FILE

222

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

Case No. 11-281-EL-FAC.

May 24, 2012

Prepared for:
PUBLIC UTLITIES COMMISSION OF OHIO

180 EAST BROAD STREET
COLUMBUS, OH 43215-3793

Prepared by:
ENERGY VENTURES ANALYSIS

1901 NORTH MOORE STREET
SUITE 1200
ARLINGTON, VA 22209

(703) 276 – 8900
www.evainc.com

Larkin & Associates PLLC

15728 FARMINGTON ROAD
LIVONIA, MI 48154

(734) 522-3420

LIST OF EXHIBITS

1 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 report covering the initial audit period January through December 2009 period was filed May 14, 2010. The second audit covering the period January through December 2010 was filed May 26, 2011. This third audit covers the period January through December 2011.

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.

[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

- 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

The 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 Mitchell station on March 22, 2012. EVA and/or Larkin conducted interviews with the individuals in the positions listed in

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

Exhibit 1-2 mostly during the third week of March, 2012. In addition to those listed, Mr. Jim Sorrels, Manager of Regulatory Analysis and Case, attended all the interviews in Columbus.

Major Management Audit Findings – 2011

1. In 2011, AEP Ohio's coal generation (coal burn) and coal purchases declined compared to 2010. The decline in purchases was greater than the decline in generation which resulted in a drawdown in inventory. At the end of the year, all plants were at or close to target levels.
2. Coal procurement costs (on a dollars per MMBtu basis) [redacted] in 2011. The largest [redacted] was experienced at [redacted] due to the decision to close the Conesville Coal Preparation Plant and the costs associated with the shortened asset life. Lower volumes at Conesville also contributed to the [redacted] unit prices. Contract price escalation under all contracts and lower generation at Gavin also contributed to the [redacted].
3. In 2011, AEPSC purchased coal for AEP Ohio under [redacted] contract and [redacted] spot purchase agreements. About [redacted] percent of the purchases were under contracts. Over [redacted] of the contract purchases were from [redacted].
4. In 2011, AEPSC conducted [redacted] coal RFP's in part for AEP Ohio requirements. [redacted] contracts and [redacted] spot purchase agreements were entered into as a result of these RFP's. [redacted] of the [redacted] purchases were for Kammer. [redacted] of the Kammer contracts represented [redacted] for Kammer. Another Kammer contract was for a [redacted] thereby providing flexibility for Kammer's [redacted]. One of the spot agreements was for [redacted] of Powder River Basin coal for [redacted] that was purchased to support compliance with the Cross States Air Pollution Rule (CSAPR) which had been scheduled to go into effect in 2012. On December 30, 2011, CSAPR was stayed by the court.
5. In 2011, AEPSC also entered into a spot purchase agreement with [redacted] for coal to Muskingum River. The pricing under this agreement was [redacted]. Rather it was based upon the [redacted]
6. The major contract events in 2011 included an agreement with [redacted]

Exhibit 1-2
List Of Interviews

Session	AEP Participants
Coal Procurement	Mike DeBord, VP - Fuel Procurement Jason Rusk, Director - Fuel Procurement Kim Chilcote, Manager II - Fuel, Emissions & Logistics (Procurement) Clint Stutler, Coordinator I - Fuel, Emissions & Logistics (Procurement) Jason Echelbarger, Coordinator I - FEL Consumables (formerly QA/QC Engineer) Brian Rupp, Senior Regulatory Consultant Shelli Sloan, Regulatory Case Manager
Conesville Coal Preparation Company	Jim Henry, VP - FEL Operations & Mining Jim Garrett, Managing Director - FEL Operations Greg Stiltner, Railcar Maint & Assett Dev Administrator (former CCPC Mgr.) Tim Dooley, Director - Energy Accounting Dorra Campbell, Manager - Regulated Accounting
Consumables Procurement	Marguerite Mills, VP - Fuel Procurement Darryl Scott, Manager - Reagents & Coal Combustine Products Reggie Pratt, Coordinator II - FEL Consumables Rick Hayek, Coordinator I - FEL Consumables
Natural Gas & Fuel Oil Procurement	Marguerite Mills, VP - Fuel Procurement Ken Howsen, Director - Gas & Oil Procurement Nita Spracklen, Manager - Gas & Fuel Oil Procurement Andy Noonan, Manager, Gas & Oil Business Operations
Biofuels	Marguerite Mills, VP - Fuel Procurement Ashley Weaver, Manager - Alternative Fuels
Environmental Compliance	John Hendricks, Director - Air Quality Karen Anderson, Manager I - Fuel, Emissions & Logistics (Emissions) Rick Hayek, Coordinator I - FEL Consumables Jeff White, Manager - Regulatory Analysis & Case (Generation) Tim Dooley, Director - Energy Accounting
Renewables	Jay Godfry, Managing Director - Renewable Energy Joe Karrasch, Manager - Asset Investments (Renewables) Alex Vaughan, Regulatory Analyst II (Commercial Operations) Tim Dooley, Director - Energy Accounting Mike Giardina, Manager - Generation Reporting (Accounting)
Purchased Power	Mark Leskowitz, Director - Commodity Accounting Craig Adelman, Manager - East Power Accounting Alex Vaughan, Regulatory Analyst II (Commercial Operations) Tim Dooley, Director - Energy Accounting
Internal Audits	Rod Burnham, Director - Audit Services
Fuel Accounting	Tim Dooley, Director - Energy Accounting Glenn Gaffney, Manager - Fuel Accounting Brian Frantz, Supervisor - Fuel & Contract Accounting
Ohio Regulatory/FAC Reporting	Andrea Moore, Manager - Regulated Pricing & Analysis (AEP Ohio) Tim Dooley, Director - Energy Accounting
AEP River Operations	Tom Palumbo, Director - Accounting & Finance (AEP River Operations) Darlene Norris, Senior Manager - River Planning, Budgeting & Costing Carolyn Minkler, Senior Cost Analyst - River Ops Brad Funk, Manager - Regulated Accounting (AEPSC) Tim Dooley, Director - Energy Accounting Glenn Gaffney, Manager - Fuel Accounting
Mitchell Plant Visit	Dan Moyer, Plant Manager - Kammer/Mitchell Chester Smith, Energy Production Superintendent Janet Hewitt, Administrative Superintendent Russel W Gwin, Maintenance Superintendent I Paul Fox, Materials Handling Superintendent I Christine King, Chief Chemist Jeff McGlynn, Lead Engineer Larry E Fraleigh, Plant System Owner Senior Melissa A Sadlowski, Administrator II

[redacted]

7. [redacted]

8. The tonnage purchased for [redacted] under [redacted] coal supply agreements was [redacted] would each have their own agreements. No changes were made other than to the volume commitments.

9. [redacted].

[redacted] Natural gas purchases and consumption [redacted] in 2011 as low natural gas prices caused [redacted]. AEPSC is continuing to purchase natural gas [redacted]

11. AEPSC purchases lime, limestone, hydrated lime, trona, and urea for its various pollution controls systems at the AEP Ohio plants. These materials are purchased from competitive solicitations and generally under multi-year deals. As a result of a downturn in burn, AEPSC has focused on [redacted].

12. AEPSC met its Renewable Energy Credit (REC) requirements in 2011. AEPSC's current strategy [redacted]. AEPSC indicates it will consider owning or controlling REC assets in Ohio if it receives regulatory certainty that its costs can be recovered. In 2011, AEPSC was able to realize significant benefits through the sale of excess Ohio solar REC's which traded at a premium to non-Ohio solar RECs. The proceeds from these sales flowed through the FAC.

Management Audit Recommendations

1. EVA recommends that prior to any future negotiations with [redacted], AEPSC develop a coal procurement strategy that allows it to conduct a competitive solicitation [redacted] and that the results of that solicitation, if favorable, be used in the negotiation. EVA further recommends that any future justification memorandum contain the results of the solicitation combined with a fulsome disclosure and analysis of comparable indexes. Finally, as necessary, AEPSC should reach out to third parties to assist it in the development and implementation of a repricing strategy to improve the quality of the results as third parties may be more aware of re-opener

negotiation strategies and relevant non-AEP transactions. If the FAC continues, EVA recommends that the strategy be provided to the next management/performance auditor for review.

2. EVA recommends that if the FAC does not continue that the next management/ performance audit determine if there should be any credit to the under-recovery due to [redacted].

3. EVA recommends that the fuel procurement manual be revised to contain more specificity. Based upon AEPSC's 2011 performance, EVA specifically recommends that AEPSC develop policies with respect to the following:

    a. Procedures for addressing the [redacted],

    b. The basic items that should be included in all [redacted] including firm indications of market price, market indexes that are representative of the products being purchased, and full disclosure to management as to the value of the transaction relative to market.

    c. The quality that should be used to evaluate coal bids from the [redacted].

    d. The exceptions when AEPSC is not required to solicit bids for procurements.

    If the FAC continues, EVA recommends that the revisions be done in time for review by the next management/performance auditor.

4. EVA recommends that any payments made to [redacted] through the remaining term of the FAC not be recoverable through the FAC.

5. EVA recommends that any proceeds received from the [redacted] be applied to the FAC under-recovery.

6. EVA recommends that AEPSC be directed to develop a strategy for addressing the [redacted] and that the strategy should consider a full range of options. If the situation has not been resolved in 2012 and the FAC continues, EVA recommends that the strategy be available for review by the next management/performance auditor.

Financial Audit Findings

1. On September 1, 2010, AEP Ohio filed an application for a Significant Excessive Earnings Test ("SEET"), which utilities are required to file annually at the PUCO in order to demonstrate whether significantly excessive earnings were made. In its Opinion and Order dated January 11, 2011, the PUCO determined that CSP generated [redacted] in significantly excessive earnings in 2009, which the Commission ordered be refunded to customers through bill credits and the elimination of any deferrals. Schedule 3, page 1, line 8 of CSP's March 1, 2011 quarterly FAC filing reflects a line item called "SEET Refund" which removes the entire CSP FAC under-recovered balance, which is shown at that time to be [redacted].

2. After zeroing-out its FAC under-recorded balance for the SEET Refund as described above, CSP had a fuel cost under-recovery of [redacted] as of June 30, 2011 (per AEP Ohio's September 1, 2011 quarterly FAC filing). Starting with the Company's December 1, 2011 quarterly FAC filing, CSP and OPCO were combined pursuant to the merger.
3. OPCO showed an FAC under-recovery of [redacted] for 2011 (per AEP Ohio's March 1, 2012 quarterly FAC filing), which is [redacted] higher than OPCO's under-recovery of [redacted] at December 31, 2010 (per AEP Ohio's March 1, 2011 quarterly FAC filing). However, the December 31, 2011 FAC under-recovery balance reflects CSP and OPCO combined balances.
4. Concerning fuel amounts being deferred that affected the review period, as of December 31, 2010, OPCO had a deferred credit balance of [redacted] recorded in Account 253 that was related to the remaining unrecognized fuel credit associated with the 2008 [redacted]. In addition, [redacted] of the related deferred credit was credited to OPCO's fuel inventory during 2010 as deliveries were made by the supplier. The remaining December 31, 2010 balance was credited to fuel inventory with the deliveries made in January 2011.
5. On January 23, 2012 the Commission issued an Opinion and Order in Case Nos. 09-872-EL-FAC and 09-873-EL-FAC, and on April 11, 2012 issued an Entry on Rehearing in those dockets which provided clarification of AEP Ohio's obligations as they affect crediting OPCO's FAC under-recovery for portions of the [redacted] not already credited to OPCO ratepayers as well as the value of the [redacted] coal reserve that AEP booked when the [redacted] was executed. AEP Ohio's crediting of those clarified amounts against OPCO's FAC under-recovery should be reviewed in the next audit.
6. Based on the Commission's Order dated January 12, 2012, for December 2011 business OPCO recorded an estimated provision for loss (accrual) of [redacted] in Account 182.3 (as a contra asset subaccount-1823260). This was disclosed in OPCO's SEC Form 10-K for 2011. Any adjustment to that provision resulting from the Commission's April 11, 2012 Order would be recorded by OPCO in 2012. As noted, in no. 5, above, AEP Ohio's crediting of those clarified amounts against OPCO's FAC under-recovery should be reviewed in the next audit.
7. REC expense for 2011 was [redacted] for CSP and [redacted] for OPCO and is recorded in Account 5570009. In addition, ending solar REC book inventory in the amounts of [redacted] and [redacted] for CSP and OPCO, respectively, were recorded in Account 1740036.
8. Similar to prior years, in 2011 AEP Ohio reflected renewables costs in its FAC under an assumption that the first dollars of FAC revenue are applied to recover such costs. Under this assumption the renewables costs, which are required to be bypassable, do not contribute to the FAC deferrals that, if existing at the end of the ESP period, would be recoverable in a non-bypassable charge.
9. The [redacted] AEP has assigned to its non-Ohio non-solar REC inventory [redacted]. The market information provided would appear to support a nominal value of [redacted] per REC in 2011,

if not more. Because AEP Ohio failed to assign any value to such REC inventory, its fuel costs for 2011 would be [redacted]. Based on the information provided in response to LA-2011-70 and LA-2011-72, the difference between assigning a [redacted] and a [redacted] value to the non-Ohio, non-solar REC inventory for 2011 is approximately [redacted] for CSP and [redacted] for OPCO.

10. In Commission Case Nos. 08-917 and 08-918, originally in the March 18, 2009 Opinion and Order at page 23, and subsequent on rehearing, the Commission authorized AEP Ohio to apply a gross-of-tax WACC based on debt and common equity financing to the under-recovered FAC balances. Larkin examined those orders and various filings from those proceedings which were provided to us by AEP Ohio and Staff and reported on this in the 2010 audit report. Those Commission Orders would appear to allow AEP Ohio to apply the gross-of-tax WACC to the under-recovered FAC balances without any recognition of, or offset for, the related non-investor supplied financing in the form of Accumulated Deferred Income Taxes (ADIT) that is recorded in Account 283, ADIT-Other, for the tax savings that are directly related to the under-recovered FAC balances. However, upon our review, it appears there is a mis-match between the authorization of a gross-of-tax WACC based on debt and equity capital, and the application of such a rate to deferred fuel under-recovery balances that were/are financed in part with non-investor supplied capital in the form of directly related credit-balance ADIT.

11. Similar to Larkin's findings in the 2010 audit report, in 2011 AEP Ohio applied the monthly debt and pre-tax equity cost rates to under-recovered fuel balances in Account 1823144 without any offset for related credit-balance ADIT it has recorded in Account 283, ADIT-Other. There would typically be credit-balance ADIT related to the fuel under-recoveries. Assuming that the Company's fuel costs are deducted currently for income tax purposes, the deferral of the under-recovery for regulatory accounting would create a temporary difference and a credit-balance ADIT would be recorded. The related tax deduction would essentially provide cost-free financing for a portion of the fuel cost under-recovery. The ADIT is a source of non-investor supplied cost-free capital. Such ADIT is not being deducted from the under-recovered fuel balances in Account 1823144 in AEP Ohio's carrying cost calculations. If the ADIT balance related to the Company's FAC under-recovery balances is not considered, or deducted somewhere else, such as in rate base, ratepayers would be over-paying carrying costs by paying for carrying costs on the portion of the Deferred Fuel balance that has been financed by tax savings, i.e., on the portion not financed with investor-supplied capital.

12. AEP Ohio believes its carrying cost calculations to apply the gross-of-tax WACC to the under-recovered FAC balances in Account 1823144 (without any recognition of the fact that financing for a portion of the Deferred Fuel balances has been provided by income tax savings reflected in the related credit-balance ADIT, Account 283) have been fully consistent with the Company's presentation and the authorization received from the Commission in Case Nos. 08-917 and 08-918, originally in the March 18, 2009 Opinion and Order at page 23, and subsequent on rehearing.

13. Larkin reviewed AEP Ohio's calculations of the carrying charges on the Deferred Fuel balance and found them to be consistent with AEP Ohio's understanding of the authorization it received from the Commission in Case Nos. 08-917 and 08-918. Larkin

also selectively verified the postings of the calculated carrying charge amounts for debt and equity to the deferral account for CSP and OPCO. No exceptions were noted.

14. In 2011, on behalf of OPCO, [redacted].

15. AEP Ohio included CSP's share of gains and losses on coal sales and transfers related to [redacted] in the FAC based [redacted]. It is unclear what these transfers are for.

16. CSP's costs reflect an amount associated with the trucking of coal from [redacted], based on CSP's ownership share of Stuart. Concerns about such trucking costs were identified in the 2011 DP&L audit report.

17. A solicitation for the CCPP was sent out by AEP Ohio to potential bidders in 2012 in an attempt to identify the level of interest in the CCPP facility.

18. The CCPP depreciation/amortization did not include a salvage value for the CCPP.

Financial Audit Recommendations

1. AEP should identify and separate the renewable energy credits (RECs) value from the energy and capacity value of its renewable energy purchases.

2. AEP should show in detail how REC costs incurred by CSP and OPCO in 2011 have been separately identified and excluded from the 12/31/2011 FAC deferral for each company, CSP and OPCO.

3. AEP should be assigning appropriate values to its Renewables inventory, including its non-Ohio, non-solar REC inventory.

4. AEP should be required to analyze the receipt of revenue and the payment of cash expenses for RTD captive operations, similar to a lead-lag study, and to present such information to support its assumption that RTD has a significant Cash Working Capital requirement. If adequate supporting information is not provided to substantiate that RTD has a significant Cash Working Capital requirement and the amount of that requirement using lead-lag study analysis of cash receipts and cash payments, the RTD Working Capital component of the RTD investment base should be removed from the cost charged by RTD to OPCO from January 1, 2011 forward.

5. AEP Ohio and the other parties to the case should re-examine whether the Commission-authorized gross-of-tax WACC for debt and common equity capital should be applied to what such investors are actually financing of the fuel cost under-recovery balances, which would appear to be the Deferred Fuel amounts recorded in Account 1823144 less the directly related credit-balance ADIT-Other for Deferred Fuel recorded in Account 283.

6. The Company should address the income tax savings it was/is recording related to the under-recovered FAC balances, and how those provide non-investor supplied capital that is financing a portion of the Deferred Fuel balances that have been recorded in Account 1823144. The Company should specifically address the related credit-balance ADIT that

is recorded in Account 283, ADIT-Other, for the tax savings-based financing that appears to be directly related to the under-recovered FAC balances.

7. On January 23, 2012 the Commission issued an Opinion and Order in Case Nos. 09-872-EL-FAC and 09-873-EL-FAC, and on April 11, 2012 issued an Entry on Rehearing in those dockets which provided clarification of AEP Ohio's obligations as they affect crediting OPCO's FAC under-recovery. AEP Ohio's crediting of those clarified amounts against OPCO's FAC under-recovery should be reviewed in the next audit.
8. AEP Ohio should be required to explain fully the derivation of, and the purpose for, the [redacted] including what those costs are for and why these items are reasonable costs to be included in the FAC.
9. AEP Ohio may want to question the costs billed to CSP [redacted] for the reasons explained in the [redacted].
10. Larkin recommends that the [redacted] difference between the December estimate and actual for Account [redacted] as it relates to Lawrenceburg be removed from the 2011 FAC.
11. Larkin recommends that AEP Ohio determine and assign a salvage value to the CCPP for the purposes of the depreciation calculations.
12. Larkin recommends that should AEP Ohio sell the CCPP, the proceeds from the sale should be credited against the December 31, 2011 under-recovered FAC balance.

2009 Audit Recommendations

A number of recommendations were made in the first audit cycle. There was agreement on most of the issues. A hearing was held in August 2010, the primary focus of which was the disputed matters. On January 23, 2012, the Commission issued an Opinion and Order (the FAC order) was entered which concluded the following:

- The Commission will adopt the management/performance auditor's recommendations 2 through 6
- All of the realized value from the [redacted] should be credited against OPCO's FAC under-recovery, namely the portion of the [redacted] lump sum payment not already credited to OPCO ratepayers as well as the [redacted] value of the [redacted] coal reserve that AEP booked when the [redacted] was executed.
- AEP should engage an auditor to examine the value of the [redacted] coal reserve and to make a recommendation to the Commission as to whether the [redacted] value, if any above the [redacted] already required to be credited against OPCO's under-recovery, should accrue to OPCO ratepayers beyond the value of the reserve that AEPSC booked under the [redacted].
- The Commission will adopt financial audit recommendations 1 through 6 with the exclusion of 6b to which the Company had already complied.

- The Commission adopted a stipulation to which the parties[3] to the proceeding had agreed which acknowledged that a determination on the collection of deferrals and carrying charges associated with an Ormet Interim Agreement is the subject of a pending case before the Commission and that the issues associated with the Ormet Interim Agreement would be addressed in that proceeding.

On February 22, 2012, applications for rehearing were filed by AEP Ohio, the Industrial Energy Users-Ohio, and the Ohio Consumers' Counsel. By entry on rehearing issued March 21, 2012, the Commission granted the applications for rehearing of the FAC order. On April 11, 2012, the Commission issued its Entry on Rehearing which stated the following:

- In its first assignment of error, AEP-Ohio requests that the Commission clarify that the FAC order does not include the return of any amounts allocable to wholesale and non-Ohio retail jurisdictions. The Commission found that the 2009 FAC under-recovery need only be credited for the share of the settlement agreement allocable to Ohio's retail jurisdictional customers.

- In its second assignment of error, AEP-Ohio requests that a sale of the reserve be ordered for valuing the property. AEP-Ohio also requested that the Commission acknowledge that an appraisal may produce a result that is more <u>or</u> less than the $41.6 million of net book value. IEU-Ohio reasons that an appraisal is the most expedient measure to determine value. The Commission rejected the Company's request that it be ordered to sell the property but clarified that an appraisal could be more or less than the $41.6 million net book value.

- In the third assignment of error, AEP-Ohio reasons that the FAC order's direction that ll of the realized value from the settlement agreement should be credited against OP's FAC under-recovery amounts to (be) selective and unlawful retroactive ratemaking. The Commission found that OP's third assignment of error should be denied.

- In its fourth assignment of error, AEP Ohio contends that the FAC order unreasonably and unlawfully modifies the ESP1 order wherein the Commission directed that annual FAC audits examine fuel procurement practices and expenses for the audit period. The Commission rejected this argument because the scope and extent of the audit were not revised or expanded as a result of the FAC order.

- In its fifth assignment of error, AEP-Ohio claims that through the FAC order, the Commission is unreasonably and unlawfully retroactively modifying the decision in the ESP1 order, which established the FAC baselines to facilitate the Companies' transition from a period without a FAC mechanism to a period with a FAC mechanism. The Commission rejected this argument because the scope and extent of the audit were not revised or expanded as a result of the FAC order.

- In its sixth assignment of error, AEP-Ohio reasons that since the auditor and the Commission did not find the settlement agreement to be imprudent, the FAC order unreasonably and unlawfully impairs the settlement agreement, which was executed by AEP-Ohio at a time when fuel costs and fuel contracts were not regulated. The

[3] AEP Ohio, Staff, OCC, IEU-Ohio, and Ormet

Commission rejected this argument because a finding of imprudence is not a condition precedent to reflecting the realized value of the Companies' fuel costs in the FAC.

- In its seventh assignment of error, AEP-Ohio argues that the FAC order selectively considers the settlement agreement, to direct a decrease in the fuel costs for 2009, but ignores the 2009 production bonus agreement also entered into when fuel contracts were not regulated. The Commission found that offsetting adjustments to the deferred fuel costs do not need to be made for the settlement agreement and therefore rejected this argument.
- In AEP-Ohio's eighth assignment of error, AEP-Ohio notes that the West Virginia coal reserve is an OP asset properly accounted for as part of the settlement agreement making the valuation of the coal reserves as directed in the FAC order unlawful. The Commission found that the FAC order did not have an accord an ownership position to AEP-Ohio ratepayers and rejected this argument.
- In its ninth assignment of error, AEP-Ohio argues that the Commission's conclusion that the delivery shortfall agreement and the contract support agreement may be examined in a future audit is unreasonable and unlawful. The Commission rejects this argument
- In its tenth assignment of error, AEPSC argues that it should not be required to add fuel procurement procedures to the update of its policies and procedures manual. In the Opinion and Order, the Commission adopted recommendation #5 which recommended that AEPSC update its policies and procedures manual. The Commission clarified its positions to state that it had issued no specific requirement for the Company to include a formal procedural section. The Commission noted that the auditor should review the updated manual and is free to recommend further revisions. With these clarifications, the Commission rejected this argument.
- In its first assignment of error, IEU-Ohio asserts that the FAC order unreasonably and unlawfully failed to require AEP-Ohio to include a carrying cost component in the value associated with the lump sum payment and West Virginia coal reserve to be credited against the FAC deferral balance. In its second assignment of error, OCC makes a comparable argument. The Commission found that both of these assignments of error should be granted.
- In its second assignment of error, IEU-Ohio asserts that the Commission unlawfully and unreasonably failed to direct AEP-Ohio to recalculate its phase-in recovery rider rates to reflect the immediate reduction of the FAC deferral balance that is collected through the rider. OCC makes a similar argument in its first assignment of error. The Commission stated that had been its intent and made explicit that AEP-Ohio should immediately implement the credit to reduce the FAC deferral balance in accordance with the FAC order. With this clarification, the Commission denied IEU-Ohio's second and OCC's first assignment of error.
- In its third assignment of error, IEU-Ohio argues that the FAC order is unreasonable and unlawful because it did not direct Staff to hire and supervise an independent audit and set a timeframe for the valuation of the West Virginia coal reserve. The Commission finds that the FAC order is sufficiently clear that the RFP would be issued by subsequent

Commission entry for the purposes of selecting a qualified appraiser and denied the assignment of error.

- In its fourth assignment of error, IEU-Ohio contends that the Commission unreasonably and unlawfully failed to direct AEP-Ohio to credit the benefits received under the contract support agreement against the FAC under-recovery. OCC in its fourth assignment of error asserts that the Commission erred in failing to credit customers for the increased price of coal that AEP-Ohio agreed to pay during 2009 pursuant to the contract support agreement and in failing to account for carrying charges. The Commission finds no new arguments have been raised with respect to this issue and that any benefits from the exercise of the option in 2013 will not be experienced until a future time. The Commission rejects this argument on both grounds but states that the contract support agreement and the delivery shortfall agreement may be examined in a future audit of AEP-Ohio's fuel costs.

On May 11, 2012, the Industrial Energy Users-Ohio submitted an Application for Rehearing of the Entry because the "Commission limited the credit for the Settlement Agreement to the Ohio Retail Jurisdiction." As a result of this filing and the potential for judicial appeal, AEPSC has advised the auditors that compliance review of the Opinion and Order is not ripe. The auditors have chosen to include their evaluation of compliance with the Opinion and Order as modified by the Entry on Rehearing simply to assist future auditors on this matter when the time is ripe.

Compliance with Opinion and Order

Management/Performance Audit

1. In recommendation 2, EVA noted that 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. EVA notes that AEPSC did not develop a formal strategy to address this recommendation. With respect to its actions, AEPSC's performance has been mixed. AEPSC entered into a [redacted] contract with one supplier that did not provide for ratable deliveries, rather establishing a total quantity for the period. This is the type of arrangement that provides flexibility for volatile burns. AEPSC also [redacted] a contract for [redacted] volumes with another supplier, likely creating an [redacted]. As was recommended in last year's audit, EVA believes AEPSC should develop a strategy to address this issue.
2. In recommendation 3, EVA recommended that the next management/performance auditor review the [redacted] scrubber situation and determine what if any FAC costs are due to this situation. Due to the timing of the Opinion and Order this has not been done. Therefore, this review should be conducted by the next management/performance auditor if the Opinion and Order is upheld.
3. In recommendation 4, EVA recommended that AEPSC should undertake a study to determine whether there is an economic justification for continuing to operate the Conesville Coal Preparation Plant and that the study should be completed in time for it to be reviewed in the next management/ performance audit. As discussed in the 2010 management/audit, AEPSC did conduct the study and eventually provided it to EVA for

review. The study concluded that the plant should be closed and AEPSC did so in the beginning of 2012.

4. In recommendation 5, EVA recommended that 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. AEPSC did complete its update of its policies and procedures manual and provided it for review in last year's management/performance audit. EVA found the revised manual to be very general and to provide little of the guidance typically provided by such manuals. In the 2011 audit report, EVA recommended that AEPSC expand its policies and procedures in its revised policy manual so that it provides true guidance and a yardstick against which to measure performance. AEPSC continues to maintain that such updates were "neither necessary nor beneficial. The Company believes that its current approach, as guided by policies, results in the efficient procurement of fuel at the lowest reasonable cost."[4] As noted throughout this report, EVA has not found AEPSC's practices to yield the lowest reasonable costs.
5. In recommendation 6, EVA recommended that prior to entering into long-term agreements for renewables with fixed pricing, AEP Ohio should fully evaluate self-build and biomass co-firing alternatives and should explore contract options that would provide some protection in the event that the contract pricing for power and/or RECs diverge with market prices for same. In 2011, the Company did not enter into any new long-term agreements for renewables with fixed pricing. The Company did not commit to evaluating self-build options as an alternative to long-term agreements.

Financial Audit

The Commission adopted Larkin's recommendations 1-5 in their entirety and 6 in part.

1. Recommendations 1 and 3 involved making improvements to AEP Ohio's monthly FAC workbooks and the related Excel files, particularly in the details and audit trail for the monthly purchased power reconciliations. AEP implemented that recommendation and its monthly FAC workbooks reflect monthly purchased power reconciliations and improve the clarity of the audit trail.
2. Recommendation 2 was that AEP Ohio include a reconciliation of fuel and purchased power accounts that have been designated as includable FAC costs in its monthly FAC workbooks. AEP Ohio implemented this recommendation and has included appropriate color-coding to facilitate a clear audit trail.
3. Recommendation 4 was that, unless it had already been presented in another forum, AEP Ohio should explain how the PJM designated "must-run" generating unit designations are affecting the costs that are recoverable in the FAC. AEP Ohio explained that the fuel costs related to the "must-run" units are included in FAC recoverable fuel costs, as are other fuel costs. AEP Ohio records the revenue it receives from PJM in another account, and credits that to costs that are included in AEP Ohio's transmission cost recovery mechanism.

[4] Company response to EVA-2011-1-56.

4. In the 2009 audit, the Company stated 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 purpose or in existing reports. Recommendation 5 from 2009 was that AEP Ohio should update and/or modify its systems to better track and be able to provide AEP East Fleet system stack information. Larkin is unsure to what extent AEP Ohio complied with this recommendation.
5. The 2009 audit recommendation 6 contained 10 sub-recommendations, numbered 6a through 6j, involving the AEP River Transportation Division (RTD), an affiliated operation which provides barge transportation to OPCo for coal and urea. The Commission's January 23, 2012 order in 09-872-EL-FAC, et al adopted all of those recommendations with the exception of 6b, for which it stated that no further action was required. AEP Ohio has complied with 2009 audit recommendations 6a and 6c through 6j involving the RTD.

2010 Audit Recommendations

A number of recommendations were made in the second audit cycle. A hearing was has not yet be held nor have the parties entered into a Stipulation regarding these recommendations.

Audit Outline

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

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

2 AEP OHIO BACKGROUND

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 Company in which Ohio Power owns Unit 1. AEP's adoption of centralized fuel procurement was designed to minimize system-wide fuel procurement costs.

Effective January 1, 2012, the merger between CSP and OPCO was completed. As the audit period covers 2011, the audit continues to refer to CSP and OPCO the individual companies and AEP Ohio combined. The plants operated by CSP and OPCO are listed in Exhibit 2-1. With the exception of Conesville 4, these plants are owned in their entirety by their respective companies. Conesville 4 is one of four CCD[5] 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 Unit 6 (operated by Duke Energy Ohio), and Stuart Plant (operated by Dayton Power & Light).

CSP recovers through the FAC its allowed costs associated 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 10-year agreement for the entire output of Lawrenceburg and pays for capacity, depreciation, fuel, and other operating costs. AEPSC buys the fuel for Lawrenceburg.

Exhibit 2-1
Columbus Southern Power And Ohio Power Plants

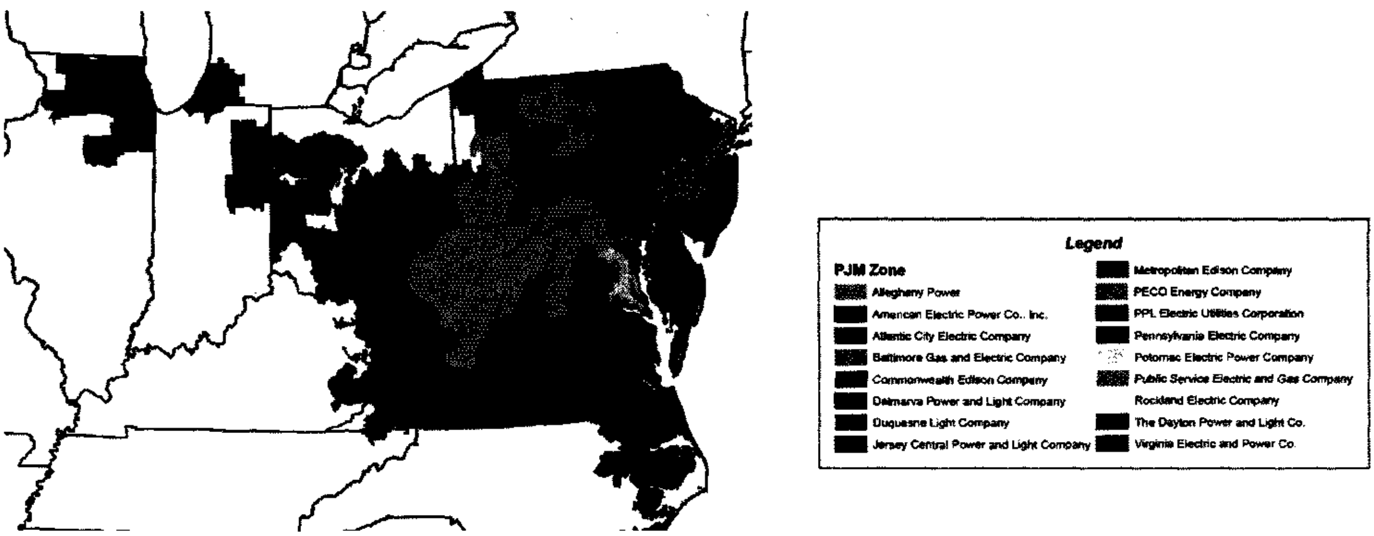
Utility	Power Plant Name	Units	Operator	Owned Capacity (MW)	Ownership (%)	Prime Mover	Fuel Type
CSP	Conesville	3, 5, 6	Columbus Southern Power	915.0	100.00	Steam Turbine	Bituminous Coal
	Conesville	4	Columbus Southern Power	339.3	43.50	Steam Turbine	Bituminous Coal
	Darby	1-6	Columbus Southern Power	507.0	100.00	Gas Turbine	Natural Gas
	Picway	5	Columbus Southern Power	100.0	100.00	Steam Turbine	Bituminous Coal
	W.H. Zimmer	ST1	Duke Energy Ohio Inc.	330.5	25.40	Steam Turbine	Bituminous Coal
	Walter C Beckjord	6	Duke Energy Ohio Inc.	52.6	12.50	Steam Turbine	Bituminous Coal
	Waterford Energy Facility		Columbus Southern Power	850.0	100.00	Combined Cycle	Natural Gas
	J.M. Stuart	1-4	Dayton Power and Light Co.	600.0	26.00	Steam Turbine	Bituminous Coal
	J.M. Stuart IC	1-4	Dayton Power and Light Co.	2.3	26.00	Internal Combustion	Distillate Fuel Oil
OPCO	Cardinal	1	Cardinal Operating Co.	580.0	100.00	Steam Turbine	Bituminous Coal
	Gen J M Gavin	1 & 2	Ohio Power Co.	2,640.0	100.00	Steam Turbine	Bituminous Coal
	John E. Amos	3	Appalachian Power Co.	867.1	66.70	Steam Turbine	Bituminous Coal
	Kammer	1-3	Ohio Power Co.	630.0	100.00	Steam Turbine	Bituminous Coal
	Mitchell (WV)	1-2	Ohio Power Co.	1,560.0	100.00	Steam Turbine	Bituminous Coal
	Muskingum River	1-5	Ohio Power Co.	1,425.0	100.00	Steam Turbine	Bituminous Coal
	Philip Sporn	2, 4 & 5	Appalachian Power Co.	1,000.0	100.00	Steam Turbine	Bituminous Coal
	Racine	1-2	Ohio Power Co.	26.0	100.00	Hydraulic Turbine	Water
TOTAL				12,424.8			

[5] CCD refers to Cincinnati Gas & Electric, Columbus Southern Power, and Dayton Power & Light.

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

AEP belongs to the regional transmission organization PJM Interconnection (PJM) which is part of the Eastern Interconnection grid operating an electric transmission system serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Among the primary purposes of PJM are to dispatch electric generating plants on a lowest cost basis, thereby reducing the electric costs for all members of the pool, to coordinate regional planning to ensure reliability to the region in which it operates, and to operate markets for capacity, energy, demand response products and ancillary services. Exhibit 2-2 provides a map of PJM.

Exhibit 2-2
PJM Interconnection Zones



AEP Ohio's share of generation by owned-plant in 2011 is summarized in Exhibit 2-3. Over 95 percent of AEP Ohio's electricity generation is from coal, over 70 percent of which is operated by AEP Ohio.

During 2011, no changes were made to the operating status of the 10 units AEP had put into "extended startup" status for nine non-peak months of the year.[6] This list included several AEP Ohio units including Picway 5, Muskingum 4, and Sporn 4 & 5. Sporn 5 was permanently closed in early 2012. In 2011, Kammer continued to operate in a "substitute operation" mode, in which only two units are operated at one time.

[6]The peak months are January, July, and August; Sporn 5 operated in the extended start-up mode for the entire year.

Exhibit 2-3
Generation by Plant, 2011 (MWH)

Utility	Power Plant Name	Units	Operator	Generation (MWH)	Percent of Total
CSP	Conesville	3, 5, 6	Columbus Southern Power	4,442,353	7.9%
	Conesville	4	Columbus Southern Power	1,053,487	1.9%
	Darby	1-6	Columbus Southern Power	35,249	0.1%
	Picway	5	Columbus Southern Power	69,373	0.1%
	W.H. Zimmer	ST1	Duke Energy Ohio Inc.	1,786,574	3.2%
	Walter C Beckjord	6	Duke Energy Ohio Inc.	274,273	0.5%
	Waterford Energy Facility		Columbus Southern Power	2,431,293	4.3%
	J.M. Stuart	1-4	Dayton Power and Light Co.	3,643,435	6.4%
OPCO	Cardinal	1	Cardinal Operating Co.	3,359,374	5.9%
	Gen J M Gavin	1 & 2	Ohio Power Co.	18,184,347	32.2%
	John E. Amos	3	Appalachian Power Co.	3,956,994	7.0%
	Kammer	1-3	Ohio Power Co.	1,778,385	3.1%
	Mitchell (WV)	1-2	Ohio Power Co.	9,124,435	16.1%
	Muskingum River	1-5	Ohio Power Co.	5,831,062	10.3%
	Philip Sporn	2, 4 & 5	Appalachian Power Co.	416,901	0.7%
	Racine	1-2	Ohio Power Co.	120,670	0.2%
TOTAL				56,508,205	100.0%
			CSP-Operated	5,600,462	9.9%
			OPCO-Operated	35,038,899	62.0%
			Coal	53,920,993	95.4%

Source: Form 1

On March 22, 2012 AEP officially notified PJM of the company's plan to retire more than 4,000 MW of coal capacity in the PJM system. AEP was required to file its plan for plant retirements prior to PJM's auction in May 2012 that will set electric generation capacity prices for June 2015 through May 2016. This plan differs slightly from anticipated retirements AEP announced in June 2011. The differences are due to the retirement of the 450-MW Sporn Unit 5 in February 2012 (which was included in the June 2011 plan). In its notifications to PJM, AEP indicated it plans to retire the following units:

- Conesville Plant Unit 3, Conesville, Ohio – 165 MW;
- Big Sandy Plant Unit 1, Louisa, Ky. – 278 MW;
- Clinch River Plant Unit 3, Cleveland, Va. – 235 MW;
- Glen Lyn Plant (two units), Glen Lyn, W.Va. – 335 MW;
- Kammer Plant (three units), Moundsville, W.Va. – 630 MW;
- Kanawha River Plant (two units), Glasgow, W.Va. – 400 MW;
- Muskingum River Plant Units 1, 2, 3 and 4, Beverly, Ohio – 840 MW;
- Picway Plant (one unit), Lockbourne, Ohio – 100 MW;
- Philip Sporn Plant (four units), New Haven, W.Va. – 600 MW, and
- Tanners Creek Plant Units 1, 2 and 3, Lawrenceburg, Ind. – 495 MW.

AEP indicated it plans to retire Conesville 3 by Dec. 31, 2012 and the other units by June 1, 2015. Duke Energy has announced its plans to retire Walter C. Beckjord Plant Unit 6, in which AEP Ohio is a minority owner. PJM must approve the retirements to insure system stability and performance.

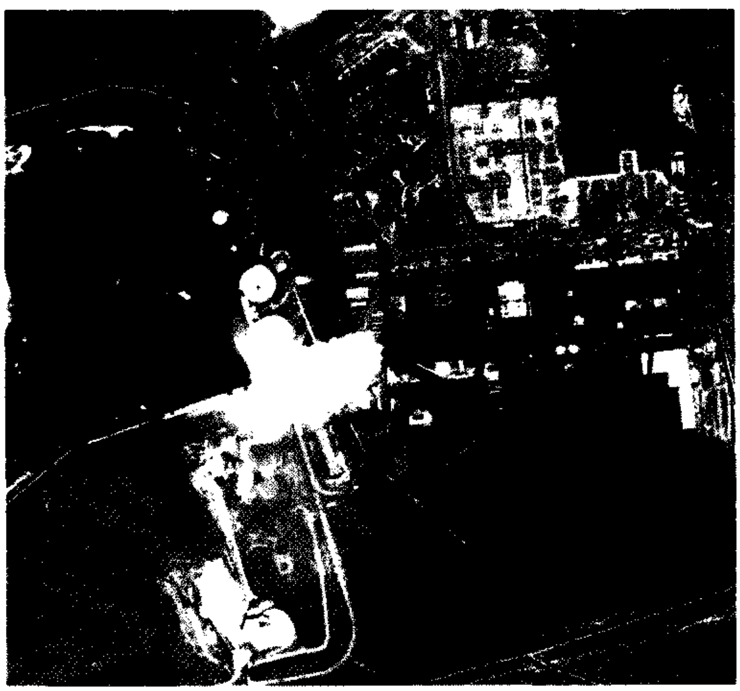
Coal Plants

This section provides background information on the six coal plants operated by AEP Ohio plus Cardinal, starting with the CSP plants.

Conesville (CSP)

The Conesville station consists of four units with a total generating capacity of 1,745 MW. Units 1 & 2 were retired in 2005. Conesville 3 has not been retrofitted with a scrubber and is now scheduled to be retired by the end of 2012. Conesville 4's retrofit was completed in 2009 but this was one of the retrofits that encountered unexpected operating results. Conesville 5 and 6 were built with scrubbers and these scrubbers were upgraded in 2009 to comply with the New Source Review settlement. As can be seen in Exhibit 2-5, Conesville 5 &6 share a stack. Coal to this station is delivered by truck and rail[7]. The Conesville Coal Preparation Plant was closed in January 2012 which eliminated deliveries by conveyor.

Exhibit 2-4
Aerial View of Conesville Plant



Recent plant operating statistics are provided in Exhibit 2-6. Generation in 2011 improved somewhat over 2009 and 2010 levels but the plant is still operating at a capacity factor below 50 percent. AEP Ohio indicated that the high delivered cost of coal to Conesville 3 and 4 has limited the plant's dispatch.

[7] Technically, the rail delivered coal has to be trucked a short distance to the power plant.

Exhibit 2-5
Conesville Operating Statistics[8]

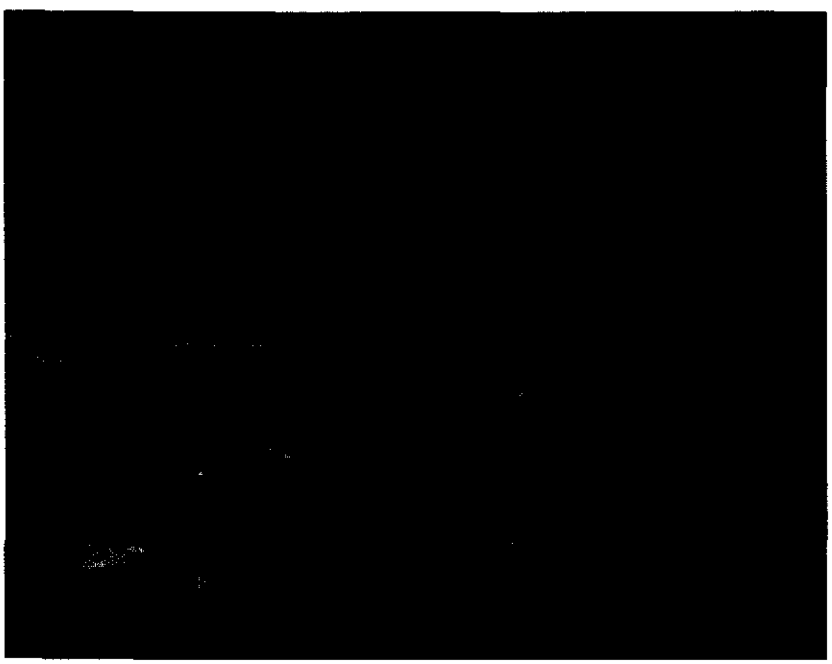
Plant	Units	Location	Ownership %	Total MW	Utility Share
Conesville	3-6	Conesville, OH	74.61	1745	1302

	2011	2010	2009	2008	2007
Generation (MWHh)	6,993,013	6,460,269	6,189,984	9,463,907	10,342,353
Consumption (tons, barrels)					
Coal	3,308,581	3,027,261	2,817,418	4,169,889	4,627,705
Oil	15,209	24,722	18,923	21,401	20,043
Capacity Factor	47.1	43.51	41.69	63.58	69.65
Heat Rate (Btu/kWh)	10,833	10,803	10,607	10,339	10,383

Picway (CSP)

Picway is AEP Ohio's smallest coal plant. (Exhibit 2-7) Coal is delivered to this station by rail or truck. This plant is not equipped with any advanced pollution control equipment. This plant is included in the list of plants that AEP intends to retire by June 1, 2015.

Exhibit 2-6
Aerial View of Picway Plant



Recent plant operating statistics are provided in Exhibit 2-8. Generation in 2011 was about the same as it was in 2010.

[8] Operating Statistics for Conesville and the other plants are derived from SNL Coal database. AEPSC notes that in some cases its data differ from the data reported herein.

Exhibit 2-7
Picway Operating Statistics

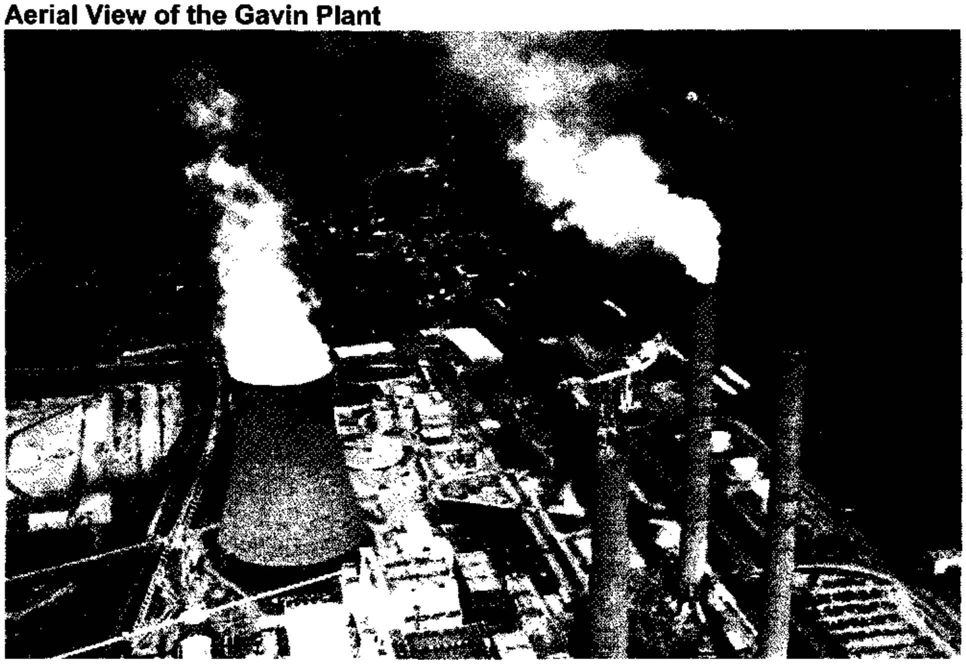
Plant	Units	Location	Ownership %	Total MW	Utility Share
Picway	5	Lockbourne, OH	100	100	100

	2011	2010	2009	2008	2007
Generation (MWHh)	69,373	65,072	124,791	329,338	342,991
Consumption (tons, barrels)					
Coal	49,912	36,965	61,270	172,584	184,197
Oil	402	1,382	2,490	5,671	4,990
Capacity Factor	7.92	7.43	14.25	37.49	39.15
Heat Rate (Btu/kWh)	16,150	13,163	11,410	12,127	12,450

Gavin (OPCO)

The Gavin station consists of two units with a total generating capacity of 2,640 MW. These units were retrofit with flue gas desulfurization units in the early 1990's as part of AEP's acid rain compliance plan. All coal to this station (Exhibit 2-9) is currently delivered by barge.

Exhibit 2-8
Aerial View of the Gavin Plant



Recent plant operating statistics are provided in Exhibit 2-10. Generation in 2011 was down about four percent over 2010 levels. This is OPCO's largest station, consistently burning more than seven million tons per year.

Exhibit 2-9
Gavin Operating Statistics

Plant	Units	Location	Ownership %	Total MW	Utility Share
Gavin	1-2	Cheshire, OH	100	2640	2640

	2011	2010	2009	2008	2007
Generation (MWHh)	18,184,347	18,885,659	19,160,246	21,102,131	18,985,853
Consumption (tons, barrels)					
Coal	7,386,506	8,125,893	7,984,101	8,503,170	7,384,095
Oil	45,582	48,111	31,047	40,380	55,505
Capacity Factor	78.63	81.68	82.85	91.08	81.98
Heat Rate (Btu/kWh)	9,750	9,889	9,721	9,761	9,571

Kammer (OPCO)

The Kammer station consists of three 210 MW coal-fired power plants. The Kammer boilers are cyclones and as such require a lower fusion coal, consistent with the high sulfur coal they were designed to burn. Compliance with clean air regulations has been a challenge for Kammer because low sulfur bituminous coals typically have a high ash fusion temperature. AEP planned to switch to a blend of 80/20 Powder River Basin/eastern bituminous coals but abandoned this plan for several reasons including concerns about selenium in the ash. An aerial view of the plant is provided in Exhibit 2-11.

Exhibit 2-10
Aerial View of Kammer Plant

The Kammer units have not been retrofitted with advanced pollution control equipment. All three units at Kammer are included in AEP's recent retirement announcement. Recent plant operating statistics are provided in Exhibit 2-12. Utilization of this plant has declined significantly in the last three years. Generation and coal burn were up slightly in 2011 but the plant's capacity factor is still very low.

Exhibit 2-11
Historical Operational Statistics for Kammer

Plant	Units	Location	Ownership %	Total MW	Utility Share
Kammer	1-3	Moundsville, WV	100	630	630

	2011	2010	2009	2008	2007
Generation (MWHh)	1,778,385	1,498,424	1,731,515	3,115,279	4,060,361
Consumption (tons, barrels)					
Coal	870,993	760,947	852,381	1,402,967	1,680,947
Oil	8,422	8,161	8,199	8,526	8,070
Capacity Factor	32.22	27.15	31.37	56.29	73.57
Heat Rate (Btu/kWh)	10,997	11,392	11,056	10,360	10,063

Mitchell (OPCO)

The Mitchell plant is located adjacent to Kammer in Moundsville. Mitchell consists of two units with a combined capacity of 1560MW. An aerial view is provided in Exhibit 2-13. This plant receives coal by belt, rail and barge. The plant was retrofitted with scrubbers and SCRs in 2007. [redacted]

Exhibit 2-12
Mitchell Plant

Recent plant operating statistics are provided in Exhibit 2-14. Generation and coal burn in 2011 were down by about 10 percent year on year.

Exhibit 2-13
Historical Operating Statistics at Mitchell

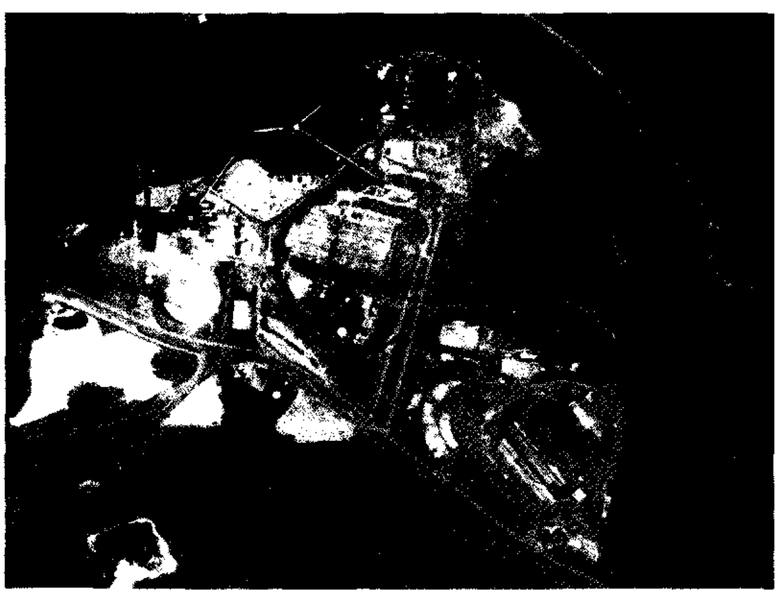
Plant	Units	Location	Ownership %	Total MW	Utility Share
Mitchell	1-2	Moundsville,	100	1560	1560

	2011	2010	2009	2008	2007
Generation (MWHh)	9,124,435	10,242,061	9,389,850	10,638,648	8,777,630
Consumption (tons, barrels)					
Coal	3,619,091	4,033,432	3,678,634	4,173,111	3,284,999
Oil	31,076	37,669	29,883	32,044	33,061
Capacity Factor	66.77	74.95	68.71	77.64	64.23
Heat Rate (Btu/kWh)	9,828	9,756	9,811	9,848	9,347

Muskingum River (OPCO)

The Muskingum River plant is located in Beverly, Ohio. Muskingum River consists of five units. The four smallest units are wet bottom boilers which require a lower fusion coal. Unit 5, the newest and largest boiler, is a dry bottom supercritical unit which can burn high fusion coals. An aerial view is provided in Exhibit 2-15. This plant receives coal by rail, as the Muskingum River is not navigable for barge deliveries. None of the units has been retrofit with scrubbers; Unit 5 has an SCR.

Exhibit 2-14
Muskingum River Plant



Muskingum River units 1-4 are on AEP's list of coal plant retirementswhich is not surprising given their size, age, and boiler design and uncontrolled operation. Muskingum River unit 5 is not on the latest retirement list but EVA was previously informed that a scrubber would most likely be needed for continued operations and engineering work on the Muskingum River 5 scrubber is not underway.

Recent plant operating statistics are provided in Exhibit 2-16. The plant's utilization fell in 2011.

Exhibit 2-15
Historical Operating Statistics at Muskingum River

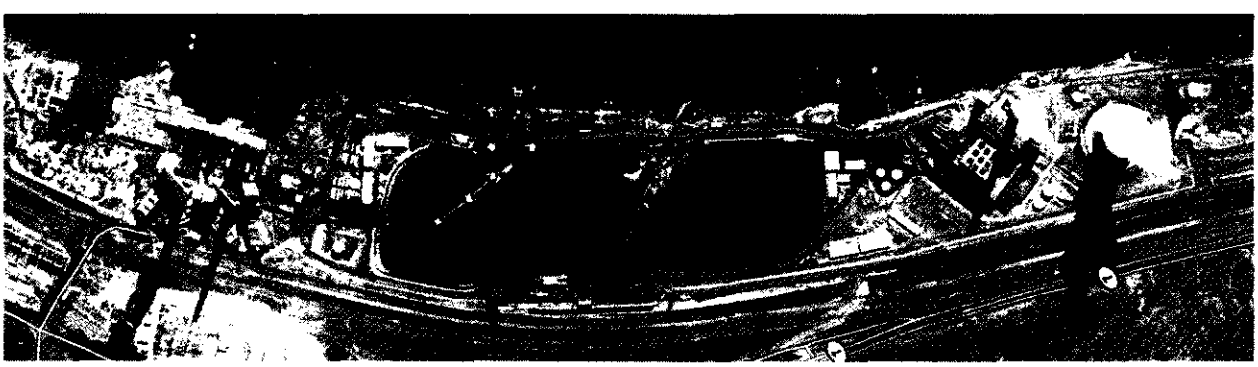
Plant	Units	Location	Ownership %	Total MW	Utility Share
Muskingum River	1-5	Beverly, OH	100	1440	1440

	2011	2010	2009	2008	2007
Generation (MWHh)	5,831,062	6,701,885	7,299,585	9,127,024	8,503,262
Consumption (tons, barrels)					
Coal	2,430,720	2,723,728	2,869,762	3,528,464	3,249,850
Oil	32,665	30,856	34,094	31,985	38,095
Capacity Factor	46.71	53.69	58.48	72.92	68.12
Heat Rate (Btu/kWh)	10,314	10,168	9,967	9,653	9,776

Cardinal (Cardinal Operating)

The Cardinal plant is located on the Ohio River, at mile marker 76.6. Cardinal consists of three units. Unit 1 is owned by Ohio Power: Units 2 and 3 are owned by Buckeye Power. Unit 1 was retrofit with a scrubber in 2008; Unit 2 was retrofit with a scrubber in 2007. The Cardinal 1 scrubber was one of the scrubbers that did not perform as designed. An aerial view is provided in Exhibit 2-17. AEPSC buys coal for the entire station. This plant receives coal by barge and rail.

Exhibit 2-16
Cardinal Plant



Recent plant operating statistics for Cardinal 1are provided in Exhibit 2-18. Cardinal 1 generation fell by almost 20 percent in 2011.

Exhibit 2-17
Historical Operating Statistics at Cardinal 1

Plant	Units	Location	Ownership %	Total MW	Utility Share
Cardinal	1	Brilliant, OH	100	595	595

	2011	2010	2009	2008	2007
Generation (MWHh)	2,693,195	3,240,567	3,474,755	3,346,423	3,450,655
Consumption (tons, barrels)					
Coal		1,344,156	1,442,748	1,361,428	1,440,158
Oil		18,620	21,403	28,838	16,538
Capacity Factor	53.01	63.79	68.39	65.69	67.92
Heat Rate (Btu/kWh)	9,629	9,912	9,900	9,782	10,021

3 FUEL PROCUREMENT AUDIT

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 mid1980s 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 3-1.[9] In 2011, AEP Ohio had a high level of contract purchases. Most spot purchases were for [redacted]. The costs provided below are missing the CCPP costs.

Exhibit 3-1
AEP Ohio Coal Purchases, 2011

[redacted]

EVA estimates that if the costs for CCPP are included, the average cost of AEP Ohio coal purchases in 2011 would increase from [redacted] per MMBtu to [redacted] per MMBtu.

CSP's and OPCO's delivered coal costs on a dollars per MMBtu basis (as reported to EIA) are compared to the other Ohio utilities for which data are publicly available in Exhibit 3-2. AEP Ohio's coal costs compare favorably with the coal purchase expenses of the other Ohio utilities[10]. OPCO had the second lowest delivered costs in 2011. CSP had the third.[11] This comparison is not dispositive with regard to performance as the utilities vary with respect to quality requirements and transportation.[12]

---

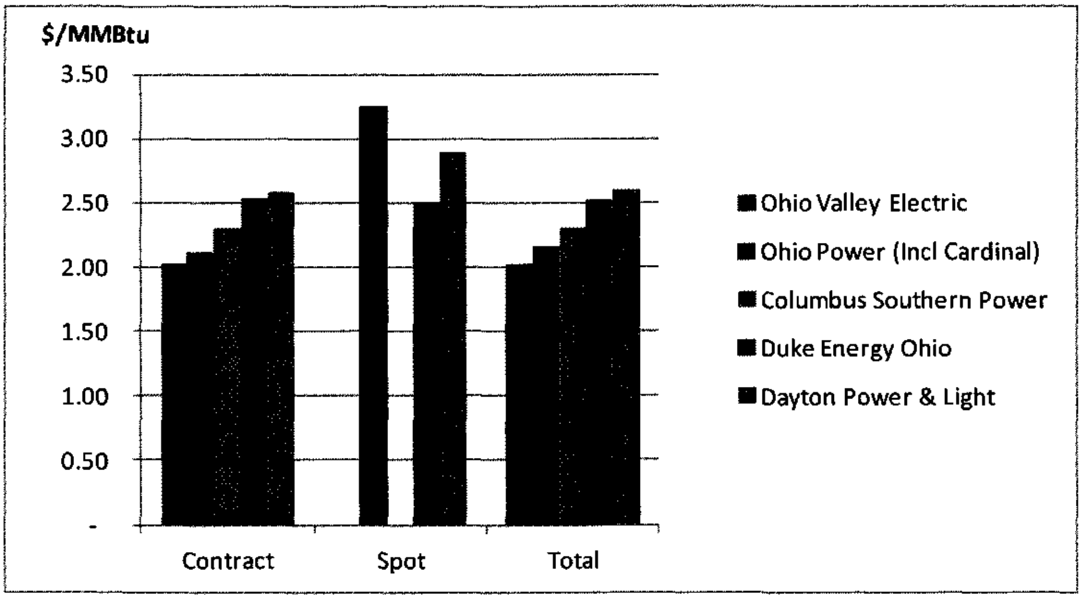
[9] This chart is developed from the data provided to EVA in 2011-1-4. As such it does not include the costs associated with the Conesville Coal Preparation Plant.

[10] 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. These data do not include the CCPP costs or any of the costs of the western coal.

[11] [redacted].

[12] The chart reflects purchase expense. Fuel expenses may be different because of credits or charges to the fuel accounts.

Exhibit 3-2
Ohio Utility Coal Purchase Costs, 2011



Source: Form 923.

Some additional detail about the purchases by the other Ohio utilities is provided on Exhibit 3-3. The average sulfur content of the coal purchased by OVEC is by far the highest for the other utilities which explains in part its performance.

Exhibit 3-3
Ohio Utility Coal Purchase Details, 2011

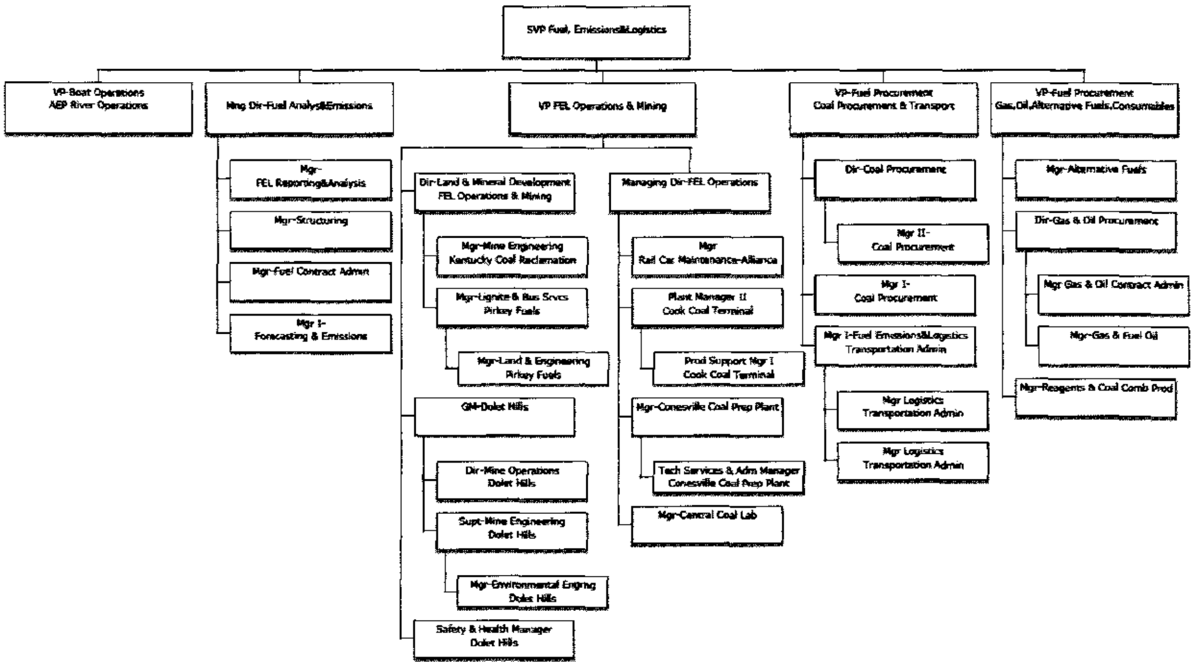
	Contract					Spot					Total					%
	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Contract
Columbus Southern Power	3,327,615	11,272	3.06	51.75	2.30	-	-	-	-	-	3,327,615	11,272	3.06	51.75	2.30	100%
DP&L	6,812,892	11,585	2.19	59.67	2.58	723,713	11,837	1.72	68.47	2.89	7,536,605	11,610	2.14	60.51	2.61	90%
Duke Energy Ohio	5,671,483	11,930	3.48	59.36	2.49	2,022,582	12,150	3.30	56.93	2.34	7,694,065	11,988	3.43	58.72	2.45	74%
Ohio Power	15,222,163	12,272	2.99	51.00	2.08	853,697	12,253	1.48	79.52	3.24	16,075,860	12,271	2.91	52.52	2.14	95%
OVEC	1,835,386	12,209	4.24	49.48	2.03	-	-	-	-	-	1,835,386	12,209	4.24	49.48	2.03	100%

Source: Form 923.

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 3-4, the Senior Vice President has five direct reports, several of which have some involvement in fuel procurement issues for AEP Ohio. The individual most responsible for AEP Ohio coal procurement is the Vice President Fuel Procurement. FEL personnel interact with other AEP personnel on a routine basis. There were no organizational changes during the review period.

Exhibit 3-4
Organization Chart For Fuel, Emissions And Logistics



Source: EVA-2010-1-47.

Policies And Procedures

AEPSC updated its Fuel, Emissions & Logistics Procurement Policy in February 2011. 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."

The organization of the manual (which has a total of 12 pages with text) is as follows:

1. The FEL Organization
   1.1. Roles and Responsibilities of the FEL Organization
   1.2. Organizational Structure of FEL
   1.3. Procurement Responsibilities
   1.4. General Administrative Duties
2. FEL Procurement Policy and Implementations
   2.1. Business Ethics and Corporate Compliances
   2.2. Procurement Considerations
   2.3. Proper Inventory Levels
3. Procurement Methods and Documentation
   3.1. Requests for Proposal
   3.2. Other Offer Evaluation
   3.3. Emergency Procurement
   3.4. Negotiating Responsibility
   3.5. Enforcement of Agreements
4. Hedging Policy

4.1. Hedging Definition
4.2. Hedging Strategy
5. Contract Administration
5.1. Overviews and Responsibilities

As noted in last year's audit that the revised manual is very general and provides little of the guidance typically provided by such manuals. EVA recommended that the manual be supplemented with greater detail; AEPSC declines to do so.

Inventory Management

The Procurement Policy states that the "primary objective of FEL shall be to ensure the availability of an adequate reliable supply of fuel and reagents for the generation of electricity." Specific "solid fuel inventory target levels shall be recommended by the Fuel Supply Task Group and subject to the approval of senior management." With respect to the actions that should be taken if the actual inventory levels diverge from targets, the Policy states simply "an appropriate course of action shall be implemented."

In 2010, AEPSC provided inventory targets which are summarized in Exhibit 3-5. The target inventories range between [redacted] and [redacted] days of burn on a full load basis. The target winter inventories are generally (but not always) [redacted] days higher. EVA was informed that the inventory targets have not changed.

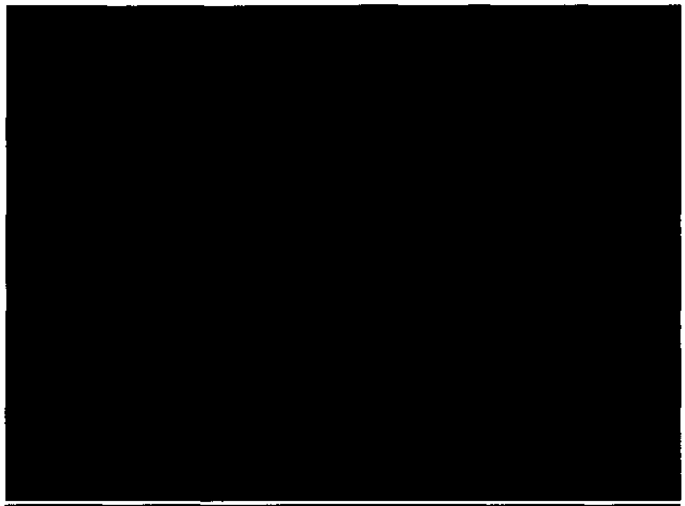
Exhibit 3-5
Inventory Targets

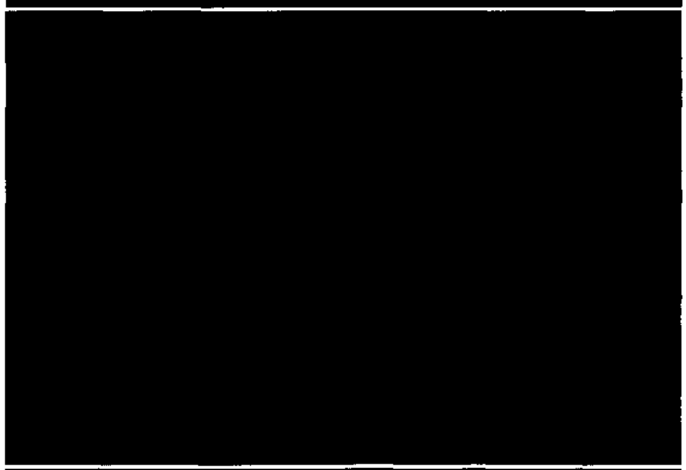
			Target Inventory		Winter Inventory	
Plant	Unit(s)	Tons/Day Full Load	Days	Tons	Days	Tons
[redacted]						

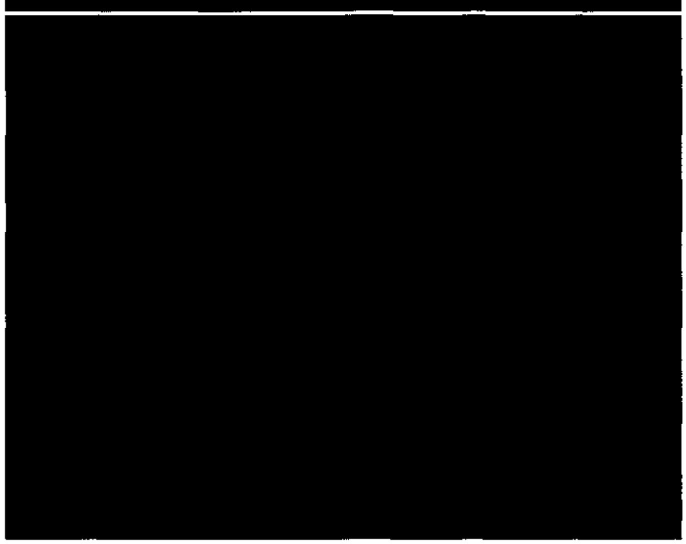
In 2011, stocks at the AEP Ohio plants declined at most plants. By year end, all plants were at or close to their target levels as shown on Exhibit 3-6.

Exhibit 3-6
Inventory Levels At AEP Ohio Plants (Tons)

[redacted]







[redacted]

In Exhibit 3-7, CSP and OPCO inventory levels are compared, respectively, to actual and normal industry levels based upon EVA's proprietary stockpile report.[13] The CSP inventories are compared to just [redacted] inventories as all the coal purchased for CSP is from [redacted]. The OPCO inventories are compared to eastern utility inventories which consist of multiple coal types. Both CSP and OPCO reduced their inventory levels in 2011. By the end of the year, both utilities were at normal levels.

Exhibit 3-7
CSP And OPCO Inventory Days Versus Industry

[redacted]

[13] 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.

[redacted]

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.[14]

The information provided on the physical inventory survey adjustments at AEP Ohio-operated plants are summarized in Exhibit 3-8. Overall, the adjustments were relatively small as a function of both total inventory and burn.

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 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.

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

Exhibit 3-8
Physical Inventory Survey Adjustments

[redacted]

Coal Procurement

According to AEP's 2011 10-K filing, about 63 million tons of coal and lignite were delivered to the AEP System plants in 2011. 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.

Coal Procurement Strategy

AEPSC's strategy is to layer in coal commitments to minimize market exposure at any one time. While not stated in its procurement policy, [redacted]. This has caused problems in recent years due to the volatility of burn levels. Going forward, AEPSC needs to consider a more flexible approach to procurement so as to avoid being over committed.

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. 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 [redacted] coal solicitations in 2011. The solicitations were in [redacted] The results of the solicitations are summarized in Exhibit 3-9. As shown, AEPSC entered into a number of agreements based upon the forecast of its open position.

Exhibit 3-9
2011 Coal RFP Results

[redacted]

Regardless of the manner in which coal is procured, a written justification is prepared for every transaction. 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. The new contract memos are well written, comprehensive documents that provide good contemporaneous support for the procurement even though most are dated subsequent to the actual transaction.

EVA reviewed the justifications for the [redacted] agreements and is in general agreement with all of the justifications except for the [redacted] purchase. As noted below, [redacted] has been a chronic under-performer with respect the [redacted] in its agreement. It is common industry practice to evaluate the bids based upon bid quality unless performance demonstrates consistent non-compliance with the guarantee. In the case of [redacted], the bid should have been evaluated at [redacted] which is the average Btu of [redacted] shipments in 2011 through September.

A comparison of the bid from [redacted] using both the bid and experienced Btu is compared with the bid from [redacted] in Exhibit 3-10. While [redacted] would still have been lower in cost when this adjustment is made, most of the difference between the [redacted] bids would have been eliminated.

Exhibit 3-10

[redacted]

A second issue with the [redacted] procurement is the tonnage amount. According to the justification, AEPSC was purchasing this coal for [redacted] to assist in the Company's compliance with CSAPR. Certainly the timing of CSAPR was challenging but by the time the Company made this procurement (which should be noted was for a scrubbed station), there was already considerably industry activity challenging the timing of the new rule among other things. With this procurement, according to the justification, AEPSC would have in excess of [redacted] of its requirements[15]. Given the recently experienced volatility in burn combined with at least some uncertainty as to whether the rule would go into effect or not, it seems that a purchase of something less than [redacted] would have been more prudent

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] system.

For the 2009 audit period, AEP ran both systems in tandem and was able to produce information requested by the auditors from the [redacted] system. For 2010, only [redacted] was available and reports needed for the management/performance audit could not be produced. The situation in 2011 was significantly improved although it is not clear whether the regulatory support for this audit should be credited or an improvement to the report-writing capabilities. Regardless, the improved reporting was enormously helpful and greatly appreciated.

EVA believes that AEP is not properly administering its coal supply agreements with respect to quality. While the language in each individual contract may vary, the contracts state what the contracted specifications are and may include the language "The Coal required and delivered hereunder at the Designated Delivery Point **shall meet the following "Contract Half-Month" Quality Specifications...** (emphasis added)[16]. As shown below, many producers are non-compliant with their contracted half-month quality specifications. AEPSC indicates that it believes other than the quality adjustments pursuant to the agreements, it has no recourse unless the suspension or rejection limits are triggered. EVA disagrees from at least a business perspective. EVA believes that the product AEPSC has purchased is defined by the contract half-month quality specifications and it is part of AEPSC's responsibilities to insist that

[15] AEPSC stated the commitment level was over-stated because the excess tons could be diverted to [redacted] which in fact they were.

[16] [redacted].

producers comply with these specifications.[17] Regular letters following each deviation from the half-month specification combined with notice that future business is in jeopardy should provide the proper incentives for producers to perform. If AEP disagrees, then the only way it can confirm it is purchasing the lowest cost coal is to evaluate each bid based upon the suspension specifications for Btu.

Spot Coal Procurements

AEP Ohio purchased coal for OPCO under a number of agreements which it classifies as spot. Generally, the spot coal agreements have a term of one year or less. Spot coal agreements are good vehicles for matching supply and demand particularly during periods of uncertainty regarding burn levels.

The agreements are listed by supplier in Exhibit 3-11. Most of the spot agreements were for [redacted]

Exhibit 3-11
Spot Coal Agreements

[redacted]

EVA is very concerned about the [redacted]. The Company made the purchase because effectively it had room to take [redacted] due to reduced plant utilization. AEP effectively offered to allow [redacted] to deliver the [redacted] coal at the same delivered price as the low sulfur coal price it was purchasing for [redacted]. AEPSC justified the economics which included diverting the coal to [redacted]. While [redacted] did not need the coal in 2011, the expected price for low sulfur price in 2012 offset the additional stockpile cost. The justification did not address whether there were lower cost options to purchasing the [redacted] coal for this purpose. The industry standard is not simply whether a transaction improves one's position but whether the transaction produces the lowest cost. [redacted]

[17] AEPSC argues that it is not harmed by non-compliance with the Btu specifications if the price is adjusted pro rata. As AEPSC does not purchase coal on a delivered price basis, this is simply not the case because there is no quality adjustment to the transportation costs. In other words, AEPSC may be buying the coal on a Btu-adjusted basis but it is transporting it per ton.

Contract Procurements

The major contract procurement events in 2011 were [redacted] contracts for OPCO, the division of the [redacted] contract, and the extension of the [redacted] agreement. The new contracts are with [redacted] tons and [redacted] tons. In addition, the purchases for [redacted] which had been combined in two contracts were separated out. Each of these transactions is discussed below.

Contract Review

AEPSC is a party to a number of [redacted] agreements. During 2011, AEP Ohio received coal under [redacted] contracts. Shipments by contract and supplier are listed in Exhibit 3-12.[18] Contract purchases were about [redacted] million tons lower in [redacted] than they had been in [redacted].

Exhibit 3-12
AEP Ohio Contract Purchases, 2011

[redacted]

[18] The exhibit does not include in-transit shipments including PRB coal at the Cook Coal Terminal

Several suppliers have multiple contracts. The [redacted] in [redacted] were [redacted] and [redacted]. Combined [redacted] and [redacted] accounted for more than [redacted] percent of AEP Ohio's [redacted] contract purchases, as shown in Exhibit 3-13. The share accounted for by [redacted] increased in [redacted] due to the overall decline in purchases. The [redacted] accounted for [redacted] percent of contract purchases.

Exhibit 3-13
AEP Ohio Contract Supplier Volume And Contract Market Share, 2011

[redacted]

The key provisions of the [redacted] are summarized in Exhibit 3-14.

Exhibit 3-14
AEP Ohio Long-Term Coal Supply Agreements

[redacted]

Performance in 2011 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 specifications for Btu, SO_2 and/or ash.

[redacted]

In 2011, AEPSC entered into a [redacted] for coal for [redacted]. AEPSC has been challenged in finding suitable coals for this plant because the cyclone boilers require lower fusion coals. This is a new source for this plant. The basic terms of the contract are summarized in Exhibit 3-15. In addition, AEPSC was able to negotiate the right to terminate at the end of 2011 if the coal did not perform as expected.

Shipments under the [redacted] contract in 2011 are summarized in Exhibit 3-16. The exhibit does not show an additional [redacted] tons that were in transit in December which brings total shipments closer to contract levels. The quality performance was mixed.

Exhibit 3-15
[redacted]

[redacted]

Exhibit 3-16
Shipments Under [redacted] Contract, 2011

[redacted]

[redacted]

The [redacted] contract is for [redacted]. The contract provided that the first [redacted] were to be at an annual rate [redacted] tons in [redacted] and [redacted] tons in [redacted]; the balance was to be at the annual rate of [redacted] tons. AEPSC also has a first right of refusal to additional production, a most favored nations clause, and the unilateral right to reopen the price beginning in [redacted].

Shipments under the [redacted] in 2011 are summarized in Exhibit 3-17. In most months, the average Btu content was below the contract specification.

Exhibit 3-17
Shipments Under [redacted], 2011

[redacted]

The contract was amended [redacted]. The [redacted] amendments were administrative related to price adjustment due to contract escalations. The [redacted] was to address a [redacted] shortfall in [redacted]. The [redacted] provided for [redacted] revisions based upon the separation of [redacted] tonnage into a separate agreement.

As noted, the [redacted] provided for an allocation of the [redacted]. The shortfall shipments will be sold at the [redacted] when the coal is shipped. The justification memorandum claims an [redacted] related to the timing of the shipments and shows that the purchases are competitive with [redacted] coal per the futures market for the delivery periods. The analysis and representations are flawed for the following reasons:

- The analysis does not identify whether the shortfalls were Seller- or Buyer- related. It is generally the Buyer's decision to purchase Seller-related shortfalls at the price in effect when the shortfall occurred and the Seller's decision to ship Buyer-related shortfalls at the price in effect when the shortfall occurred. Absent an assignment of "liability", it is difficult for management to assess the agreement.

- AEPSC did not address whether it was forced to replace the shortfalls in contract deliveries with other coals during the relevant period and what the incremental cost of that was. No replacement coal needed to be purchased for [redacted] due to its [redacted] at the beginning of the year. AEPSC did purchase some replacement coal for [redacted] at a cost similar to the contract price as shown in Exhibit 3-18.

Exhibit 3-18
Shortfall Replacement Costs

[redacted]

- Another relevant question was whether the shortfall reduced inventory carrying costs and therefore yielded a benefit to AEPSC if not to its customers. As noted above, the reduction in tons at Gavin did not need to be replaced in 2011 and, as a consequence, yielded a savings to AEPSC in inventory carrying costs. This benefit was not quantified.[19]

- Ratepayers paid a significant premium in [redacted] to keep [redacted] solvent. The payment was justified on the premise that ratepayers would benefit in the long run if the contract stayed intact. The deferral of the 2010 under-shipment now includes a period beyond the end of the ESP period, i.e., 2012. If the FAC does not continue, then the under-recovery needs to be offset by the "value" of the deferred tons.

- The comparison between the contract price and [redacted] is misleading given AEPSC purchases [redacted] coals for either [redacted] and ICAP produces an index for a coal almost exactly like the [redacted] product. The estimated (unadjusted) savings based on the two indexes are provided in Exhibit 3-19. When the

[19] AEPSC indicated it did not need to quantify this benefit because the NPV was positive without it.

lower sulfur of the [redacted] is included, the savings would be greater but so would the savings for the [redacted] coal. Given a presumed goal to provide management with accurate information, use of the [redacted] only was misleading. If AEPSC is genuinely [redacted], then it should have presented both results and solicited the market.[20]

Exhibit 3-19
Comparison of [redacted] Prices with ICAP Futures

[redacted]

AEPSC entered into an agreement [redacted] for lower sulfur coal. The [redacted] agreement started in [redacted]. The first [redacted] tons per year; the [redacted]. [redacted]. The agreement was amended in [redacted] to reflect the assignment of the contract from [redacted].

Shipments under the [redacted] in 2011 are summarized in Exhibit 3-20. [redacted] delivered the contract tons and met the SO_2 limits in each month. [redacted] was non-compliant with the monthly guaranteed Btu in several months.

[20] AEPSC footnotes its choice of the Illinois index stating "increased supply and market activity" makes the Illinois Basin index enhances pricing accuracy. AEPSC did not, however, demonstrate a correlation between the pricing for [redacted] coals into its market.

Exhibit 3-20
Shipments Under [redacted], 2011

[redacted]

[redacted]

In 2007 following the successful scrubber retrofits of the Mitchell stations, AEPSC determined the optimal coal blend for this station. To implement its strategy, AEPSC entered into several coal supply agreements in 2008 including the one with [redacted] for lower sulfur coal. The agreement [redacted] tons per year of low sulfur coal for [redacted]. The [redacted]. The contract was amended in [redacted] to add an additional mine source.

Shipments under the [redacted] in 2011 are summarized in Exhibit 3-21. The Agreement provides for two products with pricing based on the mode of transportation. Performance in 2011 was better than it had been in 2010 but there were still several instances of non-compliance with the Btu and SO_2 half-month specifications. Purchases in 2011 were short by about [redacted] tons.

Exhibit 3-21
Shipments Under [redacted], 2011

[redacted]

[redacted]

The initial [redacted] contract was signed in [redacted] tons per month of [redacted] for [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] will be switching to [redacted].

Under the contract, [redacted] obligation was either [redacted] AEPSC elected to take the mix of [redacted] for 2011. The [redacted] obligation was reduced to [redacted] by Amendment [redacted].

The [redacted] contract was amended [redacted] times in [redacted]. Amendments [redacted] and [redacted] were administrative addressing price escalations. Amendment [redacted] provided for a tonnage reduction of [redacted] in the [redacted] and [redacted] for tons not delivered in the [redacted].

In the justification memorandum for Amendment [redacted], AEPSC states that this coal was purchased for [redacted]. AEPSC states as a result of the downturn of the economy, it has over-committed for this requirement leaving it only two options: [redacted]

[redacted]

EVA believes that AEPSC in fact has [redacted] than it is currently considering.[21] Further, it is blaming the economy on the poor dispatch of the [redacted] power plant rather than recognizing the [redacted] price under the [redacted] contract as an integral part of the problem. In addition, for [redacted] in a row AEPSC has let [redacted] match the market price for spot shipments to other [redacted] plants. AEPSC is ascribing [redacted] to this arrangement in its contract analysis.

This situation is not tenable. In fact, it is likely to get worse with the closure of [redacted] at [redacted]. As a result, AEPSC needs to consider [redacted], not simply [redacted] it articulated. The options that AEPSC should be considering include [redacted]

This situation is aggravated by AEPSC's failure to come up with a comprehensive station solution given the decision to [redacted] and the [redacted]. An open position at [redacted] could have provided a vehicle for addressing both the [redacted]

Amendment [redacted] provides for a price for alternate coal for deliveries during the [redacted]. No justification was provided for this amendment.

Shipments under the [redacted] in 2011 are summarized in Exhibit 3-22. The shipments were split about [redacted] coal. In many months, neither product met the contracted [redacted].[22]

[21] AEPSC verbally indicated that it is actually considering more options than the two it identified.
[22] [redacted].

Exhibit 3-22
Shipments Under [redacted], 2011

[redacted]

This contract has become critical for AEP and its partners in the [redacted] power plant. The [redacted] has reduced the [redacted] of the plant which has resulted in the power plant being over-committed.

[redacted]

AEPSC entered into a new agreement with [redacted]. The basic terms of the agreement are summarized in Exhibit 3-23. The [redacted] contract was the result of a [redacted] RFP. EVA reviewed the solicitation in 2011 and concurred with AEPSC's decision to enter into this contract.

Exhibit 3-23
[redacted]

[redacted]

Shipments under this contract began in 2011. Shipments in 2011 are summarized in Exhibit 3-24. [redacted] was non-compliant with the Btu specifications in most months.

Exhibit 3-24
Shipments Under [redacted], 2011

[redacted]

[redacted]

The new agreement provided for [redacted] and provided a unilateral option for OPCO for up to [redacted] at a predetermined price. The agreement also imposed some good faith obligations for the parties to negotiate for [redacted]

In [redacted], the parties amended the agreement taking into account the contract obligations. The amendment provided a commitment for the [redacted] tons plus another [redacted] tons with firm pricing. The final [redacted] delivery is subject to [redacted]. The amendment also provided for some adjustments to the [redacted] for shipments in [redacted]. AEPSC agreed to increase the [redacted] per MMBtu and reduce the [redacted].

The contract was amended in [redacted] to address a cumulative 2009 and 2010 shortfall of [redacted] tons. The amendment provided for the shortfalls to be shipped first in [redacted]. AEPSC confirmed in its justification that given the pricing for the shortfalls was attractive in the context of the current market.

Shipments under the [redacted] are summarized in Exhibit 3-25. It appears that there was another [redacted] which AEPSC should schedule in 2012. Most of the coal went to the [redacted] station. In only a few months was the coal quality consistent with the [redacted] even with the relaxation of the [redacted].

Exhibit 3-25
Shipments Under [redacted], 2011

[redacted]

[redacted]

AEPSC entered into an agreement with [redacted] coal given an expectation that by [redacted] would burn a blend with [redacted]. AEPSC subsequently determined that such high usage of [redacted] coal would likely result in violations of the [redacted] within the [redacted], where the [redacted] is disposed. As a result, AEPSC is limited to [redacted]. AESPC informed [redacted] that AEPSC had the right to suspend performance and, as a result, that the [redacted] needed to be reduced by [redacted]. After review, [redacted] agreed. AEPSC also informed [redacted] of the burn uncertainty at [redacted]

Pursuant to these discussions, the parties agreed to revise their respective obligations. The annual tonnage was [redacted] and changed from a [redacted] and the term was extended.[23] The amended agreement provides for delivery to [redacted]. There were no further amendments to this agreement during 2011.

Shipments under this agreement in 2011 are summarized in Exhibit 3-26. The coal is shipped via the [redacted]. The summary shows only the receipts at [redacted]. The delivered Btu content of the coal is consistently below the contracted specification. Assuming an average Btu of [redacted], AEPSC is paying about [redacted] per ton [redacted] for the coal because of the [redacted] on transportation costs, assuming an all in transportation cost of [redacted] per ton ton. In other words, [redacted].

[redacted]

In [redacted], AEPSC and [redacted] entered into a complex contract for high volumes of [redacted] coal for an [redacted]. 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] There are multiple quality specifications, some of which vary by year. Part of the coal comprises [redacted] and is delivered [redacted]. The pricing is complex because prices for segments get reset starting for [redacted] which also affect annual tonnage nomination options. In addition to the [redacted] devoted to the Contract Price and Annual Tonnage Determination, the contract also includes by reference an [redacted].

The contract required that the parties establish pricing for a total of [redacted]. Negotiations yielded agreements on prices. AEPSC indicated that the negotiated prices compared favorably to both ICAP and Argus Coal Daily.

In [redacted], the agreement required the parties to establish pricing for a total [redacted]. This quantity includes [redacted] tons of Pricing Segment A for contract years [redacted] and [redacted]. The pricing segments are divided based upon mine origin and quality specifications.

[23] The end date is the later of December 31, 2014 or the last day of the month following delivery of a total of [redacted] tons of coal.

Exhibit 3-26
Shipments Under [redacted] 2011

[redacted]

The 2011 negotiations yielded an agreed upon [redacted] specification price of [redacted]. For all [redacted] years, AEPSC justified the price solely by comparing to it to a Northern Appalachian index and an Illinois Basin index, both from ICAP United. The Company acknowledges that it did not solicit bids of comparable quality coal during the relevant period. The Company's valuation for [redacted] is shown below.

[redacted]

AEPSC used the [redacted]. This index was chosen despite the fact that the [redacted]

[redacted].[24] ICAP's pricing for the [redacted] as shown in Exhibit 3-27.

Exhibit 3-27

[redacted]

[redacted]

As of the middle of [redacted], the basis for AEPSC's evaluation, the difference between the two indices was [redacted] which equates to [redacted]. This does not include the approximately [redacted] difference which through AEP's analysis is assumed to go entirely to [redacted]. These relationships in the ICAP forward price curve hold for all [redacted].

ICAP's differentials were similar to other sources upon which AEP's relies. (Exhibit 3-28) Argus showed the difference during the first half of [redacted] to range between [redacted] with an average of [redacted]. This also excludes the transportation differential.

Simply substituting the [redacted] shows that the [redacted] prices are significantly out of the money and AEPSC is paying about a [redacted] to market which equates to [redacted] for the entire [redacted]. (Exhibit 3-29)

[24] AEPSC notes it chose the Mon River index because of increased market activity. Neither index is liquid or traded. The indexes are for different types of coal with different market values..

Exhibit 3-28

[redacted]

[redacted]

Exhibit 3-29

[redacted]

[redacted]

EVA should note it also has a problem with the [redacted] index but given the relative competitiveness of the [redacted] coal it is somewhat irrelevant. EVA identified several contemporaneous purchases of [redacted] coal at prices significantly below the ICAP index amount.[25]

EVA was concerned about AEPSC's approach to repricing the tons under the [redacted] contract in last year's audit. EVA noted that "AEPSC has many more years in this contract and needs to develop a **better** approach for determining market prices for future redeterminations." (emphasis added) EVA made the following formal recommendation: "EVA recommends that AEPSC improve its approach to determining the market values by which it makes procurement decisions. The revised approach should be available for review in the next audit cycle." For this case, EVA asked the Company to provide a "Description of AEPSC's efforts to improve its approach to determining the market values by which it makes". The Company's disappointing response was as follows:

[25] On July 7, 2011, East Kentucky Power Cooperative entered into a three-year contract with Patriot Coal for $49, $51, and $53 per ton in 2012, 2013, and 2014, respectively, basis 11,500. This is $3.25 per ton cheaper than the ICAP index. On the same date, EKPC entered into a three-year contract with Armstrong Coal with a base price of $1.884 per MMBtu which equates to $42.00 per ton at the contract BTU minimum of 11,200, FOB barge, Green River.

While AEPSC is always striving to improve its methods and processes, the Company respectfully disagreed in the [redacted] *FAC proceeding that a change from its current methods of determining market values was necessary, therefore,* ***no efforts to significantly change its approach occurred in*** [redacted]*. The* [redacted] *audit is still pending before the Commission and no requirement was ordered by the Commission. (emphasis added)*

EVA has three specific problems with the results of the [redacted] reopener. First is that the Company is not properly preparing for or pursuing the best outcome for the reopeners. As can be seen from the response above, AEPSC dismissed the possibility it was not doing a good job. Not surprisingly, by using its same strategy, its results in [redacted] were not impressive. In [redacted], AEPSC did not solicit bids for comparable coals to establish market pricing.[26] There is no better indication of market price than a competitive solicitation. Given AEPSC's large consumption of [redacted], a broad solicitation could have been conducted that would have provided competitive results.[27] In addition to [redacted] that may have provided competition for [redacted]. As the contract allows for AEPSC to purchase the alternate coal if [redacted] and AEPSC do not agree on pricing, contemporaneous solicitations should always be conducted. If the justification memorandum is taken on its face, the only indexes AEPSC relied upon are ICAP indexes for [redacted]. Given the references to other indexes in its contract with [redacted], EVA is certain that AEPSC also has familiarity with those. In all cases, the negotiated price is above the price for the type of coal AEPSC is purchasing.

EVA's second problem is the representation to AEP management that the results of the reopener were favorable. The footnote explanation as to why the [redacted] was used is hardly sufficient. AEPSC certainly knows that the market values [redacted]. At a minimum, the evaluations for both [redacted] should be provided. Also the analysis presented by AEP is flawed with respect to how transportation costs from this alternative supply region are considered. AEP assumes the full transportation differential between a [redacted] even though the contract provides for a a [redacted] discount for coal loaded on the [redacted] which is on the [redacted].

Third is the long-term consequence of high prices on the competitiveness of [redacted] generating plants High priced coal was a large problem for [redacted] two decades ago when it was supplied with affiliate coal and is now a problem for [redacted]. Layering in high cost coal for [redacted] plants will impair their competitiveness in the highly competitive power market.

EVA recommends that prior to any future negotiations with [redacted] on re-pricing, AEPSC develop a coal procurement strategy that allows it to conduct a competitive solicitation for [redacted] and that the results of that solicitation, if favorable, be used in the negotiation. EVA further recommends that any future justification memorandum contain the results of the solicitation combined with a more fulsome disclosure and analysis of comparable indexes. Finally, as necessary, AEPSC should reach out to third parties to assist it in the development and

[26] AEPSC issued an RFP in [redacted] yet chose to not ask for quotes for coals of this quality.
[27] AEPSC's decision to not include comparable coal quality in its [redacted] RFP is of concern.

implementation of a repricing strategy to improve the quality of the results as third parties may be more familiar with non-AEP transactions.

Shipments in 2011 under the [redacted] are summarized in Exhibit 3-30. The quality specifications, except with respect to [redacted]

Exhibit 3-30
Shipments Under [redacted], 2011

[redacted]

[redacted]

In 2011, AEPSC entered into a [redacted] with [redacted] for coal for Kammer. The basic terms of the contract are summarized in Exhibit 3-31. This contract obligates Ohio Power to a [redacted]. As such it provides considerable flexibility to Ohio Power and addresses the uncertain and volatile burn at Kammer.

Exhibit 3-31
Overview of [redacted]

[redacted]

Shipments under this agreement in 2011 are summarized in Exhibit 3-32. With the exception of [redacted] in one month, the quality of the deliveries were consistent with the contract specifications.

Exhibit 3-32
Shipments Under [redacted], 2011

[redacted]

[redacted]

In 2005, Cardinal Operating and [redacted] entered into a [redacted] for the supply of [redacted] to the Cardinal plant. In addition, the agreement gives Cardinal 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 [redacted] prior to the commencement of the next year. The mine is located on reserves [redacted] The contract was amended [redacted] in 2011, two of which were price adjustment-related, based on the [redacted] outlined in the terms and conditions of the contract. [redacted] provided for the [redacted] related to Ohio Power for the reasons described below:

> *At the time the original CSAs were executed the [redacted] contained with the original CSAs were intended to be divided between [redacted]. The [redacted] of the [redacted] was intent that [redacted] from each of the original CSAs. Since the execution of the original CSAs the regulatory environment for [redacted] has changed, thus leading to both [redacted] realizing the value to each company in having their own [redacted] agreements. [redacted] have agreed to [redacted] contained within the original CSAs therefore creating [redacted] for each company. The [redacted] of the original [redacted] will cause both [redacted] to be accountable for their [redacted] for the remaining term of the original and new CSAs.*

The Company did not elaborate of what it meant with respect to the [redacted] or what the [redacted] was in having [redacted]. Other than the changes to the [redacted], the provisions in the agreement remained intact. Coincident with this [redacted] entered into a new mirror image agreement with [redacted]

Shipments in 2011 under the [redacted] are summarized in Exhibit 3-33. [redacted] was not in compliance with [redacted] for several months.

Exhibit 3-33
Shipments Under [redacted], 2011

[redacted]

[redacted]

The initial contract with [redacted] was signed in [redacted] and provided for [redacted] tons of [redacted]. With [redacted], AEPSC could elect to require [redacted] and deliver [redacted] tons per year of [redacted] in lieu of [redacted] coal. The [redacted] are described in Exhibit 3-34.

Exhibit 3-34

[redacted]

Subsequent [redacted] increased the [redacted]. In [redacted], AEPSC [redacted] the contract to increase [redacted] tons per year in [redacted] with an [redacted] to extend to [redacted]. As explained above, under the amended agreement, the [redacted] now runs to [redacted] with pricing in [redacted] and later at the agreed upon [redacted].

In 2011, AEPSC agreed to [redacted] contract through [redacted] ahead of the date actually required in the agreement. [redacted] wanted the [redacted] for its own planning purposes. AEPSC agreed to extend the agreement through [redacted] at an annual rate of [redacted]. The key terms of the amendment are as follows:

- The price for [redacted] than the expected first half year price [redacted]. According to AEPSC, this pricing structure produces an NPV benefit of over [redacted].[28]

[redacted] The price for the remaining will be set by an average of the following [redacted]

- A transportation adder starting at [redacted] per ton will be added to the annual average the indexes. The transportation added will be increased by [redacted] per year.
- Adjust the [redacted] to calculate the [redacted].

As noted in the amendment justification, [redacted] will be deducted from the [redacted] consistent with the existing agreement.

EVA reviewed the justification and concludes that AEPSC will ill-advised in extending the [redacted] in the manner it did for the following reasons:

[28] When parties make offers like this it should be a signal of their financial fragility. In exchange for [redacted] increase in the first half of the year, they are reducing their realizations in the second half of the year by [redacted]

- As previously discussed, AEPSC has a huge problem at [redacted] because the plant dispatch is impaired due to the current [redacted] coal. EVA believes that the availability of business at [redacted] provided some ability for negotiation on the [redacted] contract terms either with [redacted][29] or perhaps a [redacted] that could have provided a comprehensive solution.
- In 2010, AEPSC made the decision to [redacted]. Given the significant costs associated with the [redacted], AEPSC would have been well advised to market the plant at the same time it was considering its procurement strategy for [redacted]. EVA was told that AEPSC did not start [redacted] until after it had extended the [redacted] agreement.
- By 2011, it had become clear that AEPSC had on numerous occasions purchased more coal that it ultimately forcing buy-downs of several of its positions (including [redacted] in 2010). AEPSC provided no reasons to enter into this commitment with [redacted] at this time when its own forecast (that was contained in the justification package) showed that the [redacted] contract would leave little open position through [redacted], thereby taking away the margin necessary to insure the plant was not over-committed.
- By [redacted], it was clear in the market that significant coal-fired generation would be retiring thereby creating excess coal supply.
- [redacted] performance was suggesting its financial fragility. To its credit, AEPSC had supported [redacted] through difficult times. AEPSC gave [redacted]. AEPSC agreed to [redacted]. AEPSC agreed to allow [redacted] to ship tonnage [redacted] not at the contract price when the [redacted] but at the [redacted]. At some point, AEPSC needs to consider whether continued support is consistent with the interest of its customers.

Given these findings, EVA recommends the following:

- Any contract buy-down payments to [redacted] not be recoverable through the FAC
- Any proceeds from the sale of the [redacted] be applied to the FAC under-recovery whenever the sale occurs or in whatever form it occurs.

Shipments under the [redacted] in 2011 are summarized in Exhibit 3-35. As both products A and B were delivered in 2011, it was not possible from the available data to determine compliance.

[29] AEPSC argues that using [redacted] would not been more expensive because these units do not need washed coal [redacted]. As AEPSC did not explore how a global settlement would have worked, there is no basis for EVA to agree with AEP. Renegotiating the [redacted] contract to include additional tons for [redacted] could have been based upon alternative coals, not the coals moving to [redacted] Further, there are procedures in place to accommodate the transfer of [redacted].

Exhibit 3-35
Shipments Under [redacted], 2011

[redacted]

[redacted]

A long time source of supply to [redacted] has been the [redacted].[30] For a period of about two and a half years, this mine was owned by [redacted]. In 2004, 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 brokering the [redacted]. At the end of [redacted], [redacted] closed on its purchase of [redacted]. which included one operating surface mine in Ohio. While [redacted] is the named buyer, none of the coal as shown in Exhibit 3-30 moved to [redacted] in 2011 as [redacted] receives adequate supply from [redacted].

The contract provided for the tons to be [redacted]. According to AEPSC, the parties were not able to agree on a price going forward and the contract terminated on its own terms. The termination was appropriate given AEP Ohio's reduced coal requirements and the size of the stockpiles at [redacted] and elsewhere.

In January 2011, the parties entered into an agreement to address the [redacted]. In its justification memorandum, AEPSC noted that the parties agreed that [redacted]. Hence, the parties negotiated a price for the [redacted] and priced the Seller shortfall [redacted]. In principle this would be appropriate because the Seller would be asked to make up its shortfall only if the contract price were below market. The justification document erred, however, by comparing the blended price to the market price to justify the purchase as shown in Exhibit 3-36.

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

Exhibit 3-36
[redacted]

[redacted]

As AEPSC was not obligated to take the Buyer-related shortfall at anything other than the contract price, the blended price is irrelevant. This transaction included two separate decisions and the analysis and recommendation should be presented in this manner. The first decision relates to whether AEP should require delivery of the Seller-related shortfalls. Given the contract price versus the market, this is an easy decision. The second decision is whether AEP should purchase the Buyer-related shortfall tons at the negotiated price. As a result, the correct comparison is with the [redacted] price which yields an adjusted delivered price of [redacted] per MMBtu.. At this price, the purchase is still attractive but by a considerably lower amount than the analysis suggested. As noted elsewhere, EVA is concerned that management be given accurate information about the economics of each transaction. Given the relatively small difference between the market price and the price for the [redacted], AEPSC may have appropriately decided given the plant inventory levels to pass on this part of the purchase.

Shipments under the [redacted] in 2011 are summarized in Exhibit 3-37. There were no instances of non-compliances.

Exhibit 3-37
Shipments Under [redacted], 2011

[redacted]

[redacted]

In June [redacted], AEPSC entered into a [redacted] with shipments beginning in [redacted]. The contract provided for deliveries of [redacted]. This contract was amended twice in 2011, both administrative. EVA was provided only the first amendment to review.

Shipments under this contract in 2011 are shown in Exhibit 3-38. All of the shipments under this contract have been non-compliant with the [redacted]. This was a problem in 2010 as well. AEPSC's failure to enforcing performance in a high-price contract is problematic.

Exhibit 3-38
Shipments Under [redacted], 2011

[redacted]

[redacted]

AEPSC entered an agreement with [redacted]. The terms of the agreements are summarized in Exhibits 3-39. The [redacted] contract was the result of an [redacted]. EVA reviewed the solicitation in 2011 and concurred with AEPSC's decision to enter into this contract. Shipments under this contract began in [redacted].

Exhibit 3-39
[redacted]

[redacted]

Shipments under the [redacted] Agreement in 2011 are summarized in Exhibit 3-40. [redacted] was non-compliant with the [redacted] in five months and the [redacted] in all but two months. Given the current softness in the market and AEPSC's right to suspend shipments when the [redacted], AEPSC should consider doing so.

Exhibit 3-40
Shipments Under [redacted] Agreement, 2011

[redacted]

[redacted]

The current [redacted] contract was entered into in late [redacted]. Contract volume for [redacted] was increased in [redacted] and the [redacted] with the deferral of some [redacted] tons. This coal was purchased for Kammer. Subsequent to the purchase, Kammer became a swing plant for OPCO making requirements both variable and uncertain.

This agreement was amended twice in [redacted]. The [redacted] provided for a shifting of the [redacted] shortfall to [redacted], along with some price adjustments to allow [redacted] to recover the loss of the high cost tons. The [redacted] reduced [redacted] tons with a slight increase in the [redacted] price. The changes are summarized in Exhibit 3-41. No additional changes were made in [redacted].

Exhibit 3-41
[redacted]

[redacted]

[redacted] shipments during [redacted] are shown in Exhibit 3-42. In eight months, [redacted] was non-compliant with the [redacted].

Exhibit 3-42
Shipments Under [redacted], 2011

[redacted]

The [redacted] met the [redacted] contract requirements on a regular basis. [redacted] missed the monthly [redacted] in 10 out of the 12 months.

Transportation Review

Coal is generally offered to AEPSC FOB barge or FOB railcar and it is the responsibility of AEPSC to arrange for transportation. . Barge transportation is exclusively handled by AEP River Operations. River Operations is a wholly-owned affiliate operating within FEL. With two exceptions in 2011, River Operations directly handled AEP Ohio's requirements. The two exceptions related to delivery from Cook Coal terminal to Kammer and Gavin which River Operations subcontracted to [redacted]. River Operations indicated that this arrangement benefitted all parties and that the [redacted] rates were below what it would have charged. River Operations managed this relationship.

AEPSC is a party to multiple rail contracts under which the rail coal is delivered. The contracts are listed in Exhibit 4-43.

Exhibit 3-43
Rail Contracts

[redacted]

The only "new" contract was the [redacted] which expired at the end of [redacted] and was extended through [redacted].

AEPSC did not renew its rail contracts with [redacted] choosing instead to use [redacted]. AEPSC entered into [redacted] for this purpose. AEPSC also entered into [redacted]. The [redacted] arrangement is highly unusual as truck delivered coal [redacted] is sold FOB plant with the supplier arranging for the trucking.

Other Fuel Procurement

AEPSC also acquires natural gas for CSP. The gas is for Darby and Waterford. Darby is a peaking plant used primarily during May to October. [redacted] Waterford is a combined-cycle plant which is dispatched on an economic basis. Gas purchases in 2011 are summarized by month on Exhibit 3-44 and compared to 2010 and 2009 levels. Gas purchases [redacted] in 2011 versus 2010 and are [redacted] what they were in 2009 reflect its relative economics.

Exhibit 3-44
Natural Gas Purchases

[redacted]

AEPSC indicated that it purchases its gas [redacted] At this point, AEPSC indicated it [redacted] AEPSC continues to monitor the market in the event factors warrant a change in this position.

AEPSC also purchases fuel oil for flame stabilization and start up. Purchases are relatively low and the agreements are for requirements. A competitive bid for oil was conducted in [redacted] for [redacted]. AEPSC indicated it received [redacted] which was the most economic.

4 CONESVILLE COAL PREPARATION PLANT

Plant Description and Status

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.

In the first audit EVA performed, it recommended that AEPSC should undertake a study to determine whether there is an economic justification for continuing to operate the Conesville Coal Preparation Plant given the renegotiation of the [redacted] coal to washed coal combined with a reduction in overall Conesville coal demand. AEPSC performed the study which concluded that the closure of the plant would be economic. Given AEPSC's findings that the closure of the plant is economic, EVA recommended the following:

- AEPSC immediately evaluate whether an earlier closure could be accommodated in the context of its existing coal supply agreements.
- AEPSC should offer to sell the plant (as is or in pieces) to third parties in order to minimize closure costs.[31]

By the time, the closure study had been provided to EVA, AEPSC had restated its Asset Retirement Obligation to reflect plant closure in 12 months. AEPSC added these costs to the preparation plant expenses, thereby substantially increasing the cost of washed coal in 2011. There was no apparent consideration to an earlier closure.

AEPSC did not start is sales effort for CCPP until 2012. AEPSC explained they had prepared a prospectus for the plant but would not provide it to the auditors for review.

It is EVA's experience that assets have considerably more value when packaged with sales commitments.[32] Therefore, EVA strongly recommended in 2011 that AEPSC offer to sell the plant prior to extending the contract with [redacted]. AEPSC

[31] A sale should not include a buy back obligation until it clear washed coal is required for Conesville 5/6 and unless it is the lowest cost option for CSP customers all things considered.

[32] This is also AEP's experience with respect to the affiliate mines. AEP's April 30, 2001 press release states "Under the proposed agreement, CONSOL Energy would purchase the stock of Windsor Coal Company in West Liberty, W.Va., Southern Ohio Coal Company in Wilkesville, Ohio, and Central Ohio Coal Company in Cumberland, Ohio. In addition, AEP would enter into coal supply agreements with CONSOL Energy to purchase approximately 34 million tons of coal from these and other CONSOL Energy affiliate mines through 2008. The coal would be utilized at various AEP coal-fired power plants, including the Muskingum River, Cardinal and Gen. James. M. Gavin plants."

did the exact opposite instead by extending the [redacted] agreement without discussing the purchase of the CCPP with them.[33] AEPSC did not adequately explain its reasons for adopting this strategy. EVA believes that by failing to market CCPP in conjunction with an open coal position at Conesville most likely resulted in significantly higher closure costs associated with the CCPP closure decision.

AEPSC's written response to EVA's interrogatory regarding the actions it had taken to minimize closure expense was as follows:

> *AEPSC has been able to reduce the number of employees who will be impacted by the closing of CCPC by placing them in other positions within the Company, significantly reducing the estimated severance. In addition, the Company is pro-actively seeking potential buyers of the plant in order to avoid costs.*

As noted above, the Company was not proactive at all waiting until 2012 to start marketing the plant after it had extended the contract with [redacted] leaving no open position.

In 2011, CCPP washed raw coals from two different suppliers. As shown in Exhibit 4-1, [redacted] supplied over [redacted] percent of the raw coal. Average quality was about [redacted] per pound, [redacted] percent ash and [redacted] percent sulfur. [redacted] supplied the balance.

Exhibit 4-1
Raw Coal Shipped to CCPP, 2011

[redacted]

Operating Performance

The operating performance of the CCPP from 2007 to 2011 is shown in Exhibit 4-2. The utilization of the CCPP was below [redacted] in 2011 due to reduced demand for coal from Conesville. Yield in 2011 was the lowest of the last five years as was Btu per pound.

Exhibit 4-2
CCPP Operating Performance From 2007 To 2011

[redacted]

Operating Cost

The operating costs of the CCPP per clean and raw ton from 2007 to 2011 are summarized in in Exhibit 4-3. The [redacted] in 2011 reflected the [redacted] combined with the

[33] AEPSC actually extended the [redacted] agreement ahead of when the contract provided for.

increase in depreciation and [redacted]. *EVA believes that AEPSC could have* avoided a significant amount of these costs had it sold CCPP to an entity which would have operated the plant. The accounting for the closure costs are provided in Section 7 of this audit.

Exhibit 4-3
CCPP Clean Coal Operating Costs, 2007 to 2011

[redacted]

5 ENVIRONMENTAL AND ALTERNATIVE ENERGY SOURCES

Environmental Requirements

AEP Ohio coal plants are subject to air emission regulations through both state and federal programs. The federal programs that are resulting in additional requirements are the Cross-State Air Pollution Rule (CSAPR) and the Mercury and Air Toxics Standards (MATS) Rule. CSAPR is the replacement to the Clean Air Interstate Rule which was initially vacated but then reinstated pending a replacement. The EPA signed the CSAPR on July 6, 2011 which placed limits on state-wide emissions of NOX and SO_2 beginning in 2012. CSAPR was challenged on a number of grounds before being stayed by the court on December 30, 2011, two days prior to its effective date. Oral arguments were recently heard by the court; the court's decision is pending. It is possible that CSAPR will become effective January 1, 2013. The final MATS Rule was published by the EPA in the *Federal Register* on February 16, 2012; it became effective on April 16, 2012. The MATS Rule limits the emission rate of mercury and other toxic air pollutants. A number of appeals to the MATS Rule have been filed. Efforts are also underway to make legislative changes to both the CSAPR and MATS Rule. The only units equipped with flue gas desulfurization equipment when built were Conesville Units 5 & 6. Since then Gavin 1&2, Mitchell 1&2, Cardinal 1 and Conesville 4 have been retrofitted with scrubbers.[34] As shown in Exhibit 5-1, the only units not slated for retirement without SCR's are Conesville 5 & 6 and the only unit not slated for retirement without a scrubber is Muskingum 5.

Under Title IV, AEP must forfeit one SO_2 emission allowance for each ton of SO_2 emitted. Under the Clean Air Interstate Rule (CAIR), effective 2010 two allowances had to be proffered for each ton of SO_2 beginning in 2010. The prices of emission allowances have been very volatile. As a result of significant technology retrofits, uncertainty regarding future emission allowance markets and reduced generation, CAIR allowance prices are very low. Title IV and CAIR used the same allowance regime. CSAPR established new allowances for its limited allowable trading. These allowances are available for utilities to trade but most utilities are holding allowances until the regulatory requirements become clearer. CSAPR allowances, if CSAPR goes into effect, are expected trade at levels much higher than the CAIR amounts.

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. Seasonal and Annual NOx allowances are managed separately for CSP and OPCO Emission Banks.

[34] The scrubber retrofit on Cardinal 1

Exhibit 5-1
Status Of Environmental Retrofits On AEP Ohio-Owned Units

Plant	Unit	SCR	FGD	Retirement Planned
Amos	3 [(1)]	2002	2009	
Cardinal	1	2003	2008	
Conesville	3			2012
Conesville	4	2009	2009	
Conesville	5		2006	
Conesville	6		2008	
Gavin	1	2001	1995	
Gavin	2	2001	1995	
Kammer	1			Yes
Kammer	2			Yes
Kammer	3			Yes
Mitchell	1	2007	2007	
Mitchell	2	2007	2007	
Muskingum Rv	1			Yes
Muskingum Rv	2			Yes
Muskingum Rv	3			Yes
Muskingum Rv	4			Yes
Muskingum Rv	5	2005		
Picway	5			Yes
Sporn [(2)]	2			Yes
Sporn [(2)]	4	2008 [(4)]		Yes
Sporn [(2)]	5			Yes [(3)]

(1) OPCo has a 2/3 ownership share in Amos Unit 3. APCo has owns the remaining 1/3 and operates Unit 3.

(2) Sporn Units 2, 4, and 5 (prior to retirement) are operated by APCo, but 100% owned by OPCo.

(3) Sporn Unit 5 is retired as of February, 2012.

(4) Sporn Unit 4 has an SNCR installed.

The emission banks for AEP Ohio as of the start and end of the audit period are summarized in Exhibit 5-2. [redacted]

Exhibit 5-2
Status Of Emission Allowance Banks

[redacted]

AEP Ohio's consumption of emission allowances in 2011 is summarized in Exhibit 5-3 based upon ownership shares. [redacted]

Exhibit 5-3
Allowance Consumption During Audit Period (Tons)

[redacted]

Forecast Of Consumption Of Emission Allowances

AEP's current forecast of SO_2 emission allowance consumption through 2014 is summarized on Exhibit 5-4. Beginning in 2010, AEP assumes that two allowances must be forfeited for each ton of SO_2 emitted. [redacted]

Exhibit 5-4
Forecast Of SO_2 Emission Allowance Consumption(1,000 Allowances)

[redacted]

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

[redacted]

Exhibit 5-5
Forecasted Seasonal And Annual NOx Emission Allowance Consumption (1,000 Tons)

[redacted]

Environmental Reagents

The cost of environmental reagents is recovered in the FAC. Reagent costs have increased with the addition of scrubbers at Cardinal, Conesville 4, and Mitchell and SCRs. A schedule of reagent requirements by plant is provided in Exhibit 5-6.

Exhibit 5-6
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.

The trona is used for SO_3 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 [redacted]. Pricing is based upon the world market price for this commodity. The material is delivered [redacted]

AEPSC has multiple consumable contracts in place. During 2011, the following changes were made to consumable contracts:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

EVA notes that for all the contracts and contract extensions, AEP solicited the market for alternative supplies and justified its purchased based upon actual market prices.

In 2011, AEP conducted tests on two reagents at [redacted] for the purpose of reducing mercury and NOx emissions. As part of this test, AEPSC purchased [redacted]. [redacted]

Alternative Energy Portfolio 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 5-7. 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 5-7
Renewable Energy Benchmark Requirements

Year	Renewable Energy	Minimum Solar
2009	0.25%	0.00%
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 $400 per 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.

Ohio Power Compliance

The 2011 requirement for OPCO is based upon a benchmark as well as actual retail sales for the years 2008, 2009, and 2010. Exhibit 5-8 provides the baseline for retail sales and the REC requirements for solar and non-solar, Ohio and Ohio and other.

Exhibit 5-8
OPCO 2011 REC Requirements

	Unadjusted MWH Sales	Proposed Adjustments	Adjusted MWH Sales
2008	50,081,477	4,793,078	45,288,399
2009	45,466,719	3,942,884	41,523,835
2010	46,808,206	3,369,869	43,438,337
Baseline for 2011 Compliance Obligations			**43,416,857**
Statutory 2011 Compliance Obligations			
Non-Solar		0.97%	
Solar		0.03%	
2011 Compliance Obligations			
		Ohio or Other	Ohio
Non-Solar		210,572	210,572
Solar		6,513	6,513

The Company complied with 2011 requirements in the following ways:

- For In-State Non-Solar, the Company secured a number of RECs via forward broker and bilateral REC transactions and through two short-term wind renewable energy certificate purchase agreements (RECPA), for RECs only, with the Timber Road wind farm located in Paulding County, Ohio. The two RECPAs were executed along with two renewable energy purchase agreements (REPA) totaling [redacted] of nameplate generation from Timber Road. The REPAs are contingent upon Commission approval, which the Company is currently seeking. Upon approval of the REPAs, the RECPAs will immediately terminate. The Company is also generating in-state non-solar RECs through the [redacted].
- For Out-of-State Non Solar, the Company entered into two wind REPAs totaling [redacted] with Fowler Ridge II located in Indiana.
- For In-State Solar, the Company has installed [redacted] solar facilities at its Athens and Newark Service Centers, has obtained RECs through the Company's REC Purchase Program for customer-sited distributed generation, and has entered into a [redacted] REPA with Wyandot Solar LLC.
- For Out-of-State Solar, the Company primarily utilized the SRECs from the Wyandot project, however, did purchase some Out-of-State Solar RECs from the market.

In 2011, the Company was able to realize significant benefits through the sale of excess in-state solar RECs for out-of-state solar RECs. The net proceeds from these sales flowed through the FAC. A full discussion of the 2011 REC accounting is provided in Section 7.

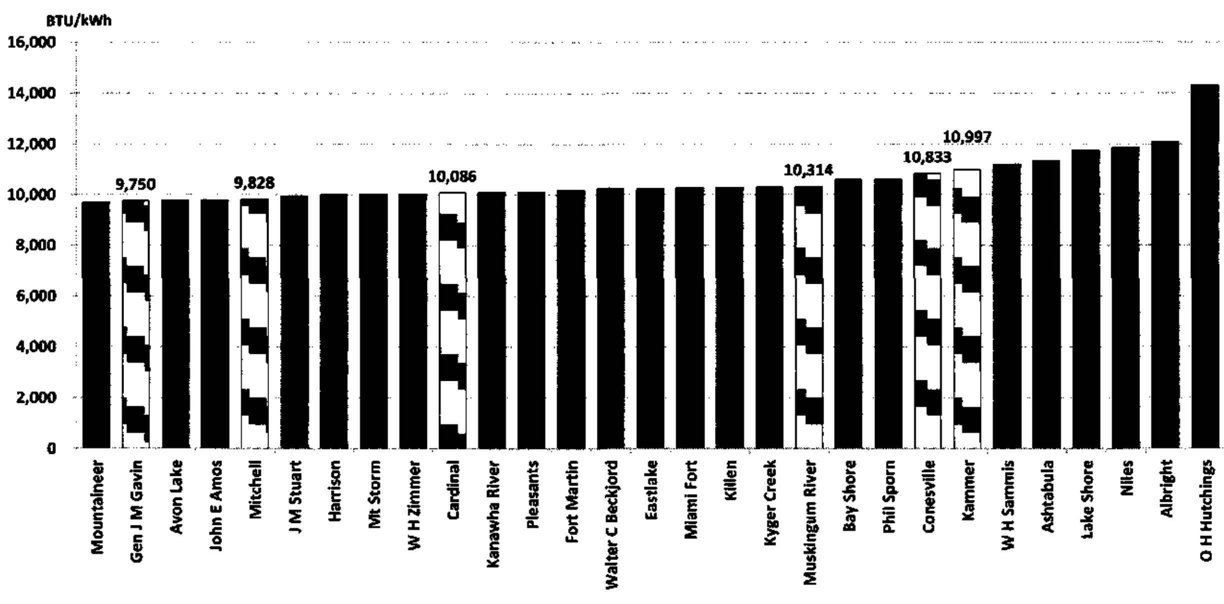
6 POWER PLANT PERFORMANCE

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 and with other coal-fired power plants in PJM. 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 during an equivalent time period.

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 2011 in Exhibit 6-1.[35] The data used to generate these figures are from the Department of Energy.[36] The AEP Ohio plants are highlighted. In 2011, Gavin had the second best heat rate out of the group and three of AEP Ohio's plants were in the top 10.

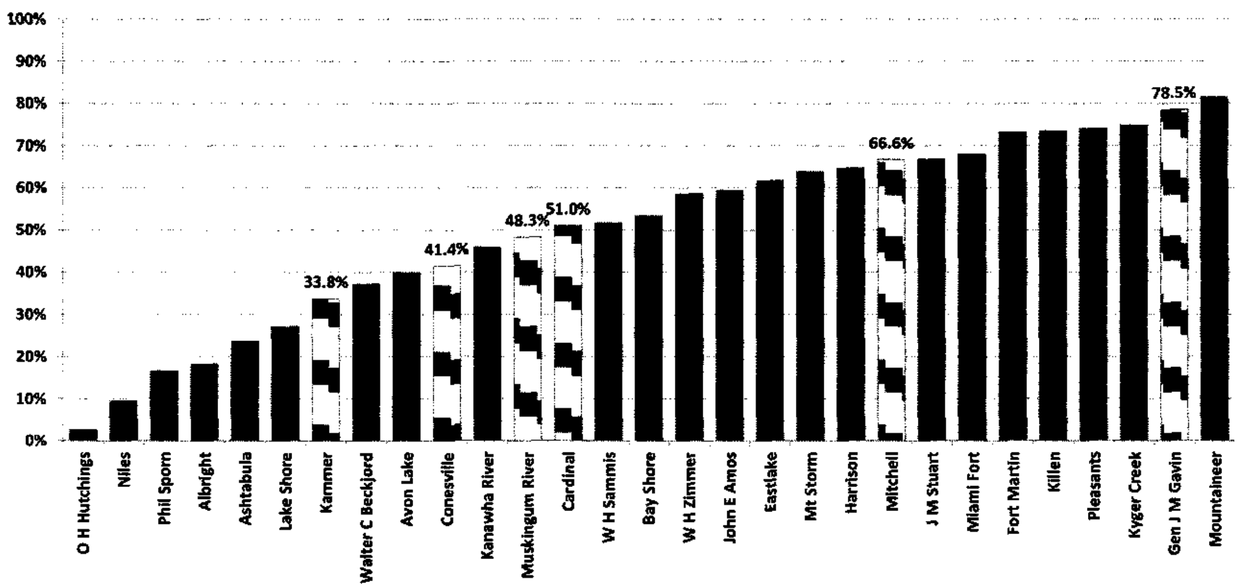
Exhibit 6-1
Coal-Fired Power Plant Heat Rates.[37] 2011



[35] Longview is not included.
[36] All of the data (AEP and other plants) come from 2011 EIA-923 (generation and MMBtu) and EIA-860 (capacity). Picway data is not reported to EIA.
[37] The heat rates are calculated based upon generation and MMBtu consumption from EIA 923.

The capacity factors for the same units for 2011 are provided in Exhibit 6-2. Gavin had the highest capacity factor of the AEP Ohio unit with only one other plant above a 60 percent capacity factor. There is a general correlation between heat rate and capacity factor in a competitive energy market, all other factors remaining constant (e.g. cost of fuel). Conesville's capacity factor improved but is suffering from the adverse impact of high coal costs on Unit 4. The extended start-up program and the Kammer strategy also affected the capacity factors of Kammer and Muskingum River plants.[38]

Exhibit 6-2
Coal-Fired Power Plant Capacity Factors 2011



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 units within PJM determines their utilization subject to transmission adders.

Exhibit 6-3 provides the heat rates for all PJM coal-fired plants in 2011. Three AEP Ohio plants fall in the top third indicating their competitiveness assuming competitively priced fuel.

The relative heat rate rankings for the AEP Ohio units with respect to total generation are provided on Exhibit 6-4 for 2011. This graph is a better measure of the competitiveness of the AEP Ohio units.

In this presentation, the same three units are on the lower part of the curve. The biggest difference between the presentations is with respect to Conesville and Kammer. Within the PJM system, Conesville and Kammer are AEP Ohio's marginal units.

[38] In 2010, AEP had put a number of units into "extended startup" status for nine non-peak months of the year including including Picway 5, Muskingum 4, and Sporn 4. In addition, Sporn 5 was put into permanent extended startup. Kammer started to operate in a "substitute operation" mode, in which only two units are operated at one time.

Exhibit 6-3
PJM Coal-Fired Power Plant Heat Rates 2011

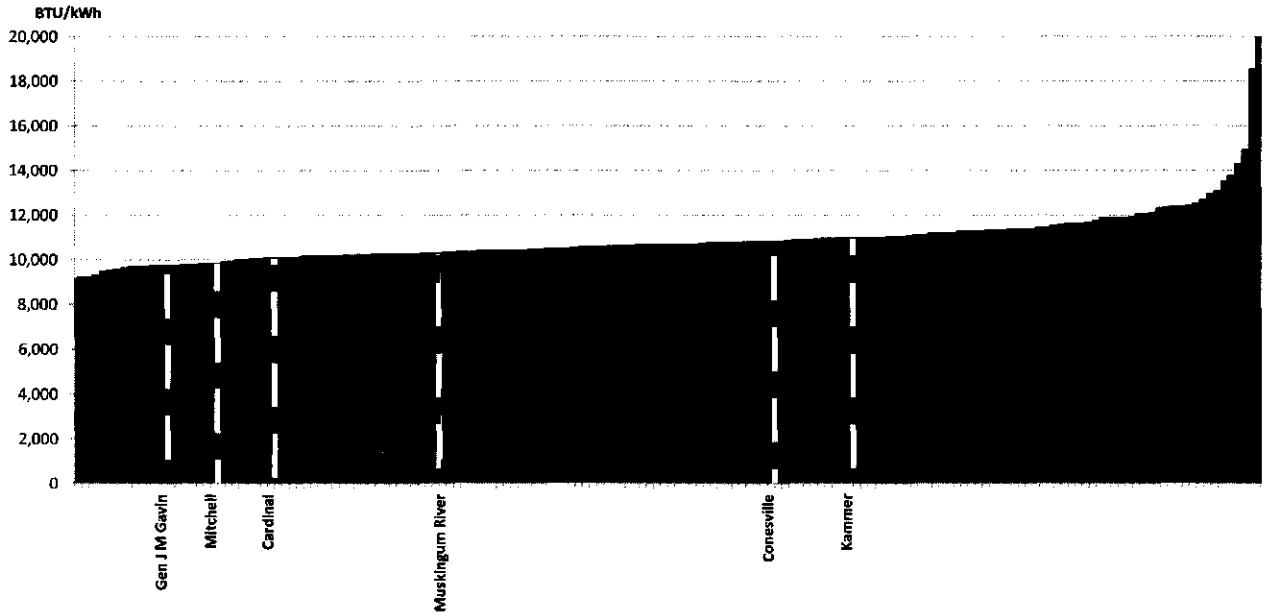
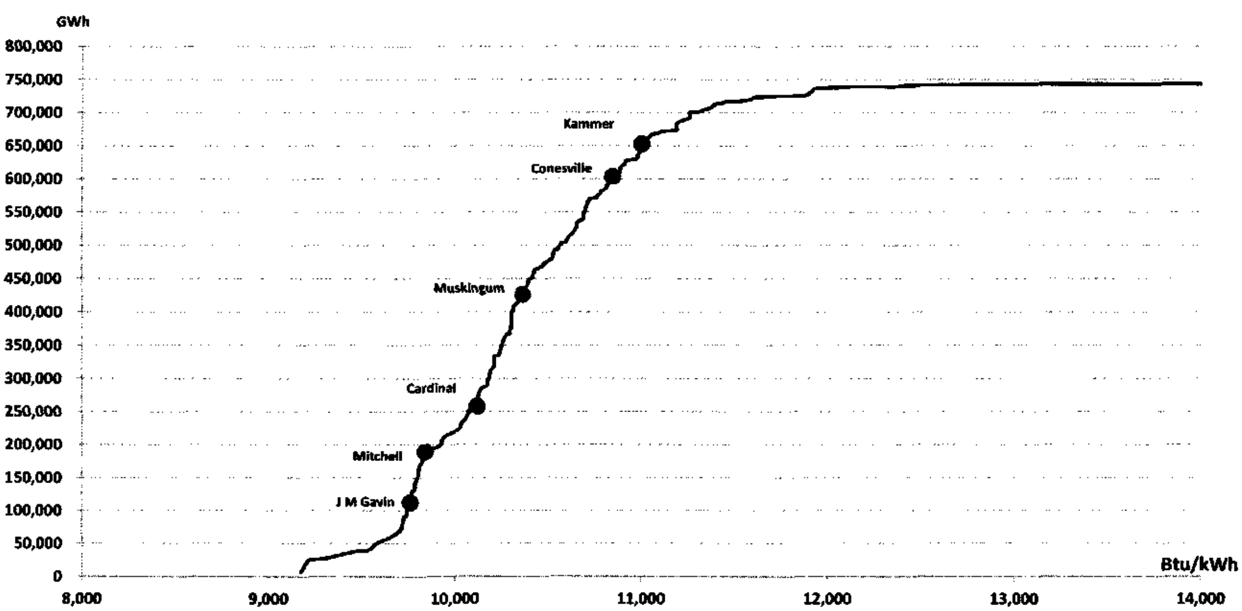


Exhibit 6-4
PJM Coal-Fired Power Plant Cumulative Generation by Heat Rate, 2011



Findings

Three 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 [redacted]. [redacted] is also a reasonably competitive plant.

7 YFINANCIAL 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
- Quarterly FAC Filing – First Quarter 2011
- Second Quarter 2011
- Third Quarter 2011
- Fourth Quarter 2011
- First Quarter 2012
- Second Quarter 2012
- Minimum Review Requirements
- CSP Jointly Owned Generation
- OPCO Jointly Owned Generation
- FAC Deferrals
- Review Related to Coal Order Processing
- Purchase Orders and Approved Purchase Requisitions
- Invoice and Voucher Procedures
- Fuel Ledger
- BTU Adjustments
- Freight and Barge Vouchers
- Fuel Analysis Reports
- Retroactive Escalations
- 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
- Reliability Must Run Generation
- Review Related to Service Interruptions and Unscheduled Outages
- FAC Filings, Supporting Workpapers and Documentation
- Lawrenceburg Generating Station
- Audit Trail for Reconciling Adjustments
- Renewable Energy Resources
- Carrying Costs on Deferred Fuel Balances
- Active Management
- Conesville Coal Preparation Plant
- Emission Allowances
- Changes to Fuel, Purchased Power Procurement and Emission Allowance Procurement
- Internal Audits
- AEP River Transportation Division

Certificate Of Accountability Of Independent Auditors

To: American Electric Power-Ohio

We have examined the quarterly FAC filings of Columbus Southern Power Company and Ohio Power Company ("AEP Ohio") for the year ended December 31, 2011 which support the calculation of the Fuel Adjustment Clause rates for the 12 month period January through December 2011. 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 2011 through December 2011 calculated with those quarterly filings, which include the Reconciliation Adjustments for the period July 2010 through December 2011 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 2011 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

Quarterly FAC Filing – First Quarter 2011

On December 14, 2010, AEP Ohio submitted quarterly FAC filings for CSP and OPCO, which reflected actual data from July through September 2010 and projected data for the period January through March 2011. 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 their initial FAC filings. The sections below discuss AEP Ohio's first quarter 2011 FAC filings by reproducing Schedules 1 through 4, broken out separately between CSP and OPCO as Exhibits 7.1 through 7.13, and then briefly summarize each schedule.

Exhibit 7-1
Summary Proposed CSP FAC Rate, January – March 2011

Schedule 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
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	3.56086	3.35790	0.32622	3.68412	**4.21352**
2	GS-1	Secondary	3.26772	3.35790	0.32622	3.68412	**4.07779**
3	GS-2	Secondary	3.48211	3.35790	0.32622	3.68412	**4.19207**
4	GS-2	Primary	3.36854	3.24838	0.31558	3.56396	**4.05535**
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	3.48211	3.35790	0.32622	3.68412	**4.19207**
6	GS-3	Secondary	3.38891	3.35790	0.32622	3.68412	**3.88835**
7	GS-3	Primary	3.27838	3.24838	0.31558	3.56396	**3.76153**
8	GS-3-LM-TOD	Secondary	3.38891	3.35790	0.32622	3.68412	**3.88835**
9	GS-4	Sub/Transmission	3.07255	3.18680	0.30960	3.49640	**3.39096**
10	IRP-D	Secondary	3.23751	3.35790	0.32622	3.68412	**3.57303**
11	IRP-D	Primary	3.13192	3.24838	0.31558	3.56396	**3.45649**
12	IRP-D	Sub/Transmission	3.07255	3.18680	0.30960	3.49640	**3.39096**
13	SL	Secondary	4.00588	3.35790	0.32622	3.68412	**4.79251**
14	AL	Secondary	4.57832	3.35790	0.32622	3.68412	**5.81988**
15	SBS	Secondary	3.41400	3.35790	0.32622	3.68412	**3.97020**
16	SBS	Primary	3.28062	3.24838	0.31558	3.56396	**3.76788**
17	SBS	Sub/Transmission	3.07255	3.18680	0.30960	3.49640	**3.39096**

Exhibit 7-2
Summary Proposed OPCO FAC Rate, January – March 2011

Schedule 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
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	2.44290	3.03090	6.68622	9.71712	**3.18012**
2	GS-1	Secondary	2.42730	3.03090	6.68622	9.71712	**3.29131**
3	GS-2	Secondary	2.30404	3.03090	6.68622	9.71712	**3.00046**
4	GS-2	Primary	2.22150	2.92231	6.44666	9.36897	**2.89296**
5	GS-2	Sub/Transmission	2.16812	2.85209	6.29176	9.14385	**2.82345**
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.30404	3.03090	6.68622	9.71712	**3.00046**
7	GS-3	Secondary	2.28159	3.03090	6.68622	9.71712	**2.82459**
8	GS-3	Primary	2.19984	2.92231	6.44666	9.36897	**2.72339**
9	GS-3	Sub/Transmission	2.14699	2.85209	6.29176	9.14385	**2.65795**
10	GS-3-ES	Secondary	2.28159	3.03090	6.68622	9.71712	**2.82459**
11	GS-4	Primary	2.05659	2.92231	6.44666	9.36897	**2.43472**
12	GS-4	Sub/Transmission	2.00717	2.85209	6.29176	9.14385	**2.37622**
13	IRP-D	Secondary	2.13301	3.03090	6.68622	9.71712	**2.52519**
14	IRP-D	Primary	2.05659	2.92231	6.44666	9.36897	**2.43472**
15	IRP-D	Sub/Transmission	2.00717	2.85209	6.29176	9.14385	**2.37622**
16	EHG	Secondary	2.40514	3.03090	6.68622	9.71712	**3.02127**
17	EHS	Secondary	2.32055	3.03090	6.68622	9.71712	**2.60641**
18	SS	Secondary	2.28630	3.03090	6.68622	9.71712	**2.91048**
19	OL	Secondary	3.01628	3.03090	6.68622	9.71712	**4.44636**
20	SL	Secondary	2.70546	3.03090	6.68622	9.71712	**3.81544**
21	SBS	Secondary	2.29305	3.03090	6.68622	9.71712	**2.91311**
22	SBS	Primary	2.19461	2.92231	6.44666	9.36897	**2.72600**
23	SBS	Sub/Transmission	2.02740	2.85209	6.29176	9.14385	**2.42134**

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 2011, and Column C reflects the RA rate necessary to recover the actual fuel under-recovery experienced through September 2010 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 2011 billing cycle.

Exhibit 7-3
CSP FC Component, January – March 2011

Schedule 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
FC Component

Line	Description		Forecast Period January	February	March	Total
1	Fuel & Purchased Power		$ 120,051,098	$ 108,647,197	$ 107,831,495	$ 336,529,790
2	Environmental (Consumables and Allowances)		$ 4,652,676	$ 4,641,033	$ 4,060,317	$ 13,354,026
3	(Gains) and Losses On Sales of Allowances		$ -	$ -	$ (17,100)	$ (17,100)
4	Other					$ -
5	Total Includible FAC Costs		$ 124,703,774	$ 113,288,230	$ 111,874,712	$ 349,866,716
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 69,401,024	$ 60,887,134	$ 60,442,529	$ 190,730,687
7	FAC for Internal Load		$ 55,302,750	$ 52,401,096	$ 51,432,183	$ 159,136,029
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	1.00000	1.00000	1.00000	1.00000
9	FAC for Retail Load Before Renewables		$ 55,302,750	$ 52,401,096	$ 51,432,183	$ 159,136,029
10	Renewables/RECs		$ 1,556,866	$ 1,258,558	$ 1,309,737	$ 4,125,161
11	FAC for Retail Load		$ 56,859,616	$ 53,659,654	$ 52,741,920	$ 163,261,190
12	Retail Non-Shopping Sales - Generation Level Kwh		1,825,538,075	1,691,940,147	1,625,543,053	5,143,021,275
13	FC Component of FAC Rate At Generation Level - Cents/kWh					3.17442
			Secondary	**Primary**	**Sub/Trans**	
14	FC Component of FAC Rate At Generation Level		3.17442	3.17442	3.17442	
15	Loss Factor		1.0578	1.0233	1.0039	
16	**FC at the Meter Level - Cents/kWh**	Line 14 x Line 15	**3.3579**	**3.24838**	**3.1868**	

Exhibit 7-4
OPCO FC Component, January – March 2011

Schedule 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
FC Component

Line	Description		Forecast Period - 1st Quarter 2011 January	February	March	Total
1	Fuel & Purchased Power		$ 61,105,151	$ 55,411,655	$ 54,550,945	$ 171,067,751
2	Environmental (Consumables and Allowances)		$ 12,796,010	$ 13,987,877	$ 11,927,580	$ 38,711,467
3	(Gains) and Losses On Sales of Allowances		$ (174,623)	$ (174,623)	$ (239,943)	$ (589,189)
4	Other		$ -	$ -	$ -	$ -
5	Total Includible FAC Costs		$ 73,726,538	$ 69,224,909	$ 66,238,582	$ 209,190,029
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ (2,317,178)	$ (1,284,379)	$ (6,060,677)	$ (9,662,234)
7	FAC for Internal Load		$ 76,043,716	$ 70,509,288	$ 72,299,259	$ 218,852,263
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92438	0.92461	0.91534	0.92438
9	FAC for Retail Load Before Renewables		$ 70,293,290	$ 65,193,593	$ 66,178,404	$ 202,302,655
10	Renewables/RECs		$ 1,632,139	$ 1,342,408	$ 1,407,876	$ 4,382,423
11	FAC for Retail Load		$ 71,925,429	$ 66,536,001	$ 67,586,280	$ 206,685,078
12	Retail Non-Shopping Sales - Generation Level Kwh		2,548,012,644	2,333,024,187	2,389,672,488	7,270,709,319
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.84271
			Secondary	**Primary**	**Sub/Trans**	
14	FC Component of FAC Rate At Generation Level		2.84271	2.84271	2.84271	
15	Loss Factor		1.0662	1.0280	1.0033	
16	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**3.0309**	**2.92231**	**2.85209**	

Schedule 2: This schedule reflects AEP Ohio estimates of monthly fuel costs it expected to incur during the period January through March 2011. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the first quarter of 2011, AEP Ohio has projected includable FAC costs of $349.867 million for CSP and $209.190 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 2011, these projected off-system costs totaled $190.731 million for CSP and ($9.662) 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 $4.125 million for CSP and $4.382 million for OPCO. The addition of the RECs result in total FAC costs for retail load of $163.261 million for CSP and $206.685 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.17442 cents per kWh for CSP and 2.84271 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 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 3.3579, 3.24838 and 3.1868 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 rates of 3.0309, 2.92231 and 2.85209 cents per kWh.

Exhibit 7-5
CSP RA Component, January – March 2011

Schedule 3
Page 1 of 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2010 through March 2011
RA Component

Actual Period - July 2010 through Sept 2010

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**							$ 9,626,191
2	Jul-10	2,028,770,725	$ 70,991,642	$ 72,343,388	$ 1,351,746	$ 412,056	$ 3,771,502	$ 5,535,305
3	Aug-10	1,993,965,411	$ 67,593,424	$ 68,182,047	$ 588,623	$ 414,393	$ (575,451)	$ 427,565
4	Sep-10	1,533,385,603	$ 53,015,582	$ 52,868,980	$ (146,602)	$ 415,564	$ (293,760)	$ (24,799)
5	**Ending Balance**	5,556,121,739	$ 191,600,648	$ 193,394,415	$ 1,793,767	$ 1,242,013	$ 2,902,291	$ 15,564,261
6	Ormet Interim Agreement Deferral	Schedule 3, pg. 3						$ 296,659
7	Total (Over)/Under Recovery Balance							$ 15,860,920
8	Loss Adjusted Retail Sales Billing Period - kWh							5,143,021,275
9	RA Component at Generation - Cents/kWh							0.30840

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		0.30840	0.30840	0.30840
11	Loss Factor		1.0578	1.0233	1.0039
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**0.32622**	**0.31558**	**0.30960**

Exhibit 7-6
OPCO RA Component, January – March 2011

Schedule 3
Page 1 of 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
RA

Actual Period - July 2010 through September 2010

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**							$ 406,464,015
2	Jul-10	2,451,401,180	$ 57,596,084	$ 68,342,007	$ 10,745,923	$ 3,268,380	$ (140,349)	$ 13,873,955
3	Aug-10	2,386,946,908	$ 54,777,265	$ 69,841,878	$ 15,064,613	$ 3,374,308	$ (372,141)	$ 18,066,780
4	Sep-10	1,975,115,589	$ 43,889,812	$ 57,185,715	$ 13,295,903	$ 3,482,301	$ (139,432)	$ 16,638,773
5	**Ending Balance**	6,813,463,677	$ 156,263,161	$ 195,369,600	$ 39,106,439	$ 10,124,990	$ (651,922)	$ 455,043,522
6	Ormet Interim Agreement Deferral	*Schedule 3, pg. 3*						$ 907,770
7	Total (Over)/Under Recovery Balance							$ 455,951,292
8	Loss Adjusted Retail Sales Billing Period - kWh							7,270,709,319
9	RA Component at Generation - Cents/kWh							6.27107

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		6.27107	6.27107	6.27107
11	Loss Factor		1.0662	1.0280	1.0033
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**6.68622**	**6.44666**	**6.29176**

Schedule 3: This three-page schedule represents the Companies' RA components of their first quarter 2011 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 2010, which were calculated as the difference between the monthly FAC revenues for the third quarter of 2010 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 $15.564 million for CSP and $455.043 million for OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with the Ormet Interim Agreement (see additional discussion below). For the third quarter of 2010, these deferrals totaled $296,659 for CSP and $907,770 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 2010 was $15.860 million and $455.951 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 0.30840 cents per kWh and 6.27107 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 0.32622, 0.31558 and 0.30960 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 6.68622, 6.44666 and 6.29176 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

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 7-7
CSP RA Component Including Ormet Deferral, January – March 2011

Schedule 3
Page 2 of 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
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
1	Jul-10	$ 114,219,640	$ 42,479,667	$ 71,739,973	1.00000	$ 71,739,973	$ 603,415	$ 72,343,388
2	Aug-10	$ 103,385,838	$ 35,770,879	$ 67,614,959	1.00000	$ 67,614,959	$ 567,088	$ 68,182,047
3	Sep-10	$ 68,557,689	$ 16,715,360	$ 51,842,329	1.00000	$ 51,842,329	$ 1,026,651	$ 52,868,980
4	Total	$ 286,163,167	$ 94,965,906	$ 191,197,261		$ 191,197,261	$ 2,197,154	$ 193,394,415

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (Wstville)	Retail	Total	Whlse (Wstville)	Retail
Actual						
5	Jul-10	-	2,119,280,726	2,119,280,726	0.00000	1.00000
6	Aug-10	-	2,081,664,229	2,081,664,229	0.00000	1.00000
7	Sep-10	-	1,598,196,179	1,598,196,179	0.00000	1.00000
Forecast						
8	January '11		1,825,538,075	1,825,538,075	0.00000	1.00000
9	February '11		1,691,940,147	1,691,940,147	0.00000	1.00000
10	March '11		1,625,543,053	1,625,543,053	0.00000	1.00000

Exhibit 7-8
OPCO RA Component Including Ormet Deferral, January – March 2011

Schedule 3
Page 2 of 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
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
1	Jul-10	$ 159,756,288	$ 86,358,375	$ 73,397,913	0.92220	$ 67,687,555	$ 654,452	$ 68,342,007
2	Aug-10	$ 150,946,731	$ 76,250,152	$ 74,696,579	0.92636	$ 69,195,923	$ 645,955	$ 69,841,878
3	Sep-10	$ 114,830,128	$ 53,842,110	$ 60,988,018	0.91971	$ 56,091,290	$ 1,094,425	$ 57,185,715
4	Total	$ 425,533,147	$ 216,450,637	$ 209,082,510		$ 192,974,768	$ 2,394,832	$ 195,369,600

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (WPC)	Retail	Total	Whlse (WPC)	Retail
Actual						
5	Jul-10	215,379,943	2,553,171,638	2,768,551,581	0.07780	0.92220
6	Aug-10	197,590,195	2,485,640,230	2,683,230,425	0.07364	0.92636
7	Sep-10	178,894,575	2,049,327,670	2,228,222,245	0.08029	0.91971
Forecast						
8	Jan-11	208,451,434	2,548,012,644	2,756,464,077	0.07562	0.92438
9	Feb-11	190,229,720	2,333,024,187	2,523,253,907	0.07539	0.92461
10	Mar-11	221,029,374	2,389,672,488	2,610,701,862	0.08466	0.91534

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the third quarter of 2010. Specifically, page 2 of Schedule 3 (lines 4-7) shows, for each Company, total monthly FAC costs incurred from July through September 2010. 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". During the third quarter of 2010, CSP and OPCO added amounts totaling $2,197,154 and $2,394,832, 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 third quarter of 2010 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for July through September2010. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for January through March2011, 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 1.00000 for each month of January, February and March2011 for CSP and .92438, .92461 and .91534 (January, February and March2011, respectively) for OPCO.

Exhibit 7-9
CSP Details Of Ormet Deferral In RA Component, January – March 2011

Schedule 3
Page 3 of 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
RA Component

<u>**Ormet Interim Agreement Deferral**</u>

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Jul-10	$ -	$ 82,587	$ 82,587
2	Aug-10	$ -	$ 93,571	$ 93,571
3	Sep-10	$ -	$ 99,075	$ 99,075
4	Total	$ -	$ 275,232	$ 275,232

Exhibit 7-10
OPCO Details Of Ormet Deferral In RA Component, January – March 2011

Schedule 3
Page 3 of 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Jul-10	$ -	$ 303,030	$ 303,030
2	Aug-10	$ -	$ 303,690	$ 303,690
3	Sep-10	$ -	$ 301,049	$ 301,049
4	Total	$ -	$ 907,770	$ 907,770

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, 2010 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.

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 [redacted] 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 [redacted] 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 that 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 [redacted] per MWh for the periods when Ormet was fully operating [redacted] per MWh for periods when Ormet curtailed production to [redacted], and [redacted] per MWh for periods when Ormet curtailed production to [redacted]. 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 under-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 charges 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").

After September 17, 2009, the Companies have continued to accrue carrying charges on the deferral related to the Ormet Interim Agreement, which the Companies have included in their RA adjustment calculations during 2011 as shown on Schedule 3, page 3 of the Companies' quarterly FAC filings.

On September 1, 2010, AEP Ohio filed an application for a Significant Excessive Earnings Test ("SEET"), which utilities are required to file annually at the PUCO in order to demonstrate whether significantly excessive earnings were made. In its Opinion and Order dated January 11, 2011, the PUCO determined that CSP generated $42.6 million in significantly excessive earnings in 2009, which the Commission ordered be refunded to customers through bill credits and the elimination of any deferrals. As a result of the Commission's Opinion and Order, CSP's Ormet interim agreement deferral amount (including carrying charges) effectively became zero as of December 31, 2010. The Companies' March 1, 2011 quarterly FAC filing (Schedule 3, page 1, line 8) reflected a line item called "SEET Refund", which removed the deferral and Ormet carrying charges which totaled $18,717,599. AEP Ohio's response to LA-2011-111 included a schedule (reproduced below) which reflected the write-off of CSP's fuel deferrals at December 31, 2010 pursuant to the SEET related Opinion and Order.

Exhibit 7-11
CSP Deferred Fuel Write-Off at December 31, 2010 Pursuant to SEET Opinion and Order

CSP OH FAC Reg. Asset Deferrals
12/31/2010

	(a) Balances through Sep10 Actual Cycle	October Actual Cycle Amounts	November Actual Cycle Amounts	December *Estimate* Cycle Amounts	GL Balances as of December 2010	(b) - not yet recorded - Known Adjs. for Dec. Actual Cycle	Balances for December
FAC Deferral:							
A/C 1823227 FAC Reg. Asset	12,546,624	(873,429)	(3,629,208)	6,191,815	14,235,802	888,466	15,124,268
A/C 1823225 TTL CC	3,296,458	115,554	107,393	73,924	3,593,331		3,593,331
Sum of Reg. Asset Deferral & TTL CC:	15,843,082	(757,875)	(3,521,815)	6,265,739	17,829,133	888,466	18,717,599

Amount to Credit Per O&O	$ 42,683,000
Balance Applied to FAC	$ (18,717,599)
Balance to per kWh bill credit	$ 23,965,401
Actual December kWh	1,735,269,718
Less: Special Contracts kWh*	(173,943,022)
Adjusted kWh	1,561,326,696
11 Month kWh (Feb-Dec 2011)	17,174,593,656
$/kWh Credit Rider	$ 0.001395

Data request LA-2011-112 asked AEP Ohio to provide the accounting entries and supporting documentation related to any Ormet true-up for calendar year 2010 that was made during 2011. In response, AEP Ohio stated that there was no true-up related to Ormet in 2010, only the SEET related write-off referenced above.

Exhibit 7-12
CSP FAC Rate Under ESP Cap, January – March 2011

Schedule 4

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
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	4.21352
2	GS-1	Secondary	4.07779
3	GS-2	Secondary	4.19207
4	GS-2	Primary	4.05535
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	4.19207
6	GS-3	Secondary	3.88835
7	GS-3	Primary	3.76153
8	GS-3-LM-TOD	Secondary	3.88835
9	GS-4	Sub/Transmission	3.39096
10	IRP-D	Secondary	3.57303
11	IRP-D	Primary	3.45649
12	IRP-D	Sub/Transmission	3.39096
13	SL	Secondary	4.79251
14	AL	Secondary	5.81988
15	SBS	Secondary	3.97020
16	SBS	Primary	3.76788
17	SBS	Sub/Transmission	3.39096

Exhibit 7-13
OPCO FAC Rate Under ESP Cap, January – March 2011

Schedule 4

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2011 through March 2011
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	3.18012
2	GS-1	Secondary	3.29131
3	GS-2	Secondary	3.00046
4	GS-2	Primary	2.89296
5	GS-2	Sub/Transmission	2.82345
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	3.00046
7	GS-3	Secondary	2.82459
8	GS-3	Primary	2.72339
9	GS-3	Sub/Transmission	2.65795
10	GS-3-ES	Secondary	2.82459
11	GS-4	Primary	2.43472
12	GS-4	Sub/Transmission	2.37622
13	IRP-D	Secondary	2.52519
14	IRP-D	Primary	2.43472
15	IRP-D	Sub/Transmission	2.37622
16	EHG	Secondary	3.02127
17	EHS	Secondary	2.60641
18	SS	Secondary	2.91048
19	OL	Secondary	4.44636
20	SL	Secondary	3.81544
21	SBS	Secondary	2.91311
22	SBS	Primary	2.72600
23	SBS	Sub/Transmission	2.42134

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 third quarter of 2011 (i.e. the proposed FAC rates from AEP Ohio's first quarter 2011 FAC filing) for OPCO and the lower of the current FAC rates or the total of the FC and RA components become effective for CSP.

Second Quarter 2011

On March 1, 2011, AEP Ohio submitted quarterly FAC filings for CSP and OPCO, which reflected actual data from October through December 2010 and projected data for the period April through June 2011. 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 2011 FAC filings by reproducing Schedules 1 through 4, broken out separately between CSP and OPCO as Exhibits 7.14 through 7.25, and then briefly summarizing each schedule.

Exhibit 7-14
CSP Schedule 1, April – June 2011

Schedule 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2011 through June 2011
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	3.56086	3.66371	0.00000	3.66371	**4.21352**
2	GS-1	Secondary	3.26772	3.66371	0.00000	3.66371	**4.07779**
3	GS-2	Secondary	3.48211	3.66371	0.00000	3.66371	**4.19207**
4	GS-2	Primary	3.36854	3.54422	0.00000	3.54422	**4.05535**
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	3.48211	3.66371	0.00000	3.66371	**4.19207**
6	GS-3	Secondary	3.38891	3.66371	0.00000	3.66371	**3.88835**
7	GS-3	Primary	3.27838	3.54422	0.00000	3.54422	**3.76153**
8	GS-3-LM-TOD	Secondary	3.38891	3.66371	0.00000	3.66371	**3.88835**
9	GS-4	Sub/Transmission	3.07255	3.47703	0.00000	3.47703	**3.39096**
10	IRP-D	Secondary	3.23751	3.66371	0.00000	3.66371	**3.57303**
11	IRP-D	Primary	3.13192	3.54422	0.00000	3.54422	**3.45649**
12	IRP-D	Sub/Transmission	3.07255	3.47703	0.00000	3.47703	**3.39096**
13	SL	Secondary	4.00588	3.66371	0.00000	3.66371	**4.79251**
14	AL	Secondary	4.57832	3.66371	0.00000	3.66371	**5.81988**
15	SBS	Secondary	3.41400	3.66371	0.00000	3.66371	**3.97020**
16	SBS	Primary	3.28062	3.54422	0.00000	3.54422	**3.76788**
17	SBS	Sub/Transmission	3.07255	3.47703	0.00000	3.47703	**3.39096**

Exhibit 7-15
OPCO Schedule 1, April – June 2011

Schedule 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2011 through June 2011
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	3.18012	3.09062	8.30572	11.39634	**3.18012**
2	GS-1	Secondary	3.29131	3.09062	8.30572	11.39634	**3.29131**
3	GS-2	Secondary	3.00046	3.09062	8.30572	11.39634	**3.00046**
4	GS-2	Primary	2.89296	2.97988	8.00815	10.98803	**2.89296**
5	GS-2	Sub/Transmission	2.82345	2.90829	7.81573	10.72402	**2.82345**
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	3.00046	3.09062	8.30572	11.39634	**3.00046**
7	GS-3	Secondary	2.82459	3.09062	8.30572	11.39634	**2.82459**
8	GS-3	Primary	2.72339	2.97988	8.00815	10.98803	**2.72339**
9	GS-3	Sub/Transmission	2.65795	2.90829	7.81573	10.72402	**2.65795**
10	GS-3-ES	Secondary	2.82459	3.09062	8.30572	11.39634	**2.82459**
11	GS-4	Primary	2.43472	2.97988	8.00815	10.98803	**2.43472**
12	GS-4	Sub/Transmission	2.37622	2.90829	7.81573	10.72402	**2.37622**
13	IRP-D	Secondary	2.52519	3.09062	8.30572	11.39634	**2.52519**
14	IRP-D	Primary	2.43472	2.97988	8.00815	10.98803	**2.43472**
15	IRP-D	Sub/Transmission	2.37622	2.90829	7.81573	10.72402	**2.37622**
16	EHG	Secondary	3.02127	3.09062	8.30572	11.39634	**3.02127**
17	EHS	Secondary	2.60641	3.09062	8.30572	11.39634	**2.60641**
18	SS	Secondary	2.91048	3.09062	8.30572	11.39634	**2.91048**
19	OL	Secondary	4.44636	3.09062	8.30572	11.39634	**4.44636**
20	SL	Secondary	3.81544	3.09062	8.30572	11.39634	**3.81544**
21	SBS	Secondary	2.91311	3.09062	8.30572	11.39634	**2.91311**
22	SBS	Primary	2.72600	2.97988	8.00815	10.98803	**2.72600**
23	SBS	Sub/Transmission	2.42134	2.90829	7.81573	10.72402	**2.42134**

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 2011. 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 2011. 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 request that the lower of Columns D and E be implemented for CSP and OPCO's filings reflect the then current FAC rates as shown in Column E.

Exhibit 7-16
CSP Schedule 2, April – June 2011

Schedule 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2011 through June 2011
FC Component

Line	Description		April	May	June	Total
			Forecast Period			
1	Fuel & Purchased Power		90,801,325	87,351,552	106,889,221	$ 285,042,097
2	Environmental (Consumables and Allowances)		4,119,680	4,189,980	4,107,046	$ 12,416,706
3	(Gains) and Losses On Sales of Allowances		-	-	-	$ -
4	Other					$ -
5	Total Includible FAC Costs		$ 94,921,005	$ 91,541,532	$ 110,996,267	$ 297,458,803
6	Less: Assigned to Off-System (Including AEP Affiliates)		48,115,510	42,327,857	55,117,556	$ 145,560,923
7	FAC for Internal Load		$ 46,805,495	$ 49,213,675	$ 55,878,711	$ 151,897,881
						0
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	1.00000	1.00000	1.00000	1.00000
9	FAC for Retail Load Before Renewables		$ 46,805,495	$ 49,213,675	$ 55,878,711	$ 151,897,881
10	Renewables/RECs		1,435,505	1,132,427	900,278	$ 3,468,210
11	FAC for Retail Load		$ 48,241,000	$ 50,346,102	$ 56,778,989	$ 155,366,091
12	Retail Non-Shopping Sales - Generation Level Kwh		1,394,099,169	1,459,140,596	1,632,546,394	4,485,786,160
13	FC Component of FAC Rate At Generation Level - Cents/kWh					3.46352
			Secondary	**Primary**	**Sub/Trans**	
14	FC Component of FAC Rate At Generation Level		3.46352	3.46352	3.46352	
15	Loss Factor		1.0578	1.0233	1.0039	
16	**FC at the Meter Level - Cents/kWh**	Line 14 x Line 15	**3.66371**	**3.54422**	**3.47703**	

Exhibit 7-17
OPCO Schedule 2, April – June 2011

Schedule 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
Apil 2011 through June 2011
FC Component

Line	Description		Forecast Period - 2nd Quarter 2011 April	May	June	Total
1	Fuel & Purchased Power		48,789,250	51,108,054	64,135,676	$ 164,032,981
2	Environmental (Consumables and Allowances)		9,547,470	7,760,973	11,167,859	$ 28,476,302
3	(Gains) and Losses On Sales of Allowances		(174,623)	(184,311)	(184,311)	$ (543,244)
4	Other		$ -	$ -	$ -	$ -
5	Total Includible FAC Costs		$ 58,162,097	$ 58,684,716	$ 75,119,225	$ 191,966,038
6	Less: Assigned to Off-System (Including AEP Affiliates)		(4,951,024)	(8,225,538)	5,018,293	$ (8,158,269)
7	FAC for Internal Load		$ 63,113,121	$ 66,910,254	$ 70,100,932	$ 200,124,307
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92111	0.91945	0.92218	0.92111
9	FAC for Retail Load Before Renewables		$ 58,134,127	$ 61,520,633	$ 64,645,677	$ 184,336,501
10	Renewables/RECs		1,548,191	1,255,372	1,020,360	$ 3,823,924
11	FAC for Retail Load		$ 59,682,319	$ 62,776,005	$ 65,666,037	$ 188,160,424
12	Retail Non-Shopping Sales - Generation Level Kwh		2,096,483,451	2,128,383,403	2,266,290,385	6,491,157,239
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.89872
			Secondary	**Primary**	**Sub/Trans**	
14	FC Component of FAC Rate At Generation Level		2.89872	2.89872	2.89872	
15	Loss Factor		1.0662	1.0280	1.0033	
16	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**3.09062**	**2.97988**	**2.90829**	

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period April through June 2011. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the second quarter of 2011, AEP Ohio has projected includable FAC costs totaling $297.459 million for CSP and $191.966 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 2011, these projected off-system costs totaled $145.561 million for CSP and ($8.158) 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 $3.468 million for CSP and $3.824 million for OPCO. The addition of the RECs result in total FAC costs for retail load of $155.366 million for CSP and $188.160 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.46352 cents per kWh for CSP and 2.89872 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 3.66371, 3.54422 and 3.47703 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 3.09062, 2.97988 and 2.90829 cents per kWh.

Exhibit 7-18
CSP Schedule 3, Page 1, April – June 2011

Schedule 3
Page 1 of 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2010 through June 2011
RA Component

Actual Period - October 2010 through December 2010

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**							$ 15,860,920
2	Oct-10	1,436,159,626	$ 48,277,649	$ 47,410,172	$ (867,477)	$ 414,758	$ (400,441)	$ (853,160)
3	Nov-10	1,589,350,286	$ 53,705,652	$ 50,064,540	$ (3,641,112)	$ 412,898	$ (400,012)	$ (3,628,227)
4	Dec-10	1,741,305,391	$ 59,298,861	$ 64,041,572	$ 4,742,711	$ 406,599	$ 1,943,957	$ 7,093,267
5	**Ending Balance**	4,766,815,303	$ 161,282,162	$ 161,516,284	$ 234,122	$ 1,234,254	$ 1,143,504	$ 18,472,800
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 244,799
7	Total (Over)/Under Recovery Balance							$ 18,717,599
8	SEET Refund							$ (18,717,599)
9	Adjusted Over/(Under) balance							$ -
10	Loss Adjusted Retail Sales Billing Period - kWh							4,485,786,160
11	RA Component at Generation - Cents/kWh							-

Line			Secondary	Primary	Sub/Trans
12	RA Component of FAC Rate At Generation Level		-	-	-
13	Loss Factor		1.0578	1.0233	1.0039
14	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**0.00000**	**0.00000**	**0.00000**

Exhibit 7-19
OPCO Schedule 3, Page 1, April – June 2011

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2011 through June 2011
RA

Actual Period - October 2010 through December 2010

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**							$ 455,951,292
2	Oct-10	1,998,154,570	$ 44,046,517	$ 56,126,103	$ 12,079,586	$ 3,627,213	$ (140,349)	$ 15,566,450
3	Nov-10	2,076,910,668	$ 46,064,582	$ 58,453,322	$ 12,388,740	$ 3,725,833	$ (139,890)	$ 15,974,683
4	Dec-10	2,420,107,214	$ 54,348,465	$ 67,912,458	$ 13,563,993	$ 3,839,135	$ (139,890)	$ 17,263,237
5	**Ending Balance**	6,495,172,452	$ 144,459,564	$ 182,491,883	$ 38,032,319	$ 11,192,180	$ (420,130)	$ 504,755,662
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 907,109
7	Total (Over)/Under Recovery Balance							$ 505,662,771
8	Loss Adjusted Retail Sales Billing Period - kWh							6,491,157,239
9	RA Component at Generation - Cents/kWh							7.79002

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		7.79002	7.79002	7.79002
11	Loss Factor		1.0662	1.0280	1.0033
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**8.30572**	**8.00815**	**7.81573**

Schedule 3: This three-page schedule represents the Companies RA components of its second quarter 2011 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 2010, which were calculated as the difference between the monthly FAC revenues for the fourth quarter of 2010 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 $18.473 million for CSP and $504.756 million for OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with Ormet. For the fourth quarter of 2010, these deferrals totaled $244,799 for CSP and $907,109 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 2010 was $18.718 million and $505.663 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 this filing was 7.79002 cents per kWh for OPCO. There was no RA component recorded for CSP. 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 OPCO, applying the loss factors resulted in RA components of the FAC rate of 8.30572, 8.00815 and 7.81573 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Similar to its first quarterly filing, 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 7-20
CSP Schedule 3, Page 2, April – June 2011

Schedule 3
Page 2 of 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2011 through June 2011
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
1	Oct-10	$ 59,498,595	$ 13,264,154	$ 46,234,441	1.00000	$ 46,234,441	$ 1,175,731	$ 47,410,172
2	Nov-10	$ 62,149,983	$ 13,474,300	$ 48,675,683	1.00000	$ 48,675,683	$ 1,388,857	$ 50,064,540
3	Dec-10	$ 83,271,855	$ 20,749,654	$ 62,522,201	1.00000	$ 62,522,201	$ 1,519,371	$ 64,041,572
4	Total	$ 204,920,433	$ 47,488,108	$ 157,432,325		$ 157,432,325	$ 4,083,959	$ 161,516,284

Monthly Jurisdictional Allocation Ratios

		Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
Line	Month	Whlse (Wstville)	Retail	Total	Whlse (Wstville)	Retail
Actual						
5	Oct-10	-	1,494,572,195	1,494,572,195	0.00000	1.00000
6	Nov-10	-	1,656,181,533	1,656,181,533	0.00000	1.00000
7	Dec-10	-	1,819,125,814	1,819,125,814	0.00000	1.00000
Forecast						
8	April '11		1,394,099,169	1,394,099,169	0.00000	1.00000
9	May '11		1,459,140,596	1,459,140,596	0.00000	1.00000
10	June '11		1,632,546,394	1,632,546,394	0.00000	1.00000

Exhibit 7-21
OPCO Schedule 3, Page 2, April – June 2011

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2011 through June 2011
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
1	Oct-10	$ 123,971,360	$ 63,974,520	$ 59,996,840	0.91477	$ 54,883,309	$ 1,242,794	$ 56,126,103
2	Nov-10	$ 117,031,909	$ 54,899,487	$ 62,132,422	0.91754	$ 57,008,982	$ 1,444,340	$ 58,453,322
3	Dec-10	$ 127,433,159	$ 55,302,444	$ 72,130,715	0.91960	$ 66,331,406	$ 1,581,052	$ 67,912,458
4	Total	$ 368,436,428	$ 174,176,451	$ 194,259,977		$ 178,223,697	$ 4,268,186	$ 182,491,883

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (WPC)	Retail	Total	Whlse (WPC)	Retail
Actual						
5	Oct-10	192,687,116	2,068,223,016	2,260,910,132	0.08523	0.91477
6	Nov-10	193,612,924	2,154,222,857	2,347,835,781	0.08246	0.91754
7	Dec-10	220,282,858	2,519,685,892	2,739,968,750	0.08040	0.91960
Forecast						
8	Apr-11	179,550,011	2,096,483,451	2,276,033,462	0.07889	0.92111
9	May-11	186,450,620	2,128,383,403	2,314,834,023	0.08055	0.91945
10	Jun-11	191,237,255	2,266,290,385	2,457,527,640	0.07782	0.92218

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the fourth quarter of 2010. Specifically, page 2 of Schedule 3 (lines 1-4) shows, for each Company, total monthly FAC costs incurred from October through December 2010. 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 2010, CSP and OPCO added amounts totaling $4,083,959 and $4,268,186, 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 2010 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for October through December 2010. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for April through June 2011, 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 1.0 for each month of April, May and June 2011 for CSP and .92111, .91945 and .92218 (April, May and June 2011, respectively) for OPCO.

Exhibit 7-22
CSP Schedule 3, Page 3, April – June 2011

Schedule 3
Page 3 of 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2011 through June 2011
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Oct-10	$ -	$ 95,286	$ 95,286
2	Nov-10	$ -	$ 88,556	$ 88,556
3	Dec-10	$ -	$ 60,958	$ 60,958
4	Total	$ -	$ 244,799	$ 244,799

Exhibit 7-23
OPCO Schedule 3, Page 3, April – June 2011

Schedule 3
Page 3 of 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2011 through June 2011
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Oct-10	$ -	$ 303,030	$ 303,030
2	Nov-10	$ -	$ 302,040	$ 302,040
3	Dec-10	$ -	$ 302,040	$ 302,040
4	Total	$ -	$ 907,109	$ 907,109

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.

Exhibit 7-24
CSP Schedule 4, April – June 2011

Schedule 4

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2011 through June 2011
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	4.21352
2	GS-1	Secondary	4.07779
3	GS-2	Secondary	4.19207
4	GS-2	Primary	4.05535
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	4.19207
6	GS-3	Secondary	3.88835
7	GS-3	Primary	3.76153
8	GS-3-LM-TOD	Secondary	3.88835
9	GS-4	Sub/Transmission	3.39096
10	IRP-D	Secondary	3.57303
11	IRP-D	Primary	3.45649
12	IRP-D	Sub/Transmission	3.39096
13	SL	Secondary	4.79251
14	AL	Secondary	5.81988
15	SBS	Secondary	3.97020
16	SBS	Primary	3.76788
17	SBS	Sub/Transmission	3.39096

Exhibit 7-25
OPCO Schedule 4, April – June 2011

Schedule 4

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2011 through June 2011
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	3.18012
2	GS-1	Secondary	3.29131
3	GS-2	Secondary	3.00046
4	GS-2	Primary	2.89296
5	GS-2	Sub/Transmission	2.82345
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	3.00046
7	GS-3	Secondary	2.82459
8	GS-3	Primary	2.72339
9	GS-3	Sub/Transmission	2.65795
10	GS-3-ES	Secondary	2.82459
11	GS-4	Primary	2.43472
12	GS-4	Sub/Transmission	2.37622
13	IRP-D	Secondary	2.52519
14	IRP-D	Primary	2.43472
15	IRP-D	Sub/Transmission	2.37622
16	EHG	Secondary	3.02127
17	EHS	Secondary	2.60641
18	SS	Secondary	2.91048
19	OL	Secondary	4.44636
20	SL	Secondary	3.81544
21	SBS	Secondary	2.91311
22	SBS	Primary	2.72600
23	SBS	Sub/Transmission	2.42134

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 third quarter of 2011 (i.e. the proposed FAC rates from AEP Ohio's first quarter 2011 FAC filing) for OPCO and the lower of the current FAC rates or the total of the FC and RA components become effective for CSP.

Third Quarter 2011

On June 1, 2011, AEP Ohio submitted quarterly FAC filings for CSP and OPCO, which reflected actual data from January through March 2011 and projected data for the period July through

September 2011. 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 third quarter 2011 FAC filings by reproducing Schedules 1 through 4, broken out separately between CSP and OPCO as Exhibits 7.26 through 7.37, and then briefly summarizing each schedule.

Exhibit 7-26
CSP Schedule 1, July – September 2011

Schedule 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2011 through September 2011
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	3.18012	3.15364	8.18808	11.34172	**3.27533**
2	GS-1	Secondary	3.29131	3.15364	8.18808	11.34172	**3.37470**
3	GS-2	Secondary	3.00046	3.15364	8.18808	11.34172	**2.71690**
4	GS-2	Primary	2.89296	3.04065	7.89471	10.93536	**2.61956**
5	GS-2	Sub/Transmission	2.82345	2.96759	7.70502	10.67261	**2.55662**
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	3.00046	3.15364	8.18808	11.34172	**2.71690**
7	GS-3	Secondary	2.82459	3.15364	8.18808	11.34172	**2.68319**
8	GS-3	Primary	2.72339	3.04065	7.89471	10.93536	**2.58705**
9	GS-3	Sub/Transmission	2.65795	2.96759	7.70502	10.67261	**2.52489**
10	GS-3-ES	Secondary	2.82459	3.15364	8.18808	11.34172	**2.68319**
11	GS-4	Primary	2.43472	3.04065	7.89471	10.93536	**2.45960**
12	GS-4	Sub/Transmission	2.37622	2.96759	7.70502	10.67261	**2.40051**
13	IRP-D	Secondary	2.52519	3.15364	8.18808	11.34172	**2.55100**
14	IRP-D	Primary	2.43472	3.04065	7.89471	10.93536	**2.45960**
15	IRP-D	Sub/Transmission	2.37622	2.96759	7.70502	10.67261	**2.40051**
16	EHG	Secondary	3.02127	3.15364	8.18808	11.34172	**3.14564**
17	EHS	Secondary	2.60641	3.15364	8.18808	11.34172	**2.72653**
18	SS	Secondary	2.91048	3.15364	8.18808	11.34172	**2.98211**
19	OL	Secondary	4.44636	3.15364	8.18808	11.34172	**4.57953**
20	SL	Secondary	3.81544	3.15364	8.18808	11.34172	**3.92403**
21	SBS	Secondary	2.91311	3.15364	8.18808	11.34172	**2.70036**
22	SBS	Primary	2.72600	3.04065	7.89471	10.93536	**2.58393**
23	SBS	Sub/Transmission	2.42134	2.96759	7.70502	10.67261	**2.41857**

Exhibit 7-27
OPCO Schedule 1, July – September 2011

Schedule 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2011 through September 2011
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	3.18012	3.15364	8.18808	11.34172	**3.27533**
2	GS-1	Secondary	3.29131	3.15364	8.18808	11.34172	**3.37470**
3	GS-2	Secondary	3.00046	3.15364	8.18808	11.34172	**2.71690**
4	GS-2	Primary	2.89296	3.04065	7.89471	10.93536	**2.61956**
5	GS-2	Sub/Transmission	2.82345	2.96759	7.70502	10.67261	**2.55662**
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	3.00046	3.15364	8.18808	11.34172	**2.71690**
7	GS-3	Secondary	2.82459	3.15364	8.18808	11.34172	**2.68319**
8	GS-3	Primary	2.72339	3.04065	7.89471	10.93536	**2.58705**
9	GS-3	Sub/Transmission	2.65795	2.96759	7.70502	10.67261	**2.52489**
10	GS-3-ES	Secondary	2.82459	3.15364	8.18808	11.34172	**2.68319**
11	GS-4	Primary	2.43472	3.04065	7.89471	10.93536	**2.45960**
12	GS-4	Sub/Transmission	2.37622	2.96759	7.70502	10.67261	**2.40051**
13	IRP-D	Secondary	2.52519	3.15364	8.18808	11.34172	**2.55100**
14	IRP-D	Primary	2.43472	3.04065	7.89471	10.93536	**2.45960**
15	IRP-D	Sub/Transmission	2.37622	2.96759	7.70502	10.67261	**2.40051**
16	EHG	Secondary	3.02127	3.15364	8.18808	11.34172	**3.14564**
17	EHS	Secondary	2.60641	3.15364	8.18808	11.34172	**2.72653**
18	SS	Secondary	2.91048	3.15364	8.18808	11.34172	**2.98211**
19	OL	Secondary	4.44636	3.15364	8.18808	11.34172	**4.57953**
20	SL	Secondary	3.81544	3.15364	8.18808	11.34172	**3.92403**
21	SBS	Secondary	2.91311	3.15364	8.18808	11.34172	**2.70036**
22	SBS	Primary	2.72600	3.04065	7.89471	10.93536	**2.58393**
23	SBS	Sub/Transmission	2.42134	2.96759	7.70502	10.67261	**2.41857**

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 July through September 2011. 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 March 2011. 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 request that the lower of Columns D and E be implemented for CSP and OPCO's filings reflect the then current FAC rates as shown in Column E.

Exhibit 7-28
CSP Schedule 2, July – September 2011

Schedule 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2011 through September 2011
FC Component

Line	Description		Forecast Period July	August	September	Total
1	Fuel & Purchased Power		116,801,827	114,837,256	100,542,064	$ 332,181,147
2	Environmental (Consumables and Allowances)		4,545,902	4,698,433	4,011,828	$ 13,256,162
3	(Gains) and Losses On Sales of Allowances		-	-	-	$ -
4	Other					$ -
5	Total Includible FAC Costs		$ 121,347,729	$ 119,535,689	$ 104,553,892	$ 345,437,310
6	Less: Assigned to Off-System (Including AEP Affiliates)		59,923,331	59,005,378	53,976,137	$ 172,904,845
7	FAC for Internal Load		$ 61,424,398	$ 60,530,311	$ 50,577,755	$ 172,532,464
						0
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	1.00000	1.00000	1.00000	1.00000
9	FAC for Retail Load Before Renewables		$ 61,424,398	$ 60,530,311	$ 50,577,755	$ 172,532,464
10	Renewables/RECs		1,449,035	1,310,466	1,476,451	$ 4,235,952
11	FAC for Retail Load		$ 62,873,433	$ 61,840,777	$ 52,054,206	$ 176,768,416
12	Retail Non-Shopping Sales - Generation Level Kwh		1,809,779,881	1,788,012,352	1,460,348,985	5,058,141,219
13	FC Component of FAC Rate At Generation Level - Cents/kWh					3.49473
			Secondary	**Primary**	**Sub/Trans**	
14	FC Component of FAC Rate At Generation Level		3.49473	3.49473	3.49473	
15	Loss Factor		1.0578	1.0233	1.0039	
16	**FC at the Meter Level - Cents/kWh**	Line 14 x Line 15	**3.69673**	**3.57616**	**3.50836**	

Exhibit 7-29
OPCO Schedule 2, July – September 2011

Schedule 2

1000000
OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2011 through September 2011
FC Component

Line	Description		Forecast Period - 3rd Quarter 2011 July	August	September	Total
1	Fuel & Purchased Power		$ 82,606,624	$ 85,100,271	$ 60,145,051	$ 227,851,945
2	Environmental (Consumables and Allowances)		$ 12,653,719	$ 12,860,174	$ 10,868,416	$ 36,382,309
3	(Gains) and Losses On Sales of Allowances		$ (184,311)	$ (184,311)	$ (184,311)	$ (552,932)
4	Other		$ -	$ -	$ -	$ -
5	Total Includible FAC Costs		$ 95,076,032	$ 97,776,134	$ 70,829,156	$ 263,681,322
6	Less: Assigned to Off-System (Including AEP Affiliates)		$ 20,216,547	$ 21,617,903	$ 3,553,443	$ 45,387,893
7	FAC for Internal Load		$ 74,859,485	$ 76,158,231	$ 67,275,713	$ 218,293,428
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92237	0.91899	0.92125	0.92237
9	FAC for Retail Load Before Renewables		$ 69,048,143	$ 69,988,653	$ 61,977,750	$ 201,347,310
10	Renewables/RECs		$ 1,572,313	$ 1,428,823	$ 1,580,822	$ 4,581,959
11	FAC for Retail Load		$ 70,620,456	$ 71,417,476	$ 63,558,573	$ 205,929,268
12	Retail Non-Shopping Sales - Generation Level Kwh		2,414,878,407	2,369,304,365	2,177,993,461	6,962,176,233
13	FC Component of FAC Rate At Generation Level - Cents/kWh					2.95783
			Secondary	**Primary**	**Sub/Trans**	
14	FC Component of FAC Rate At Generation Level		2.95783	2.95783	2.95783	
15	Loss Factor		1.0662	1.0280	1.0033	
16	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**3.15364**	**3.04065**	**2.96759**	

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period July through September 2011. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the third quarter of 2011, AEP Ohio has projected includable FAC costs totaling $345.437 million for CSP and $263.681 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 third quarter of 2011, these projected off-system costs totaled $172.905 million for CSP and $45.387 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 their 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 $4.236 million for CSP and $4.582 million for OPCO. The addition of the RECs result in total FAC costs for retail load of $176.768 million for CSP and $205.929 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.49473 cents per kWh for CSP and 2.95783 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 3.69673, 3.57616 and 3.50836 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 3.15364, 3.04065 and 2.96759 cents per kWh.

Exhibit 7-30
CSP Schedule 3, Page 1, July – September 2011

Schedule 3
Page 1 of 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2011 through September 2011
RA Component

Actual Period - January 2011 through March 2011

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**							$ -
2	Jan-11	1,758,968,520	$ 59,981,003	$ 69,754,722	$ 9,773,719	$ -	$ (1,686,346)	$ 8,087,373
3	Feb-11	1,463,750,121	$ 49,659,043	$ 51,020,961	$ 1,361,918	$ 68,600	$ (5,952)	$ 1,424,566
4	Mar-11	1,456,829,865	$ 50,327,518	$ 60,348,067	$ 10,020,549	$ 81,294	$ (5,952)	$ 10,095,891
5	**Ending Balance**	4,679,548,506	$ 159,967,564	$ 181,123,750	$ 21,156,186	$ 149,894	$ (1,698,250)	$ 19,607,830
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ -
7	Total (Over)/Under Recovery Balance							$ 19,607,830
8	Loss Adjusted Retail Sales Billing Period - kWh							5,058,141,219
9	RA Component at Generation - Cents/kWh							0.38765

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		0.38765	0.38765	0.38765
11	Loss Factor		1.0578	1.0233	1.0039
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**0.41006**	**0.39668**	**0.38916**

Exhibit 7-31
OPCO Schedule 3, Page 1, July – September 2011

Schedule 3
Page 1 of 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2011 through September 2011
RA

Actual Period - January 2011 through March 2011

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**							$ 505,662,771
2	Jan-11	2,475,267,750	$ 62,356,928	$ 70,711,863	$ 8,354,935	$ 3,963,191	$ (139,890)	$ 12,178,236
3	Feb-11	2,193,095,040	$ 60,723,509	$ 62,447,478	$ 1,723,969	$ 4,039,584	$ (139,890)	$ 5,623,663
4	Mar-11	2,312,154,880	$ 64,923,712	$ 71,315,083	$ 6,391,371	$ 4,050,871	$ (139,737)	$ 10,302,505
5	**Ending Balance**	6,980,517,670	$ 188,004,149	$ 204,474,424	$ 16,470,275	$ 12,053,646	$ (419,518)	$ 533,767,174
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 905,789
7	Total (Over)/Under Recovery Balance							$ 534,672,963
8	Loss Adjusted Retail Sales Billing Period - kWh							6,962,176,233
9	RA Component at Generation - Cents/kWh							7.67968

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		7.67968	7.67968	7.67968
11	Loss Factor		1.0662	1.0280	1.0033
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**8.18808**	**7.89471**	**7.70502**

Schedule 3: This three-page schedule represents the Companies' RA components of their third quarter 2011 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 January through March 2011, which were calculated as the difference between the monthly FAC revenues for the first quarter of 2011 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 $19.608 million for CSP and $533.767 million for OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with Ormet. For the first quarter of 2011, these deferrals totaled $905,789 for OPCO. There were no deferrals recorded for CSP. 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 first quarter of 2011 was $19.608 million and $534.673 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 0.38765 cents per kWh and 7.67968 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 0.41006, 0.39668 and 0.38916 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 8.18808, 7.89471 and 7.70502 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Similar to its previous quarterly filings, AEP Ohio stated that it is probable that OPCO will have a long-term deferral to be recovered subsequent to the end of the ESP period.

Exhibit 7-32
CSP Schedule 3, Page 2, July – September 2011

Schedule 3
Page 2 of 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2011 through September 2011
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
1	Jan-11	$ 95,058,588	$ 26,634,147	$ 68,424,441	1.00000	$ 68,424,441	$ 1,330,281	$ 69,754,722
2	Feb-11	$ 68,855,744	$ 19,477,049	$ 49,378,695	1.00000	$ 49,378,695	$ 1,642,266	$ 51,020,961
3	Mar-11	$ 83,391,277	$ 24,695,537	$ 58,695,740	1.00000	$ 58,695,740	$ 1,652,327	$ 60,348,067
4	Total	$ 247,305,609	$ 70,806,733	$ 176,498,876		$ 176,498,876	$ 4,624,874	$ 181,123,750

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh Whlse (Wstville)	Jurisdictional Sales at Gen Level Kwh Retail	Jurisdictional Sales at Gen Level Kwh Total	Jurisdictional Ratios Whlse (Wstville)	Jurisdictional Ratios Retail
Actual						
5	Jan-11	-	1,837,920,245	1,837,920,245	0.00000	1.00000
6	Feb-11	-	1,526,461,808	1,526,461,808	0.00000	1.00000
7	Mar-11	-	1,515,968,453	1,515,968,453	0.00000	1.00000
Forecast						
8	July '11		1,809,779,881	1,809,779,881	0.00000	1.00000
9	Aug '11		1,788,012,352	1,788,012,352	0.00000	1.00000
10	Sep '11		1,460,348,985	1,460,348,985	0.00000	1.00000

Exhibit 7-33
OPCO Schedule 3, Page 2, July – September 2011

Schedule 3
Page 2 of 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2011 through September 2011
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
1	Jan-11	$ 141,007,067	$ 65,843,255	$ 75,163,812	0.92204	$ 69,304,041	$ 1,407,822	$ 70,711,863
2	Feb-11	$ 118,010,268	$ 52,196,702	$ 65,813,566	0.92263	$ 60,721,570	$ 1,725,908	$ 62,447,478
3	Mar-11	$ 129,279,477	$ 53,563,452	$ 75,716,025	0.91842	$ 69,539,112	$ 1,775,971	$ 71,315,083
4	Total	$ 388,296,812	$ 171,603,409	$ 216,693,403		$ 199,564,723	$ 4,909,701	$ 204,474,424

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh Whlse (WPC)	Jurisdictional Sales at Gen Level Kwh Retail	Jurisdictional Sales at Gen Level Kwh Total	Jurisdictional Ratios Whlse (WPC)	Jurisdictional Ratios Retail
Actual						
5	Jan-11	218,201,347	2,580,776,346	2,798,977,693	0.07796	0.92204
6	Feb-11	191,000,745	2,277,815,191	2,468,815,936	0.07737	0.92263
7	Mar-11	213,384,646	2,402,198,808	2,615,583,454	0.08158	0.91842
Forecast						
8	Jul-11	203,241,300	2,414,878,407	2,618,119,706	0.07763	0.92237
9	Aug-11	208,857,055	2,369,304,365	2,578,161,420	0.08101	0.91899
10	Sep-11	186,185,693	2,177,993,461	2,364,179,154	0.07875	0.92125

Page 2 of Schedule 3 reflects monthly data on the Companies' actual fuel costs during the first quarter of 2011. Specifically, page 2 of Schedule 3 (lines 1-4) shows, for each Company, total monthly FAC costs incurred from January through March 2011. For each month (January through March), 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 first quarter of 2011, CSP and OPCO added amounts totaling $4,624,874 and $4,909,701, 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 first quarter of 2011 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for January through March 2011. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for July through September 2011, 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 1.00000 for each month of July, August and September 2010 for CSP and .92237, .91899 and .92125 (July, August and September 2011, respectively) for OPCO.

Exhibit 7-34
CSP Schedule 3, Page 3, July – September 2011

Schedule 3
Page 3 of 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2011 through September 2011
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Jan-11	$ -	$ -	$ -
2	Feb-11	$ -	$ -	$ -
3	Mar-11	$ -	$ -	$ -
4	Total	$ -	$ -	$ -

Exhibit 7-35
OPCO Schedule 3, Page 3, July – September 2011

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2011 through September 2011
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Jan-11	$ -	$ 302,040	$ 302,040
2	Feb-11	$ -	$ 302,040	$ 302,040
3	Mar-11	$ -	$ 301,710	$ 301,710
4	Total	$ -	$ 905,789	$ 905,789

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.

Exhibit 7-36
CSP Schedule 4, July – September 2011

Schedule 4

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2011 through September 2011
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	4.70591
2	GS-1	Secondary	4.49783
3	GS-2	Secondary	4.56910
4	GS-2	Primary	4.42008
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	4.56910
6	GS-3	Secondary	4.13114
7	GS-3	Primary	3.99641
8	GS-3-LM-TOD	Secondary	4.13114
9	GS-4	Sub/Transmission	3.50271
10	IRP-D	Secondary	3.69077
11	IRP-D	Primary	3.57040
12	IRP-D	Sub/Transmission	3.50271
13	SL	Secondary	5.74685
14	AL	Secondary	7.40422
15	SBS	Secondary	4.25081
16	SBS	Primary	4.00635
17	SBS	Sub/Transmission	3.50271

Exhibit 7-37
OPCO Schedule 4, July – September 2011

Schedule 4

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
July 2011 through September 2011
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	3.27533
2	GS-1	Secondary	3.37470
3	GS-2	Secondary	2.71690
4	GS-2	Primary	2.61956
5	GS-2	Sub/Transmission	2.55662
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.71690
7	GS-3	Secondary	2.68319
8	GS-3	Primary	2.58705
9	GS-3	Sub/Transmission	2.52489
10	GS-3-ES	Secondary	2.68319
11	GS-4	Primary	2.45960
12	GS-4	Sub/Transmission	2.40051
13	IRP-D	Secondary	2.55100
14	IRP-D	Primary	2.45960
15	IRP-D	Sub/Transmission	2.40051
16	EHG	Secondary	3.14564
17	EHS	Secondary	2.72653
18	SS	Secondary	2.98211
19	OL	Secondary	4.57953
20	SL	Secondary	3.92403
21	SBS	Secondary	2.70036
22	SBS	Primary	2.58393
23	SBS	Sub/Transmission	2.41857

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 third quarter of 2011 (i.e. the proposed FAC rates from AEP Ohio's first quarter 2011 FAC filing) for OPCO and the lower of the current FAC rates or the total of the FC and RA components become effective for CSP.

Fourth Quarter 2011

On September 1, 2011, AEP Ohio submitted quarterly FAC filings for CSP and OPCO, which reflected actual data from April through June 2011 and projected data for the period October through December 2011. 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 fourth quarter 2011 FAC filings by reproducing Schedules 1 through 4, broken out separately between CSP and OPCO as Exhibits 7.38 through 7.49, and then briefly summarizing each schedule.

Exhibit 7-38
CSP Schedule 1, October – December 2011

Schedule 1

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2011 through December 2011
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	4.10679	3.82715	0.67222	4.49937	**4.70591**
2	GS-1	Secondary	4.10679	3.82715	0.67222	4.49937	**4.49783**
3	GS-2	Secondary	4.10679	3.82715	0.67222	4.49937	**4.56910**
4	GS-2	Primary	3.97284	3.70233	0.65029	4.35262	**4.42008**
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	4.10679	3.82715	0.67222	4.49937	**4.56910**
6	GS-3	Secondary	4.10679	3.82715	0.67222	4.49937	**4.13114**
7	GS-3	Primary	3.97284	3.70233	0.65029	4.35262	**3.99641**
8	GS-3-LM-TOD	Secondary	4.10679	3.82715	0.67222	4.49937	**4.13114**
9	GS-4	Sub/Transmission	3.50271	3.63214	0.63797	4.27011	**3.50271**
10	IRP-D	Secondary	3.69077	3.82715	0.67222	4.49937	**3.69077**
11	IRP-D	Primary	3.57040	3.70233	0.65029	4.35262	**3.57040**
12	IRP-D	Sub/Transmission	3.50271	3.63214	0.63797	4.27011	**3.50271**
13	SL	Secondary	4.10679	3.82715	0.67222	4.49937	**5.74685**
14	AL	Secondary	4.10679	3.82715	0.67222	4.49937	**7.40422**
15	SBS	Secondary	4.10679	3.82715	0.67222	4.49937	**4.25081**
16	SBS	Primary	3.97284	3.70233	0.65029	4.35262	**4.00635**
17	SBS	Sub/Transmission	3.50271	3.63214	0.63797	4.27011	**3.50271**

Exhibit 7-39
OPCO Schedule 1, October – December 2011

Schedule 1

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2011 through December 2011
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	3.27533	3.31292	9.20228	12.51520	**3.27533**
2	GS-1	Secondary	3.37470	3.31292	9.20228	12.51520	**3.37470**
3	GS-2	Secondary	2.71690	3.31292	9.20228	12.51520	**2.71690**
4	GS-2	Primary	2.61956	3.19422	8.87258	12.06680	**2.61956**
5	GS-2	Sub/Transmission	2.55662	3.11747	8.65939	11.77686	**2.55662**
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.71690	3.31292	9.20228	12.51520	**2.71690**
7	GS-3	Secondary	2.68319	3.31292	9.20228	12.51520	**2.68319**
8	GS-3	Primary	2.58705	3.19422	8.87258	12.06680	**2.58705**
9	GS-3	Sub/Transmission	2.52489	3.11747	8.65939	11.77686	**2.52489**
10	GS-3-ES	Secondary	2.68319	3.31292	9.20228	12.51520	**2.68319**
11	GS-4	Primary	2.45960	3.19422	8.87258	12.06680	**2.45960**
12	GS-4	Sub/Transmission	2.40051	3.11747	8.65939	11.77686	**2.40051**
13	IRP-D	Secondary	2.55100	3.31292	9.20228	12.51520	**2.55100**
14	IRP-D	Primary	2.45960	3.19422	8.87258	12.06680	**2.45960**
15	IRP-D	Sub/Transmission	2.40051	3.11747	8.65939	11.77686	**2.40051**
16	EHG	Secondary	3.14564	3.31292	9.20228	12.51520	**3.14564**
17	EHS	Secondary	2.72653	3.31292	9.20228	12.51520	**2.72653**
18	SS	Secondary	2.98211	3.31292	9.20228	12.51520	**2.98211**
19	OL	Secondary	4.57953	3.31292	9.20228	12.51520	**4.57953**
20	SL	Secondary	3.92403	3.31292	9.20228	12.51520	**3.92403**
21	SBS	Secondary	2.70036	3.31292	9.20228	12.51520	**2.70036**
22	SBS	Primary	2.58393	3.19422	8.87258	12.06680	**2.58393**
23	SBS	Sub/Transmission	2.41857	3.11747	8.65939	11.77686	**2.41857**

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 2011. 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 June 2011. 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' request that the lower of Columns D and E be implemented for CSP and OPCO's filings reflect the then current FAC rates as shown in Column E.

Exhibit 7-40
CSP Schedule 2, October – December 2011

Schedule 2

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2011 through December 2011
FC Component

Line	Description		Forecast Period October	November	December	Total
1	Fuel & Purchased Power		53,899,166	52,965,694	58,347,937	$ 165,212,797
2	Environmental (Consumables and Allowances)		4,094,506	4,010,329	5,183,847	$ 13,288,682
3	(Gains) and Losses On Sales of Allowances		-	-	-	$ -
4	Other					$ -
5	Total Includible FAC Costs		$ 57,993,671	$ 56,976,023	$ 63,531,784	$ 178,501,479
6	Less: Assigned to Off-System (Including AEP Affiliates)		9,069,500	7,262,150	9,032,729	$ 25,364,380
7	FAC for Internal Load		$ 48,924,171	$ 49,713,873	$ 54,499,055	$ 153,137,099
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	1.00000	1.00000	1.00000	1.00000
9	FAC for Retail Load Before Renewables		$ 48,924,171	$ 49,713,873	$ 54,499,055	$ 153,137,099
10	Renewables/RECs		2,102,976	2,361,434	2,773,783	$ 7,238,193
11	FAC for Retail Load		$ 51,027,147	$ 52,075,307	$ 57,272,838	$ 160,375,292
12	Retail Non-Shopping Sales - Generation Level Kwh		1,407,175,703	1,368,052,475	1,657,444,167	4,432,672,345
13	FC Component of FAC Rate At Generation Level - Cents/kWh					3.61803

Line	Description		Secondary	Primary	Sub/Trans
14	FC Component of FAC Rate At Generation Level		3.61803	3.61803	3.61803
15	Loss Factor		1.0578	1.0233	1.0039
16	**FC at the Meter Level - Cents/kWh**	Line 14 x Line 15	**3.82715**	**3.70233**	**3.63214**

Exhibit 7-41
OPCO Schedule 2, October – December 2011

Schedule 2

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2011 through December 2011
FC Component

Line	Description		Forecast Period - 4th Quarter 2011 October	November	December	Total
1	Fuel & Purchased Power		88,718,219	87,299,530	100,487,471	$ 276,505,221
2	Environmental (Consumables and Allowances)		9,784,817	8,889,456	12,533,226	$ 31,207,500
3	(Gains) and Losses On Sales of Allowances		(174,623)	(174,623)	4,907,377	$ 4,558,131
4	Other		-	-	-	$ -
5	Total Includible FAC Costs		$ 98,328,414	$ 96,014,363	$ 117,928,075	$ 312,270,851
6	Less: Assigned to Off-System (Including AEP Affiliates)		32,217,652	26,325,330	39,336,175	$ 97,879,157
7	FAC for Internal Load		$ 66,110,762	$ 69,689,033	$ 78,591,900	$ 214,391,695
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92061	0.91923	0.92438	0.92061
9	FAC for Retail Load Before Renewables		$ 60,862,228	$ 64,060,250	$ 72,648,781	$ 197,371,138
10	Renewables/RECs		2,192,643	2,433,385	2,841,041	$ 7,467,069
11	FAC for Retail Load		$ 63,054,872	$ 66,493,634	$ 75,489,822	$ 204,838,208
12	Retail Non-Shopping Sales - Generation Level Kwh		2,140,500,177	2,121,484,066	2,330,336,569	6,592,320,813
13	FC Component of FAC Rate At Generation Level - Cents/kWh					3.10722
			Secondary	**Primary**	**Sub/Trans**	
14	FC Component of FAC Rate At Generation Level		3.10722	3.10722	3.10722	
15	Loss Factor		1.0662	1.0280	1.0033	
16	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**3.31292**	**3.19422**	**3.11747**	

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period October through December 2011. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the fourth quarter of 2011, AEP Ohio has projected includable FAC costs totaling $178.501 million for CSP and $312.271 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 fourth quarter of 2011, these projected off-system costs totaled $25.364 million for CSP and $97.879 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 $7.238 million for CSP and $7.467 million for OPCO. The addition of the RECs result in total FAC costs for retail load of $160.375 million for CSP and $204.838 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.61803 cents per kWh for CSP and 3.10722 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 3.82715, 3.70233 and 3.63214 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 3.31292, 3.19422 and 3.11747 cents per kWh.

Exhibit 7-42
CSP Schedule 3, Page 1, October – December 2011

Schedule 3
Page 1 of 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2011 through December 2011
RA Component

Actual Period - April 2011 through June 2011

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**							$ 19,607,830
2	Apr-11	1,266,028,273	$ 45,149,792	$ 47,190,159	$ 2,040,367	$ 173,641	$ (627,417)	$ 1,586,590
3	May-11	1,383,316,034	$ 49,509,538	$ 54,230,675	$ 4,721,137	$ 192,627	$ -	$ 4,913,764
4	Jun-11	1,490,708,638	$ 55,880,469	$ 57,704,975	$ 1,824,506	$ 236,360	$ -	$ 2,060,866
5	**Ending Balance**	4,140,052,945	$ 150,539,799	$ 159,125,809	$ 8,586,010	$ 602,628	$ (627,417)	$ 28,169,051
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ -
7	Total (Over)/Under Recovery Balance							$ 28,169,051
8	Loss Adjusted Retail Sales Billing Period - kWh							4,432,672,345
9	RA Component at Generation - Cents/kWh							0.63549

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		0.63549	0.63549	0.63549
11	Loss Factor		1.0578	1.0233	1.0039
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**0.67222**	**0.65029**	**0.63797**

Exhibit 7-43
OPCO Schedule 3, Page 1, October – December 2011

Schedule 3
Page 1 of 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2011 through December 2011
RA

Actual Period - April 2011 through June 2011

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**							$ 534,672,963
2	Apr-11	1,981,853,697	$ 54,387,687	$ 61,250,606	$ 6,862,919	$ 4,131,713	$ (140,502)	$ 10,854,131
3	May-11	2,138,486,743	$ 58,518,459	$ 67,283,684	$ 8,765,225	$ 4,231,244	$ (141,725)	$ 12,854,744
4	Jun-11	2,185,211,910	$ 60,297,411	$ 65,826,180	$ 5,528,769	$ 4,293,834	$ (141,113)	$ 9,681,490
5	**Ending Balance**	6,305,552,350	$ 173,203,557	$ 194,360,470	$ 21,156,913	$ 12,656,792	$ (423,340)	$ 568,063,327
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 914,041
7	Total (Over)/Under Recovery Balance							$ 568,977,369
8	Loss Adjusted Retail Sales Billing Period - kWh							6,592,320,813
9	RA Component at Generation - Cents/kWh							8.63091

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		8.63091	8.63091	8.63091
11	Loss Factor		1.0662	1.0280	1.0033
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**9.20228**	**8.87258**	**8.65939**

Schedule 3: This three-page schedule represents the Companies' RA components of their second quarter 2011 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 April through June 2011, which were calculated as the difference between the monthly FAC revenues for the second quarter of 2011 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 $28.169 million for CSP and $568.063 million for OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with Ormet. For the second quarter of 2011, these deferrals totaled $0 for CSP and $914,041 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 second quarter of 2011 was $28.169 million and $568.977 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 0.63549 cents per kWh and 8.63091 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 0.67222, 0.65029 and 0.63797 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 9.20228, 8.87258 and 8.65939 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Similar to its previous quarterly filings, AEP Ohio stated that it is probable that OPCO will have a long-term deferral to be recovered subsequent to the end of the ESP period.

Exhibit 7-44
CSP Schedule 3, Page 2, October – December 2011

Schedule 3
Page 2 of 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2011 through December 2011
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
1	Apr-11	$ 74,310,885	$ 28,619,861	$ 45,691,024	1.00000	$ 45,691,024	$ 1,499,135	$ 47,190,159
2	May-11	$ 72,764,768	$ 19,693,707	$ 53,071,061	1.00000	$ 53,071,061	$ 1,159,614	$ 54,230,675
3	Jun-11	$ 93,451,549	$ 36,606,475	$ 56,845,074	1.00000	$ 56,845,074	$ 859,901	$ 57,704,975
4	Total	$ 240,527,202	$ 84,920,043	$ 155,607,159		$ 155,607,159	$ 3,518,650	$ 159,125,809

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (Wstville)	Retail	Total	Whlse (Wstville)	Retail
Actual						
5	Apr-11	-	1,316,025,135	1,316,025,135	0.00000	1.00000
6	May-11	-	1,437,559,708	1,437,559,708	0.00000	1.00000
7	Jun-11	-	1,551,593,038	1,551,593,038	0.00000	1.00000
Forecast						
8	Oct-11		1,407,175,703	1,407,175,703	0.00000	1.00000
9	Nov-11		1,368,052,475	1,368,052,475	0.00000	1.00000
10	Dec-11		1,657,444,167	1,657,444,167	0.00000	1.00000

Exhibit 7-45
]OPCO Schedule 3, Page 2, October – December 2011

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2011 through December 2011
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
1	Apr-11	$ 119,005,956	$ 54,419,487	$ 64,586,469	0.92394	$ 59,674,022	$ 1,576,584	$ 61,250,606
2	May-11	$ 100,422,758	$ 28,737,024	$ 71,685,734	0.92137	$ 66,049,085	$ 1,234,599	$ 67,283,684
3	Jun-11	$ 146,332,183	$ 76,035,624	$ 70,296,559	0.92292	$ 64,878,100	$ 948,080	$ 65,826,180
4	Total	$ 365,760,897	$ 159,192,135	$ 206,568,762		$ 190,601,207	$ 3,759,263	$ 194,360,470

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (WPC)	Retail	Total	Whlse (WPC)	Retail
Actual						
5	Apr-11	168,826,577	2,050,855,400	2,219,681,977	0.07606	0.92394
6	May-11	188,926,086	2,213,797,395	2,402,723,481	0.07863	0.92137
7	Jun-11	189,305,999	2,266,651,475	2,455,957,474	0.07708	0.92292
Forecast						
8	Oct-11	184,590,517	2,140,500,177	2,325,090,695	0.07939	0.92061
9	Nov-11	186,418,512	2,121,484,066	2,307,902,578	0.08077	0.91923
10	Dec-11	190,642,214	2,330,336,569	2,520,978,783	0.07562	0.92438

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the second quarter of 2011. Specifically, page 2 of Schedule 3 (lines 1-4) shows, for each Company, total monthly FAC costs incurred from April through June 2011. For each month (April 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 monthly retail sales at the generation level divided by total sales at the generation level to derive its "Retail FAC Before Renewables". During the second quarter of 2011, CSP and OPCO added amounts totaling $3,518,650 and $3,759,263, 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 second quarter of 2010 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for April through June 2011. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for October through December 2011, 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 1.00000 for each month of October, November and December 2010 for CSP and .92061, .91923 and .92438 (October, November and December 2011, respectively) for OPCO.

Exhibit 7-46
CSP Schedule 3, Page 3, October – December 2011

Schedule 3
Page 3 of 3

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2011 through December 2011
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Apr-11	$ -	$ -	$ -
2	May-11	$ -	$ -	$ -
3	Jun-11	$ -	$ -	$ -
4	Total	$ -	$ -	$ -

Exhibit 7-47
OPCO Schedule 3, Page 3, October – December 2011

Schedule 3
Page 3 of 3

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2011 through December 2011
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Apr-11	$ -	$ 303,360	$ 303,360
2	May-11	$ -	$ 306,001	$ 306,001
3	Jun-11	$ -	$ 304,680	$ 304,680
4	Total	$ -	$ 914,041	$ 914,041

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.

Exhibit 7-48
CSP Schedule 4, October – December 2011

Schedule 4

COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2011 through December 2011
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	4.70591
2	GS-1	Secondary	4.49783
3	GS-2	Secondary	4.56910
4	GS-2	Primary	4.42008
5	GS-2-TOD AND GS-2-LM-TOD	Secondary	4.56910
6	GS-3	Secondary	4.13114
7	GS-3	Primary	3.99641
8	GS-3-LM-TOD	Secondary	4.13114
9	GS-4	Sub/Transmission	3.50271
10	IRP-D	Secondary	3.69077
11	IRP-D	Primary	3.57040
12	IRP-D	Sub/Transmission	3.50271
13	SL	Secondary	5.74685
14	AL	Secondary	7.40422
15	SBS	Secondary	4.25081
16	SBS	Primary	4.00635
17	SBS	Sub/Transmission	3.50271

Exhibit 7-49
OPCO Schedule 4, October – December 2011

Schedule 4

OHIO POWER COMPANY
Calculation of Quarterly FAC For Billing During
October 2011 through December 2011
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	3.27533
2	GS-1	Secondary	3.37470
3	GS-2	Secondary	2.71690
4	GS-2	Primary	2.61956
5	GS-2	Sub/Transmission	2.55662
6	GS-2 Rec, GS-TOD AND GS-2-ES	Secondary	2.71690
7	GS-3	Secondary	2.68319
8	GS-3	Primary	2.58705
9	GS-3	Sub/Transmission	2.52489
10	GS-3-ES	Secondary	2.68319
11	GS-4	Primary	2.45960
12	GS-4	Sub/Transmission	2.40051
13	IRP-D	Secondary	2.55100
14	IRP-D	Primary	2.45960
15	IRP-D	Sub/Transmission	2.40051
16	EHG	Secondary	3.14564
17	EHS	Secondary	2.72653
18	SS	Secondary	2.98211
19	OL	Secondary	4.57953
20	SL	Secondary	3.92403
21	SBS	Secondary	2.70036
22	SBS	Primary	2.58393
23	SBS	Sub/Transmission	2.41857

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 third quarter of 2011 (i.e. the proposed FAC rates from AEP Ohio's first quarter 2011 FAC filing) for OPCO and the lower of the current FAC rates or the total of the FC and RA components become effective for CSP.

First Quarter 2012

On December 1, 2011, AEP Ohio submitted quarterly FAC filings for CSP and OPCO, which reflected actual data from July through September 2011 and projected data for the period January through March 2012. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 3 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 first quarter 2012 FAC filings by reproducing Schedules 1 through 3 as Exhibits 7.50 through 7.54, and then briefly summarizing each schedule.

Exhibit 7-50
OPCO and CSP Combined Schedule 1, January – March 2012

Schedule 1

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2012 through March 2012
Summary - Proposed FAC Rate

Line	Delivery Voltage	A Schedule 2 Forecast (FC) Component	B Schedule 3 Reconciliation (RA) Adjustment Comp.	C Total of FC and RA Components
1	Secondary	3.65934	0.00000	3.65934
2	Primary	3.53239	0.00000	3.53239
3	Sub/Transmission	3.46202	0.00000	3.46202

Schedule 1: This schedule reflects the then current FAC rate components by delivery voltage. Column A reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period January through March 2012. Column B 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 September 2011. Column C reflects the sum of the FC and RA components.

Exhibit 7-51
OPCO and CSP Combined Schedule 2, January – March 2012

Schedule 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2012 through March 2012
FC Component

Line	Description		Forecast Period - 1st Quarter 2012 January	February	March	Total
1	Fuel & Purchased Power		184,711,107	169,001,458	149,137,318	$ 502,849,883
2	Environmental (Consumables and Allowances)		15,848,072	14,476,070	13,877,449	$ 44,201,591
3	(Gains) and Losses On Sales of Allowances		(325,000)	(325,000)	(325,000)	$ (975,000)
4	Other		-	-	-	$ -
5	Total Includible FAC Costs		$ 200,234,179	$ 183,152,528	$ 162,689,767	$ 546,076,474
6	Less: Assigned to Off-System (Including AEP Affiliates)		68,497,295	59,332,006	41,534,886	$ 169,364,187
7	FAC for Internal Load		$ 131,736,884	$ 123,820,522	$ 121,154,881	$ 376,712,287
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.93337	0.93030	0.93146	0.93337
9	*FAC for Retail Load Before Renewables*		*$ 122,959,255*	*$ 115,190,232*	*$ 112,850,925*	*$ 351,611,947*
10	Renewables/RECs		5,720,346	5,034,843	4,773,172	$ 15,528,361
11	FAC for Retail Load		$ 128,679,601	$ 120,225,075	$ 117,624,097	$ 367,140,308
12	Retail Non-Shopping Sales - Generation Level Kwh		3,834,400,207	3,346,595,168	3,461,993,539	10,642,988,914
13	FC Component of FAC Rate At Generation Level - Cents/kWh					3.44960

Line	Description		Secondary	Primary	Sub/Trans
14	FC Component of FAC Rate At Generation Level		3.44960	3.44960	3.44960
15	Loss Factor		1.0608	1.0240	1.0036
16	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**3.65934**	**3.53239**	**3.46202**

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period January through March 2012. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the first quarter of 2012, AEP Ohio has projected includable FAC costs totaling $546.076 million for CSP and 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 first quarter of 2012, these projected off-system costs totaled $169.364 million for CSP and 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 $15.528 million for CSP and OPCO. The addition of the RECs result in total FAC costs for retail load of $367.140 million for CSP and OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.44960 cents per kWh for CSP and 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 and OPCO applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 3.65934, 3.53239 and 3.46202 cents per kWh.

Exhibit 7-52
OPCO and CSP Combined Schedule 3, Page 1, January – March 2012

Schedule 3
Page 1 of 3

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2012 through March 2012
RA

Actual Period - July 2011 through September 2011

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**							$ 597,146,420
2	Jul-11	4,327,319,410	$ 141,697,966	$ 143,360,802	$ 1,662,836	$ 4,592,992	$ (140,961)	$ 6,114,868
3	Aug-11	3,930,514,690	$ 128,333,661	$ 134,081,144	$ 5,747,483	$ 4,608,176	$ (140,961)	$ 10,214,699
4	Sep-11	3,285,080,912	$ 106,222,558	$ 112,680,990	$ 6,458,432	$ 4,661,217	$ (44,739,334)	$ (33,619,685)
5	**Ending Balance**	11,542,915,012	$ 376,254,185	$ 390,122,936	$ 13,868,751	$ 13,862,385	$ (45,021,255)	$ 579,856,301
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 913,051
7	*Total (Over)/Under Recovery Balance							$ 580,769,353 *
8	Loss Adjusted Retail Sales Billing Period - kWh							10,642,988,914
9	RA Component at Generation - Cents/kWh							5.45683

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		5.45683	5.45683	5.45683
11	Loss Factor		1.0608	1.0240	1.0036
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**5.78860**	**5.58779**	**5.47647**

* Balance Moved to Phase-In Rider to be effective with the first billing cycle of January 2012.

Schedule 3: This three-page schedule represents the Companies RA components of its third quarter 2011 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 July through September 2011, which were calculated as the difference between the monthly FAC revenues for the third quarter of 2011 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 $579.856 million for CSP and OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with Ormet. For the third quarter of 2011, these deferrals totaled $913,051 for CSP and 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 2011 was $580.769 million, the balance of which was transferred to the Phase-In Rider, which became effective with the first billing cycle of January 2012. 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 and OPCO for this filing was 5.45683 cents per kWh. 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 and OPCO, the application of the loss factors results in RA components of the FAC rate of 5.78860, 5.58779 and 5.47647 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

AEP Ohio stated that the under-recovery balance is not included in the RA component of Schedule 1, due to its inclusion in the Phase-In Rider.

Exhibit 7-53
OPCO and CSP Combined Schedule 3, Page 2, January – March 2012

Schedule 3
Page 2 of 3

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2012 through March 2012
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
1	Jul-11	$ 280,980,015	$ 133,222,113	$ 147,757,902	0.96080	$ 141,965,092	$ 1,395,710	$ 143,360,802
2	Aug-11	$ 244,041,284	$ 105,571,788	$ 138,469,496	0.95789	$ 132,638,957	$ 1,442,187	$ 134,081,144
3	Sep-11	$ 210,295,749	$ 94,189,095	$ 116,106,654	0.95373	$ 110,734,805	$ 1,946,185	$ 112,680,990
4	Total	$ 735,317,048	$ 332,982,996	$ 402,334,052		$ 385,338,854	$ 4,784,082	$ 390,122,936

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh			Jurisdictional Ratios	
		Whlse (WPC)	Retail	Total	Whlse (WPC)	Retail
Actual						
5	Jul-11	202,986,657	4,505,564,882	4,708,551,539	0.04311	0.95689
6	Aug-11	200,577,437	4,090,368,141	4,290,945,578	0.04674	0.95326
7	Sep-11	185,986,999	3,406,322,257	3,592,309,256	0.05177	0.94823
Forecast						
8	Jan-12	273,725,095	3,834,400,207	4,108,125,302	0.06663	0.93337
9	Feb-12	250,736,657	3,346,595,168	3,597,331,825	0.06970	0.93030
10	Mar-12	254,759,447	3,461,993,539	3,716,752,986	0.06854	0.93146

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the third quarter of 2011. Specifically, page 2 of Schedule 3 (lines 1-4) shows, for each Company, total monthly FAC costs incurred from July through September 2011. 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". During the third quarter of 2011, CSP and OPCO added an amount totaling $4,784,082 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. 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 2011 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for July through September 2011. In addition, this schedule reflected the

Companies' forecasted monthly jurisdictional sales at the generation level for January through March 2012, 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 .93337, .93030 and .93146 (January, February and March 2012, respectively) for CSP and OPCO.

Exhibit 7-54
OPCO and CSP Combined Schedule 3, Page 3, January – March 2012

Schedule 3
Page 3 of 3

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
January 2012 through March 2012
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Jul-11	$ -	$ 304,350	$ 304,350
2	Aug-11	$ -	$ 304,350	$ 304,350
3	Sep-11	$ -	$ 304,350	$ 304,350
4	Total	$ -	$ 913,051	$ 913,051

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, 2010 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.

Second Quarter 2012

On March 1, 2012, AEP Ohio submitted its quarterly FAC filings, reflecting the merger of CSP and OPCO (now collectively referred to as OPCO), which provided actual data from October through December 2011 and projected data for the period April through June 2012. AEP Ohio's filing for this quarter included a submittal letter, Schedules 1 through 3 supporting the Companies' proposed calculations for 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 2012 FAC filings by reproducing Schedules 1 through 3 as Exhibits 7.55 through 7.59, and then briefly summarizing each schedule.

Exhibit 7-55
OPCO and CSP Combined Schedule 1, April – June 2012

Schedule 1

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2012 through June 2012
Summary - Proposed FAC Rate

		A	B	C
		Schedule 2	Schedule 3	
Line	Delivery Voltage	Forecast (FC) Component	Reconciliation (RA) Adjustment Comp.	Total of FC and RA Components
1	Secondary	3.67755	0.00000	3.67755
2	Primary	3.54997	0.00000	3.54997
3	Sub/Transmission	3.47925	0.00000	3.47925

Schedule 1: This schedule reflects the then current FAC rate components by delivery voltage. Column A reflects the forecast component ("FC") rate necessary to recover the estimated fuel expense for the period April through June 2012. Column B 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 2011. Column C reflects the sum of the FC and RA components.

Exhibit 7-56
OPCO and CSP Combined Schedule 2, April – June 2012

Schedule 2

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2012 through June 2012
FC Component

Line	Description		Forecast Period - 2nd Quarter 2012 April	May	June	Total
1	Fuel & Purchased Power		130,768,264	144,690,719	166,077,060	$ 441,536,042
2	Environmental (Consumables and Allowances)		12,149,437	12,506,628	14,161,520	$ 38,817,585
3	(Gains) and Losses On Sales of Allowances		(325,000)	(725,000)	(725,000)	$ (1,775,000)
4	Other		-	-	-	$ -
5	Total Includible FAC Costs		$ 142,592,701	$ 156,472,346	$ 179,513,580	$ 478,578,627
6	Less: Assigned to Off-System (Including AEP Affiliates)		35,586,844	46,055,236	59,615,890	$ 141,257,971
7	FAC for Internal Load		$ 107,005,857	$ 110,417,110	$ 119,897,689	$ 337,320,656
8	Retail Jurisdictional Allocation Ratio	Schedule 3 pg. 2	0.92668	0.92831	0.92736	0.92746
9	FAC for Retail Load Before Renewables		$ 99,160,187	$ 102,501,308	$ 111,188,321	$ 312,852,444
10	Renewables/RECs		4,922,565	4,282,014	3,056,983	$ 12,261,562
11	FAC for Retail Load		$ 104,082,753	$ 106,783,322	$ 114,245,304	$ 325,114,006
12	Retail Non-Shopping Sales - Generation Level Kwh		2,922,078,018	3,105,476,601	3,350,445,531	9,378,000,150
13	FC Component of FAC Rate At Generation Level - Cents/kWh					3.46677

Line	Description		Secondary	Primary	Sub/Trans
14	FC Component of FAC Rate At Generation Level		3.46677	3.46677	3.46677
15	Loss Factor		1.0608	1.0240	1.0036
16	**FC at the Meter Level - Cents/kWh**	**Line 14 x Line 15**	**3.67755**	**3.54997**	**3.47925**

Schedule 2: This schedule reflects AEP Ohio's estimates of monthly fuel costs it expected to incur during the period April through June 2012. AEP Ohio stated that it calculated the rates by voltage necessary to recover its forecast costs. For the second quarter of 2012, AEP Ohio has projected includable FAC costs totaling $478.579 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 2012, these projected off-system costs totaled $141.258 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 $12.262 million for OPCO. The addition of the RECs result in total FAC costs for retail load of $325.114 million for OPCO. From these amounts, the Companies calculated the FC portion of the FAC rate at the Generation level. This amounted to 3.46677 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.

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. OPCO applied the loss factors of 1.0608, 1.0240 and 1.0036 cents per kWh for secondary, primary and sub/trans voltage levels, respectively, which resulted in FC's of 3.67755, 3.54997 and 3.47925 cents per kWh.

Exhibit 7-57
OPCO and CSP Combined Schedule 3, Page 1, April – June 2012

Schedule 3
Page 1 of 3

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2012 through June 2012
RA

Actual Period - October 2011 through December 2011

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**							$ 580,769,353
2	Oct-11	3,231,944,687	$ 106,510,060	$ 117,839,533	$ 11,329,473	$ 4,506,912	$ (4,093,559)	$ 11,742,826
3	Nov-11	3,158,604,359	$ 106,255,761	$ 109,226,099	$ 2,970,338	$ 4,606,108	$ 1,839,372	$ 9,415,818
4	Dec-11	3,391,808,212	$ 116,626,473	$ 129,544,666	$ 12,918,193	$ 4,632,825	$ (67,495,787)	$ (49,944,769)
5	**Ending Balance**	9,782,357,258	$ 329,392,294	$ 356,610,298	$ 27,218,004	$ 13,745,844	$ (69,749,973)	$ 551,983,229
6	Ormet Interim Agreement Deferral		Schedule 3, pg. 3					$ 913,051
7	Total (Over)/Under Recovery Balance							$ 552,896,280 *
8	Loss Adjusted Retail Sales Billing Period - kWh							9,378,000,150
9	RA Component at Generation - Cents/kWh							5.89567

Line			Secondary	Primary	Sub/Trans
10	RA Component of FAC Rate At Generation Level		5.89567	5.89567	5.89567
11	Loss Factor		1.0608	1.0240	1.0036
12	**RA at the Meter Level - Cents/kWh**	Line 10 x Line 11	**6.25413**	**6.03717**	**5.91690**

*** Balance Moved to Phase-In Rider**

Schedule 3: This three-page schedule represents the Companies RA components of its fourth quarter 2011 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 2011, which were calculated as the difference between the monthly FAC revenues for the fourth quarter of 2011 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 $551.983 million for CSP and OPCO.

Schedule 3, page 1, line 6 reflects the addition of a deferral associated with Ormet. For the fourth quarter of 2011, these deferrals totaled $913,051 for OPCO. The derivation of these deferral amounts are summarized on Schedule 3, page 3.

After adding the amounts associated with Ormet, OPCO's under recovery for the fourth quarter of 2011 was $552.896 million, the balance of which was moved to the Phase-In Rider. The under-recovery balance is no longer included in the RA component of Schedule 1 of this quarterly filing. From these amounts, OPCO 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 OPCO for this filing was 5.89567 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 OPCO, the application of the loss factors results in RA components of the FAC rate of 6.25413, 6.03717 and 5.91690 cents per kWh for the secondary, primary and sub/trans voltage levels, respectively.

Exhibit 7-58
OPCO and CSP Combined Schedule 3, Page 2, April – June 2012

Schedule 3
Page 2 of 3

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2012 through June 2012
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
1	Oct-11	$ 180,948,590	$ 59,120,779	$ 121,827,811	0.95891	$ 116,821,728	$ 1,017,805	$ 117,839,533
2	Nov-11	$ 157,085,853	$ 45,432,200	$ 111,653,653	0.94833	$ 105,884,497	$ 3,341,602	$ 109,226,099
3	Dec-11	$ 205,332,226	$ 71,537,891	$ 133,794,335	0.94845	$ 126,897,884	$ 2,646,782	$ 129,544,666
4	Total	$ 543,366,669	$ 176,090,870	$ 367,275,799		$ 349,604,109	$ 7,006,189	$ 356,610,298

Monthly Jurisdictional Allocation Ratios

Line	Month	Jurisdictional Sales at Gen Level Kwh Whlse (WPC)	Retail	Total	Jurisdictional Ratios Whlse (WPC)	Retail
Actual						
5	Oct-11	174,172,730	3,346,842,754	3,521,015,484	0.04947	0.95053
6	Nov-11	188,492,610	3,275,034,317	3,463,526,927	0.05442	0.94558
7	Dec-11	201,443,085	2,479,006,411	2,680,449,496	0.07515	0.92485
Forecast						
8	Apr-12	231,184,020	2,922,078,018	3,153,262,038	0.07332	0.92668
9	May-12	239,827,834	3,105,476,601	3,345,304,436	0.07169	0.92831
10	Jun-12	262,442,229	3,350,445,531	3,612,887,760	0.07264	0.92736

Page 2 of Schedule 3 reflects monthly data on the Companies actual fuel costs during the fourth quarter of 2011. Specifically, page 2 of Schedule 3 (lines 1-4) shows, for each Company, total monthly FAC costs incurred from October through December 2011. 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 2011, OPCO added an amount totaling $7,006,189 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. 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 2011 were derived.

Finally, page 2 of Schedule 3 reflected the Companies' actual monthly jurisdictional sales at the generation level for October through December 2011. In addition, this schedule reflected the Companies' forecasted monthly jurisdictional sales at the generation level for April through June 2012, 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 .92668, .92831 and .92736 (April, May and June 2012, respectively) for CSP and OPCO.

Exhibit 7-59
OPCO and CSP Combined Schedule 3, Page 3, April – June 2012

Schedule 3
Page 3 of 3

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
April 2012 through June 2012
RA Component

Ormet Interim Agreement Deferral

Line	Month	Rate Discount	Carrying Charges	Total Underrecovery Deferral - Ormet
1	Oct-11	$ -	$ 304,350	$ 304,350
2	Nov-11	$ -	$ 304,350	$ 304,350
3	Dec-11	$ -	$ 304,350	$ 304,350
4	Total	$ -	$ 913,051	$ 913,051

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.

Commission Opinion and Order Rejecting Stipulation

On January 27, 2011, AEP Ohio filed an application for a standard service offer pursuant to Section 4928.141 of the revised Ohio code in Case Nos. 11-346-El-SSO, 11-348-EL-SSO, 11-349-EL-AAM and 11-350-EL-AAM. The Companies' application requested approval of an electricity security plan ("ESP 2"), which would commence on January 1, 2012 and expire May 31, 2014. On September 7, 2011, AEP Ohio and numerous other signatory parties filed a Joint Stipulation and Recommendation ("Stipulation"), the purpose of which was to resolve issues raised in the aforementioned cases as well as matters related to other AEP Ohio cases pending before the Commission. After initially approving the Stipulation in its Order and Opinion dated December 14, 2011, the Commission subsequently rejected the Stipulation in its Order and Opinion dated February 23, 2012 for the reasons discussed therein.

As noted above, AEP Ohio's quarterly FAC filings for the first and second quarters of 2012 reflect combined FC and RA components for CSP and OPCO pursuant to the merger. However, as a result of the Commission's rejection of the Stipulation, AEP Ohio was ordered to calculate separate fuel rates for CSP's and OPCO's rate zones. Pursuant to the Commission's directive, AEP Ohio filed revised workpapers from which it calculated the unmerged rates. In response to Larkin's inquiry as to how this adjustment affected costs flowing through the 2011 FAC, the Companies stated in part:

> *The FC was based on a merged forecast and we had no way to separate out the costs associated with each operating company when the Commission ordered the rates to be separate. We had to split the first and second quarter 2012 forecast component into CSP*

and OPCO rate zones in order to produce an unmerged rate. In order to do that we used the cost relationship from the latest information we had where the data was separate between OPCO and CSP, which was the fourth quarter 2011 actuals (RA Component)...we just used the fourth quarter actuals to allocate the first and second quarter forecast when we needed an unmerged rate.

Only Schedule 2 was actually adjusted, which represents the first quarter 2012 fuel costs. It does not affect any of the 2011 costs.

Larkin reviewed the Companies' revised workpapers for the second quarter of 2012 and noted that the RA component of the workpapers (i.e. Schedule 3) reflected a line item titled "Remove Pool Capacity Payments 4th Quarter", which reduced fourth quarter 2011 FAC costs by $10,193,130 to $346,417,168[39] as shown in the replacement Schedule 3 below:

Exhibit 7-60
Replacement Schedule 3 for Second Quarter 2012

Schedule 3

OHIO POWER COMPANY and COLUMBUS SOUTHERN POWER COMPANY
Calculation of Quarterly FAC For Billing During
Actual Period - October 2011 through December 2011

		Columbus Southern Power Rate Zone				
Line	**Month**	**Kwh Retail Non-Shopping Sales**		**Renewable & FAC Revenue**		**FAC Cost**
1	**Beginning Balance**					
2	Oct-11	1,281,255,822	$	49,785,918	$	59,376,154
3	Nov-11	1,217,139,701	$	45,699,336	$	45,964,350
4	Dec-11	1,369,580,104	$	50,542,207	$	56,143,281
5	**Ending Balance**	3,867,975,627	$	146,027,461	$	161,483,785
Remove Pool Capacity Payments 4th Quarter					$	(10,193,130)
Revised CSP Ending Balance					$	151,290,655

			Ohio Power Rate Zone				
Line	**Month**		**Kwh Retail Non-Shopping Sales**		**Renewable & FAC Revenue**		**Schedule 3 , p2 FAC Cost**
1	**Beginning Balance**						
2	Oct-11		1,950,688,865	$	56,724,142	$	58,463,379
3	Nov-11		1,941,464,658	$	60,556,425	$	63,261,749
4	Dec-11		2,022,228,108	$	66,084,266	$	73,401,385
5	**Ending Balance**	$	5,914,381,631	$	183,364,833	$	195,126,513
	AEP Ohio		9,782,357,258			$	346,417,168
	CSP Rate Zone		39.54%				43.67%
	OPCO Rate Zone		60.46%				56.33%

[39] The fourth quarter 2011 FAC costs from AEP Ohio's March 1, 2012quarterly FAC filing reflected FAC costs of $356,610,298.

The $10,193,130 adjustment for Pool Capacity Payments was not reflected in the Companies' original second quarter 2012 FAC filing (which reflected the RA component for the fourth quarter of 2011). In response to Larkin's inquiry as to whether the fourth quarter 2011 FAC should be adjusted to reflect the removal of the Pool Capacity payments, AEP Ohio stated:

> *None of the adjustments affect the 4th quarter FAC. When the operating Companies merged (January 2012) there are no longer capacity payments being made to OPCO. However, in the 4th quarter 2011 the companies were not merged so the capacity payments were made to OPCO and should not be adjusted. However, for the purposes of trying to allocated the 1st quarter 2012 forecast, these types of adjustments made sense to get the allocation as close as possible to what would actually happen in 2012.*
>
> *The $10,193,130 was not and does not need to be removed from the FAC anywhere. It was only used to get a % allocator that was more reasonable than just using actual 4th quarter costs.*

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"[40] 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

[40] 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.

(7) Procedures for calculating the FAC 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:

- Plant personnel enter the fuel receipts information into the Companies' fuel accounting system [redacted]. 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 [redacted], which in turn is run through a feed each night to the [redacted] system, where such payments are executed.
- After testing is performed, the resulting analysis is fed into the [redacted] system from the [redacted] system software. Certain purchases are paid for based on information provided by the Companies' suppliers, which is then entered into the [redacted] system by plant personnel.

Larkin also reviewed the Companies' procedures for weighing, testing and reporting coal burned per data request LA-2011-2. 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 conformance with American Society for Testing Standards ("ASTM"). In addition, unit samples are collected and sent to the [redacted] to be analyzed. The analyzed results are then fed into the [redacted] system. Burn reports, which include tonnage and quality characteristics, can be generated by the [redacted] system for the relevant reporting period.

CSP and OPCO's procedures for recording purchases and interchanges of energy, as described in response to LA-2011-3, 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 Energy-Ohio ("Duke") and Dayton Power & Light ("DP&L") and are referred to as the Cincinnati, Columbus and Dayton ("CCD") owners. 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 their respective plant's ending inventory according to each company's ownership share. 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). With respect to the units operated by Duke and DP&L, these companies bill the other CCD owners for their respective portion of coal optimization credits/charges which are recorded as part of fuel consumed.

OPCO Jointly Owned Generation

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

- Cardinal Operating Company operates Cardinal Plant. Units 2 and 3 are owned by Buckeye Power, a non-affiliated partner. OPCO owns Unit 1. The fuel inventories at the facility are jointly owned by Buckeye and OPCO.
- Amos Plant Unit 3 is operated and co-owned by Appalachian Power Company ("APCO"), an affiliate.
- APCO also operates Sporn Plant Units 2 and 4, but these units are owned 100 percent by OPCO.

Cardinal Plant Units 2 and 3

- The total fuel 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 the 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.

Amos Plant Unit 3

- The total fuel 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 (current month consumption plus the next 11 months' projected consumption).
- OPCO owns two-thirds of Unit 3 Ending Inventory and associated monthly consumption.
- The joint owners' receipts are calculated as the difference between Beginning Inventory and Available Inventory.
- Available Inventory is calculated as Ending Inventory plus Consumption.

Sporn Plant Units 2 and 4

- The total fuel 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 and 5). This allocation is based on projected consumption by unit (current month consumption plus the next 11 months' projected consumption).
- The joint owners' receipts are calculated as the difference between Beginning Inventory and Available Inventory.
- Available Inventory is calculated as Ending Inventory plus Consumption.

Larkin requested in LA-2011-108 that, for each month of 2011, the Companies provide copies of invoices issued to AEP Ohio for fuel, transportation and consumables for each jointly owned plant. In response, AEP Ohio provided four confidential attachments (A-D) which were copies of invoices from Dayton Power & Light Company ("DP&L"), Duke Energy ("Duke") and Duke Energy Ohio ("Duke Ohio")[41].

The first set of invoices [redacted]

Exhibit 7-61
[redacted]

[redacted]

[redacted]

41 [redacted]

Exhibit 7-62

[redacted]

[redacted]

[redacted]

Of the invoices the Companies received from the joint owners in 2011, AEP Ohio provided the following summary of the portions from each invoice that are included in the FAC:

DP&L Fuel Related Bills

- Coal consumed and coal sales/transfers gains/losses (Account 5010001) are included in the FAC.
- Oil consumed (Account 5010019) is included in the FAC.

DP&L O&M Related Bills

These DP&L-billed O&M costs are included in the FAC:

- Fuel (Ash Handling (Account 5010000)
- Fuel Procurement - Unloading and Handling (Account 5010003)
- Ash Sale Proceeds (Account 5010012)
- Gypsum Handling/Disposal Costs (Account 5010027)
- Urea Expense (Account 5020002)
- Limestone Expense (Account 5020004)

Duke Fuel Related Bills

- Coal consumed and coal sales/transfers gains/losses (Account 5010001) are included in the FAC.
- Oil consumed (Account 5010019) is included in the FAC.

Duke O&M Related Bills

These Duke-billed O&M costs are included in the FAC:

- Fuel Procurement - Unloading and Handling (Account 5010003)
- Ash Sale Proceeds (Account 5010012)
- Gypsum Sale Proceeds (Account 5010028)
- Lime Expense (Account 5020001)
- Trona Expense (Account 5020003)
- Lime Hydrate Expense (5020004)

Trucking Costs from Killen to Stuart

An issue relating to the trucking of coal to DP&L's Stuart Plant was noted in the 2011 DP&L fuel audit.

Conclusion:

With respect to the DP&L fuel related bills, AEP Ohio should be required to explain the 2011 "Transfer (Gains)/Losses" of [redacted], including why those transfer losses were incurred and why such transfer losses are reasonable costs to be included in the FAC.

AEP Ohio may want to question the costs billed to CSP for trucking coal from Killen to Stuart for the reasons explained in the 2011 DP&L audit report.

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."[42]

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

In LA-2011-56, 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-2011-56 also requested that the Companies' provide an 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 provided the calculation of the Phase-In Recovery Rider (PIRR) and AEP's FAC Deferral Amortization Schedule, as approved by PUCO in Case No. 11-346.[43] AEP Ohio's PIRR calculation indicated an estimated deferral balance of $611,621,799 at December 31, 2011. The FAC Deferral Amortization schedule indicated the Companies deferral balance will be fully amortized to zero by December 1, 2018.

The Companies' response to data request LA-2011-47, which requested a complete set of supporting workpapers for all the calculations in the quarterly FAC filings for the review period (and discussed in more detail later in this report), referred to the response to LA-2011-49, which included the Accounting Department's summary schedules and monthly FAC workbooks of actual cycle calculations of under/over recovery as well as carrying charge calculations. The monthly FAC workbooks are discussed in more detail in a later section of this report.

LA-2011-5 asked the Companies to identify, by amount and account, any fuel amounts being deferred that affected the review period and to explain why such amounts were being deferred. In its confidential response, AEP Ohio stated that [redacted].

Review Related To Coal Order Processing

The following is a description of AEP Ohio's procedures for processing fuel purchase orders (per LA-2011-6):

- A coal buyer initiates a request for proposal, 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 buyer will analyze the offers received. An award will be made based on the following: (1) cost, (2) compatible quality, and (3) credit approval.
- 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 internal approval of the purchase order has been established and has been returned by the counterparty, a formal purchase order is assembled and entered into the Company's fuel accounting system.

[43] As previously described, Larkin's review also examined AEP Ohio's December 1, 2011 Quarterly FAC Filings, which covered projected information for January through March 2012 and actual information for the RA component for July through September 2011.

Purchase Orders And Approved Purchase Requisitions

Data requests LA-2011-7 and LA-2011-8 requested copies of fuel purchase orders ("POs") and approved purchase requisitions recorded in July 2011. In response, AEP Ohio referred to the confidential response to EVA-2011-1-3. The response to EVA-2011-1-3 included a confidential attachment which was a summary of all new coal POs that were executed in 2011. This summary also included a listing of any POs to which amendments were made along with a notation which indicated the justification for the amendments. As the number of POs in the confidential attachment was voluminous, Larkin selected a sample of POs for review. Each PO that Larkin selected was properly executed and was accompanied by an intercompany memo which summarized the details of the corresponding PO. No exceptions were noted.

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 July 2011. These were provided in the confidential response to data request LA-2010-9. In addition, the response to LA-2011-9 stated in part:

> *...OPCO receives a share of receipts at the Amos, Cardinal, and Sporn plants and CSP receives a share of receipts at the Beckjord, Stuart, and Zimmer plants in accordance with the joint plant agreements governing each of these plants.*

For CSP, the confidential information provided in LA-2011-9 included payment documentation for the Conesville and Conesville Prep plants. For OPCO, the information provided in LA-2011-9 included payment documentation for the Gavin plant. For each purchase, this documentation included a summary of invoices paid by CSP and OPCo, invoices, payment vouchers (with supporting detail), and a report titled "Penalty/Premium Pricing Report", which is a detailed calculation report of the amounts due to the Companies vendors for deliveries under a given contract or purchase order. Also included was a report titled "Daily Fuel Report", which recorded the daily unit activity for July 2011, the year to date unit activity, and the commodity total and shipments for the month of July 2011 and July 2011 year to date.

Larkin's review included tracing the invoices to the supporting data that was provided by the Companies. Larkin first examined each invoice and compared the vendor name, invoice number and invoice date to the accompanying voucher and voucher supporting detail (a document called a "Request for Payment Detail"). The Request for Payment Detail broke out the purchases by station, source date, commodity, entry type, description, quantity and value. We then traced the total of the amount(s) listed for each generating station on the Requests for Payment Detail to the invoices and Penalty/Premium Pricing Reports. No exceptions were noted.

Fuel Ledger

Larkin reviewed the data the Companies provided in response to LA-2011-10, which requested CSP's and OPCO's fuel ledgers for the period January through December 2011. Upon reviewing the fuel ledgers, including accompanying reconciliation pages, Larkin was able to tie the amounts shown to the FAC workbooks provided in LA-2011-49 and the general ledger (See additional discussion below).

BTU Adjustments

As part of its review, Larkin requested that the Companies provide documentation for Btu adjustments for fuel purchases recorded in July 2011 per data request LA-2011-11. In its response, AEP Ohio referred to the response to data request LA-2011-1-15, in which AEP Ohio provided confidential documents titled "Analysis Results Summary Report". AEP Ohio provided these confidential reports for the following power plants: Cardinal, Cook Coal Terminal, Conesville, Conesville Prep, Gavin, Kammer, Mitchell, and Muskingum River. Upon its initial review of the Analysis Results Summary Reports, Larkin noted that each such report had a calculation under the heading "Btu Adjustment". Larkin asked AEP Ohio to provide clarification as to how the calculations are derived as well as their relationship to the Penalty/Premium Pricing Reports. In response, the Companies provided the following narrative:

> *The analysis summary information provides detail into the dollar value to be calculated not only for the BTU quality adjustments, but for all coal quality related pricing components. These costs are calculated based on the terms of the particular contract. The report summarizes the contract pricing component, based on the specific calculation of the contract. The below examples reflect two different BTU adjustments.*
>
> <u>*Example 1*</u>
>
> [redacted]
>
> <u>*Example 2*</u>
>
> [redacted]
>
> [redacted]
>
> [redacted]
>
> [redacted]

[redacted]

From these reports, Larkin compared the Btu adjustment calculation to the specific contract as well as recalculated the amounts used in the Btu adjustment calculation. No exceptions were noted.

Freight And Barge Vouchers

LA-2011-12 requested that AEP Ohio provide freight cash vouchers for two days of coal receipts in July 2011 as well as copies of the portions of the corresponding coal received reports. For CSP, the confidential response to LA-2011-12 included documentation related to three payments that CSP made for freight associated with coal received at the [redacted] Specifically, this documentation included:

- Copies of invoices for each of the payments referenced above;
- Copies of payment vouchers (each also including a Request for Payment Detail) that are associated with those payments; and
- Copies of documents titled "Transportation Cost Report", which provides a breakout of the coal deliveries to which the total freight costs shown on the payment vouchers and invoices relate.

Upon reviewing the aforementioned documents, Larkin verified the freight costs reflected on the Transportation Cost Reports to the invoices. In addition, Larkin tied out the amounts reflected on the invoices and Transportation Cost Reports to the payment vouchers. No exceptions were noted.

For OPCO, the confidential response to LA-2011-12 included [redacted].

Specifically, this documentation included:

- Copies of invoices and/or freight bills for the payments referenced above;
- Copies of payment vouchers (each also including a Request for Payment Detail) that are associated with those payments;
- Copies of Transportation Cost Reports, which provides a breakout of the coal deliveries to which the freight costs shown on the payment vouchers and invoices/freight bills relate;

Larkin verified the freight costs reflected on the Transportation Cost Reports to the invoices. In addition, Larkin tied out the amounts reflected on the invoices and Transportation Cost Reports to the payment vouchers. No exceptions were noted.

LA-2011-13 requested that AEP Ohio provide two cash vouchers from each barge company for coal unloaded at Company plants during July 2011 as well as copies of the portions of the corresponding coal unloading reports and purchase orders. In response, AEP Ohio stated that CSP does not incur any barging costs, but that OPCO's barging services are provided by I&M River Transportation Division ("RTD"). OPCO's barging services are discussed in further detail in the AEP River Transportation Division section of this report. As the RTD is an affiliated company of OPCO, RTD issues a monthly invoice, which is settled by an inter-unit journal entry. As part of its response to LA-2011-13, AEP Ohio provided a confidential copy of the journal entry, RTD invoices for July 2011, which included data related to coal shipments received at the Gavin, Kammer, Mitchell, and Muskingum River plants. In addition, the Companies' provided copies of Transportation Cost Reports, which provided the detail for barging shipments of coal received in July 2011 for the noted plants.

Upon reviewing and comparing the data listed on the July 2011 RTD invoices (document titled Billed Freight – Coal – Captive) and the July 2011 [redacted] Transportation Cost reports, Larkin was able to verify the quantities and prices from the [redacted] reports to the RTD invoice.

Fuel Analysis Reports

LA-2011-14 requested that AEP Ohio provide the Companies' procedures for preparing monthly fuel analysis reports. In response, AEP Ohio stated that fuel analysis data is captured in the [redacted] and fed to the [redacted] system. In addition, AEP Ohio stated that monthly fuel analysis reports can be generated for each plant from the [redacted] system.

LA-2011-15 requested that AEP Ohio provide copies of fuel analysis reports related to fuel purchases recorded during July 2011. In its confidential response the Company provided copies of the aforementioned Analysis Results Summary Reports for the Cardinal, Conesville, Conesville Prep, Cook Coal Terminal, Gavin, Kammer, Mitchell, and Muskingum River plants. These reports listed the Companies' fuel purchases by mine, station and vendor, and broke out the fuel purchases by quantity, moisture, ash, sulfur, SO2 lbs/mmBTU's, BTUs on an "as received" as well as a "dry" basis.

Retroactive Escalations

Larkin requested that AEP Ohio identify all pending or approved retroactive escalations that affect fuel cost for the period January through December 2011. In response to LA-2011-16, the Company stated that there are no pending retroactive escalations and that approved escalations were provided with EVA-2011-1-1 in a confidential attachment.

Review Related To Station Visitation And Coal Processing Procedure

Larkin conducted a site visit to OPCO's Mitchell plant on March 22, 2012. Data requests LA-2011-17 through LA-2011-39 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 for the Mitchell plant was provided in AEP Ohio's response to LA-2011-17. The coal is delivered to the Mitchell plant by one of three ways: rail, barge, or conveyor directly from the mine.

For barge coal, once the plant tow boat moves the barges in place for unloading, the coal is moved onto conveyor belts to be transported to either the Main storage pile or the Reserve storage pile.

For rail coal, locomotives from the plant transport the loaded trains from the plant in-bound yard to the rotary unloader. Similar to the barge coal, the coal is unloaded from the rail cars onto conveyor belts and is transported to either the Main storage pile or the Reserve storage pile.

High sulfur coal is located at the supplier's prep plant, which is across the road from the Mitchell plant. This coal is conveyed directly to the high sulfur coal storage pile.

Scale Calibrations and the Company's Shipped vs. Unloaded report serve as controls for shortages, overages, and other discrepancies.

LA-2011-18 asked AEP Ohio to describe the process of how coal is weighed when it is received. In response, the Companies stated that coal received at the Mitchell Plant is weighed by belt scales when it is delivered by barge or [redacted] Coal received by rail is weighed by a static rail scale.

LA-2011-19 asked AEP Ohio to describe how freight bill and car number discrepancies are handled. AEP stated that the car number is verified with the bill of lading and the Mitchell Plant rail car pull list. If after verification there is still a discrepancy, FEL is contacted for further verification with the coal vendor.

LA-2011-20 asked AEP Ohio to describe how damaged cars are handled. AEP Ohio's response stated that the rail cars are inspected for damage by the onsite rail car repair service regularly. Claims for shortages are instigated by the Mitchell plant's accounting department.

LA-2011-38 requested a description of how freight bills, barge number and coal quantity and quality discrepancies are handled. In response, the Companies stated that such discrepancies are handled in the following manner:

- Billing discrepancies are handled by the Canton General Accounting Office, which pays the barge freight bills.
- In the event of a barge number discrepancy, verification of the barge number with the River Operations group is performed by material handling before the coal is unloaded.
- As the Mitchell Plant pays for coal based on supplier rates for all barge shipments, there are no coal quantity discrepancies.

- For coal quality, multiple samples are typically taken. If a discrepancy is discovered, a sub-sample sealed and held by the sampling party ("referee sample") is sent to an independent lab. If a small difference is found between the original analysis and the independent lab analysis, the original analysis is used. In the event of a large difference between the original analysis and the independent lab analysis, the independent lab analysis is used.

LA-2011-39 requested a description of how damaged barges are checked and who instigates claims for shortages. In response, AEP Ohio stated that barges at the Mitchell plant are inspected upon arrival in the harbor, where they are secured and inspected by material handling. If damage is noted, the River Operations group is notified by the material handling supervisor. The barge is sent out for repairs by River Operations after the barge is unloaded. In addition, Mitchell's accounting department instigates the claims for shortages when necessary.

As it relates to month-end cut-off procedures at the Mitchell Plant, AEP Ohio stated in response to LA-2011-21 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-2011-22 as follows:

- One hundred percent of the coal delivered by barge and rail to Mitchell is sampled by a belt sampler. The coal samples are collected by a primary and a secondary cutter which swipes across the path of the coal belts in order to obtain a statistical representation of the coal from the barge or rail system. The coal is funneled into plastic bags and each bag is labeled by coal yard personnel.
- The high sulfur coal received directly from McElroy is also sampled by a belt sampler which is located on the conveyor. The coal samples are collected by a primary and a secondary cutter which swipes across the coal belts in order to obtain a statistical representation of the coal. The coal flow is reduced and funneled into plastic bags which are then collected by laboratory personnel along with copies of the unloading sheets.
- The coal combusted in the steam generators are sampled by a dual belt sampler and is designated "as burned". These coal samples are also collected by a primary and a secondary cutter which swipes across the coal belts in order to obtain a statistical representation of the coal that is combusted in the plant's steam generators. The coal is funneled into plastic bags which are then collected by laboratory personnel.
- All samples are taken to the Kammer Plant laboratory where they are placed into sealed plastic bags and assigned an ATN number. These samples are then sent to the [redacted] Each ATN is entered into the [redacted] system at which point the [redacted] performs its analysis and enters it into the [redacted] where it matches the ATN with the shipment and populates the analysis.

LA-2011-23 requested the portion of total coal deliveries that were not analyzed for each Company operated coal-fired plant. This confidential response indicated that [redacted]

LA-2011-24 asked the Companies to provide their procedures for sampling and testing Powder River Basin ("PRB") coal and to provide the associated documentation from the Companies vendors. In response, AEP Ohio stated it does not have procedures in place for sampling and testing PRB coal since shipments originating in the PRB are paid on vendor analysis. However, AEP Ohio provided a confidential attachment called a [redacted].

LA-2011-25 requested that the Companies provide copies of reports related to the annual field visit and inspection of PRB mines that are conducted by AEP and which included the sampling procedures used at the mines and/or load-out locations from each mine that is owned or operated by CSP and OPCO. In its response, AEP Ohio stated:

> *During the period of September 12th – 14nd, 2011 Freelin Wright, Manager of the AEP Central Coal Lab, accompanied by Tim Matis, Operations Supervisor CCPC, and Russell Stanfield, FEL Western Field Representative visited the following PRB load outs and their onsite labs:* [redacted]
>
> *During the visits the sample systems at each location that generated the payment samples were visually inspected and an explanation of their sampling processes was given by the Coal Company representatives. All the systems were found to be in good mechanical condition and sized correctly for the lots to be sampled. All the locations had documentation of Bias Tests and ongoing sample system quality control reports.*
>
> *The on site labs for each site were toured and quality control procedures and documentation were shared by the Lab supervisors.* [redacted] *All the facilities were found to contain up to date equipment and knowledgeable employees.*
>
> *Overall there was nothing that was observed that would lead us to believe that ASTM D05 procedures and best industry practices were not being adhered to in the collection and analysis of the payment samples at the locations visited.*

Scale calibration logs for the period January through July 2011 were requested in LA-2011-26. In its response, AEP Ohio provided six confidential attachments with belt scale calibration logs and accompanying Company memos which covered the noted period for the Cardinal, Conesville, Gavin, Kammer and Mitchell plants.

A description of the procedures followed when coal scales are inoperable was provided in the response to LA-2011-27.

- For inoperable rail scales on contracts that are based on station weights, the terms of the supplier contract is used to determine the weights, including supplier weights, the weighted average from a previous period, or negotiations between the buyer and seller.
- In cases where the conveyer scale is inoperable, inventory tonnage is used until the scale is back in operation.
- The barge unloader is not used for official weights at the Mitchell plant because it is not certified.

Copies of laboratory sampling reports for coal purchases recorded in July 2011 were requested in LA-2011-28 in order to compare such reports with accounting and purchasing records. The Companies' confidential response included the previously noted "Analysis Results Reports" and included data related to coal sampling at the Mitchell plant that occurred in July 2011.

AEP Ohio's procedure for handling coal from the stockpile to the firebox or boiler at the Mitchell plant was provided in response to LA-2011-29. Low sulfur coal is moved from the stockpile or directly from the rail or barge to underground coal feeders by a radial stacker system. The coal feeders supply coal that is continuously blended on the plant supply conveyor belts with high sulfur coal from the high sulfur storage pile. The blended coal is subsequently transferred to one of six storage silos on each unit. Finally, the coal is fed from the silos by conveyor belts where it is pulverized and blown into the steam generators.

AEP Ohio's procedure for taking physical inventories of coal and fuel oil is described in the response to LA-2011-30. Fuel oil is measured monthly by Store Room staff by using a weighted measuring stick. Physical inventories of coal are conducted at a minimum of once a year [redacted] A Circular Letter dated October 17, 1996 (and revised November 12, 2007), which outlined specific coal pile inventory procedures and guidelines, was provided as a confidential attachment to AEP Ohio's response to LA-2011-30.

The Company provided working papers on the 2011 physical inventories taken at the Mitchell plant in February 2011 and August 2011 in the responses to LA-2011-31 and LA-2011-33, which consisted of the following documentation:

- Company memos for the inventory adjustments in February and August 2011
- Journal Entry Detail Reports
- Intercompany emails
- Inventory Ledger for the Mitchell plant
- Coal Receipts Ledger for the Mitchell plant
- Daily Fuel Reports
- Coal Storage Inventory Reports
- Fuel Data Reporting System reports

The Company memos described the results of the Coal Storage Inventory Reports. The winter 2011 memo (dated February 15, 2011), which discusses a coal pile survey conducted at the Mitchell plant on February 1 and February 2 of 2011, stated in part:

> *The book inventory for the **entire storage** area is [redacted] tons. The inventory results indicate the coal piles contain [redacted] tons. The resulting shortage of [redacted] tons represents a [redacted] difference from the book inventory.*
>
> *The book inventory for the **low sulfur** coal in the storage area is [redacted] tons, while the inventory results indicate that [redacted] tons are present. The resulting shortage of [redacted] tons represents a [redacted] difference from the book inventory. The book inventory for the*

> ***high sulfur*** *coal in the storage areas is* [redacted] *tons, while the inventory results indicate that* [redacted] *tons are present. The resulting shortage of* [redacted] *tons represents a* [redacted] *difference from the book inventory.*

This memo indicated that possible reasons for the inventory adjustments related to (1) a defective load cell in the railcar dumper scale; (2) the HSC-1 coal belt scale was found with an error of +0.084% when compared to the state certified Mitchell truck scale; (3) the blending associated with the 3A and 3B coal blending scales; and (4) inaccuracies in the R2 barge unloading belt scale.

The summer 2011 memo (dated August 29, 2011), which discusses the follow-up coal pile survey conducted at the Mitchell plant on August 9 and August 10 of 2011, stated the following results:

> *The book inventory for the* ***entire storage*** *area is* [redacted]*. The inventory results indicate the coal piles contain* [redacted]*. The resulting shortage of* [redacted] *represents a* [redacted] *difference from the book inventory. The results of this inventory check are a significant improvement over the* [redacted] *shortage found during the First Quarter 2011 survey.*
>
> *The book inventory for the* ***low sulfur*** *coal in the storage areas is* [redacted]*, while the inventory results indicate that* [redacted] *are present. The resulting shortage of* [redacted] *represents a* [redacted] *difference from the book inventory. The book inventory for the* ***high sulfur*** *coal in the storage areas is* [redacted]*, while the inventory results indicate that* [redacted] *are present. The resulting overage of* [redacted] *represents a* [redacted] *difference from the book inventory.*

This memo also stated in part the following with respect to these discrepancies:

> *The cause of these* [redacted] *discrepancies is the* [redacted]*. During normal operations, coal is fed from the high sulfur coal pile to the blending station via the HRC-1 conveyor, and weighed via the HSCL-2 scale. the low sulfur coal is sent to the blending station via the 4-East and 4-West conveyors, and weighed via the 4-East and 4-West scales. The blended coal is then weighed via the 3A and 3B scales, which are located upstream of the blending station. This set-up allows for a means of distinction between high and low sulfur coal.* [redacted]

The memo further stated that AEP Ohio anticipated that [redacted]. However, during Larkin's onsite field visit to the Mitchell plant, plant personnel stated that [redacted]

The journal entry detail reports referenced above reflect the recording of the dollars associated with the two inventory adjustments discussed above. Specifically, a journal entry dated February 28, 2011 shows a debit to FERC Account 151 for OPCO in the amount of [redacted], which reflects the dollar amount associated with the overage of [redacted] discussed in the February 15, 2011 memo referenced above. The corresponding debits to FERC Account 501 were for [redacted] and [redacted], which represented the inventory adjustments to Units 1 and 2, respectively as shown on OPCO's inventory ledger for the Mitchell plant for February 2011. In addition, a journal entry dated August 31, 2011 shows a debit to FERC Account 151 for OPCO in the amount of [redacted] which reflects the dollar amount associated with the overage of [redacted] tons discussed in the August 29, 2011 memo referenced above. For this inventory adjustment, the corresponding debits to FERC Account 501 were for [redacted] and [redacted], which represented the inventory adjustments to Units 1 and 2, respectively, as shown on OPCO's inventory ledger for the Mitchell plant for August 2011.

Data request LA-2011-32 asked the Companies' how they account for CSP and OPCO base coal inventories at each coal plant. In response, AEP Ohio stated that it capitalizes its base coal inventory cost in account 311 - Structures. AEP Ohio then expenses the inventory to account 4030001 - Depreciation expense. In addition, no adjustments were made to CSP's or OPCO's coal inventories in 2011 nor did either company have any adjustments to base coal inventories. Furthermore, AEP did not amortize any base coal costs into fuel costs.

AEP Ohio's response to LA-2011-34 provided the following description which relates to the levels of review applicable to plant operating statistics:

- The [redacted] has three general types of data which is derived directly from the plants: fuel consumption; generation; and outages and curtailments.
- Scale readings measure fuel consumption. These readings are corrected periodically through coal pile surveys if necessary.
- The [redacted] application transmits generation data. The Companies verify the accuracy of the data entered into [redacted] by performing a generation-checkout process.
- Outage and curtailment events are entered into [redacted] which is a front-end system where records are reviewed with plant staff throughout the operating month. After month-end, the plants have 10 days to review, correct, and approve the event records before being submitted to [redacted].

Larkin requested copies of generating station reports for the period January through December 2011 in LA-2011-35. In its confidential response, AEP Ohio stated that it does not have a document titled "generating station reports". However, the Companies provided a confidential attachment titled "Monthly Generation Station Report" for Mitchell Units 1 and 2 (and the aggregate for both units) for the period January through December 2011.

These confidential attachments reflected the service hours, available service hours, net heat rate, operating (gross) heat rate, gross generation, net generation, reserve hours, and startups for each generating unit at the Mitchell plant.

LA-2011-36 asked the Companies to identify any internal investigations which resulted from what was reported on the Monthly Generating Station Reports provided in LA-2011-35 for the review period. AEP Ohio responded that that no internal investigations were conducted during the review period.

Larkin requested copies of the station reports for the review period January through December 2011 which were sent to the Company's general office for incorporation into company statistics and to provide workpapers sufficient to trace the reports to those statistics in LA-2011-37. In response, 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-2011-34, 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-2011-40, AEP Ohio confirmed that no AEPSC affiliates supply fuel to OPCO. In addition, none of the AEP Ohio companies own or control any coal mines or entities that supply fuel to the Companies.

Review Related To Purchased Power

Documentation relating to the review of purchased power is included in the responses to LA-2011-41 and LA-2011-42. LA-2011-41 asked the Company to provide the following information: "For CSP and OPCO, for purchases of power recorded in July 2011 that are included in the FAC, please provide the related invoices, and paid cash voucher or cash receipts." In the confidential response to LA-2011-41, the Company provided (1) a summary of July 2011 invoices; (2) copies of invoices; (3) July 2011 FAC schedule for OPCO used to tie to the invoice summary; and (4) July 2011 FAC schedule for CSP used to tie to the invoice summary.

The summary of July 2011 invoices broke out the Companies purchases of power by (1) total invoice amount, (2) total [redacted], and (3) physical purchases allocated between CSP and OPCO which are the amounts included in the FAC for each company. There were substantial differences noted between the total invoice amounts versus what was allocated to the Companies. The summary sheet included a footnote, which stated:

The difference between the invoice amounts and the purchased power recorded by Ohio Power and Columbus Southern Power are due to: 1) The amounts recorded by the three other AEP East Generating Companies (APCO, I&M, KPCO) or 2) Netting agreements with particular counterparties to whom AEP also sells power. In these instances, the purchase and sale are netted on the invoice which may result in a net receivable.

Larkin attempted to tie out the amounts allocated to CSP and OPCO in July 2011 that were reflected on the invoice summary to workpapers "EXH CSP 1" and "EXH OPCO 1" from the monthly FAC Excel workbooks provided in LA-2011-49 (see additional discussion below). Larkin was able to tie out most of these amounts, but not all. However, Larkin was able to tie out the remaining amounts to the FAC schedules that were provided as confidential attachments C and D to the response to LA-2011-41, which in turn, tied to workpapers "EXH CSP 1" and "EXH OPCO 1" noted above. In addition, in LA-2011-50, AEP Ohio provided monthly reconciliations between recorded purchased power in the general ledger and the amounts included in the monthly FAC workbooks. Upon reviewing the FAC schedules provided in LA-2011-41 as well as the monthly reconciliations provided in LA-2011-50, Larkin was able to tie out the July 2011 purchased power amounts from LA-2011-41. There were minor unreconciled differences on the monthly reconciliations, but such amounts were immaterial.

Reliability Must Run Generation

As confirmed in the response to LA-2011-42, dispatch of the Companies' generating units was under the control of PJM during the review period of January through December 2011.

LA-2011-43 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."

In its confidential response, AEP Ohio stated that [redacted] are designated as "must run" for reliability or voltage control purposes. In addition, as it relates to the four generating plants referenced above, AEP Ohio stated in part:

> *...each of the above generating units was required to operate as a Must Run resource by PJM in 2011. 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 response to LA-2011-43, AEP Ohio provided two confidential attachments. The first attachment (Attachment 1) was an extensive listing of the hours that the [redacted] were required to operate as a "must run" resource by PJM during 2011. This listing covered the entire review period of January through December 2011. The second confidential attachment (Attachment 2) provided the average production cost of each "must run" generating unit referenced above. This was expressed in terms of $/MW for each month of 2011 and is reproduced in the CONFIDENTIAL exhibit below.

Exhibit 7-63
Average Production Cost of "Must Run" Generating Units

[redacted]

The Company was asked to identify the dates and hours in 2011 when the [redacted] plant was running out of economic dispatch to provide voltage support to [redacted]. AEP Ohio referred to the attachment provided in LA-2011-43 related to the [redacted] plant and stated that all of the RMR dates and hours for [redacted] (per LA-2011-43) are related to [redacted].

The [redacted] plant was designated as a RMR unit for PJM dispatching purposes when [redacted] was running out of economic dispatch in order to provide support to [redacted]. [redacted]

[redacted]

EVA-2-39 asked AEP Ohio to provide the incremental fuel costs incurred when it ran the Must Run units out of economic dispatch during 2011 and to explain any significant assumptions. In response, the Companies stated that the PJM RTO is responsible for the reliability related dispatch of AEP East's generating units, and that, if available, the AEP East generating units must respond to the dispatch instructions of PJM. In addition, AEP Ohio stated:

> *...Within operational constraints, all dispatchable generating resources are economically stacked during cost reconstruction, with the most expensive being assigned to meet off system sales (OSS) obligations. The cost of the remaining resources are then assigned to serve the internal retail and firm wholesale load of the AEP Companies. As such, unit cost are subsequently designated between (OSS) and internal load on this basis regardless of the reason (i.e., economic or RMR) that PJM originally dispatched the unit. Consequently, the specific incremental fuel costs associated with a unit running for reliability purposes are not determined.*

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-2011-44 and LA-2011-45.

LA-2011-44 asked about instances in which customer power supplies were interrupted (or requested to be interrupted) during the review period January through December 2011. In response, AEP Ohio stated that OPCO's customers did not experience a single generation-caused customer interruption during the review period of January through December 2011.

LA-2011-45 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:

6. The cause(s) of the outage.
7. Steps taken by the Companies to minimize the impacts of the unscheduled outage.
8. Efforts made to secure replacement power, if applicable.
9. The methodology employed to price the replacement power, if applicable.
10. The cost impacts resulting from the periods during which the unscheduled outage occurred.

In response to item 1, AEP Ohio provided an attachment, which provided a brief description of what caused the unscheduled outages during the review period at the OPCO owned generating units listed below.

- Amos Units 1, 2 & 3
- Beckjord Unit 6
- Cardinal Units 1, 2 & 3

- Conesville Units 3, 4, 5 & 6
- Darby Units 1, 2, 3 & 4
- Gavin Units 1 & 2
- Kammer Units 1, 2 &3
- Lawrenceburg 1A, 1B, 1S, 2A, 2B & 2S
- Mitchell Units 1 & 2
- Muskingum River Units 1, 2, 3, 4 & 5
- Picway Unit 5
- Racine Units 1 & 2
- Sporn Units 2, 4 & 5
- Stuart Units 1, 2, 3 & 4
- Waterford Units CT1, CT2, CT3 & ST1
- Zimmer Unit 1

With respect to items 2 through 5 from LA-2011-45, AEP Ohio stated:

> *Ohio Power Company is a member of the AEP East Pool. Forced outages and curtailments to the Company's 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.*

FAC Filings, Supporting Workpapers And Documentation

Documentation relating to the review of supporting workpapers for calculations in the FAC filings was requested in data requests LA-2011-46 through LA-2011-52. LA-2011-46 requested copies of AEP Ohio's quarterly FAC filings. The Companies provided CSP's and OPCO's FAC filings for the first, second, third and fourth quarters of 2011 as well as for the first and second quarters of 2012. The RA portion of the second quarter 2012 fuel filing, which was filed March 1, 2011, included actual data from October through December 2011.

Data requests LA-2011-47, LA-2011-49, LA-2011-50 and LA-2011-51 requested the Excel files associated with the FAC filings as well as all documentation which provides a complete audit trail to the Companies FAC calculations. AEP Ohio's response to LA-2011-49 provided the Accounting Department's summary schedules and monthly Excel workbooks which contained the actual cycle calculations of under/over recovery as well as carrying charge calculations.

Specifically, LA-2011-49 asked that:

> *For each Reconciliation Adjustment (RA) in a Rider FAC filing covering the review period, please provide a complete audit trail for all amounts in the RA portions of such filings including: (1) the accounting records and other documentation needed to trace each dollar amount in the RAs through from the Rider FAC filings to the fuel ledger, from the fuel ledger to the general ledger, and from the fuel ledger to the purchase orders and invoices; (2) the complete documentation to trace the energy and system loss quantities in the Rider FAC filings to the source documents; (3) all journal entries, journal entry supporting documentation and workpapers related to recording RA adjustments in the Companies accounting records; and (4) provide all calculations and supporting documentation related to computing RA adjustments in the Companies' Rider FAC filings.*

In response, AEP Ohio provided an index of attachments and the Accounting Department's summary schedules and what it referred to as monthly FAC workbooks of under/recovery and carrying charge calculations, which are the main support for the Companies' FAC filings including the RA portion of such 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

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).

Upon reviewing the monthly FAC workbooks, Larkin was able to tie out the amounts reflected in the workbooks to the FAC filings using the source data listed above and performing recalculations. In addition, the FAC schedules provided in the response LA-2011-41 and the monthly purchased power reconciliations provided in the response to LA-2011-50 also facilitated Larkin's ability to tie out the amounts reflected in the FAC workbooks.

Larkin noted the discrepancy discussed below with respect to the Lawrenceburg generating station for which the Companies provided an explanation.

Lawrenceburg Generating Station

On March 15, 2007, CSP entered into an agreement to purchase the Lawrenceburg Generating Station ("Lawrenceburg") from AEP Generating Company. Lawrenceburg is a combined-cycle natural gas power plant with a generating capacity of 1,096 MW and is located in Lawrenceburg, Indiana.

The non-fuel purchased power costs associated with Lawrenceburg are included in the FAC for CSP as shown on the EXH CSP-1 workpaper, which was included in the FAC workbooks provided in LA-2011-49. In data request LA-2011-57, Larkin asked for a summary of the non-energy components related to Lawrenceburg that were included in the FAC during 2011. In its confidential response, AEP Ohio provided a schedule which showed [redacted]. Larkin compared the amounts from this schedule to the EXH CSP-1 workpaper. No exceptions were noted. However, the EXH CSP-1 workpaper for December 2011 indicated that the amounts reflected therein were estimates. Upon Larkin's inquiry, AEP Ohio stated that of the accounts that comprise Lawrenceburg's non-energy components, only Account No. 5550046 - Purch Power-Fuel Portion-Aff reflected an estimate of [redacted] for December 2011 when the actual recorded amount was [redacted], or a difference of [redacted]. In addition, a similar circumstance was noted in the 2010 fuel audit report whereby AEP Ohio stated that the difference between the estimated and actual December 2010 amount for Account No. 5550046, [redacted], flowed through the FAC in January 2011. The responses to LA-2011-49 and LA-2011-57 indicated that the January 2011 amount for Account No. 5550046 was [redacted]. Larkin inquired as to whether the [redacted] noted above was embedded in this amount. In response, AEP Ohio stated:

> *The [redacted] is the January actual amount for Lawrenceburg, it would not include the [redacted] referenced. The [redacted] is the difference between the December estimate FAC spreadsheet and the December actual FAC spreadsheet. This amount would have flowed through the December actual deferred fuel entry that was recorded in January 2011 business.*

Larkin recommends that the [redacted] difference between the December estimate and actual for Account No. 5550046 as it relates to Lawrenceburg be removed from the 2011 FAC.

Audit Trail for Reconciling Adjustments

As discussed previously, LA-2011-50 requested a complete audit trail for all amounts in the RA portions of the FAC filings for each sub-account of purchased power during the review period. In response, the Companies provided monthly reconciliations between purchased power recorded in the general ledger and purchased power included as part of monthly FAC costs. These monthly reconciliations were provided as part of AEP's implementation of Larkin's recommendation from the 2009 FAC audit that AEP Ohio provide a better audit trail as it relates to being able trace the Companies monthly purchased power costs from the vendor invoices and paid cash vouchers (provided in the response to LA-2011-41) to the FAC workbooks provided in LA-2011-49.

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 7-64
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.*

On January 27, 2011, AEP Ohio witness Philip J. Nelson submitted direct testimony in Case Nos. 11-346-EL-SSO and 11-348-EL-SSO in which the Companies proposed the implementation of an Alternative Energy Rider ("AER") which would segregate the REC value from Renewable Energy Purchase Agreements ("REPA"). In other words, the REC component of renewable energy costs would be recovered through the AER and the non-REC portion of such costs would continue to be recovered through the FAC. AEP Ohio is proposing that this methodology begin with the review period January through December 2012. Therefore, AEP

Ohio's proposed methodology for segregating the REC value of renewable energy purchases was not applied by the Company during the January through December 2011 FAC review period.

As part of its review of renewable energy resources, Larkin asked AEP Ohio a series of questions pertaining to its renewable energy purchases and RECs. In LA-2011-63, Larkin asked whether the Companies maintained an inventory system for its RECs, and if so, to provide the REC inventory for each month of 2011. In its confidential response, AEP Ohio stated that the [redacted]

Exhibit 7-65

[redacted]

[In a follow-up to LA-2011-63, specifically LA-2011-76, Larkin asked AEP Ohio to provide separately for CSP and OPCO, an accurate listing of the "Out of State Non-Solar" inventory position for each month of 2011, and within this listing to identify the quantities of "Out of State Non-Solar" RECs for each of the following:

RECs related to previous year compliance.

RECs used for 2011 compliance in each month.

Unused "Out of State Non-Solar" RECs that are in inventory that could be used for 2010 or subsequent period compliance.

In response, AEP Ohio referenced a confidential attachment that was provided in LA-2011-70, and reproduced in and reproduced in

Exhibit 7-66 below.

Exhibit 7-66

[redacted]

[redacted]

[redacted]

7-66 [redacted]

[redacted] 7-66 [redacted]

[redacted]

[redacted]

On February 5, 2009, CSP and OPCO entered into separate REPA for wind energy with the Fowler Ridge II Wind Farm LLC ("Fowler Ridge") which provided for the purchase of wind generation amounting to [redacted]. The Fowler Ridge facility began commercial operations on December 17, 2009.

[redacted]

Exhibit 7-67 [redacted]

Exhibit 7-67

[redacted]

[redacted]

[redacted]

LA-2011-73 asked whether any of the 2011 non-Ohio non-solar REC obligation was fulfilled with REC purchases. In response, AEP Ohio stated that all of CSP's and OPCO's 2011 non-solar REC obligation was fulfilled solely by RECs from the Fowler Ridge 2 wind farm and that CSP and OPCO each have a long-term Renewable Energy Purchase Agreement ("REPA") with Fowler Ridge 2. In addition, in the response to LA-2011-74, the Companies stated that its non-Ohio or other non-solar REC obligation was fulfilled with spot market or contract purchases of renewable power via the Fowler Ridge wind PPAs, the quantities and costs of which are reflected in Exhibit 7-68 below.

Exhibit 7-68

[redacted]

LA-2011-75 asked AEP Ohio to explain the monthly positions of CSP and OPCO as it relates to Ohio non-solar RECs for each month of 2011 and to indicate whether the Companies were in a short position throughout 2011 with respect to non-solar RECs. In its confidential response, [redacted]

Exhibit 7-69

[redacted]

LA-2011-64 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 [redacted] is the only REC inventory tracking system being used by both CSP and OPCO. In addition, the Companies track the associated dollars in the general ledger for accounting purposes.

LA-2011-65 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-2011-66 requested that AEP Ohio indicate whether the Companies are relying on any particular accounting guidance for how items are entered into or extracted from REC inventory, and if so, to describe such guidance. AEP Ohio stated that it 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 for future periods, a REC book inventory is maintained. This book inventory is based on the weighted average cost of RECs acquired but not yet utilized to meet the Companies obligation. The number and cost of RECs acquired will be added to book inventory. In addition, the extraction of RECs from book inventory will be based on the periodic utilization of RECs to meet the Companies obligation with the periodic REC expense calculated based on the weighted average cost of inventory for that period.

Concerning the kinds of costs, other than REC purchase costs, that are included in REC inventory, AEP Ohio stated that only direct third-party REC purchase costs are added to REC inventory.

Concerning the value at which RECs are entered into inventory if they are generated by AEP Ohio, and if other than zero, to describe the methodology used for determining the value, AEP Ohio stated that solar RECs generated by the Companies are added to inventory at zero cost, but serve to reduce the Companies REC quantity obligation.

Concerning the value at which RECs are entered into inventory if they are purchased as part of a bundled energy transaction, AEP Ohio stated that the solar REC portion of the bundled energy purchases from Wyandot is valued at approximately [redacted] of the price paid.

AEP was asked to explain when RECs are considered consumed or surrendered and when the costs appear in the Companies' rates. AEP Ohio stated that it uses accrual accounting and that each month, a cost approximating one-twelfth of the Ohio mandated obligation is charged to an expense account which is included in the FAC calculation.

LA-2011-67 asked AEP Ohio to identify all specific costs, by amount and account, in REC inventory that were charged to FAC-includable accounts during 2011. In response, AEP Ohio indicated that REC expense was [redacted] for CSP and [redacted] for OPCO and is recorded in Account 5570009. In addition, [redacted] for CSP and OPCO, respectively, was recorded in Account 1740036. As a result of the December 31, 2011 merger between CSP and OPCO, CSP's solar inventory was added to OPCO's solar inventory for a combined total of [redacted]).[44]

[44] See the response to EVA-2-37.

Larkin compared the [redacted] and [redacted] identified in the response to LA-2011-67, to the total REC expense in CSP's and OPCO's FAC workbooks (provided in LA-2011-49) for the review period of January through December 2011. Other than minor rounding, no exceptions were noted.

LA-2011-77 asked AEP Ohio to indicate the accounts in which the following renewable items were booked in 2011 and to provide the 2011 detail general ledger pages for each such account:

- REC purchase costs
- Gains on sale of RECs
- Loss on sale of RECs
- Costs associated with Attribute Tracking System(s)
- Consumed or surrendered RECs

In response, the Companies stated that the items referenced above are not reflected in the general ledger, but provided the schedule below from its revised response to LA-2011-77, which shows the accounts and amounts associated with the above referenced items.

Exhibit 7-70

[redacted]

[redacted]

Since the amounts associated with the Companies' REC purchases, gains, losses and consumption are not recorded in the general ledger (as noted above), Larkin requested that AEP Ohio provide a breakout of the REC expense that was included in the FAC during 2011. Exhibit 7-71 below provides the requested breakout of the component detail associated with CSP's and OPCO's REC dollars and quantities[45]. As can be seen, the dollar amounts correspond with the [redacted] and [redacted] for CSP and OPCO, respectively, that were included in the FAC in 2011.

[45] The quantities included in the FAC during 2011 were provided in EVA-2-35.

Exhibit 7-71

[redacted]

Larkin requested that AEP Ohio explain how the gains noted above were accounted for in EVA-2-34. In response, the Companies' explained that gains are recorded as credits to Account No. 5570009, which reduces overall REC expenses charged to the FAC. The exhibit below shows how the gains were calculated.

Exhibit 7-72

[redacted]

EVA-2-36 requested a table which reflects the monthly REC power purchases (quantity and price) by PPA. In its confidential response, [redacted]

Exhibit 7-73
Monthly Power Purchases By PPA

[redacted]

Larkin noted that the dollars and MWh for Fowler Ridge II were identical between CSP and OPCO. In response to our inquiry, AEP Ohio stated that the Fowler Ridge II purchases were split evenly between both companies.

LA-2011-80 requested a summary and details of CSP's and OPCO's status regarding renewable energy (wind and solar) objectives and minimum requirements for 2011 and whether there was a shortfall in achieving the minimum requirements, and if so, to identify and quantify the amount of the shortfall as well as the reason(s) for such shortfall. Larkin also requested that the Companies identify and provide a copy of any waivers obtained related to its meeting its 2011 renewable energy objectives for 2011. In response, AEP Ohio referred to its Annual Alternative Energy Compliance Plan and Annual Alternative Energy Status and Compliance Report, which were filed with the PUCO on April 16, 2012. A review of these reports indicated that that the Companies were able to meet their 2011 renewable energy minimum requirements and the reports reflected AEP Ohio's 2011 Renewable Energy Benchmark Minimum Requirements, expressed in terms of MWh, which are shown in the table below.

Exhibit 7-74
CSP and OP 2011 Renewable Benchmark Minimum Requirements (MWh)

Description	CSP	OPCO	Total
Solar	5,754	7,271	13,025
Non-Solar	186,036	235,108	421,144

LA-2011-68 asked AEP Ohio to show how non-solar RECs were valued during 2011 and to identify and provide all accounting policies and procedures in effect during 2011 that related to the valuation of RECs. In response, the Companies stated:

[redacted]

Through interviews conducted with AEP Ohio personnel during the onsite field visit on March 22, 2012, the Companies confirmed that they still [redacted]. Larkin requested that the Companies provide all written guidance, emails, accounting policy directives and any other written documentation from the Accounting Policy Group that relates to the use of a zero dollar inventory value for 2011 non-Ohio non-solar RECs. AEP Ohio provided a Company memo in its confidential response to LA-2011-71. This memo, which is dated January 31, 2009, discusses the REPAs that both companies entered into with Fowler Ridge.

Upon reviewing the memo, Larkin noted that the only portion that appears to relate to [redacted]

[redacted]

Larkin also asked AEP Ohio to identify and provide all comparable market information which supports [redacted]b value for the 2011 non-Ohio non-solar REC inventory in LA-2011-72. In its response, AEP Ohio provided four confidential attachments, each of which was a document titled "SNL Energy Power Daily", issued by [redacted]

[redacted]

Biomass and Biodiesel Fuel

As it relates to biomass fuel testing, LA-2011-78 asked AEP Ohio to identify the plants, units and dates where biomass testing was conducted in 2011 and to identify the cost per MMBtu of the biomass fuel burned. This data request also asked how the Companies identified and

---

46 [redacted].

separated (1) the energy value, and (2) the environmental (REC) value for the biomass burned. In its confidential response, AEP Ohio stated [redacted]

With regard to biodiesel fuel testing, LA-2011-79 asked AEP Ohio to identify the plants, units and dates where biodiesel testing was conducted in 2011 and to identify the cost per MMBtu of the biodiesel fuel burned. This data request also asked how the Companies identified and separated (1) the energy value, and (2) the environmental (REC) value for the biodiesel burned. In its confidential response, AEP Ohio stated that [redacted]

Exhibit 7-75
[redacted]

[redacted]

[redacted]

Carrying Costs on Deferred Fuel Balances

AEP Ohio's FAC rider adjusts quarterly. AEP Ohio was granted a carrying cost ratio based on its weighted average cost of capital ("WACC"). The equity portion of the WACC was grossed-up for income taxes. The gross-of-tax WACC allows the Company to recover the cost of investor-supplied financing, including (1) the cost of debt, (2) the cost of equity, and (3) income taxes related to the cost of equity. The carrying cost changes as the debt rate changes.

AEP has applied the gross-of-tax WACC-based carrying cost rate on a monthly basis to the monthly Deferred Fuel balances. AEP supplied detailed calculations of carrying costs for 2010 in response to LA-2011-49 in Excel files for CSP and OPCo, respectively.[47]

As an example, for January 2011 carrying charges, the WACC is applied, separately for the debt and equity pieces, to the 12/31/2010 Deferred Fuel balance.[48]

Both CSP and Ohio Power had been in an under-recgovery position. As explained in AEP Ohio's response to LA-2011-111, the deferred fuel balance for CSP was adjusted to zero as a result of the SEET order. That write-off took the CSP balance from $18,717,599 to zero as of December 2010. A portion of the Ormet Interim Agreement amount was included in CSP's pre-December 2010 deferred fuel balance. As a result of the SEET order, CSP has applied the remainder of the $42.683 million amount to be credited, after applying $18.718 million to its deferred FAC balance, as a credit rider which has reduced customer bills in 2011 by approximately $23.965 million or $0.001395 per kWh.[49]

In Commission Case Nos. 08-917 and 08-918, originally in the March 18, 2009 Opinion and Order at page 23, and subsequent on rehearing, the Commission authorized AEP Ohio to apply the gross-of-tax WACC to the under-recovered FAC balances. Larkin examined those orders and various filings from those proceedings which were provided to us by AEP Ohio and Staff. Those Commission Orders would appear to allow AEP Ohio to apply the gross-of-tax WACC to the under-recovered FAC balances without any recognition of, or offset for, the related non-investor supplied financing in the form of Accumulated Deferred Income Taxes (ADIT) that is recorded in Account 283, ADIT-Other, for the tax savings that are directly related to the under-recovered FAC balances. [redacted]

[redacted]

[redacted]

[redacted]

[47] See, e.g., Excel Attachments M and MM to LA-2011-49, respectively.
[48] This is also referred to as the under-recovered FAC balance.
[49] CSP's calculations of the Credit Rider amount were provided in LA-2011-1-111 Attachment 1.

[redacted]

Exhibit 7-76

[redacted]

[redacted]

50 [redacted]

51 [redacted]g

Exhibit 7-77

[redacted]

Exhibit 7-78

[redacted]

[redacted]

[redacted]

Active Management

LA-2011-48 asked whether AEP Ohio engaged in "active management" of its fuel, purchased power or emission allowance positions during the review period January through December 2011, and if so, to identify, quantify and provide the accounting documentation for each such transaction during that period. In addition, LA-2011-48 asked AEP Ohio to fully explain the reasoning and estimated economic benefit that was anticipated for each transaction. In response, AEP Ohio stated:

> *No, the Company does not engage in "active management" as defined by the auditor to be "the practice of flattening one's position on a frequent (daily) basis to align coal commitments with power sales outlook."*

Conesville Coal Preparation Plant

As discussed above by EVA, 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 in order to provide more flexibility to AEPSC in its coal procurement for the Conesville station. EVA had recommended in the 2009 management/performance audit that AEPSC should undertake a study to determine whether there is an economic justification for continuing to operate the Conesville Coal Preparation Plant given the renegotiation of the [redacted] coal to washed coal combined with a reduction in overall Conesville coal demand. AEPSC agreed to perform the study, which was ultimately provided to the auditors on April 21, 2011.

In its study, AEPSC concluded that it was not economic to continue operating the CCPP beyond the first quarter of 2012. This conclusion came with a caveat with respect to new hazardous air pollution regulations. AEPSC had revised its Asset Retirement Obligation ("ARO") and increased its monthly charge to the CCPP in anticipation of the first quarter 2012 closing. AEP Ohio stated that there were no updates to the CCPP closure study during the 2011 review period.[52]

In the 2010 management/performance audit report, EVA had recommended that AEPSC work to minimize the costs associated with the closure of the CCPP. In addition, EVA had recommended that AEPSC provide its plan for accounting for the closure costs to the auditor for review in the next audit cycle. In order to facilitate that review, Larkin asked AEP Ohio a series of questions related to the CCPP which are discussed below.

Data request LA-2011-113 asked AEP Ohio to identify all costs recorded during 2011 that relate to the CCPP and to show in detail how such costs have affected the fuel cost of CSP during the review period. In response, the Companies' referred to the response to EVA-2011-1-20, which is CCPP's 2011 income statement which AEP Ohio stated reflects all recorded CCPP expenses during 2011[53]. As to how CSP's fuel costs were affected in 2011, a review of this income statement indicated that for Account No. 501 - Fuel-Steam Power, CSP incurred costs totaling [redacted] during 2011 versus [redacted] which was incurred in 2010, or a difference of [redacted]. The confidential attachment provided in response to LA-2011-116 indicates [redacted]

In a follow-up question, LA-2011-116 asked AEP Ohio to identify, quantify and explain in detail how cost accelerations and depreciation and amortization periods related to the remaining anticipated useful life and/or potential shut-down of the CCPP affected fuel costs during 2011. In response, the Companies' provided a confidential attachment, which provided explanations for operating cost increases from 2010 to 2011 for closure related expense increases. These explanations are summarized in the exhibit below:

[52] See the responses to EVA-2011-1-27 and LA-2011-115.
[53] The CCPP's 2011 balance sheet was provided in EVA-2011-1-24.

Exhibit 7-79

[redacted]

[redacted] Larkin requested the details related to the M&S write-off at December 31, 2011. In its response to EVA-2-21, the Companies' provided a confidential attachment which stated in part:

> [redacted]

Larkin reviewed M&S inventory study which was provided as Confidential Attachment 3 with EVA-2-21 and noted that the M&S items that comprised the "unique" and "not unique" items totaled the [redacted] noted above. However, this amount is [redacted] higher than the [redacted] M&S write-off amount that was indicated in the response to LA-2011-116 (and shown in Exhibit 7-79 above). The CCPP balance sheet for CCPP (provided in EVA-2011-1-24) reflects the [redacted] M&S balance at December 31, 2011. In response to Larkin's inquiry about this discrepancy, AEP Ohio stated:

> *The actual write-off amount is from financial general ledger,* [redacted]*, and the analysis reports are from the inventory subsystem, Asset Suite. There can be timing delays between the systems for several reasons. Receipts of materials are based on the purchase order price which can differ from the vendor invoice and are adjusted when the invoice is processed. Transfers of equipment between facilities are not recorded until material is receipted at the receiving location. Catalog unit price adjustments on returned materials are not adjusted before material is returned to inventory. Material is purchased to inventory without catalog ID detail.*

Larkin requested that the Companies provide the Human Resource detail of the severance costs, including payroll, benefits and payroll taxes. In its confidential response to EVA-2-8, AEP Ohio provided the following breakout of the severance accrual of [redacted]:

Exhibit 7-80

[redacted]

As it relates to the UMWA Curtailment Fee accrual, AEP Ohio stated:

[redacted]

In a related question, AEP Ohio was asked to identify the dates and amounts of payments to the UMWA for the fee and to provide an explanation of anticipated dates and amounts of remaining payments if the Curtailment fee has not been fully paid yet. In response to EVA-2-12, the Companies' stated:

[redacted]

[redacted]

The exhibit below reflects an approximation of the [redacted] that is allocated to CCPP Units 4, 5 and 6 including the amounts allocated to Unit 4's joint owners.

Exhibit 7-81

[redacted]

EVA-2-4 asked AEP Ohio to identify and provide cost information related to Materials and Supplies ("M&S") purchases at the CCPP during 2011. In response, the Companies' provided an attachment which reflected the CCPP 2011 M&S activity, including the purchases and uses along with the associated quantities and amounts, which are summarized below. As shown in the exhibit, there was an overall decrease in M&S expense of [redacted] in 2011.

Exhibit 7-82

[redacted]

AEP Ohio stated in the response to EVA-2-5 that all CCPP related amortizations were completed on December 31, 2011. The response to EVA-2-6, which asked the Companies to identify the O&M account being charged with CCPP costs while the plant is idle, stated that beginning in 2012, costs not associated with or related to delivered fuel cost adjustment charges or credits are charged to Account No. 5060000 – Miscellaneous Steam Power Expense. In addition, CCPP related delivered fuel cost adjustment charges and credits are charged or credited as fuel cost to Account No. 1510000 – Fuel Inventory.

EVA-2-7 requested explanations and quantifications for each component of the CCPP related ARO. In response, AEP Ohio provided a confidential response which reflected the data in Exhibit 7-83 below:

Exhibit 7-83

[redacted]

[redacted]

AEP Ohio stated the following with respect to the ARO amounts in Exhibit 7-83:

[redacted]

[redacted]

[redacted]

Larkin inquired about the CCPP's real and personal property tax assessment completed at the end of 2011 in EVA-2-9. In response AEP Ohio stated that there were no personal property taxes assessed at the CCPP since only utility companies pay such taxes in Ohio and CCPP does not qualify as a utility. With respect to the real property tax assessment, AEP Ohio provided a copy of its property record card for Coshocton County, which is where the CCPP is located. This document indicated a land assessed value of [redacted] and a building assessed value of [redacted] for a total assessed value of the CCPP of [redacted]. The Companies stated that the assessed value did not change from 2010 to 2011 and the associated taxes were not payable until 2012, of which CCPP has paid the first half.

In terms of the approximately [redacted] tons of coal inventory at the CCPP as of December 31, 2011, the response to EVA-2-14 stated that the last [redacted] tons of washed coal, valued at [redacted], were billed to CSP and recorded in Account 1510004 - Coal Inventory in Transit. These tons and their related costs were ultimately transferred to the Conesville Plant at the Unit 3 and Unit 4 piles, and recorded in Account 15100001 - Inventory Available for Consumption where they became part of the weighted average cost in January 2012.

EVA-2-16 requested that AEP Ohio provide a detailed description of actions taken by AEPSC to sell the CCPP in its entirety and by component. In response, the Companies stated that there were no actions taken by AEPSC during 2011 to sell the CCPP facilities either in their entirety or by its components. However, a solicitation was sent out by AEP Ohio to potential bidders in 2012 in an attempt to identify the level of interest in the CCPP facility. Larkin requested that AEP Ohio provide the documents that were sent to the prospective purchasers of the CCPP and the accompanying land, equipment and M&S inventory in EVA-2-17 as well as a list of the contacted parties in EVA-2-18. AEP Ohio objected to these inquiries by stating:

> *AEP Ohio objects to the extent the question seeks information outside of the defined audit period.*

AEP Ohio provided similar objections in its responses to EVA-2-15 and EVA-2-23, which requested that the Companies provide the communications with the Conesville Unit 4 co-owners as it relates to idling as well as other issues concerning the CCPP.

Larkin inquired about the salvage values that were utilized for the CCPP ARO in EVA-2-20 and the Companies' stated the ARO calculations do not include salvage values.

EVA-2-24 asked for AEP Ohio to provide illustrative actual data for July and December 2011 which shows how the costs were developed for bidding each Conesville unit into PJM. In response, the Companies' stated [redacted]

Conclusion:

11. Larkin recommends that AEP Ohio determine and assign a salvage value to the CCPP for purposes of the depreciation calculations.
12. Larkin also recommends that should AEP Ohio sell the CCPP, that the proceeds from the sale should be credited against the December 31, 2011 under-recovered FAC balance.

Emission Allowances

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-2011-54 through LA-2011-55.

LA-2011-54 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-2011-1-35 for a schedule of emission allowance purchases, sales as well as related gains and losses for both CSP and OPCO. The following exhibit summarizes for CSP the emission allowance purchases, sales, and gains and losses that occurred during the January through December 2011 review period:

Exhibit 7-84

[redacted]

[redacted]

The table below summarizes for OPCO, the emission allowances purchases, sales and gains and losses that occurred during the January through December 2011 review period:

Exhibit 7-85
OPCO Emission Allowance Activity

[redacted]

LA-2011-55 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-2011-55 also included confidential attachments which reflected CSP's and OPCO's monthly EA inventory balances during 2011. The exhibit below summarizes for CSP the monthly EA month ending inventory balances for each month of the January through December 2011 review period:

Exhibit 7-86
[redacted]

[redacted]

The exhibit below summarizes for OPCO, the monthly EA inventory balances for each month of the January through December 2011 review period:

Exhibit 7-87

[redacted]

[redacted]

Data request EVA-2-32 asked AEP Ohio to explain and document the combination of the CSP and OPCO EA inventory balances as of December 31, 2011 following the completion of the merger. In response, the Companies' provided the schedule below:

Exhibit 7-88

[redacted]

[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 2010 includes AEP Ohio's responses to LA-2011-58 and LA-2011-59.

LA-2011-58 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 there were no organizational changes to the Companies' Fuel, Emissions and Logistics during the review period.

LA-2011-59 requested information similar to LA-2011-58, although from a procedural versus organizational standpoint. In response to LA-2011-59, AEP Ohio stated that there were no procedural, policy or accounting changes related to the Fuel, Purchased Power and Emission Allowance Procurement.

Internal Audits

LA-2011-62 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, AEP Ohio provided four internal audit reports, which were issued at various points during 2011. The following indicates the areas that were the subject of the internal audits, along with a summary of recommendations for each area:

1. 2011 Fuel Restructuring Review (report issued January 17, 2011)

The staffing levels for the fuel accounting functions at the plant and service company level were impacted by the voluntary and involuntary severance program in the first half of 2010 as well as the subsequent personnel reassignments. This restructuring primarily impacted the West Fuel Accounting Group and the Conesville, Big Sandy and Kanawha River plants.

The objective of this internal audit was to determine whether key controls within the Fuel Accounting system, including the plant fuel accounting activities, remained effective subsequent to the personnel changes noted above and the scope included a review of the following processes:

<u>West Fuel Accounting</u>

- Fuel Journal Entries
- Reporting requirements

<u>Conesville, Big Sandy and Kanawha River Plants</u>

- Coal receiving, consumption and inventories
- Coal sampling and quality analysis
- Fuel oil (diesel) receiving and consumption

The conclusion reached by performing this review was that improvements in controls were needed as it relates to the coal sampling and quality analysis. Specifically, audit services concluded that "subsequent to restructuring, East Plant personnel responsible for coal sampling and quality analysis do not have a consistent understanding of their control responsibilities and how they contribute to effective monitoring of coal quality performed by FEL". Audit services identified the following functions as not performing effectively:

- Monthly Quality Comparison Reports
- Sampler Inspection Reports
- Sampling Ratio Reports
- Bias Testing

In terms of resolving these issues, this internal audit report stated the following:

> *FEL Operations management will work with Generation Business Services management to develop guidelines, in coordination with the plants, for the requirements related to the sampler inspection reports and sampling ratio reports, as well as coordinate the communication of these guidelines to the appropriate personnel at the plants. In addition, the sampling ratio reports will be enhanced by utilizing* [redacted] *instead of spreadsheets to monitor the sampling system performance. FEL Operations will continue to monitor the plant deliverables and will document the follow-up performed on any variances.*

FEL Operations management will coordinate the monitoring of the bias testing requirements for all plants in order to centralize responsibility and ensure compliance.

2. 2010 Coal Inventories (report issued February 3, 2011)

This internal audit related to the review of AEP's coal pile inventory results for 2010, which comprised a total of 39 inventories being conducted at 21 plants and the Cook Coal Terminal. The purpose of this review was to:

- Review the System Power Plants' Spring and Fall coal inventory reports for completeness and propriety.
- Assess the reasonableness of the book inventory number at the time of the survey, which is compared to physical inventory results to determine the coal inventory adjustment.
- Determine whether the coal inventory adjustments reported by the Power Plants were calculated accurately and in compliance with AEP System Accounting Bulletin No. 4. This bulletin requires recording 100% of the difference between the physical inventory and book inventory and performing another physical inventory within six months, if the difference, as a percent of consumed, is greater than +/- 2%.
- Determine that plants with a variance of +/- 2% investigated the variances and addressed any issues discovered.
- Verify that the accounting entries recording the adjustments were reasonable and complete.
- Observe the inventory volume and density measurement activities at one plant to evaluate compliance with AEP Circular Letter CI-O-CL-0084.

Audit Services reached the following conclusions as a result of its review:

- Audit Services noted an error during its review that related to the [redacted] Plant reporting incorrect book inventory which resulted in inventory being overstated by 4,994 tons. As a result, a revised 0955A report was issued in January 2011.
- Management self-detected an error in which the [redacted] Plant miscalculated book inventory which resulted in an understatement of inventory of 1,007 tons. As a result, a revised 0955A report was issued in July 2010 although the understatement was considered immaterial to the extent that no adjusting entry was made.
- Audit Services concluded that the coal pile inventory results and adjustments were properly stated in all material respects as of December 31, 2010.

3. Review of Regulated Trading Activities (report issued August 9, 2011)

AEP Service Corporation ("AESPC") is responsible for regulated wholesale marketing and trading business activities within the PJM, MISO and SPP markets. For the six months ended June 30, 2011, AEPSC's regulated trading business recognized $181.2 million in net gross margin for the combined trading and off system business activities.

The objective of this internal audit was to:

- Perform business process walkthroughs of the regulated trading business and independent risk support functions to validate and update our understanding of the processes, systems and controls documented in the Sarbanes-Oxley ("SOX") 302/404 process.
- Perform an internal control design assessment to ensure controls are adequately designed to mitigate business process risks for select operational areas not covered by the annual SOX 404 effort.
- Perform targeted substantive testing that complements and expands upon the annual SOX 404 testing, while also covering operational areas excluded from the scope of the SOX 404 effort.

This review, which primarily covered power and coal transactions and limited coverage of gas transactions, encompassed the following processes:

- Trading Strategy
- Trade Execution and Capture (routine transactions)
- Broker activities
- Monitoring compliance with Trader Vacation Policy
- Risk Management
- Energy Scheduling
- Contract Administration
- Third Party Settlements
- Trade Confirmations
- Market Risk Oversight
- Commodity and Energy Accounting

Audit Services concluded that minor improvements were needed in the area of Market Compliance with Trader Vacation Policy. Specifically, Audit Services made the following comment:

> *In response to the Societe Generale fraud in 2008, AEP implemented a new Policy that requires traders to take a minimum of two, one-week vacations (must be at least seven consecutive days) per year. The process for monitoring compliance with the Trader Vacation Policy (the Policy) only utilizes the recorded vacation from the [redacted] to verify compliance with the Policy. It does not incorporate actual trading activity from the Magnum System; therefore, traders could transact while on vacation and this condition may not be detected as a Policy violation.*

In terms of a resolution to this issue, this internal audit report stated that on a quarterly basis, recorded vacation time for each applicable trader will be extracted from the [redacted] and compared with the Magnum System in order to verify that the traders are not performing transactions while on vacation as well as overall compliance with the annual Policy requirement.

4. Pre-Implementation Review for Fuelworks System Imbalance Project (report issued August 24, 2011)

Fuelworks is a SOX application that will be able to systematically track trading or selling of imbalances by pipeline and according to the pipeline contract clauses. The project will encompass changes needed to add functionality to manage gas pipeline imbalances, perform inventory calculations, support gas sales and trades, and report these numbers to Accounting for monthly booking.

The objective and scope of this internal audit were to perform an assessment to verify that internal controls related to the Fuelworks Imbalance Project were adequately designed to mitigate legal, reputational and security risks and to test those controls for operating effectiveness.

The business processes included within the scope of this internal audit included:

- Gas Procurement - This is the process used to procure gas for gas plants.
- Gas Sales - This is the process used to sell gas for gas plants.
- Gas Turn Back - This is the process used to sell turn-back gas for gas plants.
- Gas Estimate - Regulated Fuel Accounting uses this best estimate cost to book fuel expense for prior month's gas purchases. the estimate is made because supplier and transporter statements that contain actual trued-up data aren't received until mid-month.
- Gas Invoicing - This is the process used to process and pay invoices from AEP's vendors.
- Gas True-Up - This is the process used to true-up accounting based on actual values that have been received and agreed upon.
- FERC 552 - FERC 552 regulatory accounting occurs annually and requires specific codes to be assigned to invoice transactions to match categorizations determined by the FERC 552 report. This process is in place to tag the transactions and to create and submit the report.

Audit Services concluded the following as a result of its review:

> *During testing the project team encountered several defects in critical path items that required additional programming and testing. These defects are related to both processing and reporting. This has caused delays in the implementation; however, the project team has documented the defects, and is working to resolve them.*
>
> *ASD performed design and effectiveness assessments of controls based on changes to the processes. The controls were related to the operational processes of gas procurement, gas sales/turn back, monthly estimates, invoicing and monthly true-up. These controls covered verifying that transactions are conducted by authorized and appropriate individuals with appropriate counterparties, as well as verifying that transactions are validly, accurately and timely recorded and reported. ASD's opinion is based on the current state of the project, which does not include delivery of the changes to the production environment. ASD determined that the controls were designed appropriately, and were operating effectively in the test environment.*

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 the Barge Transportation Agreement.

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

[redacted]

[redacted]

[redacted]*h*

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

The SEC Release No. 35-24039 dated March 4, 1986, 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 Commission ("FERC") Account 151. I&M proposes 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 Commission of Virginia and the West Virginia Public Service Commission in 1981 and 1984, respectively, and which I&M proposes to begin applying after approval by this Commission. 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 Commissions 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 Commission 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 LA-2011-82, in Confidential Attachment 1 to that response[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

The confidential Actualization file was provided with the response to EVA-2-51.

The RTD's 2011 Rate Matrix, which provides the affiliated coal barging rates for OPCO based on the 2011 budget, was provided in the Confidential Attachment 1 to LA-2011-83. 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 Amos, Cardinal, Kammer, Mitchell, Muskingum River, Sporn, and Gavin.

A listing of all operating leases for captive barges was provided with the response to LA-2011-97. Copies of the five largest operating leases based upon annual cost in 2010 and 2011 to OPCO were provided in the Confidential Attachments to LA-2011-99. Those lease and charter agreements list OPCO as Charterer for [redacted] barges. The agreements provide that the [redacted] is the owner of the vessels. Section 8(a) (provided at LA-2011-1-99 Confidential Attachment 1, page 16 of 65) provides as follows concerning maintenance and repairs:

[redacted]

[redacted]

[redacted]

The response to LA-2011-98 indicates there are no operating leases between OPCO and River Operations for OPCO-owned barges.

The affiliated freight rate true ups for the five quarters starting with the fourth quarter of 2010 through the fourth quarter of 2011 for OPCO were provided in Confidential Attachment 1 to LA-2011-84. That information is summarized in the following table:

Exhibit 7-89

[redacted]

[redacted]

For 2011, I&M had approximately [redacted] in revenue from OPCO related to the RTD. Costs and expenses were [redacted], offset by [redacted] for third party gains, less I&M's return on investment of approximately [redacted]. RTD also delivers urea to OPCO. For 2011 RTD shipped both coal and urea to OPCO plants. The 2011 quantities included urea tonnage of approximately [redacted] and coal tonnage of [redacted]. The net cost (based on RTD's Costs and Expenses, less the Third Party Gain, plus RTD's Return on Investment) for OPCO for 2010 was approximately [redacted]. For the [redacted] tons of urea and coal delivered, this is an average cost of approximately [redacted] per ton. In comparison, the average cost per ton for the fourth quarter of 2010 was [redacted], as shown in the above table.

Intercompany barge optimization reports (cross charter reports) are utilized by RTD, and are provided in response to LA-2011-95 for December 2010 and January through December 2011. These reports show, by month, the barge days associated with Captive chartered to Commercial and Commercial chartered to Captive, as well as the monthly amounts of Commercial Expense/Captive Revenue and Captive Expense/Commercial Revenue. For 2011, the total amounts of Commercial Expense/Captive Revenue and Captive Expense/Commercial Revenue were [redacted] and [redacted], respectively. The balance between these two amounts reflects the RTD operating plan to optimize combined fleet performance and not have cross-subsidies to either the captive or commercial side of the barge transportation business.

The RTD's Barge Operations Income Statements and Balance Sheets for Captive Operations for December 2010 and each month of 2011 were provided in Confidential Attachments 1 and 2 to LA-2011-92. Consolidated financial statement information for captive operations in 2011 was provided in the confidential attachment of LA-2011-85. LA-2011-85 also provided the pre-consolidation financial statement information for captive operations business segments in 2011 and the consolidating entries and adjustments for 2011 captive operations.

The RTD's "Actual Net Investment Base & Cost of Capital Billing Adder" for 2010 and 2011 was provided in Confidential Attachments 1 and 2 to LA-2012-93.

[redacted]

[redacted]

[redacted]

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 [redacted] ROE that was applied in 2010 and 2011) is appropriate and commensurate with the risk of this operation.

The Ohio PUC has not allowed either CSP or Ohio Power to use a 1/8th O&M calculation for cash working capital in any distribution rate cases from 2000 to the present. In Case Nos. 11-352-EL-AIR et al, Ohio Power's more recent distribution rate case, the Staff report, at page 7, stated that the Applicant did not prepare a lead lag study; therefore, the Staff cannot recommend a working capital allowance. A similar statement is contained in the Staff report in CSP's last distribution rate case, Case Nos. 11-351-EL-AIR et al, at page 7.

The following table shows the estimated annual revenue requirement to OPCO from the RTD's Working Capital Requirement, derived from information provided in LA-2010-70:

Exhibit 7-90

[redacted]

[redacted]

The above table shows the total amount of annual revenue requirement on the RTD Working Capital component of the RTD investment base, and the estimated portion of that becomes a cost of OPCO for 2010 and 2011. Additionally, the following table shows how much of the total annual RTD revenue requirement for the RTD investment base relates to the RTD Working Capital component:

Exhibit 7-91

[redacted]

[redacted]

The use of a 1/8th O&M calculation for determining a working capital component of investment base has been controversial. It assumes there is a net lag between the collection of revenue and the payment of cash expenses of approximately 45 days (365 / 8 = 45.625 days). The validity of this assumption should be tested via a lead-lag study. AEP should be required to analyze the receipt of revenue and the payment of cash expenses for RTD captive operations, similar to a lead-lag study.

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. Other AEP operating utilities have conducted lead-lag studies.[54] 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.

Barging rates for RTD are calculated yearly and are based on the forecasted tons to be shipped for each origin – destination pair and the projected costs. Per the confidential attachment provided with LA-2011-100 [redacted]

LA-2011-87 asked whether the RTD or AEP or OPCO had information with respect to barge transportation rates charged by competitive carriers such as [redacted]. The Company's confidential response indicated that:

> [redacted]
>
> [redacted]

As explained in the response to LA-2011-90, [redacted]

As explained in the response to LA-2011-91, OPCO did not contract for barge transportation service with carriers other than the RTD. The RTD fulfills all of AEP's barging needs, other than the occasional transaction, such as the one noted above, as described in response to LA-2011-87.

RTD provided an explanation of the use of [redacted] to transport via barge the [redacted] [redacted] billed the RTD for that transportation.

As identified in the response to LA-2011-89 total demurrage revenue recognized in 2011 for RTD was [redacted]. OPCO's portion of that was [redacted]. Per LA-2011-88, demurrage is billed according to contract terms and is reported as affiliated or outside revenue by RTD based on the identity of the customer.

---

[54] For example, Appalachian Power Company filed lead-lag studies for its generation and distribution operations in Virginia State Corporation Commission Docket No. PUE-2011-00037.

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 the following recommendations in the Recommendations section below.

AEP should be required to analyze the receipt of revenue and the payment of cash expenses for RTD captive operations, similar to a lead-lag study, and to present such information to support its assumption that RTD has a significant Cash Working Capital requirement. If adequate supporting information is not provided to substantiate that RTD has a significant Cash Working Capital requirement and the amount of that requirement using lead-lag study analysis of cash receipts and cash payments, the RTD Working Capital component of the RTD investment base should be removed from the cost charged by RTD to OPCO from January 1, 2011 forward.

AEP should address why an ROE that has been set in a FERC order or by a state commission (such as Indiana) for a utility would be appropriate for RTD, when RTD is functioning as a fully cost reimbursed operation with annual true-ups, and, consequently, the level of risk to RTD would seem to be lower than for other utility operations.