowler Ridge II Wind Farm LLC. These virtually identical agreements are for 20 years and establish an hourly price by day of the week and month which is in affect for the first three years. The base prices range from [redacted] per MWh to [redacted] per MWh. Thereafter the price escalates on an annual basis by [redacted]. The other agreement was with Wyandot Solar LLC for 10.1 MW which was entered into in June 2009. Like the wind deals, the solar contract is for 20 years. The price is fixed. The wind agreements will satisfy the non in-state portion of the renewable obligation through mid 2014. Wyandot Solar is expected to come on line in mid 2010 and will satisfy the solar requirement for 2010 (including the deferred compliance from 2009), 2011 and most of 2012.

The power prices and term in the all three contracts are reflective of the current market for renewable energy. Nevertheless, the prices are high with respect to current non-renewable generation.

In early 2010, AEPSC issued two RFPs for the supply of biomass to several of its coal-fired plants. AEPSC is looking to vendors to provide a pre-blended product on both a spot and contract basis. This idea is interesting but may require some time for coal producers to support this market. Other utilities are looking at purchasing the biomass themselves for blending at the plant.

Conclusions

AEP's strategy for developing and complying with alternative energy portfolio standards is still evolving. The initial deals were done to achieve compliance with early deadlines but EVA is extremely concerned about the cost consequences of an over-reliance on 20-year annually escalated power purchase agreements. EVA appreciates the current strategy of looking at all alternatives but strongly recommends a greater emphasis on self-build options if the 20-year terms with annual escalation (for the non-solar renewable) are the market requirement for power purchase agreements. Furthermore, EVA also recommends that if RECs are unavailable, the continued use of force majeure or in the alternative, ACPs for the non-solar renewable should be considered if additional time is needed to pursue the self build option.[1]

[1] The statutes states that the Commission may increase the amount (of the ACP) to ensure that payment of compliance payments is not used to achieve compliance ... in lieu of actually acquiring or realizing energy derived from renewable energy resources."

7

FINANCIAL AUDIT OF THE FUEL ADJUSTMENT CLAUSE RIDER (FAC) COMPONENT

Organization

The section of the report concerning the FAC filings audit is organized into the following sections:

- Certificate of Accountability of Independent Auditors
- Determination of FAC Rates in AEP Ohio's Filings for the Period Under Review
- Minimum Review Requirements
- Review Related to Coal Order Processing
- Review Related to Station Visitation and Coal Processing Procedure
- Review Related to Fuel Supplies Owned or Controlled by the Company
- Review Related to Purchased Power
- Review Related to Service Interruptions and Unscheduled Outages
- FAC Filings, Supporting Workpapers and FAC Component Audit Trail Documentation
- Changes to Fuel, Purchased Power Procurement and Emission Allowance Procurement
- Internal Audits
- Memorandum of Findings
- Summary of Recommendations

REDACTED VERSION

Certificate Of Accountability Of Independent Auditors

To: American Electric Power-Ohio

We have examined the quarterly FAC filings of Columbia Southern Power Company and Ohio Power Company ("AEP Ohio") for the year ended December 31, 2009 which support the calculation of the Fuel Adjustment Clause rates for the 12 month period January through December 2009. In conducting our review, we were aware of and considered the guidance set forth in former Chapter 4901:1 – 11 and related appendices of the Ohio Administrative Code relating to "Uniform Financial Audit Program Standards and Specifications for the Electric Fuel Component". Our examination for this purpose was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants and, accordingly, included examining on a test basis, the accounting records and such other procedures as we considered necessary in the circumstances. We did not make a detailed examination as would be required to determine that each transaction was recorded in accordance with the financial procedural aspects of former Chapter 4901:1 – 11 and related appendices of the Ohio Administrative Code. Our examination does not provide a legal determination of AEP Ohio's compliance with specific requirements.

These filings are the responsibility of the Company's management. Our responsibility is to express an opinion as to AEP Ohio's fair determination of the FAC rates for January through December 2009 calculated with those quarterly filings, which include the Reconciliation Adjustments for the period January through December 2009 that were reflected by AEP Ohio through the Company's quarterly FAC filings.

In our opinion, except for the error corrections noted in this report, AEP Ohio has determined, in all material respects, the FAC rates for the 12-month period January through December 2009, including the Reconciliation Adjustments for this period in accordance with its proposed procedures and its interpretation of what should be includable in the FAC rates.

Larkin & Associates PLLC

Larkin & Associates PLLC
Livonia, Michigan

Initial Quarterly FAC Filing – Fourth Quarter 2009

On September 29, 2009, AEP Ohio submitted its initial quarterly FAC filings for CSP and OPCO which reflected actual data from January through June 2009 and projected data for the period October through December 2009. AEP Ohio's filing included a submittal letter, Schedules 1 through 4, which support the Companies proposed calculations and are broken out separately between CSP and OPCO, as well as a brief explanation of each schedule. In its submittal letter, the Companies stated that its initial filing did not reflect any fuel related deferrals associated with Ormet Primary Aluminum Corporation ("Ormet") and that recovery of those deferrals would be the subject of a subsequent application by the Companies (see additional discussion below). The following sections discuss AEP Ohio's initial FAC filing by reproducing Schedules 1 through 4, broken out separately between CSP and OPCO as Exhibits 7.1 through 7.10 and then briefly summarizing the Companies' explanations of each such schedule.

Exhibit 7-1. Proposed CSP FAC Rate, October Through December 2009

Schedule 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2009 through December 2009
Summary - Proposed FAC Rate

			Cents Per kWh				
			A	B	C	D	F
				Schedule 2	Schedule 3		Schedule 4
Line	Tariff	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components	FAC Rate Permitted Under ESP Cap
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.09912	3.11514	0.04447	3.15961	**3.09912**
2	GS-1	Secondary	2.83715	3.11514	0.04447	3.15961	**2.83715**
3	GS-2	Secondary	2.73102	3.11514	0.04447	3.15961	**2.73102**
4	GS-2	Primary	2.61131	3.01354	0.04302	3.05656	**2.61131**
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	2.73102	3.11514	0.04447	3.15961	**2.73102**
6	GS-3	Secondary	2.96126	3.11514	0.04447	3.15961	**2.96126**
7	GS-3	Primary	2.83016	3.01354	0.04302	3.05656	**2.83016**
8	GS-3-LM-TOD	Secondary	2.96126	3.11514	0.04447	3.15961	**2.96126**
9	GS-4	Sub/Transmission	2.75375	2.95641	0.04220	2.99861	**2.75375**
10	IRP-D	Secondary	3.01564	3.11514	0.04447	3.15961	**3.01564**
11	IRP-D	Primary	2.88944	3.01354	0.04302	3.05656	**2.88944**
12	IRP-D	Sub/Transmission	2.75376	2.95641	0.04220	2.99861	**2.75375**
13	SL	Secondary	3.58863	3.11514	0.04447	3.15961	**3.58863**
14	AL	Secondary	3.70227	3.11514	0.04447	3.15961	**3.70227**
15	SBS	Secondary	2.89922	3.11514	0.04447	3.15961	**2.89922**
16	SBS	Primary	2.82543	3.01354	0.04302	3.05656	**2.82543**
17	SBS	Sub/Transmission	2.75375	2.95641	0.04220	2.99861	**2.75375**

Exhibit 7-2. Proposed OPCO FAC Rate, October – December 2009

Schedule 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2009 through December 2009
Summary - Proposed FAC Rate

Cents Per kWh

			A	B	C	D	F
				Schedule 2	Schedule 3		Schedule 4
Line	Tariff	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components	FAC Rate Permitted Under ESP Cap
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	1.90098	3.05414	2.22184	5.27598	1.90098
2	GS-1	Secondary	1.71505	3.05414	2.22184	5.27598	1.71505
3	GS-2	Secondary	1.69858	3.05414	2.22184	5.27598	1.69858
4	GS-2	Primary	1.66091	2.94472	2.14223	5.08695	1.66091
5	GS-2	*Sub/Transmission*	1.62897	2.87396	2.09076	4.96472	1.62897
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	1.69858	3.05414	2.22184	5.27598	1.69858
7	GS-3	Secondary	1.82132	3.05414	2.22184	5.27598	1.82132
8	GS-3	Primary	1.78192	2.94472	2.14223	5.08695	1.78192
9	GS-3	Sub/Transmission	1.75585	2.87396	2.09076	4.96472	1.75585
10	GS-3-ES	Secondary	1.82132	3.05414	2.22184	5.27598	1.82132
11	GS-4	Primary	1.64876	2.94472	2.14223	5.08695	1.64876
12	GS-4	Sub/Transmission	1.66488	2.87396	2.09076	4.96472	1.66488
13	IRP-D	Secondary	1.72188	3.05414	2.22184	5.27598	1.72188
14	IRP-D	Primary	1.64876	2.94472	2.14223	5.08695	1.64876
15	IRP-D	Sub/Transmission	1.66488	2.87396	2.09076	4.96472	1.66488
16	EHG	Secondary	1.98340	3.05414	2.22184	5.27598	1.98340
17	EHS	Secondary	2.26400	3.05414	2.22184	5.27598	2.26400
18	SS	Secondary	1.73533	3.05414	2.22184	5.27598	1.73533
19	OL	Secondary	2.05067	3.05414	2.22184	5.27598	2.05067
20	SL	Secondary	1.87303	3.05414	2.22184	5.27598	1.87303
21	SBS	Secondary	1.75954	3.05414	2.22184	5.27598	1.75954
22	SBS	Primary	1.75933	2.94472	2.14223	5.08695	1.75933
23	SBS	Sub/Transmission	1.67456	2.87396	2.09076	4.96472	1.67456

Schedule 1: Column A of this schedule reflects the then current FAC rate by tariff and delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period October through December 2009. Column C presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced from January through June 2009. Column D reflects the sum of the FC and RA components. AEP Ohio stated that the amounts shown in Column D would have been its requested FAC rates if not for the ESP rate caps ordered by the PUCO. However, since AEP Ohio's FAC filings are subject to ESP rate caps, the Companies' initial filings reflect the then current FAC rates as shown in Column E. Therefore, AEP Ohio did not request an increase in customer rates in this initial filing.

REDACTED VERSION

Exhibit 7-3. CSP FC Component, October – December 2009

Schedule 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2009 through December 2009
FC Component

Line	Month		Forecast Period October	November	December	Total
1	Fuel & Purchased Power		$ 50,307,000	$ 48,967,000	$ 58,734,000	$ 158,008,000
2	Environmental (Consumables and Allowances)		$ 2,870,000	$ 2,822,000	$ 3,822,000	$ 9,514,000
3	Gains and Losses On Sales of Allowances		$ -	$ -	$ -	$ -
4	Other		$ -	$ -	$ -	$ -
5	Total Includible FAC Costs		[redacted]			$ 167,522,000
6	Less: Assigned to Off-System (including AEP Affiliates)					$ 12,049,000
7	FAC for Internal Load					$ 155,473,000
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2				0.97719
9	FAC for Retail Load Before Renewables					$ 151,926,669
10	Add: Renewables/RECs					$ 400,000
11	FAC for Retail Load					$ 152,326,669
12	Retail Non-Shopping Sales - Generation Level Kwh					5,172,527,946
13	FC Component of FAC Rate At Generation Level - Cents/KWh					2.94492

[redacted]

Line			Secondary	Primary	Sub/Trans
14	FC Component of FAC Rate At Generation Level		2.94492	2.94492	2.94492
15	Loss Factor		1.0578	1.0233	1.0039
16	FC at the Meter Level - Cents/kWh	Line 14 x Line 15	3.11514	3.01354	2.95641

Exhibit 7-4. OPCO FC Component, October – December 2009

Schedule 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2009 through December 2009
FC Component

Line	Month		Forecast Period October	November	December	Total
1	Fuel & Purchased Power		$ 108,054,000	$ 97,009,000	$ 114,847,000	$ 319,910,000
2	Environmental (Consumables and Allowances)		$ 9,206,000	$ 8,823,000	$ 10,118,000	$ 28,147,000
3	Gains and Losses On Sales of Allowances		$ -	$ -	$ -	$ -
4	Other		$ -	$ -	$ -	$ -
5	Total Includible FAC Costs		[redacted]			$ 348,057,000
6	Less: Assigned to Off-System (including AEP Affiliates)					$ 151,034,000
7	FAC for Internal Load					$ 197,023,000
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2				0.92349
9	FAC for Retail Load Before Renewables					$ 181,948,770
10	Add: Renewables/RECs					$ 500,000
11	FAC for Retail Load					$ 182,448,770
12	Retail Non-Shopping Sales - Generation Level Kwh					6,369,264,103
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.86451

[redacted]

Line			Secondary	Primary	Sub/Trans
14	FC Component of FAC Rate At Generation Level		2.86451	2.86451	2.86451
15	Loss Factor		1.0662	1.0280	1.0033
16	FC at the Meter Level - Cents/kWh	Line 13 x Line 14	3.05414	2.94472	2.87396

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period October through December 2009. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. As shown on lines 1-4 of Schedule 2, the categories included in AEP Ohio's includable FAC costs

of $167.522 million (CSP) and $348.057 million (OPCO) are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, gains and losses on sales of allowances, and "other". As shown on line 6 of Schedule 2, the Companies then removed the costs totaling $12.049 million (CSP) and $151.034 million (OPCO), which were associated with off-system sales (including such sales to AEP affiliates), to derive the FAC costs designated for internal load as shown on line 7 of Schedule 2. After applying a retail jurisdictional allocation ratio (see additional discussion below), the Companies derived its FAC costs for retail load before adding a component for renewables. Line 10 of Schedule 2 reflects the Companies' component for renewable energy credits ("RECs"), the addition of which results in the total FAC costs for retail load of $152.327 million for CSP and $182.449 million for OPCO. From these amounts, the Companies calculated its FC portion of the FAC rate at Generation level of 2.94492 cents per kWh for CSP and 2.86451 cents per kWh for OPCO by dividing the amounts from line 10 by each Company's projected retail non-shopping sales at Generation level (see Schedule 3 discussion below). Finally, each Company applied loss factors to its respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. For CSP, as shown on Schedule 2 at line 15, these loss factors are 1.0578, 1.0233 and 1.0039 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which result in FCs of the FAC rate of 3.11514, 3.01354 and 2.95641 cents per kWh. For OPCO, the loss factors are 1.0662, 1.0280 and 1.0033 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which result in FCs of the FAC rate of 3.05414, 2.94472 and 2.87396 cents per kWh.

Exhibit 7-5. CSP RA Component, October – December 2009

Schedule 3, page 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2009 through December 2009
RA Component

Actual Period - January 2009 through June 2009

Line	Month	Kwh Retail Non-Shopping Sales	FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	Beginning Balance							$ -
2	January	2,041,668,306	$ 55,968,975	$ 65,053,443	$ 9,084,468	$ -	$ (7,505,640)	$ 1,578,828
3	February	1,675,273,439	$ 45,876,514	$ 47,920,116	$ 2,043,602	$ 85,939	$ (5,101,633)	$ (2,972,092)
4	March	1,792,225,671	$ 49,794,046	$ 53,531,850	$ 3,737,804	$ 104,604	$ (4,844,273)	$ (1,001,865)
5	April	1,527,784,428	$ 43,858,233	$ 51,128,040	$ 7,269,807	$ 139,888	$ (3,694,104)	$ 3,715,591
6	May	1,600,218,534	$ 45,934,106	$ 49,382,543	$ 3,448,437	$ 208,297	$ (3,381,413)	$ 275,321
7	June	1,788,388,021	$ 51,290,036	$ 55,298,555	$ 4,008,619	$ 240,746	$ (3,670,642)	$ 578,623
8	Ending Balance	10,423,566,399	$ 292,721,910	$ 322,314,547	$ 29,592,637	$ 779,474	$ (28,197,704)	$ 2,174,407
9	Loss Adjusted Retail Sales Billing Period - kWh							5,172,527,946
10	RA Component at Generation - Cents/kWh							0.04204

Line			Secondary	Primary	Sub/Trans
11	RA Component of FAC Rate At Generation Level		0.04204	0.04204	0.04204
12	Loss Factor		1.0578	1.0233	1.0039
13	RA at the Meter Level - Cents/kWh	Line 11 x Line 12	0.04447	0.04302	0.04220

Exhibit 7-6. OPCO RA Component, October – December 2009

Schedule 3, page 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2009 through December 2009
RA Component

Actual Period - January 2009 through June 2009

Line	Month	Kwh Retail Non-Shopping Sales	FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	Beginning Balance							$ -
2	January	2,558,403,026	$ 46,827,952	$ 70,963,634	$ 24,135,682	$ -	$ (1,744,626)	$ 22,391,056
3	February	2,136,138,950	$ 39,023,729	$ 54,298,706	$ 15,274,977	$ 219,876	$ (1,216,944)	$ 14,277,909
4	March	2,243,999,540	$ 43,372,584	$ 67,439,472	$ 24,066,888	$ 355,484	$ (2,210,569)	$ 22,211,803
5	April	1,874,521,925	$ 38,132,105	$ 64,003,443	$ 25,871,338	$ 576,376	$ 525,553	$ 26,973,267
6	May	1,795,814,141	$ 36,539,468	$ 60,294,328	$ 23,754,860	$ 798,779	$ 675,897	$ 25,229,536
7	June	2,018,613,745	$ 41,263,491	$ 60,780,692	$ 19,517,201	$ 1,026,982	$ 1,100,707	$ 21,644,890
8	Ending Balance	12,824,491,329	$ 245,159,329	$ 377,780,274	$ 132,620,945	$ 2,977,497	$ (2,869,982)	$ 132,728,460
9	Loss Adjusted Retail Sales Billing Period - kWh							6,369,264,103
10	RA Component at Generation - Cents/kWh							2.08368

Line			Secondary	Primary	Sub/Trans
11	RA Component of FAC Rate At Generation Level		2.08368	2.08368	2.08388
12	Loss Factor		1.0662	1.0280	1.0033
13	RA at the Meter Level - Cents/kWh	Line 11 x Line 12	2.22184	2.14223	2.09076

Schedule 3: This two-page schedule represents the Companies Reconciliation Adjustment ("RA") components of its FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' under-recovery of fuel expenses for each month during the period January through June 2009, which were calculated as the difference between the

monthly FAC revenues for the period January through June 2009 and the monthly jurisdictional retail FAC costs (calculated on page 2 of Schedule 3 as discussed below) for the same period. In addition, page 1 of this schedule reflects carrying costs associated with those under-recoveries, as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders.

Per the Companies' calculations, the sum of these items resulted in total under-recoveries of $2.174 million for CSP and $132.728 million for OPCO during the period January through June 2009. From these amounts, each Company calculated the RA component of its FAC rate at Generation level by dividing such amounts by the same projected retail non-shopping sales at Generation level referenced in the Schedule 2 section above (see additional discussion below). The RA component for CSP for this filing was 0.04204 cents per kWh and 2.08388 cents per kWh for OPCO. The Companies then applied the same loss factors discussed above as it relates to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. For CSP, as shown on Schedule 3, page 1 at line 13, application of these loss factors results in RA components of the FAC rate of 0.04447, 0.04302 and 0.04220 cents per kWh. For OPCO, applying the loss factors resulted in RA components of the FAC rate of 2.22184, 2.14223 and 2.09076 cents per kWh.

AEP Ohio stated in its initial filing that CSP may be in the position to begin recovering its actual fuel expense concurrently with the recovery of the deferrals prior to the end of the ESP period, whereas it is probable that OPCO will have a long-term deferral to be recovered subsequent to the end of the ESP period.

Exhibit 7-7. CSP Monthly Retail FAC Costs, October – December 2009

Schedule 3, page 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2009 through December 2009
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC Cost
1	January	$ 88,238,264	$ 21,676,532	$ 66,561,732	0.97734	$ 65,053,443	$ -	$ 65,053,443
2	February	$ 69,552,840	$ 20,521,176	$ 49,031,664	0.97733	$ 47,920,116	$ -	$ 47,920,116
3	March	$ 71,520,909	$ 16,849,153	$ 54,671,756	0.97915	$ 53,531,850	$ -	$ 53,531,850
4	April	$ 67,903,562	$ 15,595,451	$ 52,308,111	0.97744	$ 51,128,040	$ -	$ 51,128,040
5	May	$ 64,198,473	$ 13,666,324	$ 50,532,149	0.97725	$ 49,382,543	$ -	$ 49,382,543
6	June	$ 78,547,730	$ 22,008,131	$ 56,539,599	0.97805	$ 55,298,555	$ -	$ 55,298,555
7	Total	$ 439,961,778	$ 110,316,767	$ 329,645,011		$ 322,314,547	$ -	$ 322,314,547

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh: Whlse (Wstville)	Retail	Total	Jurisdictional Ratios: Whlse (Wstville)	Retail
Actual						
8	January	49,419,743	2,131,771,120	2,181,190,864	0.02266	0.97734
9	February	40,527,687	1,747,364,957	1,787,892,644	0.02267	0.97733
10	March	39,783,813	1,868,586,317	1,908,370,130	0.02085	0.97915
11	April	36,694,339	1,589,727,100	1,626,421,439	0.02256	0.97744
12	May	38,787,691	1,666,097,746	1,704,885,438	0.02275	0.97725
13	June	41,795,942	1,862,749,465	1,904,545,407	0.02195	0.97805
Forecast						
14	Oct. - Dec.	120,739,152	5,172,527,946	5,293,267,098	0.02281	0.97719

Exhibit 7-8. OPCO Monthly Retail FAC Costs, October – December 2009

Schedule 3, page 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2009 through December 2009
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC Cost
1	January	$ 149,554,635	$ 73,014,240	$ 76,540,395	0.92714	$ 70,963,634	$ -	$ 70,963,634
2	February	$ 113,063,674	$ 54,401,878	$ 58,661,796	0.92562	$ 54,298,706	$ -	$ 54,298,706
3	March	$ 133,973,923	$ 61,465,757	$ 72,508,166	0.93009	$ 67,439,472	$ -	$ 67,439,472
4	April	$ 123,710,457	$ 54,469,570	$ 69,240,887	0.92436	$ 64,003,443	$ -	$ 64,003,443
5	May	$ 93,146,884	$ 27,281,375	$ 65,865,509	0.91542	$ 60,294,328	$ -	$ 60,294,328
6	June	$ 127,720,962	$ 61,611,996	$ 66,108,966	0.91940	$ 60,780,692	$ -	$ 60,780,692
7	Total	$ 741,170,535	$ 332,244,816	$ 408,925,719		$ 377,780,274	$ -	$ 377,780,274

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (WPC)	Retail	Total	Whlse (WPC)	Retail
Actual						
8	January	209,456,700	2,665,312,146	2,874,768,846	0.07286	0.92714
9	February	178,474,583	2,221,118,307	2,399,592,890	0.07438	0.92562
10	March	175,396,483	2,333,667,220	2,509,063,703	0.06991	0.93009
11	April	159,086,489	1,944,093,944	2,103,180,433	0.07564	0.92436
12	May	172,114,063	1,862,711,307	2,034,825,371	0.08458	0.91542
13	June	184,125,209	2,100,353,126	2,284,478,335	0.08060	0.91940
Forecast						
14	Oct. - Dec.	527,656,440	6,369,284,103	6,896,940,543	0.07651	0.92349

As stated in AEP Ohio's filing, Page 2 of Schedule 3 reflects monthly data on the Companies' actual fuel costs during the period January through June 2009. Specifically, page 2 of Schedule 3 (lines 1-7) shows, for each Company, total monthly FAC costs incurred from January through June 2009. For each month (January through June), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". Neither Company included any amounts for renewables in its initial filing, so this column was left blank on Schedule 3, page 2. Therefore, the retail FAC before renewable amounts were carried over to Schedule 3, page 1 to derive the Companies FAC over/under recoveries discussed above. Finally, page 2 of Schedule 3 reflects forecasted jurisdictional sales at the generation level from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from this forecasted amount, the Companies calculated a retail jurisdictional allocation ratio of .97719 for CSP and .92349 for OPCO.

AEP Ohio stated in its filing that, excluding the aforementioned adjustments, each company would have substantially under-recovered its respective fuel costs and that it is probable that OPCO will have a long-term deferral subject to recovery subsequent to the ESP period, but that under current conditions, it may be possible for CSP to begin recovering its actual fuel expense prior to the end of the ESP period.

Exhibit 7-9. CSP FAC Rate Under ESP Cap, October – December 2009

Schedule 4

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2009 through December 2009
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff *
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.09912
2	GS-1	Secondary	2.83715
3	GS-2	Secondary	2.73102
4	GS-2	Primary	2.61131
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	2.73102
6	GS-3	Secondary	2.96126
7	GS-3	Primary	2.83016
8	GS-3-LM-TOD	Secondary	2.96126
9	GS-4	Sub/Transmission	2.75375
10	IRP-D	Secondary	3.01564
11	IRP-D	Primary	2.88944
12	IRP-D	Sub/Transmission	2.75375
13	SL	Secondary	3.58863
14	AL	Secondary	3.70227
15	SBS	Secondary	2.89922
16	SBS	Primary	2.82543
17	SBS	Sub/Transmission	2.75375

* Same as current FAC rates

Exhibit 7-10. OPCO FAC Rate Under ESP Cap, October – December 2009

Schedule 4

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2009 through December 2009
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff*
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	1.90098
2	GS-1	Secondary	1.71505
3	GS-2	Secondary	1.69858
4	GS-2	Primary	1.66091
5	GS-2	Sub/Transmission	1.62897
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	1.69858
7	GS-3	Secondary	1.82132
8	GS-3	Primary	1.78192
9	GS-3	Sub/Transmission	1.75585
10	GS-3-ES	Secondary	1.82132
11	GS-4	Primary	1.64876
12	GS-4	Sub/Transmission	1.66488
13	IRP-D	Secondary	1.72188
14	IRP-D	Primary	1.64876
15	IRP-D	Sub/Transmission	1.66488
16	EHG	Secondary	1.98340
17	EHS	Secondary	2.26400
18	SS	Secondary	1.73533
19	OL	Secondary	2.05067
20	SL	Secondary	1.87303
21	SBS	Secondary	1.75954
22	SBS	Primary	1.75933
23	SBS	Sub/Transmission	1.67456

*** Same as current FAC rates**

Schedule 4: This schedule breaks out current FAC rates by tariff. As noted above in the discussion of Schedule 1, the then current FAC rates remained in place during the fourth quarter of 2009. However, the Companies stated that Schedule 4 will provide the applicable capped quarterly FAC rates in subsequent filings.

First Quarter 2010

On December 1, 2009, AEP Ohio submitted quarterly FAC filings for CSP and OPCO, which reflected actual data from July through September 2009 and projected data for the period January through March 2010. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 4 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule. In addition, this quarterly filing also included a third page to Schedule 3, reflecting a monthly rate deferral and associated carrying costs related to the Ormet Interim Agreement, which is discussed in further detail below. Moreover, AEP Ohio included workpapers with Schedule 4, which provide support for the Companies contention that the proposed FAC rates were in compliance with the provision for the capped rate percentage increases approved by the PUCO in its ESP Orders.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's first quarter 2010 FAC filings by reproducing Schedules 1 through 4, broken out separately between CSP and OPCO as Exhibits 7.11 through 7.22, and then briefly summarizing each schedule.

Exhibit 7-11. Summary Proposed CSP FAC Rate, January – March 2010

Schedule 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
Summary - Proposed FAC Rate

Cents Per kWh

			A	B	C	D	E
				Schedule 2	Schedule 3		Schedule 4
Line	Tariff	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components	FAC Rate Permitted Under ESP Cap
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.09912	3.08485	0.65758	3.74243	3.65191
~~2~~	~~GS-1~~	~~Secondary~~	~~2.83715~~	~~3.08485~~	~~0.65758~~	~~3.74243~~	~~3.82381~~
3	GS-2	Secondary	2.73102	3.08485	0.65758	3.74243	3.68943
4	GS-2	Primary	2.61131	2.98424	0.63613	3.62037	3.56910
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	2.73102	3.08485	0.65758	3.74243	3.68943
6	GS-3	Secondary	2.96126	3.08485	0.65758	3.74243	3.47461
7	GS-3	Primary	2.83016	2.98424	0.63613	3.62037	3.38128
8	GS-3-LM-TOD	Secondary	2.96126	3.08485	0.65758	3.74243	3.47461
9	GS-4	Sub/Transmission	2.75375	2.92766	0.62407	3.55173	3.11671
10	IRP-D	Secondary	3.01564	3.08485	0.65758	3.74243	3.28405
11	IRP-D	Primary	2.88944	2.98424	0.63613	3.62037	3.17694
12	IRP-D	Sub/Transmission	2.75375	2.92766	0.62407	3.55173	3.11671
13	SL	Secondary	3.58863	3.08485	0.65758	3.74243	3.95288
14	AL	Secondary	3.70227	3.08485	0.65758	3.74243	4.50885
15	SBS	Secondary	2.89922	3.08485	0.65758	3.74243	3.53250
16	SBS	Primary	2.82543	2.98424	0.63613	3.62037	3.36677
17	SBS	Sub/Transmission	2.75375	2.92766	0.62407	3.55173	3.11671

Exhibit 7-12. Summary Proposed OPCO FAC Rate, January – March 2010

Schedule 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
Summary - Proposed FAC Rate

			A	B	C	D	E
				Cents Per kWh			
				Schedule 2	Schedule 3		Schedule 4
Line	Tariff	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components	FAC Rate Permitted Under ESP Cap
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	1.90098	2.99679	3.70815	6.70494	2.56084
2	GS-1	Secondary	1.71505	2.99679	3.70815	6.70494	2.59206
3	GS-2	Secondary	1.69858	2.99679	3.70815	6.70494	2.44661
4	GS-2	Primary	1.66091	2.88942	3.57529	6.46471	2.35886
5	GS-2	Sub/Transmission	1.62897	2.82000	3.48939	6.30939	2.30218
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	1.69858	2.99679	3.70815	6.70494	2.44661
7	GS-3	Secondary	1.82132	2.99679	3.70815	6.70494	2.37838
8	GS-3	Primary	1.78192	2.88942	3.57529	6.46471	2.28317
9	GS-3	Sub/Transmission	1.75585	2.82000	3.48939	6.30939	2.23807
10	GS-3-ES	Secondary	1.82132	2.99679	3.70815	6.70494	2.37838
11	GS-4	Primary	1.64876	2.88942	3.57529	6.46471	2.13408
12	GS-4	Sub/Transmission	1.66488	2.82000	3.48939	6.30939	2.08280
13	IRP-D	Secondary	1.72188	2.99679	3.70815	6.70494	2.21338
14	IRP-D	Primary	1.64876	2.88942	3.57529	6.46471	2.13408
15	IRP-D	Sub/Transmission	1.66488	2.82000	3.48939	6.30939	2.08280
16	EHG	Secondary	1.98340	2.99679	3.70815	6.70494	2.48485
17	EHS	Secondary	2.26400	2.99679	3.70815	6.70494	2.29960
18	SS	Secondary	1.73533	2.99679	3.70815	6.70494	2.40193
19	OL	Secondary	2.05067	2.99679	3.70815	6.70494	3.22634
20	SL	Secondary	1.87303	2.99679	3.70815	6.70494	2.87354
21	SBS	Secondary	1.75954	2.99679	3.70815	6.70494	2.41287
22	SBS	Primary	1.75933	2.88942	3.57529	6.46471	2.29129
23	SBS	Sub/Transmission	1.67456	2.82000	3.48939	6.30939	2.10693

Schedule 1: This schedule presents the then current FAC rate by tariff and delivery voltage. Column B reflects the FC rate necessary to recover estimated fuel expense for the first quarter of 2010, and Column C reflects the RA rate necessary to recover the actual fuel under-recovery experienced through September 2009 with Column D being the sum of the FC and RA components. AEP Ohio stated that the amounts shown in Column D would have been its requested FAC rates if not for the ESP rate caps ordered by the PUCO. However, since AEP Ohio's FAC filings are subject to ESP rate caps, the Companies proposed to implement the FAC rates shown in Column E with the January 2010 billing cycle.

REDACTED VERSION

Exhibit 7-13. CSP FC Component, January – March 2010

Schedule 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
FC Component

Line	Description		Forecast Period January	February	March	Total
1	Fuel & Purchased Power		$ 57,518,000	$ 53,301,000	$ 61,271,000	$ 172,090,000
2	Environmental (Consumables and Allowances)		$ 3,365,000	$ 3,006,000	$ 3,241,000	$ 9,612,000
3	(Gains) and Losses On Sales of Allowances				$ (65,000)	$ (65,000)
4	Other					$ -
5	Total Includible FAC Costs		$ 60,883,000	$ 56,307,000	$ 64,447,000	$ 181,637,000
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 5,615,000	$ 6,011,000	$ 7,009,000	$ 18,635,000
7	FAC for Internal Load		$ 55,268,000	$ 50,296,000	$ 57,438,000	$ 163,002,000
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.97591	1.00000	1.00000	0.97591
9	FAC for Retail Load Before Renewables		$ 53,936,594	$ 50,296,000	$ 57,438,000	$ 159,075,282
10	Renewables/RECs		$ 1,624,000	$ 1,185,000	$ 1,146,000	$ 3,955,000
11	FAC for Retail Load		$ 55,560,594	$ 51,481,000	$ 58,584,000	$ 163,030,282
12	Retail Non-Shopping Sales - Generation Level Kwh		2,004,808,000	1,787,030,000	1,798,492,000	5,590,330,000
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.91629
[redacted]						
			Secondary	Primary	Sub/Trans	
14	FC Component of FAC Rate At Generation Level		2.91629	2.91629	2.91629	
15	Loss Factor		1.0578	1.0233	1.0039	
16	FC at the Meter Level - Cents/kWh	Line 14 x Line 15	3.08485	2.98424	2.92766	

Exhibit 7-14. OPCO FC Component, January – March 2010

Schedule 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
FC Component

Line	Description		Forecast Period - 1st Quarter 2010 January	February	March	Total
1	Fuel & Purchased Power		$ 120,952,000	$ 109,210,000	$ 115,310,000	$ 345,472,000
2	Environmental (Consumables and Allowances)		$ 10,599,000	$ 11,860,000	$ 10,649,000	$ 33,108,000
3	(Gains) and Losses On Sales of Allowances		$ (200,000)	$ (200,000)	$ (449,000)	$ (849,000)
4	Other		$ -	$ -	$ -	$ -
5	Total Includible FAC Costs		$ 131,351,000	$ 120,870,000	$ 125,510,000	$ 377,731,000
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 59,061,000	$ 54,562,000	$ 57,887,000	$ 171,510,000
7	FAC for Internal Load		$ 72,290,000	$ 66,308,000	$ 67,623,000	$ 206,221,000
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92809	0.92643	0.92536	0.92809
9	FAC for Retail Load Before Renewables		$ 67,091,626	$ 61,429,720	$ 62,575,619	$ 191,391,648
10	Renewables/RECs		$ 1,652,000	$ 1,215,000	$ 1,178,000	$ 4,045,000
11	FAC for Retail Load		$ 68,743,626	$ 62,644,720	$ 63,753,619	$ 195,436,648
12	Retail Non-Shopping Sales - Generation Level Kwh		2,428,902,000	2,191,326,000	2,333,038,000	6,953,266,000
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.81072
[redacted]						
			Secondary	Primary	Sub/Trans	
14	FC Component of FAC Rate At Generation Level		2.81072	2.81072	2.81072	
15	Loss Factor		1.0662	1.0280	1.0033	
16	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**2.99679**	**2.88942**	**2.82000**	

Schedule 2: This schedule reflects AEP Ohio estimates of monthly fuel costs it expected to incur during the period January through March 2010. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the first quarter of 2010, AEP Ohio's has projected includable FAC costs of $181.637 million for CSP and $377.731 million for OPCO, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies' then removed costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the first quarter of 2010, these projected off-system costs totaled $18.635 million for CSP and $171.510 million for OPCO. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component for renewable energy credits ("RECs"), which totaled \$3.955 million for CSP and \$4.045 million for OPCO. The addition of the RECs result in total FAC costs for retail load of \$163.030 million for CSP and \$195.437 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 2.91629 cents per kWh for CSP and 2.81072 cents per kWh for OPCO, and was calculated by dividing the projected FAC for internal load by each Company's projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. Similar to its initial quarterly filing, CSP applied loss factors of 1.0578, 1.0233 and 1.0039 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 3.08485, 2.98424 and 2.92766 cents per kWh. OPCO applied loss factors of 1.0662, 1.0280 and 1.0033 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 2.99679, 2.88942 and 2.82000 cents per kWh.

Exhibit 7-15. CSP RA Component, January – March 2010

Schedule 3, page 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
RA Component
Actual Period - July 2009 through September 2009

Line	Month	Kwh Retail Non-Shopping Sales	FAC Revenue	Schedule 3, p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	Beginning Balance							$ 2,174,407
2	Jul-09	1,761,228,916	$ 51,279,359	$ 56,176,797	$ 4,897,428	$ 278,487	$ (4,893,657)	$ 282,236
3	Aug-09	1,919,595,757	$ 56,354,722	$ 60,085,535	$ 3,730,813	$ 324,552	$ (2,985,952)	$ 1,069,413
4	Sep-09	1,538,227,487	$ 45,104,381	$ 47,572,864	$ 2,468,483	$ 355,836	$ (2,723,152)	$ 101,167
5	Ending Balance	5,219,052,160	$ 152,738,472	$ 163,835,197	$ 11,096,725	$ 958,855	$ (10,602,761)	$ 3,627,225
6	Ormet Interim Agreement Deferral	Schedule 3, pg. 3						$ 31,124,968
7	Total (Over)/Under Recovery Balance							$ 34,752,193
8	Loss Adjusted Retail Sales Billing Period - kWh							5,590,330,000
9	RA Component at Generation - Cents/kWh							0.62165

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		0.62165	0.62165	0.62165
11	Loss Factor		1.0578	1.0233	1.0039
12	RA at the Meter Level - Cents/kWh	Line 10 x Line 11	0.65758	0.63613	0.62407

Exhibit 7-16. OPCO RA Component, January – March 2010

Schedule 3, page 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
RA
Actual Period - July 2009 through September 2009

Line	Month	Kwh Retail Non-Shopping Sales	FAC Revenue	Schedule 3 , p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	Beginning Balance							$ 132,728,460
2	Jul-09	1,974,367,109	$ 37,895,735	$ 62,355,977	$ 24,460,242	$ 1,198,893	$ 1,628,745	$ 27,287,880
3	Aug-09	2,214,490,089	$ 39,291,137	$ 66,331,965	$ 27,040,828	$ 1,415,303	$ (4,229,680)	$ 24,226,451
4	Sep-09	1,895,888,649	$ 33,451,158	$ 58,520,576	$ 25,069,418	$ 1,640,528	$ (3,488,062)	$ 23,221,884
5	Ending Balance	6,084,745,847	$ 110,638,030	$ 187,208,518	$ 76,570,488	$ 4,254,724	$ (6,088,997)	$ 207,464,675
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 34,363,615
7	Total (Over)/Under Recovery Balance							$ 241,828,290
8	Loss Adjusted Retail Sales Billing Period - kWh							6,953,286,000
9	RA Component at Generation - Cents/kWh							3.47791

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		3.47791	3.47791	3.47791
11	Loss Factor		1.0662	1.0280	1.0033
12	RA at the Meter Level - Cents/kWh	Line 10 x Line 11	3.70815	3.57529	3.48939

Schedule 3: This three-page schedule represents the Companies' RA components of their first quarter 2010 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the Companies' under-recovery of fuel expenses for each month during the period July through September 2009, which were calculated as the difference between the monthly FAC revenues for the third quarter of 2009 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of carrying costs associated with those under-recoveries as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The addition of the carrying charges and other credits and charges resulted in total under-recoveries of $3.627 million for CSP and $207.465 million for OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with the Ormet Interim Agreement ("Ormet" - see additional discussion below). For the period January through September 2009, these deferrals totaled $31,124,968 for CSP and $34,363,615 for OPCO. The derivation of these deferral amounts are summarized on Schedule 3, page 3.

After adding the amounts associated with Ormet, CSP's and OPCO's under recovery for the third quarter of 2009 was $34.752 million and $241.828 million, respectively. From these amounts, each Company then calculated the RA component of its FAC rate at Generation level by dividing the under recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for CSP for this filing was 0.62165 cents per kWh and 3.47791 cents per kWh for OPCO. The Companies then applied the loss factors discussed above as it relates to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. For CSP, as shown on Schedule 3, page 1 at line 12, application of the loss factors results in RA components of the FAC rate of 0.65758, 0.63613 and 0.62407 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively. For OPCO, applying the loss factors resulted in RA components of the FAC rate of 3.70815, 3.57529 and 3.48939 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

AEP Ohio stated in its filing that CSP may be in the position to begin recovering its actual fuel expense concurrently with the recovery of the deferrals prior to the end of the ESP period, whereas it is probable that OPCO will have a long-term deferral to be recovered subsequent to the end of the ESP period.

Exhibit 7-17. CSP RA Component Including Ormet Deferral, January – March 2010

Schedule 3, page 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
RA Component

Ormet Interim Rate Deferral

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC Cost
4	Jul-09	$ 80,152,062	$ 22,718,034	$ 57,434,028	0.97811	$ 56,176,797	$ -	$ 56,176,797
5	Aug-09	$ 85,808,845	$ 24,255,887	$ 61,552,958	0.97616	$ 60,085,535	$ -	$ 60,085,535
6	Sep-09	$ 66,154,555	$ 17,390,310	$ 48,764,245	0.97447	$ 47,519,294	$ 53,570	$ 47,572,864
7	Total	$ 232,115,462	$ 64,364,231	$ 167,751,231		$ 163,781,626	$ 53,570	$ 163,835,197

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh: Whlse (Wstville)	Retail	Total	Jurisdictional Ratios: Whlse (Wstville)	Retail
Actual						
8	Jul-09	41,132,368	1,838,103,377	1,879,235,745	0.02189	0.97811
9	Aug-09	48,926,669	2,003,381,172	2,052,307,841	0.02384	0.97616
10	Sep-09	42,033,480	1,604,110,502	1,646,143,982	0.02553	0.97447
Forecast						
11	Jan '10	49,491,911	2,004,808,000	2,054,299,911	0.02409	0.97591
12	Feb '10	-	1,787,030,000	1,787,030,000	0.00000	1.00000
13	Mar '10	-	1,798,492,000	1,798,492,000	0.00000	1.00000

Exhibit 7-18. OPCO RA Component Including Ormet Deferral, January – March 2010

Schedule 3, page 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC Cost
4	Jul-09	$ 142,297,414	$ 74,697,730	$ 67,599,684	0.92243	$ 62,355,977	$ -	$ 62,355,977
5	Aug-09	$ 148,848,838	$ 76,955,959	$ 71,892,879	0.92265	$ 66,331,965	$ -	$ 66,331,965
6	Sep-09	$ 119,774,518	$ 55,838,651	$ 63,935,867	0.91446	$ 58,466,793	$ 53,783	$ 58,520,576
7	Total	$ 410,920,770	$ 207,492,340	$ 203,428,430		$ 187,154,734	$ 53,783	$ 187,208,518

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh: Whlse (WPC)	Retail	Total	Jurisdictional Ratios: Whlse (WPC)	Retail
Actual						
8	Jul-09	172,721,436	2,053,983,048	2,226,704,484	0.07757	0.92243
9	Aug-09	193,317,632	2,305,947,405	2,499,265,037	0.07735	0.92265
10	Sep-09	184,106,881	1,968,209,148	2,152,316,029	0.08554	0.91446
Forecast						
11	Jan '10	188,194,800	2,428,902,000	2,617,096,800	0.07191	0.92809
12	Feb '10	174,029,600	2,191,326,000	2,365,355,600	0.07357	0.92643
13	Mar '10	188,194,800	2,333,038,000	2,521,232,800	0.07464	0.92536

Page 2 of Schedule 3 reflects monthly data on the Companies' actual fuel costs during the third quarter of 2009. Specifically, page 2 of Schedule 3 (lines 4-7) shows, for each Company, total monthly FAC costs incurred from July through September 2009. For each month (July through September), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". In September 2009, CSP and OPCO added $53,570 and $53,783, respectively for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Section 4928.64 of the revised Ohio Code. AEP Ohio stated that future FAC revenues will first be applied towards recovering renewable energy costs so that they are not embedded in the long-term deferrals of either CSP or OPCO. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the third quarter of 2009 were derived. Renewables are discussed in further detail in a later section of this report.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for July through September 2009. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for January through March 2010, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of .97591 (January 2010) and 1.0000 (February and March 2010) for CSP and .92809, .92643 and .92536 (January, February and March 2010, respectively) for OPCO.

Exhibit 7-19. CSP Details Of Ormet Deferral In RA Component , January – March 2010

Schedule 3, page 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Jan-09	$ 4,154,975	$ -	$ 4,154,975
2	Feb-09	$ 3,660,302	$ 39,306	$ 3,699,608
3	Mar-09	$ 4,149,056	$ 73,464	$ 4,222,520
4	Apr-09	$ 3,916,040	$ 112,584	$ 4,028,624
5	May-09	$ 3,549,316	$ 149,434	$ 3,698,750
6	Jun-09	$ 3,150,701	$ 182,833	$ 3,333,534
7	Jul-09	$ 3,211,313	$ 212,481	$ 3,423,794
8	Aug-09	$ 2,618,212	$ 242,700	$ 2,860,912
9	Sep-09	$ 1,437,755	$ 264,496	$ 1,702,251
10	Total	$ 29,847,670	$ 1,277,298	$ 31,124,968

Exhibit 7-20. OPCO Details Of Ormet Deferral In RA Component, January – March 2010

Schedule 3, page 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Jan-09	$ 4,621,825	$ -	$ 4,621,825
2	Feb-09	$ 3,985,948	$ 42,105	$ 4,028,053
3	Mar-09	$ 4,608,436	$ 77,642	$ 4,686,078
4	Apr-09	$ 4,321,138	$ 120,003	$ 4,441,141
5	May-09	$ 3,922,750	$ 156,784	$ 4,079,534
6	Jun-09	$ 3,489,750	$ 194,857	$ 3,684,607
7	Jul-09	$ 3,568,282	$ 225,547	$ 3,793,829
8	Aug-09	$ 2,899,119	$ 256,948	$ 3,156,067
9	Sep-09	$ 1,592,553	$ 279,928	$ 1,872,481
10	Total	$ 33,009,801	$ 1,353,814	$ 34,363,615

As noted above, page 3 of Schedule 3 reflects the derivation of the monthly rate deferral and carrying costs associated with the Ormet Interim Agreement pursuant to Case No. 09-1094-EL-FAC. The deferrals included in the Companies' FACs are for the period January 1, 2009 through September 17, 2009. Ormet related rate discounts that occurred subsequent to September 17, 2009 will be recovered through each Company's Economic Development Cost Recovery Rider ("EDR").

Ormet Interim Agreement

In Case No. 07-1317-EL-UNC, the PUCO approved a market rate for 2008 of $53.03 per MWh related to power sold to the Ormet Primary Aluminum Corporation ("Ormet"). In a prior PUCO Order, Ormet's 2008 purchases were at a price of $43 per MWh. In order for AEP Ohio to be compensated for providing to Ormet for less than the market rate, the PUCO authorized the Companies to amortize a regulatory liability of $56.968 million that was created by AEP Ohio in June 2005 when the Ohio Franchise Tax was phased out. This amortization was based on the difference between the $53.03 per MWh market rate and the $43 per MWh rate paid by Ormet. Upon the regulatory liability being fully amortized, the Companies were authorized to recover the difference from customers.

In its Finding and Order dated January 7, 2009 (Case Nos. 08-1338-EL-AAM and 08-1339-EL-UNC, filed on December 29, 2008), the PUCO directed that the arrangement between the Companies and Ormet continue until the PUCO ruled on the Companies' then pending ESP application, or until Ormet submitted a new contract proposal to the PUCO. On February 17, 2009, in Case No. 09-119-EL-AEC, Ormet filed an application pursuant to Section 4905.31 of the Revised Code to establish a unique arrangement between CSP and OPCO as it relates to electric service being provided to Ormet's aluminum producing facility in Hannibal, Ohio. Ormet filed an amended application on April 10, 2009 in this proceeding.

The PUCO approved Ormet's amended application with several modifications in its Order and Opinion dated July 15, 2009. Specifically, the PUCO directed AEP Ohio to bill Ormet at a rate which averaged $38 per MWh for the periods when Ormet was fully operating (6 potlines), $35 per MWh for periods when Ormet curtailed production to 4.6 potlines, and $34 per MWh for periods when Ormet curtailed production to 4 potlines. This rate was authorized for the balance of 2009. In its Order and Opinion, the PUCO stated that further proceedings would be necessary as it relates to the recovery of "delta revenues" by AEP Ohio. Therefore, the PUCO authorized AEP Ohio to defer the delta revenues for the remainder of 2009. In addition, the PUCO directed AEP Ohio to file an application to recover the deferrals authorized in Case No. 08-1338-EL-AAM, as well as the delta revenues for 2009.

In its Application dated November 13, 2009 in Case No. 09-1094-EL-FAC, the Companies proposed to recover the deferrals authorized pursuant to the Interim Agreement. Specifically, the Companies' proposed to recover through each Company's FAC, the cumulative FAC uner-recovery regulatory asset at September 17, 2009. As of September 17, 2009, the Companies had a deferred regulatory asset of $29,847,670 for CSP and $33,009,802 for OPCO. In addition, the Companies had a deferred regulatory asset in carrying costs of $1,556,972 for CSP and $1,610,301 for OPCO. These carrying costs were calculated based on each Company's Weighted Average Cost of Capital ("WACC").

In summary, the Companies requested that the PUCO approve the recovery the unrecovered deferrals under the interim agreement plus the associated carrying costs through each Company's FAC.

Exhibit 7-21. CSP FAC Rate Under ESP Cap, January – March 2010

Schedule 4

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.65191
2	GS-1	Secondary	3.82381
3	GS-2	Secondary	3.68943
4	GS-2	Primary	3.56910
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	3.68943
6	GS-3	Secondary	3.47461
7	GS-3	Primary	3.38128
8	GS-3-LM-TOD	Secondary	3.47461
9	GS-4	Sub/Transmission	3.11671
10	IRP-D	Secondary	3.28405
11	IRP-D	Primary	3.17694
12	IRP-D	Sub/Transmission	3.11671
13	SL	Secondary	3.95288
14	AL	Secondary	4.50885
15	SBS	Secondary	3.53250
16	SBS	Primary	3.36577
17	SBS	Sub/Transmission	3.11671

Exhibit 7-22. OPCO FAC Rate Under ESP Cap, January – March 2010

Schedule 4

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2010
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	2.56084
2	GS-1	Secondary	2.59206
3	GS-2	Secondary	2.44651
4	GS-2	Primary	2.35886
5	GS-2	Sub/Transmission	2.30218
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.44651
7	GS-3	Secondary	2.37838
8	GS-3	Primary	2.29317
9	GS-3	Sub/Transmission	2.23807
10	GS-3-ES	Secondary	2.37838
11	GS-4	Primary	2.13408
12	GS-4	Sub/Transmission	2.08280
13	IRP-D	Secondary	2.21338
14	IRP-D	Primary	2.13408
15	IRP-D	Sub/Transmission	2.08280
16	EHG	Secondary	2.48485
17	EHS	Secondary	2.29960
18	SS	Secondary	2.40193
19	OL	Secondary	3.22634
20	SL	Secondary	2.87354
21	SBS	Secondary	2.41267
22	SBS	Primary	2.29129
23	SBS	Sub/Transmission	2.10693

Schedule 4: This schedule reflects the Companies' proposed FAC rates by tariff to be effective with first billing cycle of January 2010. AEP Ohio stated that these rates are in compliance with the provision for the capped rate percent increases authorized by the PUCO in its ESP Orders. AEP Ohio provided workpapers with Schedule 4 which support the PUCO's directive that the Companies' phase-in of authorized rate increases do not exceed six percent for CSP and seven percent for OPCO during 2010 pursuant to its Opinion and Order dated March 18, 2009 (Case Nos. 08-917-EL-SSO and 08-918-EL-SSO).

Second Quarter 2010

On March 8, 2010, AEP Ohio submitted quarterly FAC filings for CSP and OPCO, which reflected actual data from October through December 2009 and projected data for the period April through June 2010. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 4 supporting the Companies proposed calculations for CSP and OPCO, and the explanations of each schedule.

The Companies used the same methodology described above as it relates to the format of the schedules in its initial FAC filing. The sections below discuss AEP Ohio's second quarter 2010 FAC filings by reproducing Schedules 1 through 4, broken out separately between CSP and OPCO as Exhibits 7.23 through 7.34, and then briefly summarizing each schedule.

Exhibit 7-23. CSP Schedule 1, April – June 2010

Schedule 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
Summary - Proposed FAC Rate

			Cents Per kWh				
			A	B	C	D	E
				Schedule 2	Schedule 3		Schedule 4
Line	Tariff	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components	FAC Rate Permitted Under ESP Cap
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.65191	3.11855	0.80364	3.92219	3.65191
2	GS-1	Secondary	3.82381	3.11855	0.80364	3.92219	3.82381
3	GS-2	Secondary	3.68943	3.11855	0.80364	3.92219	3.68943
4	GS-2	Primary	3.56910	3.01684	0.77743	3.79427	3.56910
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	3.68943	3.11855	0.80364	3.92219	3.68943
6	GS-3	Secondary	3.47461	3.11855	0.80364	3.92219	3.47461
7	GS-3	Primary	3.36128	3.01684	0.77743	3.79427	3.36128
8	GS-3-LM-TOD	Secondary	3.47461	3.11855	0.80364	3.92219	3.47461
9	GS-4	Sub/Transmission	3.11671	2.95965	0.76269	3.72234	3.11671
10	IRP-D	Secondary	3.28405	3.11855	0.80364	3.92219	3.28405
11	IRP-D	Primary	3.17694	3.01684	0.77743	3.79427	3.17694
12	IRP-D	Sub/Transmission	3.11671	2.95965	0.76269	3.72234	3.11671
13	SL	Secondary	3.95288	3.11855	0.80364	3.92219	3.95288
14	AL	Secondary	4.50885	3.11855	0.80364	3.92219	4.50885
15	SBS	Secondary	3.53250	3.11855	0.80364	3.92219	3.53250
16	SBS	Primary	3.36577	3.01684	0.77743	3.79427	3.36577
17	SBS	Sub/Transmission	3.11671	2.95965	0.76269	3.72234	3.11671

Exhibit 7-24. OPCO Schedule 1, April – June 2010

Schedule 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
Summary - Proposed FAC Rate

			Cents Per kWh				
			A	B	C	D	E
				Schedule 2	Schedule 3		Schedule 4
Line	Tariff	Delivery Voltage	Current FAC Rate	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components	FAC Rate Permitted Under ESP Cap
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	2.56084	2.91750	5.17386	8.09136	2.56084
2	GS-1	Secondary	2.59206	2.91750	5.17386	8.09136	2.59206
3	GS-2	Secondary	2.44651	2.91750	5.17386	8.09136	2.44651
4	GS-2	Primary	2.35886	2.81297	4.98849	7.80146	2.35886
5	GS-2	Sub/Transmission	2.30218	2.74538	4.86863	7.61401	2.30218
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.44651	2.91750	5.17386	8.09136	2.44651
7	GS-3	Secondary	2.37838	2.91750	5.17386	8.09136	2.37838
8	GS-3	Primary	2.29317	2.81297	4.98849	7.80146	2.29317
9	GS-3	Sub/Transmission	2.23807	2.74538	4.86863	7.61401	2.23807
10	GS-3-ES	Secondary	2.37838	2.91750	5.17386	8.09136	2.37838
11	GS-4	Primary	2.13408	2.81297	4.98849	7.80146	2.13408
12	GS-4	Sub/Transmission	2.08280	2.74538	4.86863	7.61401	2.08280
13	IRP-D	Secondary	2.21338	2.91750	5.17386	8.09136	2.21338
14	IRP-D	Primary	2.13408	2.81297	4.98849	7.80146	2.13408
15	IRP-D	Sub/Transmission	2.08280	2.74538	4.86863	7.61401	2.08280
16	EHG	Secondary	2.48485	2.91750	5.17386	8.09136	2.48485
17	EHS	Secondary	2.29960	2.91750	5.17386	8.09136	2.29960
18	SS	Secondary	2.40193	2.91750	5.17386	8.09136	2.40193
19	OL	Secondary	3.22634	2.91750	5.17386	8.09136	3.22634
20	SL	Secondary	2.87354	2.91750	5.17386	8.09136	2.87354
21	SBS	Secondary	2.41267	2.91750	5.17386	8.09136	2.41267
22	SBS	Primary	2.29129	2.81297	4.98849	7.80146	2.29129
23	SBS	Sub/Transmission	2.10693	2.74538	4.86863	7.61401	2.10693

Schedule 1: Column A of this schedule reflects the then current FAC rate by tariff and delivery voltage. Column B reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period April through June 2010. Column C presents the Companies reconciliation adjustment ("RA"), which is calculated in order for AEP Ohio to derive the actual fuel over or under recovery it experienced through December 2009. Column D reflects the sum of the FC and RA components. AEP Ohio stated that the amounts shown in Column D would have been its requested FAC rates if not for the ESP rate caps ordered by the PUCO. However, since AEP Ohio's FAC filings are subject to ESP rate caps, the Companies' filings reflect the then current FAC rates as shown in Column E. Therefore, AEP Ohio did not request an increase in customer rates in its second quarter 2010 filing.

REDACTED VERSION

Exhibit 7-25. CSP Schedule 2, April – June 2010

Schedule 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
FC Component

			Forecast Period			
Line	**Description**		**April**	**May**	**June**	**Total**
1	Fuel & Purchased Power		$ 52,985,000	$ 51,677,000	$ 62,020,000	$ 166,682,000
2	Environmental (Consumables and Allowances)		$ 3,106,000	$ 2,887,000	$ 2,922,000	$ 8,915,000
3	(Gains) and Losses On Sales of Allowances				$ -	$ -
4	Other					$ -
5	Total Includible FAC Costs		$ 56,091,000	$ 54,564,000	$ 64,942,000	$ 175,597,000
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 7,824,000	$ 6,671,000	$ 10,157,000	$ 24,652,000
7	FAC for Internal Load		$ 48,267,000	$ 47,893,000	$ 54,785,000	$ 150,945,000
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.96103	0.96101	0.96084	0.96103
9	FAC for Retail Load Before Renewables		$ 46,386,035	$ 46,025,652	$ 52,639,619	$ 145,062,673
10	Renewables/RECs		$ 1,299,952	$ 948,952	$ 726,952	$ 2,975,856
11	FAC for Retail Load		$ 47,685,987	$ 46,974,604	$ 53,366,571	$ 148,038,529
12	Retail Non-Shopping Sales - Generation Level Kwh		1,594,260,000	1,618,226,000	1,808,912,000	5,021,398,000
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.94815
			Secondary	**Primary**	**Sub/Trans**	
14	FC Component of FAC Rate At Generation Level		2.94815	2.94815	2.94815	
15	Loss Factor		1.0578	1.0233	1.0039	
16	**FC at the Meter Level - Cents/kWh**	Line 14 x Line 15	**3.11855**	**3.01684**	**2.95965**	

Exhibit 7-26. OPCO Schedule 2, April – June 2010

Schedule 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
FC Component

Line	Description		April	May	June	Total
			Forecast Period - 2nd Quarter 2010			
1	Fuel & Purchased Power		$ 83,735,000	$ 78,573,000	$ 99,693,000	$ 262,001,000
2	Environmental (Consumables and Allowances)		$ 6,765,000	$ 6,842,000	$ 9,016,000	$ 22,623,000
3	(Gains) and Losses On Sales of Allowances		$ (200,000)	$ (200,000)	$ (200,000)	$ (600,000)
4	Other		$ -	$ -	$ -	$ -
5	Total Includible FAC Costs		$ 90,300,000	$ 85,215,000	$ 108,509,000	$ 284,024,000
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 29,307,000	$ 24,317,000	$ 43,988,000	$ 97,612,000
7	FAC for Internal Load		$ 60,993,000	$ 60,898,000	$ 64,621,000	$ 186,412,000
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92545	0.88191	0.92719	0.92545
9	FAC for Retail Load Before Renewables		$ 56,445,972	$ 53,706,555	$ 59,823,226	$ 172,514,985
10	Renewables/RECs		$ 1,333,976	$ 983,976	$ 761,976	$ 3,079,928
11	FAC for Retail Load		$ 57,779,948	$ 54,690,531	$ 60,585,202	$ 175,594,913
12	Retail Non-Shopping Sales - Generation Level Kwh		2,084,690,974	2,096,134,541	2,236,305,167	6,417,130,682
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.73635
			Secondary	Primary	Sub/Trans	
14	FC Component of FAC Rate At Generation Level		2.73635	2.73635	2.73635	
15	Loss Factor		1.0662	1.0280	1.0033	
16	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**2.9175**	**2.81297**	**2.74538**	

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period April through June 2010. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the second quarter of 2010, AEP Ohio has projected includable FAC costs totaling $175.597 million for CSP and $284.024 million for OPCO, which are comprised of fuel and purchased power, an environmental component consisting of consumables and allowances, and gains and losses on sales of allowances.

As shown on line 6 of Schedule 2, the Companies removed the costs that were assigned to off-system (including AEP affiliates) in order to derive the FAC costs designated for internal load. For the second quarter of 2010, these projected off-system costs totaled $24.652 million for CSP and $97.612 million for OPCO. After applying a retail jurisdictional allocation ratio based on the forecasted retail jurisdictional non-shopping sales at the generation level, the Companies derived its FAC costs for retail load before adding a component for renewables.

Line 10 of Schedule 2 reflects the Companies' projected component for renewable energy credits ("RECs"), which totaled $2.976 million for CSP and $3.080 million for OPCO. The addition of the RECs result in total FAC costs for retail load of $148.039 million for CSP and $175.595 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 2.94815 cents per kWh for CSP and 2.73635 cents per kWh for OPCO and was calculated by dividing the projected FAC for internal load by each Company's projected retail non-shopping sales at the Generation level.

CSP and OPCO then applied loss factors to each respective FC portion of the FAC rate based on delivery voltage levels in order to derive the FC portion of the FAC rate at meter level. CSP applied the loss factors of 1.0578, 1.0233 and 1.0039 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 3.11855, 3.01684 and 2.95965 cents per kWh. OPCO applied the loss factors of 1.0662, 1.0280 and 1.0033 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 2.9175, 2.81297 and 2.74538 cents per kWh.

Exhibit 7-27. CSP Schedule 3, Page 1, April – June 2010

Schedule 3, page 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
RA Component

Actual Period - October 2009 through December 2009

Line	Month	Kwh Retail Non-Shopping Sales	Renewable & FAC Revenue	Schedule 3, p2 FAC Cost	FAC (Over)/Under Recovery	Carrying Charges On (Over)/Under Recovery	Other Credits/Charges	Total (Over)/Under Recovery
1	Beginning Balance							$ 34,752,193
2	Oct-09	1,577,809,201	$ 46,118,090	$ 47,757,030	$ 1,638,940	$ 380,757	$ (2,240,591)	$ (220,894)
3	Nov-09	1,511,929,804	$ 44,315,547	$ 46,823,441	$ 2,607,894	$ 396,058	$ (2,801,463)	$ 602,499
4	Dec-09	1,797,074,905	$ 53,092,369	$ 57,509,333	$ 4,416,964	$ 419,502	$ (2,660,208)	$ 2,176,258
5	Ending Balance	4,886,813,910	$ 143,526,006	$ 152,089,804	$ 8,563,798	$ 1,196,317	$ (7,202,252)	$ 37,310,056
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 839,019
7	Total (Over)/Under Recovery Balance							$ 38,149,075
8	Loss Adjusted Retail Sales Billing Period - kWh							5,021,398,000
9	RA Component at Generation - Cents/kWh							0.75973

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		0.75973	0.75973	0.75973
11	Loss Factor		1.0576	1.0233	1.0039
12	RA at the Meter Level - Cents/kWh	Line 10 x Line 11	0.80364	0.77743	0.76269

REDACTED VERSION

Exhibit 7-28. OPCO Schedule 3, Page 1, April – June 2010

Schedule 3, page 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
RA

Actual Period - October 2009 through December 2009

Line	Month	Kwh Retail Non-Shopping Sales		Renewable & FAC Revenue		Schedule 3 , p2 FAC Cost		FAC (Over)/Under Recovery		Carrying Charges On (Over)/Under Recovery		Other Credits/Charges		Total (Over)/Under Recovery
1	Beginning Balance												$	241,826,290
2	Oct-09	1,993,951,473	$	35,193,489	$	58,392,454	$	23,198,965	$	1,825,001	$	(2,238,860)	$	22,585,106
3	Nov-09	1,878,190,513	$	33,245,734	$	54,446,894	$	21,201,160	$	2,088,654	$	(2,388,398)	$	20,901,416
4	Dec-09	2,300,659,121	$	40,941,630	$	66,588,089	$	25,646,459	$	2,276,663	$	(2,688,637)	$	25,234,486
5	Ending Balance	6,172,801,107	$	109,380,853	$	179,427,437	$	70,046,584	$	5,990,318	$	(7,315,894)	$	310,549,298
6	Ormet Interim Agreement Deferral			Schedule 3, pg. 3									$	849,672
7	Total (Over)/Under Recovery Balance												$	311,398,970
8	Loss Adjusted Retail Sales Billing Period - kWh													6,417,130,682
9	RA Component at Generation - Cents/kWh													4.85262

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		4.85262	4.85262	4.85262
11	Loss Factor		1.0662	1.0280	1.0039
12	RA at the Meter Level - Cents/kWh	Line 10 x Line 11	5.17386	4.98849	4.86963

Schedule 3: This three-page schedule represents the Companies RA components of its second quarter 2010 FAC filings. Specifically, page 1 of Schedule 3 reflects the Companies' beginning cumulative balance as well as the under-recovery of fuel expenses for each month during the period October through December 2009, which were calculated as the difference between the monthly FAC revenues for the fourth quarter of 2009 and the monthly jurisdictional retail FAC costs for the same period. In addition, page 1 of this schedule reflects the addition of the carrying costs associated with those under-recoveries as well as other credits and charges, which, according to AEP Ohio, reflect adjustments to the FAC deferrals and are predicated on prior PUCO orders. The addition of the carrying charges and other credits and charges resulted in total under-recoveries of $37.310 million for CSP and $310.549 million for OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with Ormet. For the fourth quarter of 2009, these deferrals totaled $839,019 for CSP and $849,672 for OPCO. The derivation of these deferral amounts are summarized on Schedule 3, page 3.

After adding the amounts associated with Ormet, CSP's and OPCO's under recovery for the fourth quarter of 2009 was $38.149 million and $311.399 million, respectively. From these amounts, each Company calculated the RA component of its FAC rate at Generation level by dividing the under recoveries by the same forecasted retail non-shopping sales at Generation level referenced in the Schedule 2 section above. The RA component for CSP for this filing was 0.75973 cents per kWh and 4.85262 cents per kWh for OPCO. The Companies applied the loss factors related to the secondary, primary and sub/trans voltage levels to these RA components in order to derive the RA portion of the FAC rate at meter level. For CSP, the application of the loss factors results in RA components of the FAC rate of 0.80364, 0.77743 and 0.76269 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively. For OPCO, applying the loss factors resulted in RA components of the FAC rate of 5.17386, 4.98849 and 4.86863 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Similar to its first two quarterly filings, AEP Ohio stated that CSP may be in the position to begin recovering its actual fuel expense concurrently with the recovery of the deferrals prior to the end of the ESP period, whereas it is probable that OPCO will have a long-term deferral to be recovered subsequent to the end of the ESP period.

Exhibit 7-29. CSP Schedule 3, Page 2, April – June 2010

Schedule 3, page 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
RA Component

Ormet Interim Rate Deferral

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
4	Oct-09	$ 62,652,943	$ 13,786,738	$ 48,866,205	0.97718	$ 47,751,078	$ 5,952	$ 47,757,030
5	Nov-09	$ 63,827,561	$ 16,310,063	$ 47,517,498	0.97696	$ 46,422,695	$ 400,746	$ 46,823,441
6	Dec-09	$ 81,049,409	$ 23,687,582	$ 57,361,827	0.97634	$ 56,004,646	$ 1,504,687	$ 57,509,333
7	Total	$ 207,529,913	$ 53,784,383	$ 153,745,530		$ 150,178,419	$ 1,911,385	$ 152,089,804

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh: Whlse (Wstville)	Retail	Total	Jurisdictional Ratios: Whlse (Wstville)	Retail
Actual						
8	Oct-09	38,387,385	1,643,611,320	1,681,998,705	0.02282	0.97718
9	Nov-09	37,165,102	1,575,606,737	1,612,771,839	0.02304	0.97696
10	Dec-09	45,470,301	1,876,645,453	1,922,115,754	0.02366	0.97634
Forecast						
11	April '10	64,642,496	1,594,260,000	1,658,902,496	0.03897	0.96103
12	May '10	65,652,535	1,618,226,000	1,683,878,535	0.03899	0.96101
13	June '10	73,732,847	1,808,912,000	1,882,644,847	0.03916	0.96084

Exhibit 7-30. OPCO Schedule 3, Page 2, April – June 2010

Schedule 3, page 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
RA Component

Monthly Retail FAC Cost

Line	Month	Total Company FAC Cost	Less Assigned OSS And Pool	= Internal Load FAC Cost	Times Retail Allocation Ratio	= Retail FAC before Renewables	+ Renewables	= Retail FAC & Renewable Cost
4	Oct-09	$ 136,540,400	$ 73,372,764	$ 63,167,636	0.92431	$ 58,386,478	$ 5,976	$ 58,392,454
5	Nov-09	$ 128,587,451	$ 69,666,181	$ 58,921,270	0.91726	$ 54,046,124	$ 400,770	$ 54,446,894
6	Dec-09	$ 162,894,359	$ 92,755,013	$ 70,139,346	0.92529	$ 64,899,235	$ 1,688,854	$ 66,588,089
7	Total	$ 428,022,210	$ 235,793,958	$ 192,228,252		$ 177,331,837	$ 2,095,600	$ 179,427,437

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh Whlse (WPC)	Retail	Total	Jurisdictional Ratios Whlse (WPC)	Retail
Actual						
8	Oct-09	169,607,736	2,071,176,358	2,240,784,094	0.07569	0.92431
9	Nov-09	176,092,035	1,952,041,637	2,128,133,672	0.08274	0.91726
10	Dec-09	193,642,580	2,398,420,474	2,592,063,054	0.07471	0.92529
Forecast						
11	Apr-10	167,942,194	2,084,690,974	2,252,633,169	0.07455	0.92545
12	May-10	280,672,189	2,096,134,541	2,376,806,730	0.11809	0.88191
13	Jun-10	175,616,698	2,236,305,167	2,411,921,865	0.07281	0.92719

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the fourth quarter of 2009. Specifically, page 2 of Schedule 3 (lines 4-7) shows, for each Company, total monthly FAC costs incurred from October through December 2009. For each month (October through December), the Companies deducted amounts assigned to off-system sales in order to derive the amounts assigned to internal load. From each monthly internal load amount, the Companies then applied a retail jurisdictional allocation ratio, calculated as monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". During the fourth quarter of 2009, CSP and OPCO added amounts totaling $1,911,385 and $2,095,600, respectively for renewables, which reflects the revenue requirement associated with solar panels that were installed by CSP and OPCO pursuant to meeting the renewable energy requirements of Senate Bill 221 as well as other renewable energy costs. AEP Ohio stated that future FAC revenues will first be applied towards recovering renewable energy costs so that they are not embedded in the long-term deferrals of either CSP or OPCO.. The impact of adding the renewables component resulted in the retail FAC costs that were carried over to Schedule 3, page 1, and from which the Companies' FAC over/under recoveries for the fourth quarter of 2009 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for October through December 2009. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for April through June 2010, from which both the FC and RA components of each Company's FAC rate were calculated as discussed above. In addition, from these forecasted amounts, the Companies calculated retail jurisdictional allocation ratios of .96103, .96101 and .96084 (April, May and June 2010, respectively) CSP and .92545, .88191 and .92719 (April, May and June 2010, respectively) for OPCO.

Exhibit 7-31. CSP Schedule 3, Page 3, April – June 2010

Schedule 3, page 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Oct-09	$ -	$ 279,673	$ 279,673
2	Nov-09	$ -	$ 279,673	$ 279,673
3	Dec-09	$ -	$ 279,673	$ 279,673
4	Total	$ -	$ 839,019	$ 839,019

Exhibit 7-32. OPCO Schedule 3, Page 3, April – June 2010

Schedule 3, page 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Oct-09	$ -	$ 256,486	$ 256,486
2	Nov-09	$ -	$ 296,758	$ 296,758
3	Dec-09	$ -	$ 296,428	$ 296,428
10	Total	$ -	$ 849,672	$ 849,672

As noted above, page 3 of Schedule 3 reflects the derivation of the monthly rate deferral and carrying costs associated with Ormet Interim Agreement pursuant to Case No. 09-1094-EL-FAC. The deferrals included in the Companies' FACs are for the period January 1, 2009 through September 17, 2009. Ormet related rate discounts that occurred subsequent to September 17, 2009 will be recovered through each Company's Economic Development Cost Recovery Rider ("EDR").

Exhibit 7-33. CSP Schedule 4, April – June 2010

Schedule 4

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff
1	R-R, R-R-1, RLM, RS-ES, RS-TOD	Secondary	3.65191
2	GS-1	Secondary	3.82381
3	GS-2	Secondary	3.68943
4	GS-2	Primary	3.56910
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	3.68943
6	GS-3	Secondary	3.47461
7	GS-3	Primary	3.36128
8	GS-3-LM-TOD	Secondary	3.47461
9	GS-4	Sub/Transmission	3.11671
10	IRP-D	Secondary	3.28405
11	IRP-D	Primary	3.17694
12	IRP-D	Sub/Transmission	3.11671
13	SL	Secondary	3.95288
14	AL	Secondary	4.50885
15	SBS	Secondary	3.53250
16	SBS	Primary	3.36577
17	SBS	Sub/Transmission	3.11671

Exhibit 7-34. OPCO Schedule 4, April – June 2010

Schedule 4

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2010
FAC Rate Calculated Under the ESP Rate Cap

Line	Tariff	Voltage	Capped FAC Rates By Tariff
1	RS, RS-ES, RS-TOD, AND RDMS	Secondary	2.56084
2	GS-1	Secondary	2.59206
3	GS-2	Secondary	2.44651
4	GS-2	Primary	2.35886
5	GS-2	Sub/Transmission	2.30218
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.44651
7	GS-3	Secondary	2.37838
8	GS-3	Primary	2.29317
9	GS-3	Sub/Transmission	2.23807
10	GS-3-ES	Secondary	2.37838
11	GS-4	Primary	2.13408
12	GS-4	Sub/Transmission	2.08280
13	IRP-D	Secondary	2.21338
14	IRP-D	Primary	2.13408
15	IRP-D	Sub/Transmission	2.08280
16	EHG	Secondary	2.48485
17	EHS	Secondary	2.29960
18	SS	Secondary	2.40193
19	OL	Secondary	3.22634
20	SL	Secondary	2.87354
21	SBS	Secondary	2.41267
22	SBS	Primary	2.29129
23	SBS	Sub/Transmission	2.10693

Schedule 4: This schedule breaks out current FAC rates by tariff. AEP Ohio stated that these rates are in compliance with the provision for the capped rate percent increases approved by the PUCO in its Opinion and Order dated March 18, 2009. As noted above in the discussion of Schedule 1, AEP Ohio proposes that the current FAC rates remain in place for the second quarter of 2010 (i.e. the proposed FAC rates from AEP Ohio's first quarter 2010 FAC filing).

Minimum Review Requirements

As noted above, Larkin referred to the objectives and procedures outlined in Appendix E of former Chapter 4901:1-11 of the Ohio Administrative Code as guidance for the review requirements of this project. The purpose of the Uniform Financial Audit Program Standards and Specifications for the Electric Fuel Component is to provide uniform standards and specifications as guidelines for an independent auditing firm which conducted an EFC "financial audit"[1] pursuant to former section 4905.66(B)(2) of the Revised Code and former rule 4901:1-11-09 of the Administrative Code. The EFC "financial audit" program is only a guide for the auditor and should not be used to the exclusion of the auditor's initiative, imagination and thoroughness.

Section E of those Standards provides for the following Minimum Review Requirements:

The auditor's review shall include, but not be limited to, a review of:

(1) Purchasing procedures for fuel procurement not under long-term contracts;

(2) Procedures for accounting for fuel receipts, testing, and payments;

(3) Procedures for weighing, testing and reporting coal burned;

(4) Procedures for amortizing nuclear fuel costs corresponding to nuclear generated energy;

(5) Procedures for recording purchases and interchanges;

(6) Procedures for accounting treatment of emission allowances; and

(7) Procedures for calculating the EFC rate, including an evaluation of the company's compliance with the financial procedural aspects of former Chapter 4901:1-11 of the Administrative Code, and its application to customer bills.

Larkin reviewed AEP Ohio's procedures for accounting for fuel receipts, testing of samples to ensure quality, and payments to vendors. CSP and OPCO use the same accounting procedures for fuel receipts, testing and payments. These procedures are as follows:

[1] As noted above, the review of AEP Ohio's quarterly FAC filings were conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants.

- Plant personnel enter the fuel receipts information into the Companies' fuel accounting system Commodities Tracking software, or COMTRAC. This system contains the terms and conditions associated with fuel contracts. The system is also utilized to make payments to suppliers and transportation vendors. In addition, the Accounting Department creates payment requests through COMTRAC, which in turn is run through a feed to the PeopleSoft Accounts Payable system, where such payments are executed.

- After testing is performed, the resulting analysis is fed into the COMTRAC system from the Central Coal Lab system software. Certain purchases are paid for based on information provided by the Companies' suppliers, which is then entered into the COMTRAC system by plant personnel.

- The Companies stated that they commenced using COMTRAC as the fuel accounting system as of May 1, 2009, and that prior to that, plant personnel entered fuel receipt data into the Fuelsite system. The associated invoices, which included the contract terms and conditions, were then processed through the SOLARC system.

Larkin also reviewed the Companies' procedures for weighing, testing and reporting coal burned per data request LA-1-2. Specifically, consumed tonnage is measured either by belt scales or weigh feeders as coal is fed into units and/or bunkers. Unit burn samples are collected using mechanical sampling systems that are in accordance with American Society for Testing Standards ("ASTM") standards. In addition, unit samples are collected and sent to the AEP Central Coal Lab to be analyzed. As noted above, the analyzed results were fed into the Fuelsite system prior to May 1, 2009 and are currently fed into the COMTRAC system. Burn reports, which include tonnage and quality characterstics, can be generated by both the Fuelsite and COMTRAC systems for the relevant reporting period.

Larkin followed up on the response to LA-1-2 with data request LA-2-2, which requested that AEP Ohio provide the Fuelsite burn reports for April 2009 and the COMTRAC burn reports for August 2009 for each CSP and OPCO coal plant. In response, AEP Ohio provided the requested Fuelsite and COMTRAC reports as attachments, the total tons of which are summarized in the following tables:

Exhibit 7-35. Fuelsite Reports, April 2009

Fuelsite Reports for CSP - April 2009

Unit	Consumed Tons
Conesville Unit 3	25,114
Conesville Unit 5	99,891
Conesville Unit 6	100,479
Total	225,484

Fuelsite Reports for OPCO - April 2009

Unit	Consumed Tons
Gavin Unit 1	372,158
Gavin Unit 2	40,062
Kammer Unit 1	34,585
Kammer Unit 2	21,415
Kammer Unit 3	25,841
Mitchell Unit 1	138,979
Mitchell Unit 2	110,308
Muskingum River Unit 1	26,283
Muskingum River Unit 2	2,052
Muskingum River Unit 3	35,791
Muskingum River Unit 4	34,282
Muskingum River Unit 5	156,286
Amos Unit 3	269,981
Cardinal Unit 1	149,261
Sporn Unit 2	27,133
Sporn Unit 4	2,891
Total	1,447,307

Exhibit 7-36. COMTRAC Reports, April 2009

COMTRAC Reports for CSP - August 2009

Unit	Consumed Tons
Conesville Unit 3	28,037
Conesville Unit 4	-
Conesville Unit 5	75,725
Conesville Unit 6	90,968
Picway Unit 5	22,693
Total	217,423

COMTRAC Reports for OPCO - August 2009

Unit	Consumed Tons
Gavin Unit 1	355,956
Gavin Unit 2	365,951
Kammer Unit 1	6,226
Kammer Unit 2	4,597
Kammer Unit 3	31,321
Mitchell Unit 1	160,656
Mitchell Unit 2	179,968
Muskingum River Unit 1	-
Muskingum River Unit 2	25,045
Muskingum River Unit 3	27,510
Muskingum River Unit 4	26,019
Muskingum River Unit 5	151,725
Amos Unit 3	290,941
Cardinal Unit 1	151,589
Sporn Unit 2	24,357
Sporn Unit 4	11,623
Sporn Unit 5	49,821
Total	1,863,305

AEP Ohio stated that the plants that are jointly-owned by CSP, and operated by Duke Ohio and Dayton Power & Light, are tracked in systems that are owned and managed by those non-affiliated companies. Therefore, there were no burn reports for the non-affiliated companies in either Fuelsite or COMTRAC.

AEP Ohio does not have nuclear generation, so the provisions of E (4) do not apply.

CSP and OPCO's procedures for recording purchases and interchanges of energy involve each Company's Accounting Department being provided information regarding power purchases from third parties and/or affiliates. The Accounting Department then records such data into Account 555 – Purchased Power.

The Companies account for fuel at jointly owned generation plants as follows:

CSP Jointly Owned Generation

CSP participates in four jointly owned power plants. In addition to CSP, the joint owners are Duke Ohio ("Duke") and Dayton Power & Light ("DP&L"). The four jointly owned plants include the following:

- Conesville Plant Unit 4 (operated by CSP)

- Zimmer Plant (operated by Duke)
- Beckjord Plant Unit 6 (operated by Duke)
- Stuart Plant (operated by DP&L)

The same accounting methodology is used at all four jointly owned power plants as illustrated below:

- The total costs of each plant are recorded in a fuel ledger and then such costs are allocated to the joint owners.
- The current month's fuel receipts are added to Beginning Inventory. From this a weighted average rate is determined for Available Tons in Inventory. Consumed expense is then calculated at the available rate for the consumed tons.
- Ending inventory is calculated as Available Inventory less Consumption.
- CSP, Duke and DP&L all have an ownership share of each plant's ending inventory. Each joint owner's consumption is calculated based on a composite ratio. This ratio represents the energy used for the month plus an ownership portion, which represents the energy necessary to maintain each unit in a state of readiness. Each joint owner's receipts are calculated as the difference between Beginning Inventory and Available Inventory with Available Inventory calculated as Ending Inventory plus Consumption.
- An additional allocation is calculated for both the Conesville Unit 4 and Beckjord Unit 6 power plants. Plant inventory is allocated, based on historic consumption, to segregate a portion of the total coal pile between the jointly owned unit and the non-jointly owned unit(s).

<u>OPCO Jointly Owned Generation</u>

OPCO participates in three jointly-owned power plants. The three jointly owned power plants are comprised of the following:

- [redacted] are operated by [redacted] and are co-owned with Buckeye Power, a non-affiliated partner.
- Amos Plant Unit 3 is operated and co-owned by Appalachian Power Company ("APCo"). APCo also operates Sporn Plant Units 2, 4 and 5, but these units are owned 100 percent by OPCO.

[redacted]

- The total costs of the entire plant are recorded in a fuel ledger and then such costs are allocated to the joint owners.
- The current month's fuel receipts are added to Beginning Inventory. From this, a weighted average rate is determined for Available Tons in Inventory. Consumed expense is then calculated at the available rate for the consumed tons.

- Ending Inventory is calculated as Available Inventory less Consumption.

- The joint owners' share of ending inventory is based on twelve-month generation taken. This amount is updated quarterly.

- The calculation for the joint owners' consumption is based on the energy taken each month. Joint owners' receipts are calculated as the difference between Beginning Inventory and Available Inventory.

- Available Inventory is calculated as Ending Inventory plus Consumption.

<u>Amos Plant Unit 3</u>

- The total costs of the entire plant are recorded in a fuel ledger and then such costs are allocated to the joint owners.

- The current month's fuel receipts are added to Beginning Inventory. From this, a weighted average rate is determined for Available Tons in Inventory. Consumed expense is then calculated at the available rate for the consumed tons.

- Ending Inventory is calculated as Available Inventory less Consumption.

- A portion of this plant's Ending Inventory is allocated to segregate the jointly-owned Unit 3 from the non-jointly owned units. This allocation is based on projected consumption by unit.

- The joint owners' receipts are calculated as the difference between Beginning Inventory and Available Inventory.

- Available Inventory is calculated as Ending Inventory plus Consumption.

<u>Sporn Plant Units 2, 4 and 5</u>

- The total costs of the entire plant are recorded in a fuel ledger and then such costs are allocated to the joint owners.

- The current month's fuel receipts are added to Beginning Inventory. From this, a weighted average rate is determined for Available Tons in Inventory. Consumed expense is then calculated at the available rate for the consumed tons.

- Ending Inventory is calculated as Available Inventory less Consumption.

- A portion of this plant's Ending Inventory is allocated to segregate the units owned by APCo (Units 1 and 3) and the units owned by OPCO (Units 2, 4 and 5). This allocation is based on projected consumption by unit.

- Consumption is calculated based on the tons consumed by unit at the available rate for total plant inventory.

- The joint owners' receipts are calculated as the difference between Beginning Inventory and Available Inventory.

- Available Inventory is calculated as Ending Inventory plus Consumption.

FAC Deferrals

In its July 31, 2008 Application for an Electric Security Plan (and FAC), AEP Ohio proposed mitigating the rate impact of any FAC increases on its customers by phasing in the new ESP rates by deferring a portion of the annual incremental FAC costs during the three-year ESP period ending December 31, 2011. Specifically, AEP Ohio proposed that the amount of incremental FAC costs to be recovered from customers would be such that total bill increases would not be more than 15 percent during each year of the ESP. However, in its Opinion and Order dated March 18, 2009, the PUCO modified AEP Ohio's proposal to mitigate the rate impact on customers by limiting the phase-in of any FAC cost increases on a total bill basis by the following percentages:

	2009	2010	2011
Columbus Southern Power	7%	6%	6%
Ohio Power Company	8%	7%	8%

As a result of implementing this Order, CSP now has 17 different FAC rates and OPCO has 23 different FAC rates. The PUCO stated that the collection of any deferrals, including carrying costs that are remaining at the end of the ESP "shall occur from 2012 through 2018 as necessary to recover the actual fuel expenses incurred plus carrying costs."[2]

In LA-7-38, Larkin requested that AEP Ohio provide, for CSP and OPCO separately, the most current estimates and projections of the deferred FAC costs through the end of the ESP period. LA-7-38 also requested the Companies' estimate of the collection period necessary to fully recover the deferred FAC costs after the ESP period, including an estimate of the prospective surcharge and rate impact. In response, AEP Ohio stated that it is currently not projecting a significant deferral of FAC costs for CSP at the end of the ESP period, but that the current estimate of OPCO's deferred FAC costs is approximately $500 million. As for its estimates of the collection period, prospective surcharge and rate impact, AEP Ohio stated:

> *"Because the actual deferral balance, the length of the recovery period, the retail load and other variables are not known at this time, the*

[2] See PUCO's Opinion and Order dated March 18, 2009 at page 23.

Company is not in a position to provide a meaningful estimate of the surcharge and rate impacts of the deferral."

AEP Ohio stated in its response to data request LA-1-5 that during 2009, CSP and OPCO deferred fuel and other FAC items in the amounts of $37,545,778 and $297,570,318, respectively, and that such deferrals were recorded in Account 5010005. In addition, the Companies stated that no other fuel amounts were deferred.

The Companies' response to data request LA-1-47, which requested the Excel files used in producing the supporting workpapers for the FAC filings (and discussed in further detail below), included a workpaper titled "Summary of Under/Over-Recovery Journals by Month – General Ledger Account 501005 – (FAC) Fuel Deferred" for both CSP and OPCO during the period March through December 2009. The total monthly general ledger transactions reflected on each Company's workpaper agreed with the amounts referenced above at December 31, 2009. In addition, each Company's workpaper indicated that the offsetting debit to its deferrals were recorded in Account 1823144. As it relates to CSP, the offsetting debit to the deferral of $37,545,778 included an item referred to as a "Reclass of Power Acquisition Rider Liability" in the amount of $1,517,645, resulting in a net amount of $36,028,133 recorded in Account 1823144.

Review Related To Coal Order Processing

The following is a description of AEP Ohio's procedures for processing fuel purchase orders (per LA-1-6):

- A coal buyer initiates a deal ticket, which is based on the following: (1) projected coal needs, (2) inventory levels of an operating unit and/or plant, and (3) the availability and price of coal in the markets.
- The deal ticket is routed to the Contact Administration group who creates either a spot agreement or a long-term agreement.
- The coal buyer also creates a justification, which is the basis for a proposed fuel purchase order. This justification is routed to key management personnel whose approval is required for the fuel purchase order to be executed.
- Once the justification requirement has been met, the formal purchase order is assembled and entered into the appropriate Company's computer system.

Purchase Orders And Approved Purchase Requisitions

Data requests LA-1-7 and LA-1-8 requested copies of fuel purchase orders ("Pos") recorded in April 2009 and approved purchase requisitions for fuel purchases recorded in April 2009. In response, AEP Ohio stated that copies of the fuel POs recorded in April 2009 and the approved purchase requisitions were provided in the response to EVA-1-3. AEP Ohio's response to data request EVA-1-3 stated that the requested information would be made available for inspection AEP's headquarters in Columbus, Ohio. EVA reviewed these documents while on-site at AEP's headquarters in March 2010.

Invoice And Voucher Procedures

In order to enable us to track the Company's processing of fuel invoices, Larkin obtained copies of cash vouchers and payment documentation for fuel purchases recorded in April 2009. These were provided in the confidential response to data request LA-1-9. In addition, the response to LA-1-9 stated:

> *CSP and OPCo are billed their ownership share of purchases for the jointly-owned power plants. The payments to coal suppliers and transporters are paid by the company designated as the operator of the jointly-owned plant.*

For CSP, the information provided in LA-1-9 included a summary of invoices paid by CSP, invoices, payment vouchers and receiving reports. The receiving reports were for coal delivered to the Conesville Prep Plant, Conesville Power Plant and the Picway Plant. For OPCO, the information provided in LA-1-9 included invoices, shipping notices, barge survey reports, analysis reports, payment vouchers and receiving reports. The receiving reports provided were for coal delivered to the Gavin, Kammer, Mitchell and Muskingum River plants.

In reviewing the information provided in the confidential response to LA-1-9, Attachments A – C, several discrepancies were noted between the invoices and the receiving reports:

- Receiving reports were not included with a few of the invoices. It was noted on such invoices that partial payments of these invoices had been made before the coal deliveries were received at the Gavin Plant, per AEP Ohio's terms with the vendor. In response to informal discussions with AEP Ohio personnel, the

Company stated that in many cases, vendors issue invoices based on assigned pricing sheets included in the purchase orders to those vendors.

- The pricing on several invoices did not tie to the pricing on their respective receiving reports. In response to informal discussions with AEP Ohio personnel, the Company stated that if its vendors underbill, then AEP Ohio pays the "as billed" amount.

- Invoice No. AEP-88, issued by [redacted], noted that its pricing was for the balance of those invoices that did not include receiving reports, but the total of the invoices was more than the total on the receiving report. In addition, Invoice No. AEP-83, also issued by [redacted], noted that is pricing was for the balance of three invoices, but two of those invoices were not included with the purchasing documents. In response to informal discussions with AEP Ohio personnel, the Company stated that many of its vendors bill partial invoices. Larkin noted that AEP Ohio initially paid 75% of Invoice Nos. AEP-83 and AEP-88 with the remaining 25% of both invoices subsequently paid.

Discrepancies were also noted between the receiving reports provided in the confidential attachments to LA-1-9 and the Fuel Analysis reports provided in the confidential response to LA-1-15 (see additional discussion below):

- Invoices and receiving reports were provided for purchased fuel that was not included in the Fuel Analysis reports. In response to informal discussions with AEP Ohio personnel, AEP Ohio stated that it cannot control how its vendors bill for coal purchases and that invoices often include two previous months of billed coal.

- Invoices and receiving reports (per LA-1-9) were not provided for all of the fuel purchases listed on the Fuel Analysis reports (LA-1-15). The following table reflects the purchases reflected on the Fuel Analysis Reports from LA-1-15 for which no invoices/receiving reports were provided in the response to LA-1-9:

Exhibit 7-37. Purchases In Fuel Analysis Reports With No Invoices

[redacted]

Referring to Exhibit 7.37 above, and in response to informal discussions with AEP Ohio personnel, as it relates to the Conesville Prep Plant, the tons purchased represent transfers from the Conesville Prep Plant to Conesville Power Plant. Transfers such as these are recorded with a journal entry and no invoicing occurs. As it relates to the Cardinal Plant, the Company stated that no support was provided since this plant is jointly owned by OPCo and Buckeye Power and is operated by the Cardinal Operating Company

Fuel Ledger

Larkin reviewed the data the Companies provided in response to LA-1-10, which requested CSP's and OPCO's fuel ledgers for the period January through December 2009. Upon reviewing the fuel ledgers provided in the response to LA-1-10, Larkin attempted to tie the amounts shown on the FAC workbooks provided in LA-1-47 (see additional discussion below) to the amounts reflected in the fuel ledgers. Larkin was able to tie the amounts in the fuel ledgers to the accounts listed under the "Generation Fuel" and "Incremental Fuel Handling/Ash/Gypsum" cost categories in the monthly Net Energy Cost ("NEC") worksheets that were provided as part of the FAC workbooks. However, as shown in Exhibit 7.38, the following accounts, which were designated under the "Purchases Power – Fuel Portion" category of the FAC workbooks were not included in the Companies' fuel ledgers.

Exhibit 7-38. Accounts with Purchased Power Fuel Not Included in Fuel Ledgers

Account	Description
555000/0094	Purch Pwr-NonTrading (Fuel for OVEC, Trash, 3rd party Firm)
5550005	Purchased Power - Affil. Primary/Econ. Pool Energy (Fuel)
5550080	PJM Energy Purchases (Fuel)
555094/0001	Purch Pwr-Trading-Nonassoc (Fuel)
5550046	PP - Fuel Portion - Affil (PP from West Pool)
5550048	PP - Fuel Portion - Affil (PP from AEG-Lawrenceburg) - CSP only
5550031/32	Purchased Pwr - Mone (Fuel)

As a result, Larkin was unable to tie the fuel purchases recorded in the accounts above to the Companies' fuel ledgers.

BTU Adjustments

As part of its review, Larkin requested that the Companies provide documentation for Btu adjustments for fuel purchases recorded in April 2009 per data request LA-1-11. In response, AEP Ohio provided confidential documents titled "Pricing Quality Adjustment Reports". AEP Ohio provided these confidential reports for the following power plants: Gavin, Kammer, Mitchell, Muskingum River, Cardinal (HS & LS), Conesville and Picway. Larkin selected a sample of the Pricing Quality Adjustment Reports with which to test the Btu adjustments. From this sample selection, Larkin compared the Btu adjustment calculation to the specific contract as well as recalculated the amounts used in the Btu adjustment calculation. All Btu adjustments within the sample that were tested were properly calculated on the reports sampled.

Freight And Barge Vouchers

As part of its review, in data request LA-1-12, Larkin requested that AEP Ohio provide freight cash vouchers for two days of coal receipts in April 2009 as well as copies of the portions of the corresponding coal received reports. For CSP, the confidential response to LA-1-12 included the following:

(1) A summary of six payments that CSP made in May 2009 for the freight associated with coal received in April 2009, including two payments to [redacted] and four payments (two of which were addendums to the original invoices) to [redacted];

(2) Copies of six invoices for the payments referenced above;

(3) Copies of six payment vouchers that are associated with those payments;

(4) Copies of four coal receiving reports for the Conesville Plant. Two of these receiving reports were for coal received during the period April 1 through April 15, 2009 and the other two receiving reports were for coal received during the period April 16 through April 30, 2009; and

(5) Copies of eight documents titled "Rail Freight & Dumping Cost" for the second quarter 2009.

Upon reviewing the aforementioned documents, Larkin agreed with the amounts reflected on the payment vouchers to the invoices. In addition, Larkin tied out these amounts to the Rail Freight and Dumping Cost documents, where the amounts associated with the two invoices paid to [redacted] were reflected under the column heading

Dumping Fees. The amounts and quantities associated with the payments made to [redacted] were reflected under the column heading "1/2 Month Freight Cost". However, the amounts shown on the two addendum invoices referenced above from [redacted] were not reflected on the Rail Freight and Dumping Cost documents. Finally, Larkin traced the quantities reflected on the invoices and vouchers to the coal receiving reports. No exceptions were noted. AEP Ohio provided the same coal receiving reports in its confidential response to data request LA-1-9, but that response was related to CSP's coal purchases in April 2009, whereas the invoices provided in LA-1-12 pertained to the freight cost associated with those coal purchases.

For OPCO, the confidential response to LA-1-12 included the following:

(1) Copies of eight invoices for freight charges associated with coal purchases made by OPCO during April 2009, including four from [redacted], two from [redacted] and two from [redacted];

(2) Copies of eight payment vouchers associated with those payments;

(3) Copies of "Customer Load Summaries", which are associated with the coal quantities delivered by Iddings and appear to essentially be receiving reports.

(4) Copies of a document which appears to be titled "Barge Trk Coal".

(5) Copies of transportation rates related to the River Transportation Division ("RTD").

Upon reviewing the aforementioned documents, Larkin agreed with the amounts reflected on the payment vouchers to the invoices from [redacted], [redacted] [redacted]. Larkin also agreed with the amounts reflected on the [redacted] to the Barge Trk Coal document. In addition, Larkin traced the quantities reflected on the invoices and vouchers to the Customer Load Summaries. However, as noted above, AEP Ohio only provided Customer Load Summaries for the freight charges associated with coal purchases delivered by [redacted]. Except for the lack of receiving reports being provided for the [redacted] invoices, no exceptions were noted.

In data request LA-1-13, Larkin requested that AEP Ohio provide two cash vouchers from each barge company for coal unloaded at Company plants during April 2009 as well as copies of the portions of the corresponding coal unloading reports and purchase orders. AEP Ohio stated that all coal to CSP's plants is delivered via truck and/or rail, thus no barges are used. However, OPCO's barging services are provided by I&M River Transportation Division ("RTD"). As RTD is an affiliate of OPCO, RTD issues a monthly invoice, which is settled by an inter-unit journal entry. OPCO's barging services are discussed in further detail in the AEP River Transportation Division section of this report. As part of its response to LA-1-13, AEP Ohio provided a copy of the RTD invoice for April 2009, which included data related to coal shipments received at the Gavin, Kammer and Muskingum River plants. AEP Ohio also provided a copy of the Fuelsite report which details shipments of coal received in April 2009 for the Gavin, Kammer, Mitchell and Muskingum River plants.

Upon reviewing and comparing the data listed on the April 2009 RTD invoice (document titled Billed Freight – Coal – Captive) and the April 2009 Fuelsite report, Larkin noted discrepancies between the two sources as it relates to unloaded tons of coal at the referenced OPCO plants. The table below summarizes these discrepancies.

Exhibit 7-39. Differences Between April 2009 RTD Invoice and Fuelsite Report

[redacted]

In response to informal discussions with AEP Ohio personnel, the Company stated that the monthly RTD invoices overlap unloaded tons (e.g., unloaded tons in March reflected on April RTD invoices and unloaded tons in April reflected on May RTD invoices, etc.), which is the reason for the discrepancies.

In addition to the discrepancies noted in the table above, Larkin also noted the following when reviewing the RTD invoice and Fuelsite reports:

- Referencing the Fuelsite reports, with two exceptions, Larkin was able to tie out the quantities shown for Unloaded Tons to the Fuel Analysis Reports that were provided during Larkin's on-site review pursuant to data request LA-1-15. The two exceptions noted were as follows:

Plant	PO Number	Unloaded Tons
Gavin	07-77-89-999	65,175
Kammer	07-76-89-999	28,540

In response to informal discussions with AEP Ohio personnel, the Company stated that the referenced amounts are transfers from the Cook Coal Terminal, which are not included in FDR Report 2250 (Fuel Analysis Reports).

Fuel Analysis Reports

As part of our review, in LA-1-14, Larkin had requested that AEP Ohio provide the Company's procedures for preparing monthly fuel analysis reports. In response, AEP Ohio stated that fuel analysis data was captured by [redacted] systems prior to May 1, 2009, the time at which the [redacted] system was implemented. In addition, AEP Ohio stated that fuel analysis reports can be generated for each plant by capturing "as-consumed analysis" or "as-received analysis" by supplier for any reporting period.

In data request LA-1-15, Larkin requested that AEP Ohio provide copies of fuel analysis reports related to fuel purchases recorded during April 2009. The Company provided such reports during Larkin's on-site visit to AEP's headquarters in Columbus during the week of March 1, 2010. The reports provided listed the Companies' fuel purchases by mine, plant, unit, vendor, tons purchased, tons sampled and the percentage of tons sampled. As noted above in the "Invoices and Voucher Procedures" section of this report in Exhibit 7.37, the Company did not provide purchasing information for many of the April 2009 purchases reflected on the Fuel Analysis Reports.

Retroactive Escalations

Larkin requested that AEP Ohio identify all pending or approved retroactive escalations that affect fuel cost for the period January through December 2009. In response to LA-1-16, the Company stated that there are two agreements that have pending or approved retroactive escalations which affect fuel costs during the January through December 2009 review period. The two agreements are (1) [redacted] – Agreement No. [redacted], and (2) [redacted] – Agreement No. [redacted].

Review Related To Station Visitation And Coal Processing Procedure

Larkin conducted a site visit to CSP's Conesville plant site on March 4, 2010. Document requests LA-1-17 through LA-1-33 relate to fulfilling the objectives of the station visit and the review of the Company's coal processing procedure from the receipt of coal to the disposition of fly ash.

A description of the Companies' coal receiving procedures and controls for shortages, overages, and other discrepancies was provided in AEP Ohio's response to LA-1-17 and is replicated in the following table:

Exhibit 7-40. Coal Receiving Controls

Coal Receiving Controls

AEP Client's Control Activity Number (if applicable)	AEP Control Activity
Coal Receiving	
FP.CP.CR.CO4.R1.CA2	CO-CP-4.1 *All plant receiving scales used for custody transfers are calibrated in* accordance with company procedures and NIST Handbook 44 standards or other procedures which are mutually acceptable to the vendor and AEP Fuel Procurement (buyer). The calibration frequency of the scales is as follows: Belt - monthly; Rail - semiannual (every six months); Truck - semiannual (every six months).
FP.CP.CR.CO4.R1.CA1	CO-CP-4.2 - For AEP East Plants coal weights as measured by plant scales are compared to supplier weights. The comparison is reviewed at the plant and significant discrepancies are communicated to the Director of FEL Technical Services. If it is determined that the discrepancies are beyond a reasonable range, FEL Technical Services will communicate the findings to the appropriate FEL Fuel Procurement personnel for resolution. Note: Effective Q3 2009, responsibility for this control activity transferred to Tim Light, SVP of Fuel, Emissions and Logistics. Unity will be changed after the 2009 interim testing to reflect Tim Light as the Cycle Executive and FP14 as the Business Unit.
Coal Inventory (Conesville Plant)	
FP.FA.FAEW.CO1.R2.CA38	CO-FA-3.1 - The Groveport Lab personnel are responsible for performing routine physical inventories of all coal in storage at the Plants to ensure coal accounts are accurately reported and physical inventory of coal is properly recorded. This inventory is to be performed at least annually. The coal pile survey is to be performed in accordance with procedures defined in Circular Letter CI-O-CL-0084. The Civil Lab Services (CLS) drill crew (driller) shall obtain coal samples for the purpose of determining the average density of the coal in the storage area. The CLS mapping crew (mapper) shall obtain location and elevation measurements of points in the coal yard in order to compare those measurements to the base map and accurately determine the volume of the coal in the storage yard. Using the data gathered by the driller and mapper, CLS shall compute volumes, average densities and publish a report including maps. If the difference between physical inventory and book inventory is greater than 2% (+ or -) of the coal consumed in the period, a second inventory must be performed within six (6) months. Documentation of the survey is retained at the plant.
FP.FA.FAEW.CO1.R2.CA37	CO-FA-3.2 - Plant Management compares physical results of the coal inventory to inventory records at least annually (at the time of the coal pile survey). This comparison to inventory records is done at the plant. This is done to ensure coal accounts are accurately reported and physical inventory of coal is properly recorded. Adjustments are made to book inventory in ComTrac. Plant management reviews and approves all physical inventory results and resulting adjustments.
FP.FA.FAEW.CO1.R1.CA36	CO-FA-3.3 - In accordance with Account Bulletin No. 4, Fuel Accounting records adjustments to coal inventory accounts for differences between the physical inventory and the perpetual inventory records as reported by the plants. Adjustments are recorded as expeditiously as possible after receipt of the inventory report. For surveys completed prior to a quarter-end, 0955A reports are distributed no later than the first work day of the following month so that adjustments can be recorded in the same quarter. For surveys completed during the last week of a quarter-end month, whereby the completion of the CPI and 0955A reports by the first work day of the following month is not feasible, the reports *are completed as soon as possible and the results provided to Fuel Accounting immediately.* Fuel Accounting assesses the materiality of the survey adjustment to determine if the books should be reopened to *record the survey* adjustment. Prior to being recorded, adjustments are reviewed for mathematical accuracy, and the variance explanations are reviewed for *reasonableness*, and the reviews are *documented.*

AEP Ohio weighs the coal as received in the following manner: Washed coal that is received from the Conesville Prep Plant via conveyer is weighed by a "1B" belt scale then deposited on the "Ready Pile". In addition, washed and raw coal that is delivered directly from the Companies' suppliers and mines is weighed by an inbound truck scale. After being weighed, these trucks deposit the coal into a Dump Hopper, where it is then transferred via conveyer to the Ready Pile.

The Companies resolve freight bill and car number discrepancies in the following manner:

- Freight invoices are matched to pricing sheets prior to the submittal of requests for payment of freight invoices to Accounts Payable.
- Discrepancies on freight bills pursuant to pricing and payment issues are reviewed by the Contract Administration staff responsible for transportation rates and contract terms.
- Discrepancies on all other issues are discussed with the Conesville Prep Plant or Conesville employees responsible for coal received and related information. In some cases, further discussions with the trucking and rail company personnel is necessary to resolve discrepancies.
- Car number discrepancies are discussed with the Conesville Prep Plant or Conesville employees responsible for coal received and related information. Similar to the previous bullet point, further discussions with the trucking and rail company personnel may be necessary to resolve such discrepancies.

As it relates to rail cars used, AEP Ohio stated that approximately two-thirds of the rail cars used are owned by the delivering carrier, Ohio [redacted], and that the remaining one-third of the rail cars are owned by AEP. The procedures for how damaged cars are checked and who instigates claims for shortages are as follows:

- If a damaged rail car is owned by [redacted], the rail car is removed from service and the [redacted] is contacted directly for repair and/or disposition.
- If a damaged rail car is owned by AEP, the rail car is removed from service and Fuel, Emissions and Logistics ("FEL") Transportation group in Columbus is notified. This group then initiates an investigation in order to (1) assess the cause and amount of the damage; (2) identify the responsible parties; and (3) assess the value of the product salvage, if any.

In a related question, LA-1-62 requested a description of how freight bills, barge number and coal quantity and quality discrepancies are handled. Such discrepancies are handled in the following manner:

- Each plant generates a Monthly Comparison Report which compares shipped weights to unloaded weights by source. The sources in question are the shipper's weights included on bills of lading and the coal quantity in barges as determined by the seller during the loading process and by the buyer during the unloading process. In the event discrepancies are discovered, plant personnel and/or FEL Technical Services will launch an investigation to determine the cause. If the seller's weight is erroneous, adjustments to payment weights will be processed by FEL Contract Administration.

- The weight of each barge unloaded at each plant is verified. In the event a discrepancy is discovered, the appropriate billing department will be notified and a billing adjustment will be made to that plant in the following month.

- Coal quality discrepancies can occur (1) prior to the shipment leaving the supplier's loading dock; (2) while the shipment is enroute; or (3) after the shipment is received at the plant. If a coal quality discrepancy can be traced to the supplier, FEL will determine whether the shipment can be delivered as scheduled, diverted to another plant, or rejected and returned to the supplier. In the event of the second or third scenario, the related costs are typically assumed by the supplier.

In LA-2-3, Larkin asked AEP Ohio whether there were any weight or coal quality discrepancies at any CSP and OPCO plants during 2009. In response, AEP Ohio stated that in 2009, there were no such quality related discrepancies and that no coal shipments were rejected or diverted from any CSP and OPCO plants for quality reasons, although there were three coal shipments that were diverted to another plant in 2009 per the response to LA-2-4. In that response, AEP Ohio indicated that these three diverted shipments were pursuant to agreements between the Companies and their suppliers, and that such agreements (and related memoranda) were provided in the response to EVA-1-1. In addition, although weight related adjustments were made at the Companies' plants, none of these adjustments were considered discrepancies during 2009.

In data request LA-1-63, Larkin requested a description of how damaged barges are checked and who instigates claims for shortages. In response, AEP Ohio stated the following:

- Barges are inspected upon being picked up by the deck crew and they are also inspected by internal barge inspectors on a random basis. If damage is noted, a Barge Condition and Damage Report is completed and faxed to the Maintenance Department for review.
- If damage appears to be recent and a third party is responsible, an independent marine surveyor is hired to document the age and possible origin of the damage. In the event a third party is responsible, a claim is filed against such third party.
- In the event that part of a barge's cargo is lost, a claim is processed by the first party that documents the loss.

In LA-2-5, Larkin asked AEP Ohio whether there were any barge damage costs or damage repair costs recorded by either CSP or OPCO during 2009. In response, AEP Ohio stated that there were no damage costs or damage repair costs recorded directly by CSP or OPCO in 2009.

As it relates to month-end cut-off procedures, AEP Ohio stated that the month end cut-off is typically at midnight on the last day of the month.

A description of the Company's coal sampling procedures was provided in response to LA-1-22. A walk-through of the sampling process at the Conesville plant was conducted during the tour. The sampling procedures are as follows:

- One hundred percent of the coal delivered to Conesville and coal consumed is sampled either by AEP or the coal supplier (for incoming coal).
- Coal that is delivered via truck is sampled by coal auger at the truck sampler. Every incoming truck is sampled and logged by vendor code.
- The coal samples are collected and separated by AEP Lab Technicians according to ASTM standards and then sent to the Central Coal Lab to be analyzed. The vendor codes are recorded and applied to each coal sample sent to the Central Coal Lab.
- Two samplers are used on the units that sample consumed coal. Units 3 and 4 have a common sampler, as well as Units 5 and 6. These samplers are set to ASTM sampling rates and ratios.
- AEP Lab Technicians collect samples daily, affix unit codes to the samples and then send the samples to the Central Coal Lab.
- Upon the completion of the sample analysis, the results are recorded for accounting and tracking purposes.

Scale calibration logs for the period January through April 2009 were requested in LA-1-23. In response, AEP Ohio provided belt scale calibration logs, as well as truck scale calibration logs. As there are two methods of coal delivery to the Conesville Power Plant (direct from the vendor or delivered via conveyer from the Conesville Prep Plant), there are procedures in place at both locations that are designed to address inoperative coal scales.

Conesville Coal Prep Plant

Conesville's Coal Prep Plant supplies the bulk of the coal to the Conesville Plant via an overland conveyer belt. An "As-Received" coal belt scale is located on the plant or discharge end of the conveyer. In the event this belt scale becomes inoperative, a back-up belt scale at the Prep Plant is used. The scales at the Prep Plant or on the supplier end of the conveyer are used to determine flow and inventory calculations. They are not used for payment purposes.

Conesville Power Plant

Coal that is to be sent to the Conesville Power Plant via the conveyer is weighed for payment upon its arrival to the plant. There is an inbound truck scale and an outbound truck scale for this process. In the event one of these scales becomes inoperative, the remaining functioning scale is used for both inbound and outbound traffic. In the event both scales are inoperative, all deliveries are suspended until one or both scales are functioning properly.

Coal that is brought in by rail is transloaded onto trucks. The coal in these trucks and any unwashed coal is transported directly to the plant. An "as-received" truck scale is set up in a manner similar to that described above for the Prep Plant. There is an inbound truck scale and an outbound truck scale similar to that described above as it relates to coal received via conveyer from the Prep Plant. In the event one of these scales becomes inoperative, the remaining functioning scale is used for both inbound and outbound traffic. In the event both scales are inoperative, all deliveries are suspended until one or both scales are functioning properly.

Copies of laboratory sampling reports for coal purchases recorded in April 2009 were requested in LA-1-25 in order to compare such reports with accounting and purchasing records. The Companies' confidential response included documents that appeared to be titled "Log and Analysis Tracking Numbers" and included data related to coal sampling for each day in April 2009. However, these documents contained very little information in the context of what LA-1-25 requested. As a result, Larkin was unable to tie the information provided in the confidential response to LA-1-25 to the Companies' accounting and purchasing records.

AEP Ohio's procedure for handling coal from the stockpile to the firebox or boiler at Conesville was provided in response to LA-1-26. Coal is moved from the storage area to coal feeder reclaims by track type and/or rubber tire dozers. The reclaimed coal is subsequently distributed onto conveyer belts by vibratory feeders and transferred across weigh scales to unit silos. Scale readings are taken and recorded at midnight on a daily basis. Finally, the coal is fed from the silos by feeder belts where it is pulverized and blown into the boiler.

AEP Ohio's procedure for taking physical inventories of coal is described in the response to LA-1-27. Physical inventories of coal are conducted at a minimum of once a year. If the difference between book and physical inventory is two percent or greater of the coal consumed, then a second physical inventory is conducted within six months. A Circular Letter dated October 17, 1996 (and revised April 8, 2008), which outlined specific coal pile inventory procedures and guidelines, was provided as a confidential attachment to AEP Ohio's response to LA-1-27.

Fuel oil tank readings are taken monthly using the current means acceptable to AEP including, but not limited to, stick, gauge, float, plumb tape, and tape or lever indicator. These inventory readings are then used to develop a final monthly reclaim amount to reflect the proper inventory level. Upon plant personnel approving the inventory, this data is entered into the [redacted] system and is forwarded to the Fuel Accounting Department.

The Company provided working papers on the 2009 physical inventory taken at the Conesville plant on November 16 through 21, 2009 per the response to LA-1-28, which consisted of Coal Storage Inventory Report for the unwashed coal stockpile and a Coal Storage Inventory Report for the washed coal stockpile, as well as a brief narrative that describes the results reflected on both Coal Storage Inventory Reports. The referenced narrative stated:

> *The unwashed coal stockpile shows an overage of -18,148 tons, or -3.1% of the current book value. This error is equivalent to -0.9% of the total consumed coal over the survey period. In accordance with the revised Accounting Bulletin Number 4, an adjustment is required.*
>
> *The washed coal stockpile shows a shortage of +33,582 tons, or a +9.0% of the current book value. This error is also equivalent to +3.8% of the total consumed coal over the survey period. In accordance with the revised Accounting Bulletin Number 4, an adjustment is required.*

In response to data request LA-1-29, which requested accounting documentation for physical inventory adjustments recorded for the review period, including the general ledger, and fuel stock and consumption records, AEP Ohio provided the journal entry made by CSP in December 2009 in the amount of $3,205,756, which included the inventory adjustments described above for the Conesville plant, as well as an adjustment related to the Picway plant. In addition, AEP Ohio also provided the relevant pages from CSP's Coal Inventory Ledger for Conesville Units 3 and 4, as well as Units 5 and 6, which reflect the calculations of the dollar amounts associated with the inventory adjustments described above. Other documentation provided with LA-1-29 included the following:

- Additional workpapers showing how the inventory adjustments were derived;
- A memo from AEP describing the results of the Fall 2009 physical inventory at Conesville;
- Pages from AEPSC's [redacted] for Coal Inventory for the periods June and November 2009;
- Form 0955A, which is AEP Ohio's Coal Storage Inventory Report (also provided with LA-1-28); and
- Pages from CSP's general ledger for Account 5010013 for calendar year 2009 and Account 1510001, for the period December 2009. These pages from the general ledger reflect the recording of the inventory adjustments discussed above.

AEP Ohio's response to LA-1-30 describes the levels of review applicable to plant operating statistics.

AEP Ohio's confidential response to LA-1-31 provided copies of Conesville generating station reports for the period January through December 2009. Specifically, confidential Attachment 1 from LA-1-31 reflected the service hours, available service hours, net heat rate, operating (gross) heat rate, gross generation, net generation, and startups and trips for each generating unit at Conesville. Confidential Attachment 2 reflected the Fuel Burned by Unit (i.e. quantity) and Fuel Quantities by Type (i.e. received and consumed inventory). The response to LA-1-31 also referenced the response to EVA-1-17 as it relates to coal fuel receipts for Conesville.

The Company stated that Conesville uses belt scales to measure consumed coal to the silos and that some units use feeders to measure consumed coal into the boiler. In addition, daily operator logs record daily scale readings while individual feeder flows through a spreadsheet.

LA-1-32 inquired about any Company internal investigations following through on generating station reports for the review period January through December 2009. AEP Ohio's response indicated that no internal investigations were needed during the review period.

Larkin requested copies of the station reports for the review period January through December 2009 that were sent to the Companies' general office for incorporation into company statistics and workpapers sufficient to trace the reports to the statistics. In response to data request LA-1-33, AEP Ohio stated:

> *While some aspects of plant operation, such as outage events and coal scale data, are manually entered into a computer program at the generating plant, there are no "reports" that are sent to the Companies' general office for incorporation into Companies' statistics and workpapers. The electronic versions of these files are reviewed at the generating plant level as described in response to LA-1-30, but the electronic reports themselves are the "station reports", and not workpapers.*

Review Related To Fuel Supplies Owned Or Controlled By The Company

In response to LA-1-34, AEP Ohio stated that "neither the Companies nor their affiliates own or control any coal mines or entities from which coal is sourced for use at the Companies' units."

LA-1-35 requested that AEP Ohio identify and provide a copy of all accounting documentation related to costs incurred at the Conesville Coal Preparation Plant ("CCPC"), detailing how the costs of that facility are included in the cost of fuel to the Companies. In response, AEP Ohio stated that the CCPC coal washing costs are billed to CSP's generating business unit and then added to the receipt cost of the CCPC clean coal pile. This coal is then transferred to the coal piles at Conesville Units 3 and 4, or Units 5 and 6 using a weighted average unit price. The response to LA-1-35 also included monthly invoices from CCPC to CSP related to coal washing costs during the January through December 2009 review period. Each invoice included a journal entry which reflected the coal washing costs being debited to Account 1460001-144 and credited to Account 4560039.

LA-1-36 requested that AEP Ohio identify and provide a copy of all accounting documentation related to costs incurred by the AEP River Operations, detailing how the costs of the affiliated barge operation are included in the cost of fuel to the Companies. In response, AEP Ohio stated that the River Transportation Division ("RTD") is owned by Indiana Michigan Power Company, which is a subsidiary of AEP and that barge freight services are provided to RTD's affiliates (including OPCO) pursuant to an agreement dated May 1, 1986. A copy of this agreement was included in the response to LA-1-36 as Attachment 1.

RTD provides barge freight services at cost to its affiliates. This arrangement was approved by the Securities and Exchange PUCO ("SEC") as documented in Release No. 35-24039; Filing No. 70-7167 dated March 4, 1986. A copy of this authorization was included in the response to LA-1-36 as Attachment 2. A more detailed discussion of RTD's operations is included in the River Operations section of this report.

Review Related To Purchased Power

Documentation relating to the review of purchased power included in the responses to LA-1-37 through LA-1-38. LA-1-37 asked the Company to provide the following information: "*For purchases of power recorded in April 2009 that are included in the FAC..., please provide the related invoices, and paid cash voucher or cash receipts.*" In response to LA-1-37, the Company provided (1) a summary of April 2009 invoices; (2) copies of invoices from non-affiliates; (3) an Interchange Power Statement that reflected AEP System Pool purchases; and (4) copies of selected pages from AEP's bank statements which reflect receipts or payments.

Larkin attempted to tie out the amounts reflected on the invoices provided to workpapers "EXH CSP 1" and "EXH OPCO 1" from the FAC workbooks for CSP and OPCO for April 2009, but was only able to tie out a few of the amounts. Specifically, Larkin was able to trace an invoice payable to PJM in the amounts of $4,256,169 and $5,272,293 for CSP and OPCO, respectively to the FAC workpapers. In addition, Larkin was able to trace most of the amounts listed on an invoice payable to the Lawrenceburg Plant in the amount of $5,064,484. This invoice was broken out into several categories. Of the total invoice amount of $5,064,484, Larkin was able to trace all but $20,132 of fuel expense to workpaper "EXH CSP 1" from the April 2009 FAC workbook for CSP.

As confirmed in the response to LA-1-38, dispatch of the Companies' generating units was under the control of PJM during the entire period of January through December 2009.

LA-1-39 asked: "During the review period were any of the Companies' generating units designated as "must run" for reliability or voltage control purposes? If so, please identify the units, hours, and cost/Mwh for each "must run" situation at the Companies' generating units during this period." AEP Ohio's confidential response to LA-1-39 provided an extensive listing (196 total pages) of must run generation during this period for the following facilities: (1) Conesville Unit 3; (2) Kammer Units 1-3; (3) Muskingum River Units 1 and 3; and (4) Sporn Units 2 and 4. In its response to LA-1-39, AEP Ohio, referencing the generating units listed above, stated in part:

> *...each of the above generating units was required to operate as a Must Run resource by PJM in 2009. Regarding the cost/MWh for each "Must*

> *Run" situation, the intent of the Must Run is not to penalize a utility for operating a unit that is required to support the reliability and voltage levels of the PJM Interconnection. Thus, if the units selected would not otherwise be economic to operate, they are awarded at a \$/MWh rate relative to their cost-based offer (i.e. the utility is "made whole"). Costs to operate a generating unit as a Must-Run resource are the same as for normal economic operation, i.e. at production cost.*

As part of its confidential response to LA-1-39, AEP Ohio included confidential Attachment 2, which provided, for each month of 2009, the average production cost in \$/MWh for each generating unit identified above.

Unless it has already been presented in another forum, the PUCO may want to have AEP Ohio explain further how the "must run" generating unit designations are affecting the Companies' fuel and purchased power costs that are includable in the FAC filings.

Review Related To Service Interruptions And Unscheduled Outages

Documentation relating to the review of Service Interruptions and Unscheduled Outages includes AEP-Ohio's responses to LA-1-40 and LA-1-41.

LA-1-40 asked about customer power supply interruptions during the review period January through December 2009. In response, AEP Ohio stated that neither CSP nor OPCO experienced a single generation-caused customer interruption during the review period of January through December 2009.

LA-1-41 requested AEP Ohio to identify instances during the review period in which the Companies' generating units experienced unscheduled outages and to provide documentation concerning the following:

1. The cause(s) of the outage.
2. Steps taken by the Companies to minimize the impacts of the unscheduled outage.
3. Efforts made to secure replacement power, if applicable.
4. The methodology employed to price the replacement power, if applicable.
5. The cost impacts resulting from the periods during which the unscheduled outage occurred.

In response to item 1, AEP Ohio provided Attachment 1, which listed information relating to unscheduled outages at CSP's and OPCO's generating units during the review period, including the unit name and a brief description of what caused the unscheduled outages. With respect to items 2 through 5, AEP Ohio stated:

> *Ohio Power Company and Columbus Southern Power Company are members of the AEP East Pool. Forced outages and curtailments to the Companies' generating resources, as well as other impacts due to weather or load variations are managed on an AEP East fleet basis along with those of the other AEP East pool members. Multiple steps are taken to minimize the effects of forced outages concerning the generating plants. These steps include planning work as soon as possible when necessary, or attempting to safely operate the unit as long as possible until such time that any required maintenance can be performed when it will have less of an impact on the fleet.*
>
> *Power may be secured if needed to minimize the effects of any generation or load variations on an AEP East fleet basis. That power is not categorized as replacing any specific generating capacity. Therefore, it is not possible to determine whether power purchases were made to replace power lost due to an unscheduled outage versus, say, power purchased to offset a curtailment at another unit, owned by another pool member, that may have occurred at the same time as an unscheduled outage. Consequently, it is not possible to price the "replacement" power or determine, from a lost generation perspective, cost impacts resulting from periods during which the unscheduled outage occurred.*

Larkin followed up on the response to LA-1-41 with data request LA-2-1, which requested that AEP Ohio provide: (a) The dates and hours for each of the unscheduled (forced) outages listed on Attachment 1 from LA-1-41; and (b) for each forced outage listed on Attachment 1 (from LA-1-41) the AEP East Fleet system stack information (dispatch cost information) for the following periods: (1) duration of each forced outage; (2) the 24 hour period prior to the forced outage; and (3) the 24 hour period subsequent to the forced outage.

In response to part "a" of LA-2-1, AEP Ohio provided an updated Attachment 1, which contained the dates and hours for each of the forced outages from LA-1-41. Upon reviewing this updated attachment, Larkin noted that several of the forced outages were for a prolonged period of time. The table below illustrates a few examples of the longest such outages.

[redacted]

In response to part "b" of LA-2-1, AEP Ohio stated:

> *Specific hourly or 24-hour dispatch cost information is not readily available from our systems. Using an internal AEP application (the Energy Costing and Reporting System, or ECR), costs and revenues associated with serving the LSE load obligations, as well as off-system sales (OSS) are allocated for the AEP East pool members, including Ohio Power Company and Columbus Southern Power Company. On an hourly basis, the cost reconstruction model assigns generation resources, combined with market purchases. Those with the highest cost are allocated to OSS. After all OSS activity has been met by higher-priced generation and market purchases, the remaining lower-priced resources are assigned to serve AEP's LSE or internal load customers. However, this detailed cost information is not readily retrievable, nor is it used for any internal business purposes or in existing reports...it is noted that a) All AEP East fleet outages, not just Ohio-owned resources, have an impact on where the supply stack information falls, and b) Each outage cannot be viewed in isolation, as there are many other impacts, such as outages elsewhere in PJM , power purchases, and other market factors such as demand and weather.*

FAC Filings, Supporting Workpapers And Documentation

Documentation relating to the review of supporting workpapers for calculations in the FAC filings were requested in data requests LA-1-43 and LA-1-45 through LA-1-48.

LA-1-43 asked for a complete set of supporting workpapers for all calculations in the FAC filings for the review period January through December 2009 and/or which pertained to costs incurred or revenues recorded in the review period. In response, AEP Ohio referred to the response to LA-1-47 (see additional discussion below).

LA-1-45 asked the Companies to provide a complete audit trail for all amounts in the RA portions of the FAC filings. In response, the Companies referred to the response to LA-1-47.

LA-1-46 asked the Companies to provide all Excel files that were used in producing the FAC filings for the review period. In response, AEP Ohio again referred to the response to LA-1-47.

LA-1-47 requested all Excel files that were used in producing the supporting workpapers for the FAC filings for the review period. In response, AEP Ohio provided what it referred to as monthly FAC workbooks, which are the main support for the Companies' FAC filings. The FAC workbooks are comprised of several pages of data, which is culminated from several sources including:

1. General Ledger
2. NER/NEC – Net Energy Requirements and Net Energy Cost reports
3. PSUM Report – Monthly Purchase Summary Report from ECR
4. MCSR0162 Final Reports - Tariff Summary Revenue – by voltage level – one month billed & accrued
5. East Pool Interchange Power Statements
6. AEP Generating Company – BU 375 – Analysis of Fuel Receipts and Fuel Disposed of (Lawrenceburg Plant) – CSP only

In addition to the foregoing sources of data, the monthly FAC workbooks also contained the following workpapers:

1. Computation of Firm Retail Revenues, FAC Costs and the total Over/Under recovery for each month. The amounts calculated on this workpaper are reflected on Schedule 3 from the Companies' quarterly FAC filings.

2. A workpaper which calculates the FAC retail allocators.

3. A workpaper showing the FAC rates.

4. A workpaper which calculates the allocation factor for the FAC allowance accounts.

5. A workpaper which calculates the kWh delivered to customers served under OAD tariffs (Shopping kWh).

6. A workpaper reflecting the amounts related to the Ormet Interim Agreement.

Upon reviewing the monthly FAC workbooks, Larkin was able to tie out the amounts reflected in the workbooks to the FAC filings using the sources data listed above and performing recalculations. However, a number of questions arose as a result of Larkin's review of the FAC workbooks, which are addressed below.

- LA-6-2 requested AEP Ohio to explain variances noted on the workpaper titled "EXH CSP 1" between the CSP's general ledger and NEC reports. In response, AEP Ohio stated that the columns where the variances were noted are for analytic purposes only and such variances are due to the timing of recording adjustments for prior months in the general ledger. AEP Ohio also stated that the variances have no impact on the FAC filings.

- In Supplemental LA-5-1, AEP Ohio provided the East Pool Interchange Power Statements referenced above which are the source documents for the amounts recorded on the FAC workbooks in Account 5550005. Upon reviewing these statements, several discrepancies were noted between the amounts reflected on the Interchange Power Statements and the FAC workpaper EXH CSP 1. Larkin inquired about these discrepancies in LA-6-7. In response, AEP Ohio stated that the monthly differences identified are the result of a combination of prior period adjustments recorded by CSP's two pool energy revisions. In a follow-up question, Larkin asked AEP Ohio to clarify which amounts were correct – the Interchange Power Statements or workpaper EXH CSP 1. In response to LA-7-27, AEP Ohio stated that the amounts in the monthly FAC workbooks properly reflect CSP's pool energy purchases for the periods in question.

- A similar question arose with respect to OPCO's monthly FAC workbooks and the Interchange Power Statements. In response to LA-6-8, AEP Ohio explained that the variances identified are also related to prior period adjustments recorded by OPCO.

- LA-6-10 asked AEP Ohio to explain why the amounts recorded in Account 5550046 for fuel expense associated with the Lawrenceburg Plant fluctuated so much during 2009. In response, AEP Ohio stated:

  The fluctuations in the Lawrenceburg Plant fuel expenses are due to the seasonality associated with its economic operation. During the *low-demand periods of the spring and fall, load obligations are primarily met by baseload coal units, and a combined-cycle gas unit such as Lawrenceburg is rarely needed. In the winter and summer months, the impacts of higher demand are seen, and PJM has a need to call upon more and more resources. Thus, units such Lawrenceburg become part of the economic dispatch, and provide more generation in the winter and summer months.*

As a follow-up to this response, in LA-7-28 Larkin asked AEP Ohio to provide the corresponding monthly kWh that were associated with the monthly fuel expense amounts related to the Lawrenceburg Plant. Exhibit 7.42 below reflects the dollar amounts and corresponding kWh associated (provided in response to LA-7-28) with the Lawrenceburg Plant.

Exhibit 7-42: Lawrenceburg Plant Monthly Fuel Expense And Output

[redacted]

The response to LA-6-10 indicated that fluctuations between monthly expenses related to the Lawrenceburg Plant were due to seasonality associated with its economic operation. In addition, CSP had recorded the amounts of $6,491, $70,463 and $20,879 for the months of April, November and December 2009, respectively. However, the kWh associated with those months were zero per the response to LA-7-28. AEP Ohio explained that these dollar amounts were recorded in months when there was no kWh generated at the Lawrenceburg Plant because these were true-ups of prior month invoices.

- A number of discrepancies were noted between amounts reflected in the monthly FAC workbooks that were purportedly taken from the general ledger and the general ledger itself. Upon our inquiry, the Companies' stated that the discrepancies were due to timing differences and AEP Ohio provided reconciliations for each of these discrepancies.

Renewable Energy Resources

As discussed in the management audit section of this report, AEP Ohio is subject to the compliance standards as set forth in Section 4928.64 of the revised Ohio Code as it relates to an electric utility being required to provide electricity from alternative sources. Specifically, Section 4928.64, subsection (B) states in part that:

> *The baseline for a utility's or company's compliance with the alternative energy resource requirements of this section shall be the average of such total kilowatt hours it sold in the preceding three calendar years, except that the PUCO may reduce a utility's or company's baseline to adjust for new economic growth in the utility's certified territory or, in the case of an electric services company, in the company's service area in this state. Of the alternative energy resources implemented by the subject utility or company by 2025 and thereafter:*

(1) Half may be generated by advanced energy resources;

(2) At least half shall be generated from renewable energy resources, including one-half percent from solar energy resources, in accordance with the following benchmarks:

Exhibit 7-43. Renewable And Solar Benchmarks

By End of Year	Renewable Energy Resources	Solar Energy Resources
2009	0.25%	0.004%
2010	0.50%	0.010%
2011	1.00%	0.030%
2012	1.50%	0.060%
2013	2.00%	0.090%
2014	2.50%	0.12%
2015	3.50%	0.15%
2016	4.50%	0.18%
2017	5.50%	0.22%
2018	6.50%	0.26%
2019	7.50%	0.30%
2020	8.50%	0.34%
2021	9.50%	0.38%
2022	10.50%	0.42%
2023	11.50%	0.46%
2024 and beyond	12.50%	0.50%

(3) At least one-half of the renewable energy resources implemented by the utility or company shall be met through facilities located in this state; the

> *remainder shall be met with resources that can be shown to be deliverable to this state.*

In its July 31, 2008 Application for an Electric Security Plan (and FAC), AEP Ohio requested full cost recovery of its renewable energy purchases and renewable energy credits ("RECs") with the caveat that the Companies proposed including all of its renewable energy costs within the FAC mechanism, and not as part of the deferred FAC costs pursuant to Section 4928.144 of the revised Ohio Code. In its Opinion and Order dated March 18, 2009, the PUCO approved the Companies' proposed inclusion of renewable energy purchases and RECs as includable FAC costs citing Section 4928.64(E) which states:

> *All costs incurred by an electric distribution utility in complying with the requirements of this section shall be bypassable by any consumer that has exercised choice of supplier under Section 4928.03 of the Revised Code.*

As part of its review, Larkin asked AEP Ohio a series of questions pertaining to its renewable energy purchases and RECs. In LA-3-1, Larkin asked whether the Companies maintained an inventory system for its RECs. In response, AEP Ohio stated that the Companies' maintain their respective RECs in the Generation Attributes Tracking System ("GATS"), which is owned by PJM and which tracks the volume of RECs by source.

LA-3-2 asked whether AEP Ohio maintains more than one REC inventory and to describe the purpose of each such inventory. In response, AEP Ohio stated that GATS is the only REC inventory system being used by both CSP and OPCO.

LA-3-3 asked whether the Companies' participate in any speculative REC purchases utilizing below-the-line shareholder funds and if so, to describe the procurement and inventory methodologies used to account for such RECs. In response, AEP Ohio stated that neither CSP nor OPCO have participated in speculative REC transactions.

As it relates to maintaining REC inventory, LA-3-4 requested that AEP Ohio provide: (a) whether the Companies' are relying on any particular accounting guidance for how items are entered into or extracted from REC inventory; (b) the kinds of costs, other than REC purchase costs, that are included in REC inventory; (c) the value at which RECs are entered into inventory if they are generated by AEP Ohio; (d) the value at which RECs are entered into inventory if they are purchased as part of a bundled energy transaction; and (e) when RECs are considered consumed or surrendered and when the costs appear in the Companies' rates. In response, AEP Ohio provided the following information:

> a. *The Company is relying on FERC accounting guidance for emission allowances as the framework for accounting for RECs. To the extent that acquired RECs are in excess of accrued obligations and can be used in future periods a REC book inventory will be maintained. This book inventory will be based on the weighted average cost of RECs acquire [sic] but not yet utilized to meet the company's obligation. The number and cost of RECs acquired will be additive to the book inventory. Extraction of RECs from book inventory will be based on the periodic utilization of RECs to meet the company's obligation with the periodic REC expense computed based on the weighted average cost of the inventory for that period.*
>
> b. *Identifiable, direct costs to acquire RECs, including broker fees will be included in the cost of the REC book inventory.*
>
> c. *If RECs are generated by the company and specific REC costs are identifiable and are not otherwise recovered in the FAC, those specified REC costs would be reflected as the REC value in inventory or expense if no book inventory exists.*
>
> d. *Currently, in a bundled renewable energy transaction, all value is assigned to the energy and no value is assigned to the RECs. If, at some point, a value is specifically identified with RECs associated with a renewable energy purchase, then that specifically identifiable cost would enter into the book inventory.*
>
> e. *OPCo and CSP utilize accrual accounting. When a REC obligation has been incurred then the associated expense is recorded and reflected in FAC costs.*

LA-3-5 and LA-3-6 asked AEP Ohio to identify all specific costs, by amount and account, in REC inventory that were charged to FAC-includable accounts during 2009. In response, AEP Ohio indicated that REC book inventory in the amounts of $548,959 and $733,101 for CSP and OPCO, respectively, were charged to Account 5570007/5570008 during 2009 (see additional discussion below). In addition, AEP Ohio stated in response to LA-3-6 that there was no inventory in excess of consumption requirements during 2009, thus renewable purchases were recorded directly to Account 5570007.

Upon reviewing the monthly FAC filing workbooks provided in the response to LA-1-47, Larkin verified that the $548,959 and $733,101 identified above in the response to LA-3-5, were reflected in CSP's and OPCO's December 2009 FAC filing workbooks in Account 5570007.

In LA-7-39, Larkin requested that AEP Ohio provide a summary and details of CSP's and OPCO's status regarding renewable energy objectives and minimum requirements for 2009 and 2010 and whether there was any shortfall in achieving the minimum requirements. In addition, subpart "a" from LA-7-39 asked AEP Ohio to identify and provide a copy of any waivers obtained with respect to meeting renewable energy objectives for 2009.

In response, AEP Ohio provided copies of CSP's and OPCO's 2009 Annual Status & Compliance Reports which were filed under Rule 4901:1-40-05 of the Ohio Administrative Code ("OAC"). These reports indicated that both CSP and OPCO achieved compliance in meeting the 2009 benchmarks for the Ohio Alternative Energy Portfolio Standard. The tables below, which show that the Companies achieved the 2009 benchmarks, are reproduced from the Annual Status & Compliance Reports.

Exhibit 7-44. CSP And OP 2009 Renewable Performance

CSP Overview of Actual non-Solar MWH vs. Benchmarks

	Actual MWh	Benchmark
In-State Non-Solar	24,526	>=24,526
Additional Non-Solar	24,526	n/a*
Total	49,052	49,052

* While In-State non-Solar must meed or exceed 24,526 MWh, additional non-Solar does not have a target

OPCO Overview of Actual non-Solar MWH vs. Benchmarks

	Actual MWh	Benchmark
In-State Non-Solar	31,621	>=31,621
Additional Non-Solar	31,621	n/a*
Total	63,242	63,242

* While In-State non-Solar must meed or exceed 31,621 MWh, additional non-Solar does not have a target

CSP Overview of Original Solar MWH vs. Benchmarks

	Actual MWh	Benchmark
In-State Non-Solar	68	>=399
Additional Non-Solar	-	n/a*
Total	68	798

* While In-State Solar must meed or exceed 399 MWh, additional Solar does not have a target

OPCO Overview of Original Solar MWH vs. Benchmarks

	Actual MWh	Benchmark
In-State Non-Solar	95	>=514
Additional Non-Solar	-	n/a*
Total	95	1,028

* While In-State Solar must meed or exceed 514 MWh, additional Solar does not have a target

CSP Overview of Revised Solar MWH vs. Benchmarks

	Actual MWh	Benchmark
In-State Non-Solar	68	>=68
Additional Non-Solar	-	n/a*
Total	68	68

* While In-State Solar must meed or exceed 68 MWh, additional Solar does not have a target

OPCO Overview of Revised Solar MWH vs. Benchmarks

	Actual MWh	Benchmark
In-State Non-Solar	82	>=82
Additional Non-Solar	13	n/a*
Total	95	95

* While In-State Solar must meed or exceed 82 MWh, additional Solar does not have a target

As it relates to the original versus the revised solar MWh shown in the tables above, in response to subpart "a" from LA-7-39, AEP Ohio stated:

> *"The revised benchmarks for solar resources, based on an approved* force majeure *filing, are detailed in the 2009 Solar Waiver Order, attached as* ***LA-7-39 Attachment 4****. This attachment describes the sources of the solar resources, the shortfall, and the reasons behind the shortfall."*

Larkin reviewed the referenced document dated January 7, 2010 and noted that on page 9 the PUCO stated in part:

> *In light of the uncertainty regarding the PUCO's compliance requirements this first year of the benchmarks, the good faith efforts AEP Ohio has made to comply, and given that, as AEP Ohio requests, any shortfall for 2009 compliance requirements will be added to and included as part of the Companies' compliance requirements for 2010, we find that AEP Ohio has presented adequate reason for the PUCO to grant AEP Ohio's request to invoke* force majeure *and revise the Companies' 2009 SER benchmarks. Accordingly, we find that AEP Ohio's application is reasonable and should be granted.*

Active Management

LA-1-44 asked whether AEP Ohio engaged in "active management" during the review period January through December 2009, and if so, to identify, quantify and provide the accounting documentation for each such transaction during that period. In addition, LA-1-44 asked AEP Ohio to fully explain the reasoning and estimated economic benefit that was anticipated for each transaction. In response, AEP Ohio stated:

> *Prudent management of power positions in regard to serving the native load customer is a continuous process. In response to changing needs of generation, load, and market conditions, AEPSC, on behalf of CSP and OPCo, engages in energy transactions, and hedges the output of its economic generation in order to serve the native load customer in the most cost-effective manner, and also to manage the risks inherent in the wholesale energy market. Management of emission allowance positions is likewise a continuous process of optimizing the needs of the native load customer in response to changing generation, load and operational conditions, while constantly evaluating the emissions market and the factors that may affect conditions in the market. In this regard these transactions and market monitoring are all part of the regular management of fuel, purchased power and emission allowance positions. Consequently, there is no "active management" as referred to in the question.*

As a follow-up to LA-1-44, Larkin, per LA-2-6, asked AEP Ohio whether either CSP or OPCO recorded any hedging costs in FAC-includable accounts during 2009, and if so, to identify such costs by amount and account. In response, AEP Ohio stated that CSP recorded fuel hedging credits totaling $9 and that OPCO recorded $79, for a total of $88 being recorded in FAC-includable accounts during 2009.

Accounting Detail

AEP Ohio provided documentation related to accounting detail associated with costs and revenues, purchases and sales of emission allowances, and monthly emission allowance inventory in response to LA-1-48 through LA-1-50.

LA-1-48 requested the detailed general ledger pages for each account that contains costs and/or revenues that are included in the FAC filings. In response, AEP Ohio once again referred to the response to LA-1-47 as it relates to the costs included in the FAC filings. An attachment was provided with this response which included general ledger information related to revenues included in the FAC for July through December 2009.

The Companies stated that prior to July 2009, revenues were calculated by voltage level and that the calculations deriving these revenue amounts were reflected in the workpapers included with LA-1-47.

LA-1-49 requested detailed general ledger pages for all purchases and sales of emission allowances ("EA") and for gains or losses realized on such purchases and sales of EAs. In response, AEP Ohio stated that the requested detail regarding EAs is not reflected in the general ledger. The Company referred to the response to EVA-1-42 for a schedule of emission allowance purchases, sales as well as related gains and losses for both CSP and OPCO. The following table summarizes for CSP the emission allowance purchases, sales, and gains and losses that occurred during the January through December 2009 review period.

Exhibit 7-45. CSP Emission Allowance Activity

Columbus Southern Power

	January 2009		February 2009		March 2009		April 2009		May 2009		June 2009	
	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars
SO2												
Sales					1,559	$ 65,741						
Gains						$ 65,313						$ 6,044
Losses										$ (5,615)		
Purchases												
Seasonal NOx												
Sales												
Gains												
Losses												
Purchases												
Annual NOx												
Sales												
Gains												
Losses												
Purchases												

	July 2009		August 2009		September 2009		October 2009		November 2009		December 2009	
	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars
SO2												
Sales											25,922	$ 5,218,300
Gains												
Losses												
Purchases											34,701	$ 16,331,679
Seasonal NOx												
Sales												
Gains												
Losses												
Purchases											400	$ 46,000
Annual NOx												
Sales												
Gains												
Losses												
Purchases											840	$ 934,700

The table below summarizes for OPCO, the emission allowances purchases, sales and gains and losses that occurred during the January through December 2009 review period.

Exhibit 7-46. OPCO Emission Allowance Activity

Ohio Power Company

	January 2009		February 2009		March 2009		April 2009		May 2009		June 2009	
	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars
SO2												
Sales					6,507	$ 249,574						
Gains						$ 249,463				$ 188		
Losses												$ (76)
Purchases											3,959	$ 281,089
Seasonal NOx												
Sales	40	$ 25,000	1,000	$ 45,809	400	$ 230,000					200	$ 70,000
Gains		$ 23,259		$ 9,439		$ 211,452						$ 62,849
Losses												
Purchases			1,000	$ 35,809								
Annual NOx												
Sales	605	$ 2,392,000	4,850	$13,155,000	725	$ 1,563,125	200	$ 308,750	200	$ 240,000	1,069	$ 1,271,590
Gains		$ 2,381,557		$13,083,822		$ 1,552,743		$ 305,934		$ 235,892		$ 1,252,010
Losses												
Purchases												

	July 2009		August 2009		September 2009		October 2009		November 2009		December 2009	
	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars	Allowances	Dollars
SO2												
Sales											118,855	$ 15,393,222
Gains												$ 13,825,565
Losses												$ (4,129,102)
Purchases											66,666	$ 6,549,666
Seasonal NOx												
Sales	300	$ 70,500	25	$ 4,000					455	$ 52,325		
Gains		$ 55,276		$ 3,107						$ 38,795		
Losses												
Purchases												
Annual NOx												
Sales	550	$ 1,563,750	260	$ 170,600	200	$ 132,000	200	$ 105,000			1,131	$ 715,235
Gains		$ 1,554,229		$ 166,333		$ 129,000		$ 102,323				$ 700,467
Losses												
Purchases												

LA-1-50 requested CSP's and OPCO's monthly emission allowance inventory (quantity of allowances and cost) and to show how it was allocated between native and non-native customers. In response, AEP Ohio stated that the Companies do not allocate EA inventory between native and non-native load customers.

AEP Ohio's response to LA-1-50 also included attachments which reflected CSP's and OPCO's monthly EA inventory balances. The table below summarizes for CSP the monthly EA inventory balances for each month of the January through December 2009 review period.

Exhibit 7-47. CSP Emission Allowance Inventory

[redacted]

The table below summarizes for OPCO, the monthly EA inventory balances for each month of the January through December 2009 review period.

Exhibit 7-48. OPCO Emission Allowance Inventory

[redacted]

Changes To Fuel, Purchased Power Procurement And Emission Allowance Procurement

Documentation related to the review of changes to fuel, purchased power procurement and emission allowance procurement during the period January through December 2009 includes AEP Ohio's responses to LA-1-51 and LA-1-52.

LA-1-51 asked the Companies' to list and describe all organizational changes to the Companies' Fuel, Purchased Power Procurement and Emission Allowance Procurement during the review period. In response, AEP Ohio stated that with respect to organizational changes to the Companies' Fuel, Emissions and Logistics during the review period, to refer to Attachment 1 from LA-1-51 as well as Attachment 1 from the response to LA-1-53. In addition, AEP Ohio stated that there were no structural changes within the Energy Trading and Energy Marketing groups during the January through December 2009 review period.

LA-1-52 requested information similar to LA-1-51, although from a procedural versus organizational standpoint. In response to LA-1-52, AEP Ohio stated that there were no changes to the policies and procedures relating to Fuel Procurement, Purchased Power Procurement or Emission Allowance Procurement during the review period. In addition, the response to LA-1-52 also indicated that there were also no accounting changes related to fuel, purchased power or emission allowance procurement during the review period.

Internal Audits

LA-1-61 requested that the Companies' provide a listing and copies of any and all internal audit reports related to fuel procurement, synfuel, coal trading, fuel inventory management, purchased power, emission allowances, accounting for FAC-includable costs, portfolio optimization, energy sales, PJM charges and revenues, fuel and purchased power invoices, PJM invoices, allocation of PJM revenues and costs to Ohio retail load customers, allocation of other FAC includable costs and revenues to Ohio retail load customers, and/or other FAC related subject matter for the review period.

In response to LA-1-61, AEP Ohio provided five internal audit reports, which were issued at various points during 2009. The following indicates the areas that were the subject of the internal audits, along with a summary of recommendations for each area:

1. 2008 Coal Pile Inventories (Issued January 18, 2009)

The purpose of this internal audit was to:

1. Review the System Power Plants' Spring and Fall coal inventory reports for completeness and propriety.

2. Assess the reasonableness of book inventory number at the time of the survey, which is compared to physical inventory results to determine the coal inventory adjustment.

3. Determine whether the coal inventory adjustments reported by the power plants were calculated accurately and in compliance with AEP System Accounting Bulletin No. 4, which requires recording 100 percent of the difference between the physical inventory and book inventory. Another physical inventory must be conducted within six months if the difference is greater than +/- 2 percent.

4. Determine that plants with a variance of +/- 2 percent investigated the variances and addressed any issues discovered.

5. Verify that the accounting entries recording the financial adjustments were reasonable and complete.

6. Observe the inventory volume and density measurement activities at one plant to evaluate compliance with AEP Circular Letter CI-O-CL-0084.

According to the report, Audit Services detected minor errors, which did not have a material impact on the coal pile inventory results. These errors included:

- Two plants (unspecified in internal audit report) miscalculated the book inventory resulting in understatements of coal inventory of 1,132 tons and 1,921 tons, respectively. Each plant issued a revised coal inventory report to correct the error.

- The surge pile densities at two plants (unspecified in internal audit report) were not physically determined using the "free fall" method as required by AEP Circular Letter CI-O-CL-0084.

- The high sulfur storage pile at one of the plants referenced in the previous bullet point was not drilled and densities obtained were due to a miscommunication.

Another inventory was conducted prior to year end and these density errors were corrected.

Audit Services stated that based on its review, the coal pile inventory results and adjustments were properly stated in all material respects.

2. AEP Ohio ESP New Rate Implementation (Issued April 14, 2009)

The objective of this internal audit was to test the effectiveness of tariff rate change controls and perform independent testing of the Ohio ESP rate implementation to ensure accurate customer billings pursuant to tariffs approved by the PUCO on March 30, 2009 for bills issued beginning with the first billing cycle of April 2009.

The scope of this internal audit included the following:

- Documentation of testing performed
- VERX (billing validation) and exception correction
- Recalculation of customer billings

For all three areas referenced above for the scope of this internal audit, in its "Review Scorecard", Audit Services indicated the designation "Well-controlled" under the category "Conclusion Classification". Well-controlled is defined as "Controls are appropriately designed and are operating effectively to manage risks. Control issues may exist, but are minor."

3. SO2 Cost Recovery Adjustments Review (Issued May 28, 2009)

The scope of this internal audit report was to review and assess the effectiveness of the controls over the SO2 cost recovery adjustment process and the calculation of the SO2 recovery costs for 2008.

Audit Services findings included the following three issues:

1. **Issue**: Scrubber costs were calculated inconsistently among the Companies' plants due to clear guidelines and procedures not being established and communicated. In addition, the purpose of the scrubber cost and SO2 removal efficiency percentage information was not communicated to all applicable plants.

Resolution: Fuel, Emissions and Logistics will work with representatives from the Gavin, Mitchell and Mountaineer plants to prepare guidelines and procedures for all responsible parties to follow (see additional discussion below).

2. **Issue**: An error was made in the [redacted] second Half Year 2008 cost adjustment calculation for the Mitchell Plant. The contracted half year 2008 SO2 specification amount was used instead of the actual SO2 amount in determining the Per Ton Premium. The Per Ton premium should have been $1.226 instead of $1.227. The impact reduced the amount due to Consol by approximately $41,000 (see additional discussion below).

   Resolution: Contract Administration updated the amount due to reflect using the actual SO2 amount.

3. **Issue**: The calculation as stated in the [redacted] Contract does not reflect the intent, i.e. a parenthesis is missing after the "Mine As-Delivered SO2 Content" in the top half of the equation and should have been added. Without the parenthesis, the 2008 adjustment would have been $6.22 per ton instead of zero.

   Resolution: Contract Administration will amend the contract to add the parenthesis in the calculation after the Mine As-Delivered SO2 Content in the top half of the equation.

With respect to Issue No. 1 above, LA-4-10 requested that the Companies' provide the guidelines and procedures that were developed for the scrubber costs and SO2 efficiency removal percentage. In response, AEP Ohio stated that the guidelines and procedures were accomplished by developing spreadsheet templates designed to guide users when preparing cost and efficiency calculations. Examples of these templates were included as an attachment to LA-4-10. AEP Ohio stated that these templates have been implemented for 2010.

With respect to Issue No. 2 above, LA-4-9 requested AEP Ohio to state whether: (1) the $41,000 was recorded and if so, to indicate when it was recorded and to provide the journal entry; (2) there were any adjustments in 2009 for SO2 Cost Recovery Adjustments for Mitchell, Gavin or any other Ohio plants, and if so, to provide specifics; and (3) any other AEP Ohio coal plants (besides Gavin or Mitchell) have coal contracts with provisions for SO2 adjustments and if so, to identify the plants and contracts. In response, AEP Ohio stated the following with respect to each item listed above:

- The $41,000 was corrected in a spreadsheet used to calculate the overall SO2 adjustment for Consol of [redacted] (discussed further below). As a result, there was no separate journal entry for the $41,000 correction.

- In 2009, AEP paid [redacted] \$574,429 and \$1,181,708 for SO2 adjustments related to the Mitchell and Gavin plants, respectively. The SO2 adjustment due to [redacted] for the Mitchell plant was \$983,431 in 2008 and was offset by \$533,146 due to AEP for the Gavin plant. These adjustments were recorded in July and December 2009, respectively.

- No other AEP Ohio coal plants have provisions for SO2 adjustments.

4. *Fuel Contract Administration (Issued June 5, 2009)*

The objective of this internal audit was to assess the adequacy and effectiveness of the internal controls over the Fuel Contract Administration processes. The scope of this internal audit consisted of the following:

- Effectiveness of controls over the timely preparation and maintenance of executed contracts, amendments and notifications.

- Effectiveness of controls over the data inputs into the fuel transaction and reporting systems (i.e. pricing, quality/penalty specifications, shipment/tonnage thresholds).

- Effectiveness of controls that ensure compliance with pricing terms and conditions of contracts and purchase orders.

- Effectiveness of controls over the accurate and timely preparation of accruals for price changes not yet implemented.

For all four areas referenced above for the scope of this internal audit, in its "Review Scorecard", Audit Services indicated the designation "Well-controlled" under the category "Conclusion Classification", including the overall conclusion. However, Audit Services identified six items, which are characterized as "low risk" issues, which were not included within the internal audit report. Instead, these six low risk issues were documented in a separate "Low Risk Issues Document" and presented to the areas of management responsible for the function or control where the issues were identified.

5. *Compliance Review of AEP Ohio's Fuel Cost Recovery Mechanism (Issued November 5, 2009)*

The objective of this internal audit was for Audit Services to (1) evaluate the fuel costs being recovered and the deferred fuel calculations being made for compliance with the Ohio FAC approved by the PUCO, and (2) to perform a control design assessment to determine the adequacy of the controls in place that help ensure compliance with the Ohio FAC.

In addition to the parameters listed below, the scope of this internal audit also included a control design assessment and a review of the initial FAC filings of CSP and OPCO that were filed on September 29, 2009.

- **FAC Baseline**: The FAC baseline was used to determine the over/under fuel recovery amount at March 31, 2009. In addition, the FAC baseline was used to calculate the non-fuel generation base rates that became effective April 1, 2009.
- **FAC Fuel Costs**: This includes the actual fuel costs that are used in the FAC calculations.
- **FAC Fuel Revenue Billed**: This covers the billed and accrued kWh that are used to calculate the firm retail revenues in the FAC calculations.
- **Fuel Cost Recovery**: This includes the FAC calculations necessary to record the deferred fuel amounts each month.
- **Carrying Charges**: The PUCO authorized AEP Ohio to recover carrying charges on the FAC deferrals

For the five areas referenced above for the scope of this internal audit, in its "Review Scorecard", Audit Services indicated the following under the Conclusion Classification:

Scope Area	Conclusion Classification
FAC Baseline	In compliance with Order
FAC Fuel Cost	In compliance with Order
FAC Fuel Revenue Billed	In compliance with Order
Fuel Cost Recovery	In compliance with Order
Carrying Charges	In compliance with Order (after debt rate correction)
Initial Fuel Filings	Accurate initial filings were submitted
Control Design Assessment	Control design is adequate
Overall Conclusion	FAC calculations comply with Order

The conclusions above notwithstanding, Audit Service identified two issues during its review as outlined below.

The first issue identified by Audit Services concerned reconciling the FAC amounts to the general ledger. Specifically, Audit Services pointed out that for the fuel portion of purchased power costs, the source used to update the FAC filings were from a Net Energy Requirements report ("NER") and not the general ledger. The Fuel Accounting Department verifies these costs to a "purchased power report" which is generated by the Energy Cost Reporting system ("ECR"). In addition, Fuel Accounting compares the differences between the purchased power amounts used in the FAC calculation and what is recorded in the general ledger. However, Audit Services determined that a detailed reconciliation of these differences was not being performed.

Audit Service's proposed resolution was to recommend that Fuel Accounting work jointly with the East Power Accounting group to perform a detailed reconciliation between the sources of purchased power costs referenced above. As a follow-up to Audit Services recommendation, in LA-4-11, Larkin requested that AEP Ohio provide (1) the spreadsheets prepared by Fuel Accounting for 2009 costs that contain the differences to be reconciled, and (2) the detailed reconciliations of the differences between the NER report and the general ledger. In response, AEP Ohio provided attachments for CSP and OPCO that the Companies stated were the purchased power reconciliations for the months of September through December 2009. Reconciliations for January through August 2009 were not provided with this response. AEP Ohio stated that the reconciliations provided compare the purchased power expenses from the general ledger to the costs reported in the ECR reports and that in general, all differences have properly explained.

The second issue identified by Audit Services concerned the use of the monthly actual debt rate in the calculation of carrying charges related to the Companies' FAC related deferral balances. Specifically, Audit Services noted that Fuel Accounting was using fixed rate of 5.73 percent for CSP and 5.71 percent for OPCO for the debt portion of the WACC rate used for the carrying charges calculation. The use of these fixed rates was predicated on Fuel Accounting's reliance on an Accounting Implications Memorandum that was issued April 8, 2009. However, after reviewing the Opinion and Order issued by the PUCO on March 18, 2009 and AEP's testimony, Audit Services recommended that the Companies' use the actual cost of long-term debt in its calculations of carrying charges.

On October 1, 2009, Accounting Regulatory Services issued an addendum to the Accounting Implications Memorandum referenced above which provided for using the actual monthly average cost of debt rate to calculate the deferral related carrying charges. Audit Service's proposed resolution to this issue was for the Companies' to begin using the actual monthly average cost of debt rate to calculate carrying charges as of September 2009 based on the aforementioned addendum.

As a follow-up to Audit Services recommendation, in LA-4-12, Larkin requested that AEP Ohio provide the journal entries made to recalculate and adjust the carrying charges accrued for the period February through August 2009. In response, AEP Ohio provided attachments which provided CSP's and OPCO's September 2009 reversing journal entries which reversed the previously recorded FAC carrying charges. In addition, this response included journals showing the recalculated carrying charges. AEP Ohio also provided the Original Accounting Implications Memorandum dated April 8, 2009 as well as the addendum issued October 1, 2009 in the response to LA-4-13.

AEP River Transportation Division

The AEP-owned barge company, called AEP River Transportation Division (RTD) is owned by Indiana and Michigan Power Company (IMPC), a subsidiary company of AEP. Barge freight services are provided by RTD to OPCo (its affiliate) and other AEP operating companies which receive coal deliveries via river transportation under an agreement that was provided in response to LA 1-36, Attachment 1.

The response to LA 1-36 states that:

> *RTD provides barge freight services at cost to its affiliates as approved by the Securities and Exchange PUCO (Release No. 35-24039; Filing 70-7167 provided here as LA 1-36 Attachment 2. RTD's costs are allocated to the operating companies based on each company's utilization of the barging services. These costs are considered transportation costs and are included in the cost of coal inventory.*

Per the May 1986 Barge Transportation Agreement, RTD provides barge transportation services to the AEP operating subsidiaries that have coal plants located on the Kanawha, Green and Ohio Rivers, including Ohio Power Company (OPCo), Appalachian

Power Company (APCo), and AEP Generating Company (AEPGC). RTD has operated barges, tugboats and other facilities for the transportation of coal on the Kanawha, Green and Ohio Rivers and other navigable waterways to transport coal to APCO, OPCO, AEPGC and IMPC since September 4, 1973. The generating stations owned by these AEP operating companies require large quantities of coal which can be delivered to such stations in river barges.

Article V of the May 1986 Agreement provides that the RTD transportation services are to be priced as follows:

> *ARTICLE V*
> *PRICE*
>
> *The Division shall charge to each Shipper, and each Shipper shall pay to the Division, the costs of any transportation services performed by the Division for such Shipper. Such costs shall consist of all charges and expenses directly attributable to the performance of such service, a fair and equitable allocation of other charges and expenses of the Division (taking into account the transportation services performed by the Division for I&MECo), a provision for taxes at the combined normal tax and surtax rate applicable to corporations under Section 11 or any successor section of the Internal Revenue Code of 1954, as in effect from time to time, and an amount equal to 9.21% per annum of I&MECo's net investment in the Division. The determination of the 9.21% composite rate is shown in Appendix B. The Division will use the 9.21% composite after tax rate of return on its net investment until such time as it receives approval from the Public Service PUCO of West Virginia and/or The Virginia State Corporation PUCO, if necessary, to adjust the return on common equity on January 1 of each calendar year to the rate of return on common equity determined and allowed by the FERC in the most recent wholesale rate proceeding involving I&MECo. In the absence of a FERC order during the calendar year preceding each January 1, the rate of return on common equity would be that authorized by the Public Service PUCO of Indiana in an I&MECo retail electric rate proceeding, during the calendar year preceding such January 1, otherwise the existing rate of return continues until the next January 1. For purposes of this Agreement, I&MECo's net investment in the Division during any period shall be understood to consist of its investment in real and personal property and an amount equal to 1/8 of the aggregate operation, maintenance, rental and general expenses of the Division for each annual period, plus prepayments and deferred expenses at the end of such period. If for any period the aggregate charges of the Division for transportation services performed do not equal the aggregate costs of performing such services, a prospective adjustment in rates will be made. A review of the need for such prospective adjustments shall be undertaken at least annually.*
>
> *Demurrage and standby charges shall be assessed as provided in Appendix A hereto.*

The Barge Demurrage Charges and Towboat Standby Charges, provided as Appendix A to the Barge Transportation Agreement[3] is dated as effective March 1, 1978.

The SEC Release No. 35-24039 dated March 4, 1986 (provided as LA 1-36, Attachment 2), Order Authorizing the Rendition of Associated and Nonassociated Transportation Services, indicates that the primary purpose of the RTD is to move coal for the operating companies of the AEP System at the most reasonable price.

Pages 2-5 of that SEC Release address the subject of cost recovery as follows:

> *The basic principle used to determine barge rates is that revenues should equal costs. Since 1973, this principle has been adhered to on total cumulative revenues for the period 1973 to 1984 of approximately $260.5 million. The River Transportation Division's rates have been based on a detailed cost of service analysis, following normal transportation industry practice, based on a zone rate system where each river movement bears an equitable share of total costs. The zone rate structure, as a whole, is reasonable and free of undue discrimination.*
>
> *The zone rate system was designed and established so that projected revenues would be expected to cover costs. Zone rates are set prospectively in such an amount that the expected revenues will be sufficient to recover projected costs for the next period. These expenses include (1) direct expenses from each river movement, (2) an allocation of all other expenses, net of credited revenues from providing services to nonassociates and (3) provisions for taxes. The variance for each zone (deficit or surplus of revenues over expenses by zone) at the end of each calendar year is carried over to the next year and added to or subtracted from the projected costs to be recovered by the rates set to recover projected costs. The review to adjust rates is undertaken at least once a year, although an adjustment for significant cost shocks (i.e. fuel oil price changes, tax changes, wage escalations) are made as they occur and would not wait for the annual adjustment process.*
>
> *Specific barge rates are determined by zone. Currently there are four zones, each zone being treated as a cost center. Direct charges such as labor, fuel and rents are assigned to each cost center on a projected basis. Overhead costs such as supervisory salaries and expenses, general office operations and other costs are proportionately allocated to the four cost centers in the same proportion as direct expenses. Revenues from all services provided to nonassociates are first credited to reduce overhead costs, and then applied to direct charges in I&M's Federal Energy Regulatory PUCO ("FERC") Account 151. I&M proposes*

[3] This was provided as part of LA 1-36, Attachment 1.

by this application-declaration to include a provision for taxes based on or measured by income and an amount for the cost of capital of its net investment in the River Transportation Division (including working capital requirements), and to allocate such costs to zones on the same basis as overhead. A cost per ton-mile in each zone is determined by dividing projected total zone costs by projected total ton-miles moved within each zone. A barge rate for any specific move within a zone is the product of: (1) cost per ton-mile, (2) the number of adjusted miles for the movement (actual miles adjusted for down time), and (3) the number of net tones moved. In general, movements within each zone share similar characteristics, and are considered to be different from movements in other zones. These rates were reviewed before November 1, 1985 to determine what adjustment to rates, if any, were needed to adjust revenues to equal costs. I&M proposes to enter into a Barge Transportation Agreement with any Applicant requiring barge transportation services incorporating the barging rates as described, and entitling the Applicant to a service priority over any nonassociated company. Rates for nonassociated service will be at the highest practicable level, based on market conditions.

I&M proposes that the cost of capital on its net investment in the River Transportation Division be established at 9.21% per annum, which rate was approved in orders of the Corporation PUCO of Virginia and the West Virginia Public Service PUCO in 1981 and 1984, respectively, and which I&M proposes to begin applying after approval by this PUCO. It represents a weighted average cost of capital based on I&M's capitalization ratio as of September 1, 1973, when the original transportation assets were acquired. The cost of long-term debt and preferred stock are the effective rates of the most recent long-term debt and preferred stock issues by I&M prior to September 1, 1973. The return on common equity is the return ordered by FERC on March 18, 1980, in I&M's general rate proceeding. I&M proposes to use the 9.21% composite rate until such time as state PUCOs authorize, if necessary, an adjustment of the return on common equity on January 1 of each calendar year to the rate of return on common equity determined and allowed by FERC in the most recent wholesale rate proceeding involving I&M. In the absence of a FERC order during the calendar year preceding each January 1, it is proposed that the rate of return on common equity would be that authorized by the Public Service PUCO of Indiana in an I&M retail electric rate proceeding during the calendar year preceding such January 1, otherwise the existing rate of return continues until the next January 1.

The costing procedures for barge rates were provided in response to EVA 4-1, in Confidential Attachment 1 to that response. The RTD uses a 12-step of "Actualization Procedures" to determine the charges.

The RTD's 2009 Rate Matrix, which provides the affiliated coal barging rates for OPCo based on the 2009 budget, was provided in the Confidential Attachment 1 to EVA 4-2. This lists the barging rates for each OPCo plant from each potential load-out area to the plant. OPCo plants that are supplied with coal by the RTD include Cardinal, Kammer, Mitchell, Muskingum River, and Gavin.

Copies of all operating leases for captive barges based upon annual cost in 2008 and 2009 to OPCo were provided in the Confidential Attachments to EVA 4-11. Those lease and charter agreements list OPCo as Charterer for 40 barges.[4] The agreements provide that the lessor is the owner of the vessels. As an illustrative example, EVA 4-11, Confidential Attachment 2, page 10 of 65, in Section 5(a), provides that the lease term under that agreement runs from November 1, 2006 and ends on October 31, 2023 unless that Charter is terminated sooner with respect to such vessels. Section 8(a) (provided at EVA 4-11, Confidential Attachment 2, page 16 of 65) provides as follows concerning maintenance and repairs:

> *SECTION 8. MAINTENANCE AND REPAIR OF VESSELS, REPLACEMENTS, ALTERATIONS, MODIFICATIONS.*
>
> *(a) The Charterer shall pay all costs, expenses, fees and charges incurred in connection with the use and operation of the Vessels during the Term. The Charterer shall at all times during the Term, at its own cost and expense, maintain and preserve each Vessel in accordance with good commercial maintenance practices for Vessels of the same type and service owned by companies of similar size and financial standing and having similar operations and cargoes, so that such Vessel shall be (1) insofar as due diligence can make her so, tight, staunch, strong and well and sufficiently tackled, appareled, furnished, equipped and in every respect seaworthy; (2) in satisfactory operating condition, ordinary wear and tear excepted, and in satisfactory repair and working order consistent with accepted industry practice; (3) in compliance with all laws, regulations, requirements or rules; (4) maintained and repaired in compliance with all Manufacturer's recommended procedures and, if none, consistent with accepted industry practice; (5) in compliance with all applicable insurance requirements; and (6) maintained at a standard of maintenance not less than the highest standard of maintenance*

[4] AEP's response to EVA 4-11, Confidential Attachment 2, page 49 of 65, "Description of Vessels" states as follows: "[redacted] 200' x 35' x 13' semi-integrated (Rake) dry bulk cargo inland waterway open hopper barges manufactured by Jeffboat LLC together with winches and other installed equipment approved by Owner." AEP's response to EVA 4-11, Confidential Attachment 3, page 50 of 66, "Description of Vessels" states as follows: "[redacted] 200' x 35' x 13' box inland waterway open hopper barges manufactured by Jeffboat LLC together with winches and other installed equipment approved by owner." Because of when these responses were received, we were unable to follow-up to clarify whether OPCo has [redacted] of these barges.

> *performed on similar Vessels owned or chartered by the Charterer. The Charterer shall maintain complete and accurate maintenance records with respect to each Vessel, and will allow the Owner and its agents and representatives reasonable access to review, inspect and make extracts of such records in accordance with the terms hereof. The Vessels shall be drydocked by the Charterer at its sole cost and expense whenever necessary to maintain or preserve such Vessels in accordance with the provisions of this Charter Agreement.*

The response to EVA 4-10 indicates there are no operating leases between OPCo and River Operations for OPCO-owned barges. AEP's response to LA 7-30 stated that OPCo does not own any barges and that there are no leases of any type between OPCo and RTD:

> *a. OPCo does not own any barges.*
>
> *b. No. There are no leases of any type (capital leases, certificates of participation, charter agreements, or other types of leases) between OPCo and River Operations for any OPCo owned or OPCo leased barges.*

AEP's response to LA 7-30(c) indicated that any contracts or agreements between OPCO and River Operations pertaining to the use by River Operations of OPCO-leased barges, including but not limited to the 115 jumbo barges OPCO is leasing as indicated in the response to EVA 4-8, were provided in the response to LA 1-36, Attachment 1.

The affiliated freight rate true ups for the five quarters starting with the fourth quarter of 2008 for OPCo were provided in Confidential Attachments 1 through 5 to EVA 4-3. That information is summarized in the following table:

REDACTED VERSION

Exhibit 7-49. River Operations, Summary of OPCO Quarterly Actualizations

[redacted]

For 2009, I&M had approximately [redacted] million in revenue from OPCo related to the RTD. Costs and expenses were [redacted] million, offset by [redacted] million for third party gains, less I&M's return on investment of approximately [redacted]. RTD also delivers urea to OPCo. For 2009 it was necessary to also account for a net amount of Urea Revenue Less Cost of approximately [redacted] in order to re-calculate the net Over-Billing amount of [redacted] million, shown in Column F, line 7, of the above table. The net cost (based on RTD's Costs and Expenses, less the Third Party Gain, plus RTD's Return on Investment) for OPCo for 2009 was approximately [redacted] million. For the [redacted] tons delivered, this is an average cost of approximately [redacted] per ton.

AEP's response to LA 7-3(b) provides the following explanation as to how the RTD amounts impacted OPCo's FAC filings for 2009:

> *The quarterly billing adjustments for I&M-River Operations' barge costs are billed to OPCo and recorded in coal inventory (Account 1510001) for each applicable OPCo plant in the same manner as the monthly I&M-River Operations billed barge costs. As coal is consumed, coal inventory is credited for that consumption and coal fuel expense (Account 5010001) is charged. Fuel expense in Account 5010001 one of the FAC-includable costs as reflected on tab "EXH OPCO 1" in the monthly workbooks (LA-1-47, aa through ll). These monthly workbooks support the under-recovery amounts reflected in the FAC filings.*

A review of pages 5 and 7 from EVA 4-3 Confidential Attachments 2 through 5 indicated that the only amounts that reconcile between the two referenced pages relate to "Captive Open Barges" (page 5) and "Other Barge Operating Expenses" (page 7). None of the other amounts listed on page 5 appear to tie into the amounts shown on page 7. AEP's response to LA 7-3(d) explains why the amounts associated with Captive Open Barges costs are the only costs reflected on page 7:

> *"Other Barge Operating Expenses" is used to determine the cost of covered barges used to transport urea on a barge cost per day basis. As such, the [redacted] daily barge cost for covered barges is applied to the urea related barge days (461 days) to arrive at a barge cost of [redacted]. This amount is shown on the 'Allocations' tab under the "Other Barge Expense" heading for AEP/OPCO (Urea). "Barge Optimization Revenue" [redacted] is copied on the 'Allocations' tab under Revenue for Other Oper. – Barges, and is a part of the [redacted] total. "Barge Optimization Cost" [redacted] is included in the charter hire amount of [redacted], which is included in the [redacted] total in the "Other Barge Expenses" column in the "Allocations" tab.*

AEP's response to LA 7-3(f) explains the item for gain/loss from barging urea as follows:

> *The gain/loss from barging urea is factored into the over/(under) billing calculation The difference between urea revenues and urea expenses is allocated back to each operating company plant based on the percentage of actual urea tonnage delivered to each plant during the quarter to total urea tonnage delivered during the quarter. As such, the "OPCO Urea" trueup is included with each plant's barging trueup. EVA 4-3 Attachment 5 (page 4 of 7), the third column in from the end (AEP/OPCO Urea Gain/Loss) shows the urea loss that is allocated back to each plant based on delivered tonnage. The urea tonnage delivered during the quarter is in the last column (Urea Tons).*

AEP's response to LA 7-3(g) explains how the Third Party Gains are allocated to the affiliated operating companies/plants to reduce the net cost of barging:

> *Third Party Gains/Losses are a result of AEP River Captive Operations performing barging services for non-affiliated customers at market rates. The gains from third party business are allocated back to all affiliated operating companies/plants by means of the "Direct Cost %", which is the percentage of total direct towing cost for each plant divided by the total affiliated direct towing cost.*

For 4th quarter 2009, the total third party gain was [redacted]; [redacted] is barge optimization as shown on the barge income statement; [redacted] is charter rent profit realized from renting old standard barges to an outside barging company; [redacted] is gain from the sale of old barges and scrap; [redacted] is demurrage revenue; and [redacted] is third party gain from barging coal and limestone for third party customers at contract market rates.

AEP's response to LA 7-3(g) also explains how the estimated return on investment is utilized:

An estimated return on investment is determined at the time the operating budget is prepared for the next year. One twelfth of the estimated return on investment is recorded in accounting and adjusted each month for federal taxes and interest expense. At the end of each year, return on investment is actualized and the adjustment of estimated ROI to actual is added to next year's monthly estimate and spread over the year. The 2009 estimated ROI for barging was [redacted] per month.

For 2008, there was a billing adjustment. AEP's response to LA 7-3(i) explains that the 2008 billing adjustment was charged to OPCo's plant coal inventories (Account 1510001).

AEP's confidential response to LA-7-6(a) identifies the Total Boat Profit for 2009 to be [redacted] and explains how that amount was determined:

The Boat Profit/Loss for each month and year to date can be found on the Boat Income Statement under the heading "Net Income After Tax". In the table above, the sum of all four quarters equals a total Boat Income Statement Profit of [redacted] for 2009. All of RTD's boats are treated as cost centers and not profit centers; as such, all boat costs are consolidated into the barge income statement as barge operating expenses under the heading "Towing-Internal". Each month, the barges are charged an estimated rate per ton mile for all towing ton miles achieved by the boats during the month. If estimated boat revenues charged to the barges are more than boat costs, the boat profit is subtracted from total barge cost; if estimated boat revenues are less than boat costs, the boat loss is added to total barge costs. In effect, the barge income statement coupled with boat profit/loss, comprise the full cost of freight. The reconciliations in the attachments for response to EVA-4-3, "Barge Direct Operating Expense" include direct barge expenses and all boat operating and maintenance expense.

AEP's confidential response to LA-7-6(c) explains further that:

> *The [redacted] sum of Boat Profit for the four quarters benefited all captive barging operations including that for OPCo by [redacted]. Please see LA 7-6 CONFIDENTIAL Attachment 1. This benefit lowered RTD barge billings to OPCo thereby reducing its plants' coal inventory costs, and fuel expenses, and FAC underrecovery.*

We noted a number of differences in the amounts provided for the total year-to-date expenses in EVA-4-3 and EVA-4-5, and in LA-7-10, and asked AEP to provide a reconciliation of the noted differences between the total year-to-date expenses indicated on the Barge Operation Income Statements and the RTD expenses reflected on Attachments 1 and 2 from EVA-4-5. AEP's response to LA-7-10 provided reconciliation and explained the differences as follows:

> *The "Barge Operations Income Statement" includes all barge related costs with one exception; the 'Towing – Internal' amount [redacted] is an estimated billing charge from the 'Boat Operations Income Statement' to the barges for towing internal freight during the applicable periods. These same amounts are reflected as boat revenue on the "Boat Operations Income Statement" ("NB Towing – Interco." - [redacted] and 'SB Towing – Interco.' - [redacted]. In consolidations, the aforementioned intercompany towing revenue is eliminated and actual boat operating expenses and administrative expenses are added to barge operating and administrative expenses to arrive at total barge and boat operating expenses.*

AEP was asked to provide information to reconcile the amounts it used for prepayments, materials and supplies, inventory, and other current liabilities and accruals on EVA 4-5 Confidential Attachments 1 and 2, page 1, with its Balance Sheets that were provided in EVA 4-4, Confidential Attachment 3. AEP provided reconciling information in response to LA-7-11 and LA-7-19.

AEP's responses to LA-7-15 and LA-7-16 confirmed that documents related to the RTD provided by AEP in response to EVA 4-3 that indicated certain approvals and signatures were actually approved and signed.

LA 7-17 asked for detail of some of the components of RTD charges that were shown in EVA 4-4, Confidential Attachment 2. AEP's response to LA 7-17 was received on April 27, 2010, which did not permit much time for review and no follow up. As illustrative examples, AEP's response to LA 7-17(c) provided an attachment listing the following as components of Other Administration Expenses:

Exhibit 7-50. River Operations, Other Administrative Expenses

[redacted]

Similarly, AEP's response to LA 7-17(b) provided a listing of the components of "AEP Admin Charges", as follows:

Exhibit 7-51. RTD Service Corp. Bill Charges, 2009

Exhibit 7.51

[redacted]

We recommend that the details of RTD charges, including, but not limited to, Other Administration Expenses and "AEP Admin Charges" be reviewed in detail in the next audit period.

AEP was asked to provide information to reconcile the [redacted] of RTD Expenses for 2008 and 2009 used to determine the Working Capital Requirement, respectively, with RTD's Barge Operations Income Statement for Captive Operations for 2008 and 2009, which was provided in EVA 4-4 Confidential Attachment 1, pages 1 and 13. AEP provided reconciling information in response to LA-7-9, LA-7-10, and LA-7-20.

LA 7-18 identified a number of items on the RTD's Income Statement and/or Balance Sheet and inquired as to whether such items were included in deriving the "Investment Base" on EVA 4-5 Confidential Attachment 1. AEP's response identified which items were, and were not included, and indicated which items were included at one-eighth. As noted below, we have some continuing concerns regarding the logic or appropriateness of including some of the selected Balance Sheet accounts in a one-eighth type formula. We also have concerns regarding the exclusion of some other Balance Sheet accounts, such as Accumulated Deferred Income Taxes.

AEP's response to LA 7-19(b) stated that:

> *The company does not compute nor record Deferred State Income Taxes (DSIT) by individual timing differences. DSIT is recorded on one single line (as presented in the attachment to the response to LA 7-19 a. (labeled DSIT Entry - Normalized) which is computed by including the total temporary timing differences as a whole, plus or minus any other state specific differences/adjustments (if any).*

AEP's response to LA 7-19(a) and (b) (received April 27, 2010) provided the available detail on Deferred Federal and State Income Taxes. We recommend that RTD's income tax expense and Accumulated Deferred Income Taxes be reviewed in detail in the next audit period, in order to formulate recommendations for inclusion or exclusion from the calculation of RTD's charges to OPCo.

Intercompany barge optimization reports are utilized by RTD. As described in the response to LA 7-12(a):

> *The purpose of the Cross Charter Days per Barge Day Report is to book charges between the Captive and Commercial parts of AEP River Operations for daily use of barges being optimized. In addition to barge optimization expense, Captive and Commercial operations realize barge optimization revenue as their barges are optimized.*

Additionally, as described in the response to LA 7-12(b):

> *The purpose of cross charter barging is to (1) reduce empty barge relocation costs, and (2) to return empty barges promptly into service in order to increase the barges' utilization. Thus, cross charter barging lowers overall barge transportation costs. Given that there are cross charter charges being booked as reflected in EVA 4-7, Confidential Attachment 1, the net impact on overall fuel transportation costs as reported in OPCo's FAC filings is favorable.*
>
> *No studies have been performed nor are there any reports available to quantify the impact of cross charter activities on OPCo's FAC filing.*

During 2008, RTD billed OPCo for demurrage related to transportation of urea. A portion of that RTD demurrage charge remained in OPCo fuel inventory as of 12/31/2008 and thus impacted OPCo's 2009 cost of fuel. As described in the Company's response to LA 7-13:

a. The demurrage adjustment was booked by River Transportation Division (RTD) in July of 2008 and included with RTD's third quarter actualization, which was calculated in October 2008 and subsequently billed to the plants along with the normal over/under billings.

b. As with all billings from RTD for coal barge deliveries, OPCo charged the third quarter actualization billing to Account 15100001, Fuel Inventory-Coal. This billing was recorded by OPCo in December 2008. Some portion, estimated at approximately [redacted]*, remained in fuel inventory as of 12/31/08.*

During an interview with AEP and RTD personnel, the RTD personnel provided some illustrative comparisons indicating that RTD's cost to provide the transportation of coal was competitive with, or below the cost of alternative providers for comparable routes.

The RTD's Barge Operations Income Statements and Balance Sheets for Captive Operations for December 2008 and each month of 2009 were provided in Confidential Attachments 1 through 3 to EVA 4-4.

The RTD's "Actual Net Investment Base & Cost of Capital Billing Adder" for 2008 was provided in Confidential Attachment 1 to EVA 4-5.

The Investment Base consists of a Working Capital Requirement that is based on RTD's Expenses, less Sub-lease Revenues, plus a prior period Over-Collection, plus Prepayments and Materials and Supplies, less Other Current Liabilities and Accruals. The result of these items is an amount of "Net Expenses" which is multiplied by 0.125 (i.e., by 1/8th) to derive a "Working Capital Requirement."

To the Working Capital Requirement are added Real Property and Personal Property taxes (based on a 13-month average of Net Book Value). The addition of these items results in an Investment Base which is multiplied by a "Before Tax" rate of return of 12.82% to derive an Actual Return on Investment. The derivation of the 12.82% "Rate of Return on Assets" that applied for 2008 is shown on EVA 4-5 Confidential Attachment 1, page 4 of 6. It is based upon a capitalization consisting of Long Term Debt, Preferred Stock and Common Stock. The Annual Cost rate used for Common Equity of 12.00% was specified in Note D to be "*No more than the rate ordered by Indiana 11/12/93 in Case No. 39314.*" The Before-Tax rate of return reflects a gross-up for federal income taxes at a 35% tax rate.

Similar calculations for 2009 were provided in EVA 4-5 Confidential Attachment 2. On page 4 of 6 of Attachment 2, this shows that the Annual Cost rate for Common Equity was 10.50%. Note D on that page also states this to be "*No more than the rate ordered by Indiana 11/12/93 in Case No. 39314.*"

AEP's response to EVA 4-5, Confidential Attachments 1 and 2, page 4 of 6, each referenced Case No. 39314, as noted above. LA-7-24 inquired about cases subsequent to Case No. 39314. AEP's response to LA-7-24(a) stated that: "*The only I&M base rate case after No. 39314 was Indiana Utility Regulatory PUCO (IURC) Cause No. 43306, Order dated March 4, 2009.*"

AEP's response to LA-7-24(b) indicated that a 10.5% return on equity was used in that order: "*In Cause No. 43306 the IURC authorized a return on equity of 10.5%.*"

AEP's response to LA-7-24(c) Attachment 1 provided a list of AEP utility operating subsidiary authorized ROEs, which are summarized below as of December 31, 2008 and 2009 respectively:

Exhibit 7-52. AEP System Companies Return On Equity, 2008

[redacted]

Exhibit 7-53. AEP System Companies Return On Equity, 2009

[redacted]

As described in the response to LA 7-19(f):

> *f. Each month RTD is allowed to earn the amount calculated as the ROI estimate. ROI is defined as net income excluding the impact of federal income tax expense and interest income/expense. To the extent the monthly earnings are greater than the allowed ROI estimate, revenue is deferred to the "Deferred Excess Revenue/Cost" account. If monthly earnings are less than the allowed ROI estimate, revenue is accrued to the "Deferred Excess Revenue/Cost" account. The balance in the "Deferred Excess Revenue/Cost" account is the basis of the quarterly actualization.*

It appears that the way the RTD charges to the AEP captive operations are set up with the billing and a subsequent true-up (actualization), the operating companies, including OPCo, will essentially be paying the RTD for all of its costs, including the return component. Given this set-up, there does not appear to be much risk, if any, that RTD will not collect its cost of service (including the return component) from the AEP captive operating utilities that use RTD for transportation services. While some return on investment would appear to be warranted since RTD has a net investment in assets that are used to provide service, we would question whether the Return on Common Equity (especially the 12.00% ROE that was applied in 2008) is appropriate and commensurate with the risk of this operation.

A number of the amounts used in the RTD's "Actual Net Investment Base & Cost of Capital Billing Adder" for 2008 and 2009 could not be verified to source documents, such as the RTD's Income Statements and Balance Sheets that were provided in response to EVA 4-4.

The amounts listed for RTD's Expenses on EVA 4-5, Confidential Attachments 1 and 2, for 2008 and 2009, respectively, are higher than the respective amounts of expenses shown on EVA 4-4, Confidential Attachment 2, pages 1 and 13, for the twelve months ending December 31, 2008 and 2009, respectively, as summarized in the following table:

Exhibit 7-54. RTD Expenses, 2008 And 2009

[redacted]

Additional follow up questions concerning the specific calculations were asked in LA set 7.

LA 7-22(a) asked AEP to: *"Please explain the logic for <u>Adding</u> the Over Collection amount to the Working Capital Requirement base to which the 1/8 factor was applied."*

AEP's confidential response stated that:

> *While preparing the response to this series of questions, the Company discovered an error in its calculation of the 2008 Working Capital Requirement and the 2009 Working Capital Requirement, both of which are used in the Actual Return on Investment calculation for each respective year. The over collection of revenues versus costs should have been subtracted from RTD's expenses to arrive at the Net Expenses used in the Working Capital Requirement. The corrected calculations are shown in LA-7-22 CONFIDENTIAL Attachment 1 and LA-7-22 CONFIDENTIAL Attachment 2. The resulting credits [redacted] and [redacted]) to RTD's customers will be reflected in the 2nd Quarter 2010 true up and credited to the operating companies in August 2010. OPCo's portion of these credits is [redacted] and [redacted].*
>
> *(a) The 1/8 reference in the EVA 4-5, CONFIDENTIAL Attachments 1 and 2, is a standard regulatory convention that is used regarding cash working capital for O&M expenses. The amount should be added to expenses when an under collection occurs since the amount was spent in a prior period. When an over collection occurs in a prior period the amount should be subtracted from expenses in calculating the cash working capital requirements. The appropriate title of this line should be "Add: Under (Over) Collection" to reflect how the calculation should actually be performed.*

With regard to AEP's statement that "*The 1/8 reference in the EVA 4-5, CONFIDENTIAL Attachments 1 and 2, is a standard regulatory convention that is used regarding cash working capital for O&M expenses,*" this does not explain why, in the RTD "Investment Base" calculations, RTD is applying the 1/8 to what appears to be Balance Sheet accounts, not just to operating expenses. Additionally, the use of a 1/8 formula for computing cash working capital has been discredited for a number of reasons, including because it would always produce a positive cash working capital allowance, even in situations where funds were being supplied to the service provider through operations. Many of the AEP operating utilities have conducted lead-lag studies. It appears questionable that the RTD would be incapable of having an appropriate lead-lag study analysis of its cash receipts and expenditures as the basis for a cash working capital component of the RTD "Investment Base." An appropriately conducted lead-lag study analysis would also tend to be more reliable than the 1/8 formula assumption currently being used by RTD.

AEP's responses to LA 7-22(b) and (c) confirmed that an over collection represents revenues collected in excess of costs and that an over collection should be subtracted (not added):

> *(b) Yes, an over collection represents revenues collected in excess of costs.*
>
> *(c) Over collection should be subtracted from expenses as discussed in (a) above.*

AEP's response to LA 7-22(d) indicated that *"no AEP utility operating subsidiaries earn a return on RTD over-collections. The over-collections are returned to the AEP utility operating subsidiaries as soon as practical, thus no return or carrying charge is applied."*

Based on our review of RTD information to date, we believe there may be a need to revise, prospectively, the way the RTD Net Investment Base and Cost of Capital Billing Adder that is used to determine RTD charges to OPCo is derived.

Based on our review of RTD information to date, we have made several recommendations in the Recommendations section below.

Memorandum Of Findings

The FAC is a new rate element and what is included in it or excluded from it is to some degree subject to judgment and interpretation. Based on Larkin's review, there are a number of areas which deserve consideration by the PUCO. These are:

Although a number of issues and discrepancies were noted when reviewing AEP Ohio's FAC workbooks that were provided in the response to LA-1-47, AEP Ohio provided explanations through follow-up discovery. As a result, the monthly FAC workbooks generally reflected adequate audit documentation of the revenue and cost components included in the FAC filings. However, there is room for improvement in terms of the Companies' including explanations for the discrepancies described in the preceding section of this report that discusses LA-1-47.

Larkin concluded that secondary sources of audit documentation should be modified in order to provide a more complete audit trail of the includable FAC revenue and cost components. For example, the fuel ledgers provided in the response to LA-1-10 clearly reflected the fuel related transactions in the accounts designated under the "Generation Fuel" and "Incremental Fuel Handling/Ash/Gypsum" cost categories as reflected in the monthly Net Energy Cost ("NEC") worksheets that were provided as part of the FAC workbooks. The accounts designated under the "Purchases Power – Fuel Portion" category should be included in the Companies' monthly

Based on our review of AEP Ohio's RTD information, we believe there may be a need to revise, prospectively, the way the RTD Net Investment Base and Cost of Capital Billing Adder that is used to determine RTD charges to OPCo is derived.

Recommendations

1. The FAC workbooks that were provided in the response to LA-1-47 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 that were derived from other sources (e.g., the Monthly Purchase Summary Reports). In addition, these explanations should also apply to issues such as timing differences and/or prior period adjustments. AEP Ohio agrees, and has proposed to include in the monthly FAC workbooks the monthly purchased power reconciliations similar to that provided in the response to LA-4-11.

2. CSP and OPCo should include the reconciliation of the fuel and purchased power accounts that have been designated as includable FAC costs similar to LA-4-11 with the monthly FAC workbooks, with appropriate color coding, to facilitate a clear audit trail.

3. April 2009 was selected as the month for additional detailed testing. LA-1-37 requested copies of invoices and paid cash vouchers or cash receipts for purchases of power recorded in April 2009 that are included in the FAC filings. Larkin was unable to trace most of the information provided to the FAC workbooks (provided in LA-1-47) for that test period. The Companies should provide a better audit trail for tracing such costs in the next audit period. AEP Ohio agrees, and has proposed to include in the monthly FAC workbooks the monthly purchased power reconciliations similar to that provided in the response to LA-4-11.

4. The response to LA-1-39 indicated that during the period January through December 2009, four of AEP Ohio's power plants were designated as "must run" units by PJM for reliability and voltage control reasons during a number of hours. Unless it has already been presented in another forum, the PUCO may want to have AEP Ohio explain further how the "must run" generating unit designations are affecting the costs that are recoverable in the FAC.

5. The response to LA-2-1(b) indicated that hourly or 24-hour dispatch cost information is not readily available from AEP Ohio's systems. In addition, Off-System Sales detailed cost information related to forced outages is not readily available, nor is it used for any internal business purposes or in existing reports. AEP Ohio should update and/or modify its systems in order to better track the AEP East Fleet system stack information.

The following recommendations are related to Larkin's review of AEP Ohio's RTD operations.

6. 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.
7. RTD should be required to provide a procedure for updating the cost of capital and the Return on Equity component that is commensurate with the risk of the operation.

8. 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). AEP agrees that a correction is necessary for this.

9. 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 [redacted] and [redacted] to RTD's customers were recorded in its 2nd Quarter 2010 true up and credited to the operating companies in August 2010. OPCo's portion of these credits is [redacted] and [redacted]). As stated in the Company's response to LA 7-22:

> *While preparing the response to this series of questions, the Company discovered an error in its calculation of the 2008 Working Capital Requirement and the 2009 Working Capital Requirement, both of which are used in the Actual Return on Investment calculation for each respective year. The over collection of revenues versus costs should have been subtracted from RTD's expenses to arrive at the Net Expenses used in the Working Capital Requirement. The corrected calculations are shown in LA-7-22 CONFIDENTIAL Attachment 1 and LA-7-22 CONFIDENTIAL Attachment 2. The resulting credits [redacted]) and [redacted] to RTD's customers will be reflected in the 2nd Quarter 2010 true up and credited to the operating companies in August 2010. OPCo's portion of these credits is [redacted] and [redacted].*

10. 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 derivie the Investment Base is a reasonable and appropriate method.

11. OPCo, RTD and the 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. OPCO should report quarterly concerning the progress of these efforts by including a description of progress made in its quarterly FAC filings.

12. 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.

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

14. 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.

15. 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.