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FILE

REPORT OF THE MANAGEMENT/PERFORMANCE AND FINANCIAL AUDITS OF THE FUEL AND PURCHASED POWER RIDER AND THE ALTERNATIVE ENERGY RIDER OF THE OHIO POWER COMPANY

Case No. 13-1892-EL-FAC

May 9, 2014

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

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LIST OF EXHIBITS

1 INTRODUCTION

Under Senate Bill 221, utilities were required to provide consumers with a standard service offer (SSO) consisting of either a market rate offer (MRO) or an electric security plant (ESP). On March 18, 2009, the Public Utilities Commission of Ohio (PUCO) approved an ESP for the Columbus Southern Power Company (CSP) and the Ohio Power Company (OP). The ESP, which included a fuel adjustment clause (FAC), was for a three-year period ending December 31, 2011. At the end of 2011, CSP merged into OP. A second ESP (ESP2) was approved in February 2012 (after some iteration) for a period starting January 1, 2012 running through December 31, 2014. Under ESP2, the FAC continues on an unmerged basis and that an Alternative Energy Rider (AER) be implemented for each Company. The PUCO also required a series of auctions so that Ohio Power could transition to a competitive market. The first auction would be 10 percent, energy only.[1] By June 1, 2014[2], 60 percent of Ohio Power's SSO energy requirements were to be supplied via auction. By January 1, 2015, all of Ohio Power's SSO energy requirements would be supplied via auction. Under the FAC, 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.

The PUCO solicited proposals to conduct both management/performance and financial audits of the FAC and AER recovery mechanisms for the years 2012, 2013, and 2014. In addition, the PUCO wanted support for the final reconciliation and true-up of the FAC following its termination. To achieve these goals, the PUCO has defined two audits. The first audit (Audit I) will cover the years 2012 and 2013 for both the FAC and AER. The second audit (AUDIT 2) will cover the FAC and AER for 2014 as well as the reconciliation and true up of the FAC.

Following a competitive solicitation, Energy Ventures Analysis, Inc. ("EVA") and its subcontractor, Larkin & Associates PLLC ("Larkin"), were selected by the PUCO to perform the management/performance and financial[3] audits and provide reconciliation support. This first audit covers 2012 and 2013; the second audit covers 2014 and the reconciliation of the deferred fuel balance. EVA and Larkin had previously performed the audits of 2009, 2010, and 2011.

[1] The first auction date was delayed until April 1, 2014.
[2] This date was subsequently delayed to November 1, 2014.
[3] This part of the review has in prior reports been referred to as the "Financial Audit", a term which could be misleading because the work does not involve an audit of financial statements, but rather is an attestation engagement involving verification of AEP-Ohio's FAC filings that is conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants, and using guidance set forth in former Chapter 4901:1-11 and related appendices of the Ohio Administrative Code relating to "Uniform Financial Audit Program Standards and Specifications for the Electric Fuel Component"

Background On The FAC

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

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

In order to mitigate the impact of the ESP on customers, the PUCO limited 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

In January 2011, AEP filed an application to continue the ESP past 2011. In December 2011, the PUCO modified and approved a September 2011 agreement. Under the September 2011 agreement, AEP would have transitioned to a market-based generation rate structure over a four and a half year period between January 2012 and May 2016. In February 2012, the PUCO revoked the ESP and directed AEP to file a modified ESP application.

In March 2012, AEP-Ohio filed a modified ESP application which provided for AEP-Ohio to separate its generation assets from its distribution and transmission assets and provided for a transition period through 2014. The PUCO approved a modified ESP in August of 2012 which provides for the transition to a fully competitive market by June 1, 2015.

The balance in the FAC under-recovery accounts as the beginning and end of each audit years are summarized in Exhibit 1-2. These amounts are without any of the proposed adjustments. The phase in recovery rider (PIRR) started in 2012

Exhibit 1-2
Balance in FAC Accrual Accounts

[redacted]

Audit Of The FAC and AER

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 first audit should cover the calendar years of 2012 and 2013. 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. The AER audit will follow the guidance provided for this work in Attachments 3 and 4 of this RFP. The audits will also cover any other specific items identified by the PUCO or Staff.

Audit Approach

EVA and Larkin conducted this audit through a combination of document review, interrogatories, site visits and interviews. EVA and Larkin visited the Cardinal station on February 21, 2014. EVA and/or Larkin conducted interviews with the individuals in the positions listed in Exhibit 1-3 mostly during the week of February 17th, 2014. In addition to those listed, Mr. Jim Sorrels, Manager of Regulatory Analysis and Case, attended all the interviews in Columbus. Several follow-up calls were held with the listed personnel as well as others.

This audit report contains findings for both the audit years 2012 and 2013. As appropriate, the findings and discussion are presented separately by year.

Exhibit 1-3
List Of Interviews

No.	Topic	Department	Participants
1	Purchased Power	Purchased Power	Julianne Lloyd; Mark Leskowitz; Tim Dooley; Jim Sorrels; Megan Pratt
2	Environmental Compliance	Environmental Compliance	John Hendricks; Tim Dooley; Karen Anderson; Brian Rupp; Rick Hayek; Jason Echelbarger; Jim Sorrels; Megan Pratt; Michael Childs
3	Internal Audits	Internal Audits	Rod Burnham; Tim Dooley; Jim Sorrels; Megan Pratt; Michael Childs
4	Consumables Procurement	Consumables Procurement	Marguerite Mills; Darryl Scott;Richard Hayek; Jim Sorrels; Megan Pratt; Tim Dooley; Jason Echelbarger; Michael Childs
5	Natural Gas/Fuel Oil Procurement	Natural Gas/Fuel Oil Procurement	Marguerite Mills; Nita Spracklen; Jim Sorrels; Megan Pratt; Tim Dooley; Michael Childs; Lori Thompson
6	Biofuels	Biofuels	Marguerite Mills; Jim Sorrels; Megan Pratt; Nita Spracklen; Tim Dooley; Michael Childs; Karen Carey
7	Coal Procurement	Coal Procurement	Jim Henry; Marguerite Mills; Kim Chilcote; Chuck West; Jeff Dial; Freelin Wright; Jim Sorrels; Megan Pratt; Tim Dooley
8	Conesville Preparation Plant	Conesville Preparation Plant	Jim Henry; Greg Stiltner (via phone); Marguerite Mills; Chuck West; Tim Dooley; Jim Sorrels; Megan Pratt
9	Ohio Regulatory/FAC Reporting	Ohio Regulatory/FAC Reporting	Andrea Moore; John Pulsinelli; Tim Dooley; Jim Sorrels; Megan Pratt; Michael Childs
10	Fuel Accounting	Fuel Accounting	Tim Dooley; LeRoy Griffin; Jim Sorrels; Megan Pratt
11	Renewables	Renewables	Jay Godfrey; Mike Giardina; Tim Dooley; Kelly Pearce; Jim Sorrels; Megan Pratt; Mark Gundlefinger (via phone); Scott Mertz; Will Castle
12	*River Operations*	*River Operations*	*Tom Palumbo; Darlene Norris; Carolyn Minkler; Brad Funk; Tim Dooley;* Jim Sorrels; Megan Pratt
13	Cardinal Plant Visit	Cardinal Plant Visit	Charles George; Scott Hand; Joel Milliken; Frank Zeroski; Scott Blosser; Kim Chilcote; Steve Orenchuk; Jim Sorrels; Jeff Gunder

FAC Audit

Major 2012 Management Audit Findings – General

1. Coal generation accounted for 84 percent of Ohio Power generation in 2012.
2. Ohio Power purchased about 16.2 million tons of coal in 2012. This was 11.7 percent or 2.1 million tons lower than 2011 purchases. During 2012, natural gas prices fell to very low levels which resulted in gas-fired generation displacing coal-fired generation throughout the U.S. As a result, Ohio Power's coal burn was depressed. According to data provided by Ohio Power, the average cost of coal in 2012 was [redacted] which was [redacted] or 11.1 percent higher than 2011 costs.
3. Based upon company EIA 923 filings, Ohio Power had the second highest cost of coal compared to the other three companies with Ohio power plants for which data are available. According to this measure, Ohio Power's ranking declined between 2011 and 2012.
4. Ohio Power purchased [redacted] percent of its coal requirements in 2012 from five suppliers. The top two accounted for [redacted] percent.

5. Due to the decline in coal demand, Ohio Power deferred purchases under several contracts. Over 80 percent of the shortfall was under its contracts with [redacted] and [redacted].

6. There were a number of management changes in the Fuel Emission and Logistics (FEL) organization in 2012. The Vice President of Fuel Procurement retired after a short tenure in that position and an experienced director with responsibility for procurement for the Ohio Power plants was terminated due to a corporate restructuring. While the individual who had previously held the Vice President role assumed responsibility for Ohio Power fuel procurement, the net result of the loss of two key personnel was a lack of continuity during the audit period and loss of corporate knowledge regarding key events in 2012.

7. AEPSC revised its inventory targets for its Ohio Power plants. The most notable change was a reduction in the inventory targets for the plants on the retirement list to 10 days. Inventory performance varied by plant with all of the plants having inventory levels above the target amounts for most of the audit period.

8. AEPSC conducted two coal solicitations in 2012: [redacted]. The [redacted] produced bids that were useful in negotiating the [redacted] agreement and resulted in an [redacted] from [redacted] which was handled through [redacted]. The [redacted] resulted in a new contract with [redacted].

9. AEPSC entered into [redacted] with [redacted] on a sole-source basis without soliciting the market.

10. Additional coal contract events in 2012 included the [redacted] under the [redacted] contract with [redacted] the [redacted] agreement, the decision to [redacted], and a [redacted] agreement.

11. Major regulatory events included the approval of a new ESP which provided for Ohio Power to separate its generation assets from its distribution and transmission assets and provided for a transition period through 2014. Upon approval in August 2012, planning began in earnest for the corporate separation.

12. Several fuel procurement decisions in 2012 had the net effect of transferring fuel costs for 2015 or later to earlier periods. In 2012, AEPSC [redacted] under the [redacted] contract for the period 2013 through 2015 and agreed [redacted] for the [redacted] years which had the net effect [redacted]. In 2012, AEPSC entered into [redacted] with [redacted]. According to AEPSC, the coal was priced [redacted] in [redacted]. In 2012 and 2013, AEPSC elected to take coal under the [redacted]

13. In addition, AEPSC incurred higher fuel costs related to its decision in [redacted]

[redacted].

14. AEPSC's decision not to [redacted] in the fourth quarter of 2012 as a result of [redacted] Ohio Power 2012 FAC costs by [redacted].
15. In August 2012, Ohio Power entered into [redacted] agreements with [redacted] that collectively provide the basis for the installation of a [redacted]. The interest in [redacted]. In order to qualify for the [redacted] As a result, in order for the facility to qualify for the [redacted], Ohio Power must [redacted]. Other than the third party requirement, the parties have considerable flexibility in how to structure the agreements including whether [redacted].

Major 2013 Management Audit Findings – General

1. Coal generation accounted for 92 percent of Ohio Power generation in 2013.
2. Ohio Power purchased about 13.5 million tons of coal in 2013. This was about 17 percent or 2.7 million tons lower than 2012 purchases. According to data provided by AEPSC, the average cost of coal was [redacted] which was [redacted] or 2.4 percent higher than 2012 costs.
3. Based upon company EIA 923 filings, Ohio Power had the highest cost of coal compared to the other three companies with Ohio power plants for which data are available. Ohio Power's declining relative performance is attributed both to the improving performance of the other companies and Ohio Power's own higher costs.
4. Ohio Power purchased over [redacted] of its contract coal in 2013 from five suppliers. The top two accounted for [redacted]. At the end the year, the [redacted].
5. Due to the decline in coal demand, Ohio Power deferred purchases under its contracts with [redacted] and [redacted]. [redacted] only delivered [redacted] percent of the initial 2013 contracted tonnage. Given [redacted] above-market pricing, reduced tonnages under [redacted] contracts improved average costs.

6. End-of-year (2013) inventory levels were about [redacted] end-of-year (2012) inventories. At the lower levels, all of the plants still had inventory levels mostly above the target amounts.

7. Considerable management attention was focused on the corporate separation. To complete the transfer of Ohio generating capacity into AEP Generation Resources at the end of 2013 required enormous effort including the establishment of systems that would provide for a smooth transition. A [redacted] part of this was insuring each continuing contract could be assigned. A [redacted] part of this was setting up the organization that would become responsible for the fuel procurement of the plants transferred to AEP Generation Resources.

8. Major coal contract events in 2013 included another [redacted] under the [redacted] with [redacted], the decision to continue to [redacted]

9. In 2013, certain Ohio Power fuel costs were inflated by a number of fuel procurement decisions in 2012 that had the net effect of [redacted] The majority of the higher costs related to the 2012 [redacted] coal in 2013 increased fuel costs by an estimated [redacted] on a total company basis; the [redacted] contracts resulted in a [redacted] on a total company basis above market due to the front end-end loading of the option payments for 2015 deliveries; and the [redacted] along with the concomitant [redacted] increased Ohio Power net fuel purchase costs by [redacted] on a total company basis,

10. In 2013, [redacted] generated [redacted] on a total company basis in revenues related to [redacted]. AEPSC flowed none of these dollars through the FAC.

Management Audit Recommendations

1. The structure of a number of contracts and transactions resulted in the [redacted]. Unless the Commission intended to allow cost shifting in this manner, EVA recommends that the following adjustments be made to the FAC:
    a. Reduce the 2012 FAC by the retail share of [redacted] related to the [redacted] station.
    b. Reduce the 2013 FAC by the retail share of [redacted] related to the [redacted], the market premiums in the [redacted] contracts, and the [redacted] during the first five months of 2013.

2. EVA recommends that the retail share of [redacted] 2013 company revenue received from [redacted] be credited to the FAC mechanism.

3. AEPSC should seek to minimize deferrals of 2014 coal contract tonnage which is at or below the prevailing price of coal in 2014 to future years.
4. AEPSC should prepare for the final FAC reconciliation in 2015.

2012 Financial Audit Findings

1. AEP began its 2012 quarterly filings on a consolidated basis combining Ohio Power and CSP fuel and purchased power costs and FAC revenues, reflecting the merger of Ohio Power and CSP which became effective December 31, 2011.
2. For the second quarterly FAC filing for 2012 the Company re-filed to comply with a Commission Order that there be separate FAC rates for Ohio Power and CSP.
3. The Company has used kWh sales as the basis for differentiating the quarterly FAC rates for Ohio Power and CSP.
4. The Company has explained in response to LA-2012/2013-4-2 that after the merger of Ohio Power and CSP it can no longer separately identify FAC includable costs applicable to their respective areas, i.e., similar to the breakouts that were used prior to the merger.
5. At December 31, 2012, the Company showed an [redacted].
6. During 2012, the Company recorded [redacted] net losses in account 5010033 for sales transactions related to selling [redacted], as described in the response to EVA-2012/2013-1-19.
7. During 2012, the Company included [redacted] of Lawrenceburg PPA capacity charges in the FAC.
8. During 2012, the Company included [redacted] of OVEC demand charges in the FAC.
9. The Lawrenceburg PPA capacity charges and the OVEC demand charges are subject to a separate investigation to examine whether double-recovery has occurred.
10. For purposes of assigning fuel and purchased power costs between retail load and wholesale transactions, the Company runs an hourly dispatch recalculation (sometimes referred to as the system "stack"), which assigns resources starting from lowest cost to highest cost first to serve the Company's retail load, then to wholesale transactions. The capacity and demand costs from power purchases are not included in the economic dispatch recalculation model used for such cost assignment.
11. For 2012, the Company's FAC did not include carrying charges.
12. Renewables expense for 2012 included in the FAC was [redacted].
13. For 2012, consistent with prior years, 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 cost, 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. Commencing with October 2012, AEP

Ohio began recovering the REC value of renewables in a new mechanism, AER. The capacity and energy costs for renewable power purchases continued to be included in the FAC.

14. In periods up to October 2012, the Company had been keeping inventories of REC quantities and cost for its Solar RECs, and maintaining an inventory of non-Solar REC quantities at zero cost. Commencing in October 2012, the Company began assigning a cost to the non-Solar REC inventories.

15. The zero value AEP has assigned to its non-Ohio non-solar REC inventory for January through September 2012 is questionable. Prior audits had recommended that a reasonable value for the REC should be assigned. The procedure that AEP began employing in October 2012 assigns a cost to RECs based on a residual method based on subtracting from the total cost of the renewable energy purchases values for (1) capacity and (2) energy. The residual amount is the cost assigned to the REC component of the purchase.

16. As of January 2012, the Company's REC inventories were:

[redacted]

17. As of December 31, 2012, the Company's REC inventories were:

[redacted]

18. To determine the capacity cost of renewable purchases, the Company used PJM RPM auction prices of $16.46/MW-day for the period October through December 2012.

19. In Case No. 10-2929-EL-UNC, the Company presented extensive testimony of why the PJM RPM auction prices were unreasonably low and should not be applied for determining a capacity cost for AEP Ohio.

20. In Case No. 10-2929-EL-UNC, the Commission addressed capacity cost for the Company and determined that a capacity cost of $188.88/MW-day was fair and reasonable.

21. Use of a higher price for the capacity component of renewable purchases would result in a lower cost being assigned to the REC value and less cost being included in Rider AER and a higher cost amount for renewables (for renewables capacity) being included in the FAC.

22. During 2012 the Company recorded net (gains)/losses on the sale of emission allowances, as follows:

[redacted]

h) [redacted].

[redacted]

23. During 2012 the Company recorded barge transportation costs charged by an affiliate, the River Transportation Division (RTD) which included a return component for RTD based on applying a return to an RTD investment base that included a working capital component based on a formula method using one-eighth of O&M expenses. This component of RTD charges has been questioned in previous FAC audits.

2013 Financial Audit Findings

1. For is quarterly FAC filings for 2013, the Company has used kWh sales as the basis for differentiating the quarterly FAC rates for Ohio Power and CSP.
2. The Company has explained in response to LA-2012/2013-4-2 that after the merger of Ohio Power and CSP it can no longer separately identify FAC includable costs applicable to their respective areas, i.e., similar to the breakouts that were used prior to the merger.
3. At December 31, 2013, the Company shows an FAC under-recovery of $[redacted].
4. During 2013, the Company recorded [redacted] net losses in account 5010033 for sales transactions related to selling [redacted], as described in the response to EVA-2012/2013-1-19.
5. During 2013, the Company included [redacted] of Lawrenceburg PPA capacity charges in the FAC.
6. During 2013, the Company included [redacted] of OVEC demand charges in the FAC.
7. The Lawrenceburg capacity charges and the OVEC demand charges are subject to a separate investigation to examine whether double-recovery has occurred.
8. For 2013, the Company's FAC did not include carrying charges.
9. Renewables expense for 2013 included in the FAC was [redacted]. As noted above, commencing in October 2012 and continuing for 2013, the REC value of purchased power contracts for renewables was no longer included in the FAC, but was included in Rider AEP.
10. In periods up to October 2012, the Company had been keeping inventories of REC quantities and cost for its Solar RECs, and maintaining an inventory of non-Solar RECs at zero cost. Commencing in October 2012, the Company began assigning a cost to the non-Solar REC inventories. The Company maintained monthly REC inventories during 2013 with quantities and cost for each type of REC that it tracks.
11. The zero value AEP has assigned to its non-Ohio non-solar REC inventory during periods prior to October 2012 had been questioned in prior audits, in which it was recommended that a reasonable value for the REC should be assigned. The procedure that AEP began employing in October 2012 and continued using in 2013 assigns a cost to RECs based on a residual method based on subtracting from the total cost of the

renewable energy purchases values for (1) capacity and (2) energy. The residual amount is the cost assigned to the REC component of the purchase.

12. As of December 31, 2013, the Company's REC inventories were:
    a) Solar RECs: [redacted]
    b) Non-Solar, Non-Ohio RECs: [redacted]
    c) Non-Solar Ohio RECs: [redacted]
13. To determine the capacity cost of renewable purchases, the Company used PJM RPM auction prices of $16.46/MW-day for the period January through May 2013 and $27.73/MW-day for June through December 2013.
14. In Case No. 10-2929-EL-UNC, the Company presented extensive testimony of why the PJM RPM auction prices were unreasonably low and should not be applied for determining a capacity cost for AEP Ohio.
15. In Case No. 10-2929-EL-UNC, the Commission addressed capacity cost for the Company and determined that a capacity cost of $188.88/MW-day was fair and reasonable.
16. Use of a higher price for the capacity component of renewable purchases would result in a lower cost being assigned to the REC value and less cost being included in Rider AER and a higher cost amount for renewables (for renewables capacity) being included in the FAC.
17. During 2013 the Company recorded net (gains)/losses on the sale of emission allowances, as follows:

    [redacted]

    f) [redacted].
18. During 2013 the Company recorded barge transportation costs charged by an affiliate, the River Transportation Division (RTD) which included a return component for RTD based on applying a return to an RTD investment base that included a working capital component based on a formula method using one-eighth of O&M expenses. This component of RTD charges has been questioned in previous FAC audits.
19. During the fourth quarter of 2013, the RTD revenue details began showing a separate line item for [redacted]. Up to that point RTD revenues for barge transportation of coal to [redacted]. The Company's response to LA-2012/2013-13-1(f) clarified that the [redacted]
20. The Company has established a [redacted] under which the coal being delivered to [redacted], which [redacted], and [redacted] Ohio Power. There is no reduction to the cost of [redacted] under this arrangement.

21. As described in the response to LA-2012/2013-13-1 [redacted]

22. [redacted].

23. During 2013, Ohio Power recorded [redacted].[4] There were no like revenues in 2012. The 2013 revenues were recorded during the months of September, November and December 2013.

24. It has come to our attention that another electric utility with coal-fired generation that is establishing a Section 45 coal treatment project with a third party at one of its large steam generating plants has committed to passing the benefits of this arrangement to its ratepayers through its fuel adjustor.

Financial Audit Recommendations

1. For purposes of determining the capacity cost of renewables purchases for the 2012 and 2013 audit periods the capacity cost of $188.88/MW-day that the Commission determined in Case No. 10-2929-EL-UNC $188.88 was fair and reasonable should be used.
2. 2012 and 2013 FAC and AER results should be recalculated accordingly reflecting application of the $188.88/MW-day that the Commission determined in Case No. 10-2929-EL-UNC $188.88 was fair and reasonable as the capacity value for the renewables purchases.
3. 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, 2012 through December 31, 2013. Because this issue was raised in previous FAC audits, including the audit of 2011 and a Commission

[4] Response to LA-2012/2013-3-12 Confidential Attachment 1.

decision has not yet been issued for that proceeding, the Commission decision on this issue as presented in the review of 2011 FAC costs may provide resolution.

AER Audit

Management Audit Findings

1. Ohio Power was compliant with its alternative energy portfolio obligations in 2012 and 2013.
2. Ohio Power complied with its renewable energy requirement primarily through three major long-term renewable power purchase agreements which it supplemented with purchases of qualifying renewable energy credits, co-firing biomass at selected coal plants and Ohio's renewable energy technology program.
3. The Alternative Energy Rider (AER) commenced in October 2012 at which time the renewable energy credit (REC) cost recovery was transferred to this rider.
4. AEP developed a methodology to separate the REC values from the bundled prices under the three long-term contracts. AEP is using a residual accounting methodology where the cost of the energy and the capacity are deducted from the total cost of renewable power purchases to yield the REC value. An alternative methodology could be to use the market price for REC's and keep the balance of the price in the FAC.
5. The approach chosen by AEP is reasonable provided the methodology for determining the energy and capacity costs is reasonable. For the energy component, AEP is using the monthly average spot clearing price for nearest PJM pricing points multiplied by the power each produced during the month. This approach is roughly approximate to what the company would have received if it sold the output on the open market.
6. For the capacity component from the wind projects, AEP is using the capacity credit given by PJM. For [redacted] wind project, PJM gives a [redacted] capacity credit for the 100 MW under contract to Ohio Power. For the 99 MW [redacted] project, PJM assigns an initial wind project default capacity credit of 18 percent of the project rated capacity (17.82 MW).
7. For the [redacted] project, AEP currently assigns a 3.84 MW capacity credit to the facility in its capacity credit calculation. This reflects the 38 percent credit value that is the PJM default value for new grid solar projects until the plant has developed an operating history of its output during peak power consumption periods. Once [redacted] project has the historical operating data to determine the plant output during the peak demand period, it would be a better measurement of the facility's capacity value. This approach would be in line with PJM's older (>3 years old) solar project methodology.
8. AEP is calculating capacity value for these projects using the PJM capacity auction clearing price. Under this method, AEP applied the PJM auction value of \$16.46/MW-day for the period October 2012-May 2013 and then updated to the most recent capacity auction of \$27.73/MW-day for June-December 2013. EVA believes using these values

are too low. AEP as well as other PJM participants have strenuously argued that these numbers do not reflect capacity costs. In Case No. 10-2929-EL-UNC, the Commission established an Ohio Power system capacity value of $188.88 MW-day in its July 2012 order

9. The REC value when using the $188.88 per MW day is [redacted] lower during the 15 month period October 1, 2012 through December 31, 2013. For the two audit periods, there is no change in recovery and the [redacted] would be recoverable through the FAC.

10. If AEP assigned a higher capacity value to [redacted] and if AEP had used the Ohio Commission credit value in combination with a higher solar capacity value (10.1 MW vs 3.84 MW) for the [redacted] contract, AER would be reduced by an additional [redacted]

Management Audit Recommendations

1. EVA recommends that the capacity valuation determined by the Commission in Case No. 10-2929-EL-UNC be used to determine the REC value.
2. EVA recommends that AEPSC use the historical operating data for [redacted] to determine if an alternate capacity assumption is appropriate.

2012 Financial Audit Findings

1. The quarterly filing for the fourth quarter of 2012 was AEP's first Rider AER filing. For 2012, the Company included [redacted] of REC cost in the AER.
2. On its AER filings for the fourth quarter of 2012, the Company has shown kWh sales information which we were not able to verify.
3. For the quarterly AER filings, the kWh information is used only for rate design. Ultimately, actual AER revenues are reconciled with actual AER includable costs.
4. To determine the capacity cost of renewable purchases, the Company used PJM RPM auction prices of $16.46/MW-day for the period October through December 2012.
5. As noted above, in Case No. 10-2929-EL-UNC, the Company presented extensive testimony of why the PJM RPM auction prices were unreasonably low and should not be applied for determining a capacity cost for AEP Ohio.
6. As noted above, in Case No. 10-2929-EL-UNC, the Commission addressed capacity cost for the Company and determined that a capacity cost of $188.88/MW-day was fair and reasonable.
7. Use of a higher price for the capacity component of renewable purchases would result in a lower cost being assigned to the REC value and less cost being included in Rider AER and a higher cost amount for renewables (for renewables capacity) being included in the FAC.

2013 Financial Audit Findings

1. For 2013, the Company included [redacted] of REC cost in the AER.
2. As of December 31, 2013, the Company showed an over-collected AER balance of [redacted].
3. On its quarterly AER filings for 2013, the Company has shown kWh sales information which we were not able to verify and which did not agree with the kWh sales information shown in the supporting workbooks.
4. For the quarterly AER filings, the kWh information is used only for rate design. Ultimately, actual AER revenues are reconciled with actual AER includable costs.
5. As noted above, in Case No. 10-2929-EL-UNC, the Company presented extensive testimony of why the PJM RPM auction prices were unreasonably low and should not be applied for determining a capacity cost for AEP Ohio.
6. As noted above, in Case No. 10-2929-EL-UNC, the Commission addressed capacity cost for the Company and determined that a capacity cost of $188.88/MW-day was fair and reasonable.
7. Use of a higher price for the capacity component of renewable purchases would result in a lower cost being assigned to the REC value and less cost being included in Rider AER and a higher cost amount for renewables (for renewables capacity) being included in the FAC.

2013 Financial Audit Recommendations

1. The Company should improve its quarterly Rider AER filing workbook support packages and Excel files to utilize kWh information which is verifiable and which applies to that quarterly period.
2. For purposes of determining the capacity cost of renewables purchases for the 2012 and 2013 audit periods, the capacity cost of $188.88/MW-day that the Commission determined in Case No. 10-2929-EL-UNC $188.88 was fair and reasonable should be used.
3. 2012 and 2013 FAC and AER results should be recalculated accordingly reflecting application of the $188.88/MW-day that the Commission determined in Case No. 10-2929-EL-UNC $188.88 was fair and reasonable as the capacity value for the renewables purchases.

Follow Up Audit

In 2011 and 2012, EVA and Larkin conducted the Management/Performance and Financial Audits of AEP Ohio Case Nos. 10-268-EL-FAC et al. A hearing was held on November 18, 2013 on the recommendations in that case. As of this date, an order has not been issued.

Audit Outline

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

- Section 2 Ohio Power Background
- Section 3 Fuel Procurement Audit
- Section 4 Environmental Audit
- Section 6 Performance Audit
- Section 7 Financial Audit
- Section 8 AER Audit

2 AEP OHIO BACKGROUND

Background on Ohio Power Company and AEP Generation Resources

Ohio Power is a wholly-owned subsidiary of American Electric Power (AEP)[5]. Fuel procurement 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. 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.

The power plants in which Ohio Power has ownership shares during the audit periods are listed in Exhibit 2-1.

Exhibit 2-1
Ohio Power Plants

Power Plant Name	Units	Operator	Capacity	Prime Mover	Fuel Type	Ownership
Cardinal	1	Cardinal Operating Co.	595.0	Steam Turbine	Coal	100.0%
Conesville	4	Ohio Power Company	780.0	Steam Turbine	Coal	43.5%
Conesville	5-6	Ohio Power Company	750.0	Steam Turbine	Coal	100.0%
Darby	1-6	Ohio Power Company	507.0	Gas Turbine	Natural Gas	100.0%
Gen JM Gavin	1 & 2	Ohio Power Company	2,598.0	Steam Turbine	Coal	100.0%
J.M. Stuart	1-4	Dayton Power and Light Co.	2,308.0	Steam Turbine	Coal	26.0%
J.M. Stuart IC	1-4	Dayton Power and Light Co.	8.8	Internal Combustion	Distillage Fuel Oil	26.0%
John E. Amos	3	Appalachian Power	2,900.0	Steam Turbine	Coal	29.9%
Kammer	1-3	Ohio Power Company	630.0	Steam Turbine	Coal	100.0%
Mitchell	1-2	Ohio Power Company	1,560.0	Steam Turbine	Coal	50.0%
Muskingum River	1-5	Ohio Power Company	1,425.0	Steam Turbine	Coal	100.0%
Philip Sporn	2, 4 & 5	Appalachian Power	600.0	Steam Turbine	Coal	50.0%
Picway	5	Ohio Power Company	100.0	Steam Turbine	Coal	100.0%
Racine	1-2	Ohio Power Company	26.0	Hydraulic Turbine	Water	100.0%
W.H. Zimmer	ST1	Duke Energy Ohio, Inc.	1,300.0	Steam Turbine	Coal	25.4%
Walter C Beckjord	6	Duke Energy Ohio, Inc.	1,030.0	Steam Turbine	Coal	8.0%
Waterford Energy Facility		Ohio Power Company	850.0	Combined Cycle	Natural Gas	100.0%
TOTAL			17,967.8			
		Ohio Power Company	9,821.0			
		Other	8,146.8			
		Coal	16,576.0			

[5] At the end of 2011, AEP merged its Columbus Southern Power operating subsidiary into Ohio Power.

On October 31, 2012, American Electric Power Service Corporation (AEPSC) on behalf of its affiliates, Ohio Power Company (Ohio Power) and AEP Generation Resources Inc. (AEP Generation filed an application pursuant to section 203 of the Federal Power Act (FPA) requesting Commission authorization for an internal corporate reorganization that would result in the separation of Ohio Power's generation and power marketing businesses from its transmission and distribution businesses.

Effective December 31, 2013, Ohio Power transferred 11,200 megawatts of Ohio Power-owned generation to AEP Generation Resources. AEP Ohio's two-thirds ownership of John E. Amos Plant Unit 3 (867 MW) was transferred to Appalachian Power, and 50 percent of Mitchell Plant (800 MW) was transferred to Kentucky Power.[6] Following the transfers and expected retirements through 2015, including the Philip Sporn and Kammer plants in West Virginia, AEP Generation Resources expects to own approximately 8,700 MW. AEP Generation resources will bid into the PJM market, and Ohio Power will purchase electricity from PJM, from 2014 moving forward.

Part and parcel with these changes were the termination of the Interconnection Agreement between Ohio Power, Appalachian Power, Indiana & Michigan Power, Kentucky Power and AEPSC which had defined how the member companies shared the costs of their generation plants and the termination of the Interim Allowance Agreement that provided for the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement.

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.

Ohio Power generation by owned-plant is summarized in Exhibit 2-3 for 2012 and Exhibit 2-4 for 2013. In 2012, 84 percent of Ohio Power's electricity generation came from coal with about 80 percent coming from plants operated by Ohio Power.

In 2013, with a return to higher gas prices, coal generation accounted for over 90 percent of Ohio Power generation.

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

[6] The West Virginia Public Service Commission did not approve the proposed transfer of 50 percent of the Mitchell station.

Exhibit 2-2
PJM Interconnection Zones

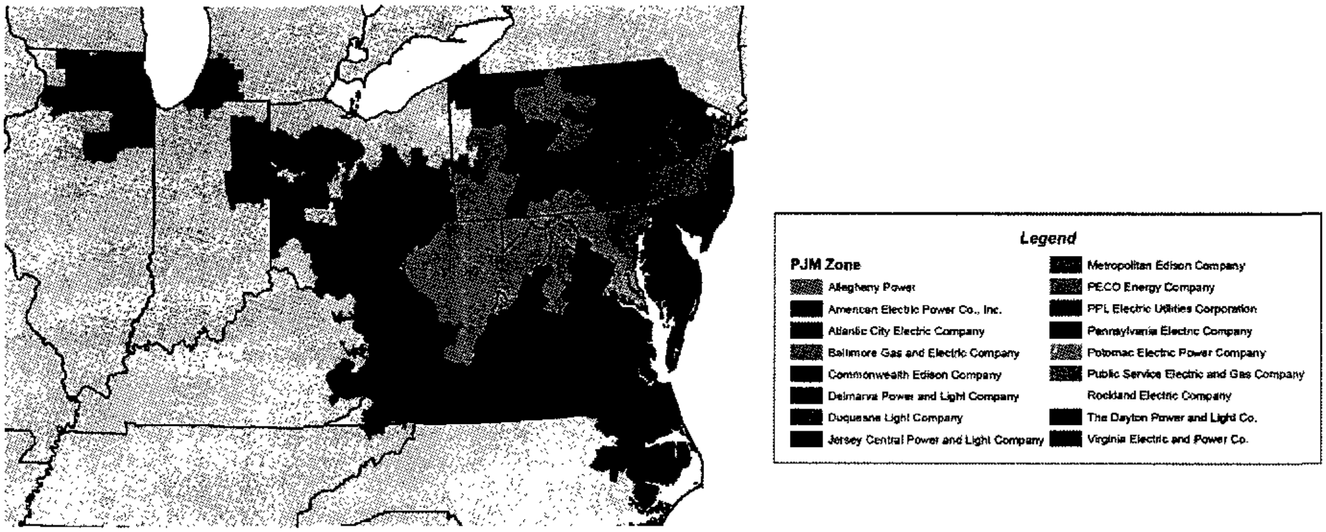


Exhibit 2-3
Generation by Plant, 2012 (MWH)

Power Plant Name	Units	Operator	Capacity	Generation (MWh)	Percent of Total	Prime Mover	Fuel Type	Ownership
Cardinal	1	Cardinal Operating Co.	595.0	1,789,615	4%	Steam Turbine	Coal	100.0%
Conesville	4	Ohio Power Company	780.0	1,232,669	3%	Steam Turbine	Coal	43.5%
Conesville	5-6	Ohio Power Company	750.0	2,955,323	7%	Steam Turbine	Coal	100.0%
Darby	1-6	Ohio Power Company	507.0	77,009	0%	Gas Turbine	Natural Gas	100.0%
Gen JM Gavin	1 & 2	Ohio Power Company	2,598.0	17,220,105	38%	Steam Turbine	Coal	100.0%
J.M. Stuart	1-4	Dayton Power and Light Co.	2,308.0	2,991,201	7%	Steam Turbine	Coal	26.0%
J.M. Stuart IC	1-4	Dayton Power and Light Co.	8.8	109	0%	Internal Combustion	Distillage Fuel Oil	26.0%
John E. Amos	3	Appalachian Power	2,900.0	3,877,745	9%	Steam Turbine	Coal	29.9%
Kammer	1-3	Ohio Power Company	630.0	1,784,836	4%	Steam Turbine	Coal	100.0%
Mitchell	1-2	Ohio Power Company	1,560.0	3,772,169	8%	Steam Turbine	Coal	50.0%
Muskingum River	1-5	Ohio Power Company	1,425.0	1,789,615	4%	Steam Turbine	Coal	100.0%
Philip Sporn	2, 4 & 5	Appalachian Power	600.0	493,683	1%	Steam Turbine	Coal	50.0%
Picway	5	Ohio Power Company	100.0	119,613	0%	Steam Turbine	Coal	100.0%
Racine	1-2	Ohio Power Company	26.0	138,386	0%	Hydraulic Turbine	Water	100.0%
W.H. Zimmer	ST1	Duke Energy Ohio, Inc.	1,300.0	1,214,351	3%	Steam Turbine	Coal	25.4%
Walter C Beckjord	6	Duke Energy Ohio, Inc.	1,030.0	258,703	1%	Steam Turbine	Coal	8.0%
Waterford Energy Facility		Ohio Power Company	850.0	5,027,420	11%	Combined Cycle	Natural Gas	100.0%
TOTAL			17,967.8	44,742,551	100%			
		Ohio Power Company	9,821.0	18,476,520	41%			
		Other - Operated	8,146.8	26,266,031	59%			
		Coal Generation	16,576.0	37,710,012	84%			

Source: SNL

Exhibit 2-4
Generation by Plant, 2013 (MWH)

Power Plant Name	Units	Operator	Capacity	Ohio Power Generation (MWh)	Percent of Total	Prime Mover	Fuel Type	Ownership
Cardinal	1	Cardinal Operating Co.	595.0	11,004,382	21%	Steam Turbine	Coal	100.0%
Conesville	4	Ohio Power Company	780.0	558,119	1%	Steam Turbine	Coal	43.5%
Conesville	5-6	Ohio Power Company	750.0	3,413,313	7%	Steam Turbine	Coal	100.0%
Darby	1-6	Ohio Power Company	507.0	46,323	0%	Gas Turbine	Natural Gas	100.0%
Gen JM Gavin	1 & 2	Ohio Power Company	2,598.0	15,676,848	30%	Steam Turbine	Coal	100.0%
J.M. Stuart	1-4	Dayton Power and Light Co.	2,308.0	3,461,655	7%	Steam Turbine	Coal	26.0%
J.M. Stuart IC	1-4	Dayton Power and Light Co.	8.8	93	0%	Internal Combustio	Distillage Fuel Oi	26.0%
John E Amos	3	Appalachian Power	2,900.0	4,279,421	8%	Steam Turbine	Coal	29.9%
Kammer	1-3	Ohio Power Company	630.0	941,712	2%	Steam Turbine	Coal	100.0%
Mitchell	1-2	Ohio Power Company	1,560.0	2,978,496	6%	Steam Turbine	Coal	50.0%
Muskingum River	1-5	Ohio Power Company	1,425.0	2,222,804	4%	Steam Turbine	Coal	100.0%
Philip Sporn	2, 4 & 5	Appalachian Power	600.0	548,596	1%	Steam Turbine	Coal	50.0%
Picway	5	Ohio Power Company	100.0	61,274	0%	Steam Turbine	Coal	100.0%
Racine	1-2	Ohio Power Company	26.0	215,379	0%	Hydraulic Turbine	Water	100.0%
W.H. Zimmer	ST1	Duke Energy Ohio, Inc.	1,300.0	2,377,881	5%	Steam Turbine	Coal	25.4%
Walter C Beckjord	6	Duke Energy Ohio, Inc.	1,030.0	203,139	0%	Steam Turbine	Coal	8.0%
Waterford Energy Facility		Ohio Power Company	850.0	3,839,020	7%	Combined Cycle	Natural Gas	100.0%
TOTAL			17,967.8	51,828,453	100%			
		Ohio Power Company	9,821.0	40,957,669.1	79%			
		Other	8,146.8	10,870,784.0	21%			
		Coal	16,576.0	47,727,638.3	92%			

Source: SNL

through May 2016. AEP has also indicated on July 11, 2013 that it intends to retire its 585 MW Muskingum River unit 5. In its notifications to PJM, AEP indicated it plans to retire the following units:

- 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;
- Muskingum River Plant Unit 5, Beverly, Ohio – 585 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 most units by June 1, 2015, receiving an extension on the EPA MATS compliance deadline of January 1, 2015 in order to fulfill existing generation obligations to PJM. Duke Energy has announced it will retire Walter C. Beckjord Plant Unit 6 on January 2, 2015, in which Ohio Power is a minority owner.

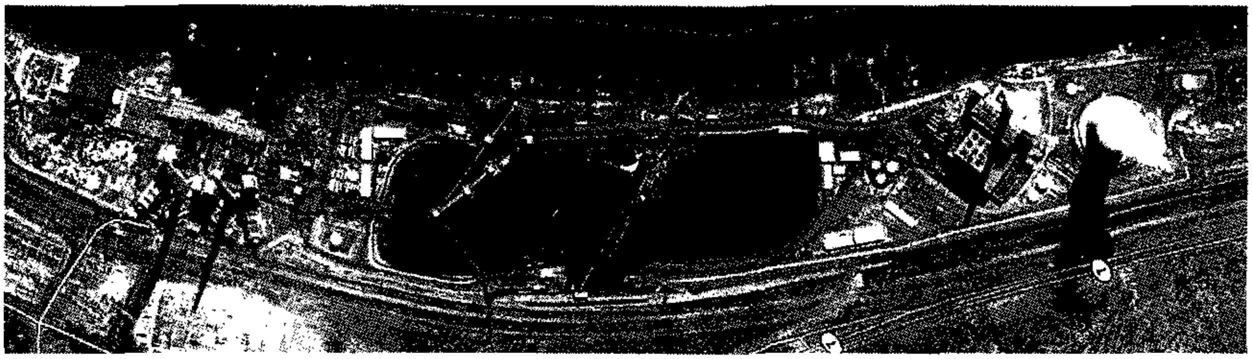
Coal Plants

This section provides background information on the six coal plants operated by Ohio Power plus Cardinal.

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 extended outage in 2012 was necessary to modify the scrubber. An aerial view is provided in Exhibit 2-5. AEPSC buys coal for the entire station but the contracts are now independent. This plant receives coal by barge and truck.

Exhibit 2-5
Cardinal Plant



Recent plant operating statistics for Cardinal 1are provided in Exhibit 2-6. Cardinal 1 generation fell by almost 70 percent in 2012 due to the scrubber-related outage. Generation began to return to normal levels in 2013, operating at 69 percent capacity factor and producing 3,597 GWh.

Exhibit 2-6
Historical Operating Statistics at Cardinal 1[7]

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

	2013	2012	2011	2010	2009
Generation (MWh)	3,597,108	1,789,615	2,693,195	3,602,911	3,468,277
Consumption					
Coal (tons)	1,407,512	782,974	2,430,720	2,723,728	2,869,762
Oil (barrels)	16,667	19,452	32,665	30,856	34,094
Capacity Factor	69.0%	17.2%	51.7%	69.1%	66.5%
Heat Rate (Btu/kWh)	9,638	10,820	10,314	10,168	9,967

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

Conesville

The Conesville station consisted of four units with a total generating capacity of 1,745 MW. Units 1 & 2 were retired in 2005 at the beginning of the audit period. Conesville 3 was retired in 2012. Conesville 4 was retrofit with a scrubber in 2009. This scrubber was a jet bubbling reactor design which AEP deployed at a number of plants. AEP has encountered numerous problems with this technology which it determined to be a result of fundamental design deficiencies. Beginning in September 2012 and continuing through early May 2013, problems with the scrubber at Conesville 4 forced the unit out of operation. Conesville 5 and 6 were built with scrubbers and these scrubbers were upgraded in 2009 to comply with the New Source Review settlement. [redacted]. AEPSC conducted testing of a washed coal in 2013 but initial results did not indicate that this would resolve the problem.

As can be seen in Exhibit 2-7, Conesville 5 & 6 share a stack. Coal to this station is delivered by truck and rail[8]. The Conesville Coal Preparation Plant was closed in January 2012 and sold to [redacted] in 2013. The plant was operated for a short period in 2013 under AEP's permits with contract personnel to prepare washed coal for testing at Conesville 5 & 6.

Exhibit 2-7
Aerial View of Conesville Plant

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

Recent plant operating statistics are provided in Exhibit 2-8. Because Conesville 4 is jointly-owned with Dayton Power & Light and Duke Energy, the data are reported separately. (Conesville 3 is included until its retirement in 2012) Generation at Conesville 4 has been fairly flat for the last five years. Generation at Conesville 5 & 6 declined significantly in 2012 with a slight rebound in 2013.

Exhibit 2-8
Conesville Operating Statistics

Plant	Units	Location	Ownership %	Total MW	Utility Share
Conesville	4	Conesville, OH	43.5	780	339

	2013	2012	2011	2010	2009
Generation (MWh)	2,949,497	2,833,721	2,755,498	2,979,407	2,208,720
Consumption					
Coal (tons)	1,272,386	1,279,367	1,265,198	1,380,334	1,213,633
Oil (barrels)	4,193	6,791	10,391	19,586	13,218
Capacity Factor	43.2%	41.5%	40.3%	43.6%	32.3%
Heat Rate (Btu/kWh)	10,027	10,511	10,599	10,779	12,778

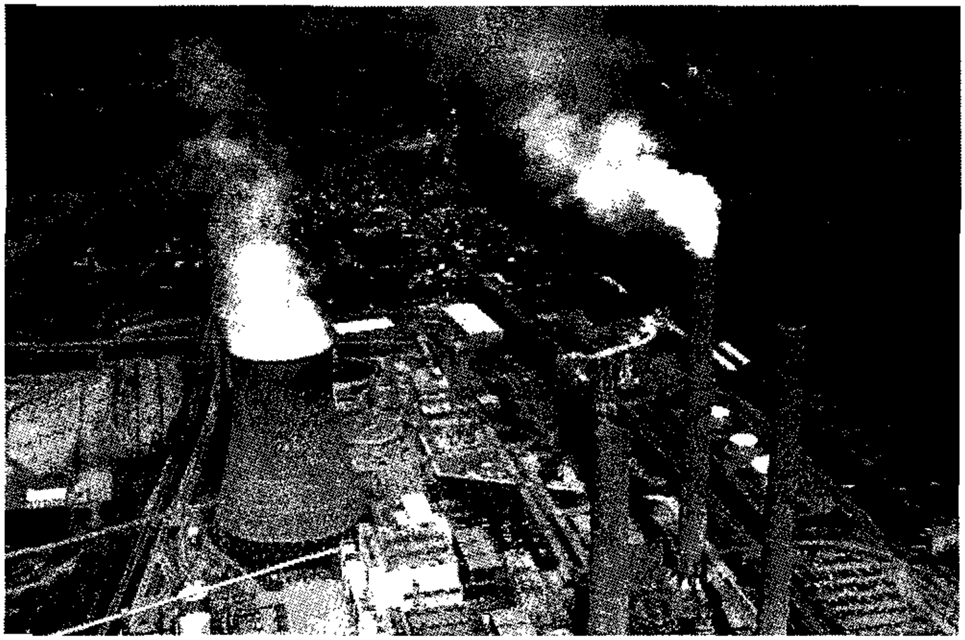
Plant	Units	Location	Ownership %	Total MW	Utility Share
Conesville	5 & 6	Conesville, OH	100	750	750

	2013	2012	2011	2010	2009
Generation (MWh)	3,413,313	2,955,323	4,237,515	3,480,862	3,981,264
Consumption					
Coal (tons)	1,607,210	1,429,062	2,043,383	1,646,927	1,603,785
Oil (barrels)	2,956	5,174	4,818	5,136	5,705
Capacity Factor	52.0%	45.0%	64.5%	53.0%	60.6%
Heat Rate (Btu/kWh)	10,855	11,179	10,986	10,824	9,247

Gavin

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 2-9
Aerial View of the Gavin Plant



Recent plant operating statistics are provided in Exhibit 2-10. Generation in both 2012 and 2013 was down compared with 2011. This is Ohio Power's largest station and before 2013 consistently burned more than seven million tons per year. In 2013 the unit burned 6.5 million tons and ran at an operating capacity factor of 68 percent.

Exhibit 2-10
Gavin Operating Statistics

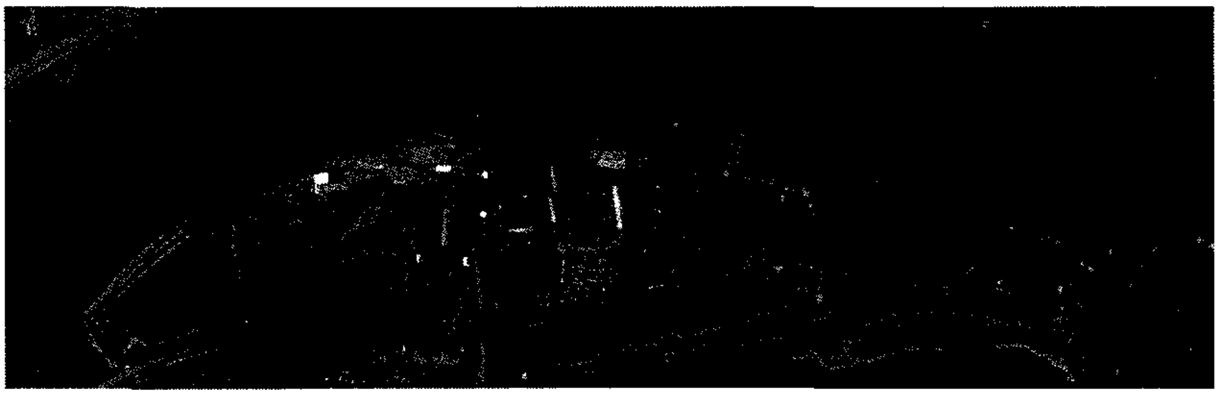
Plant	Units	Location	Ownership %	Total MW	Utility Share
Gavin	1-2	Cheshire, OH	100	2,640	2,640

	2013	2012	2011	2010	2009
Generation (MWh)	15,676,848	17,220,105	18,184,347	18,885,659	19,160,246
Consumption					
Coal (tons)	6,513,396	7,139,309	7,386,506	8,125,893	7,984,101
Oil (barrels)	35,296	36,512	45,582	48,111	31,047
Capacity Factor	67.8%	75.4%	78.6%	81.7%	82.9%
Heat Rate (Btu/kWh)	10,131	9,902	9,750	9,889	9,721

Kammer

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 2-11
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 from 2012. Capacity factor fell from 33 percent in 2011 and 2012 to only 17 percent in 2013.

Exhibit 2-12
Operational Statistics for Kammer

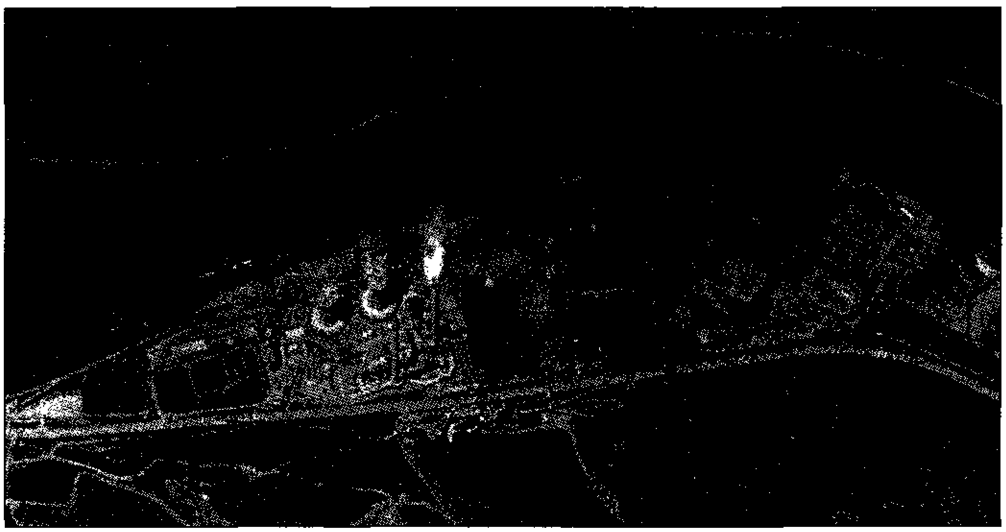
Plant	Units	Location	Ownership %	Total MW	Utility Share
Kammer	1-3	Moundsville, WV	100	630	630

	2013	2012	2011	2010	2009
Generation (MWh)	941,712	1,784,836	1,778,385	1,498,424	1,731,515
Consumption					
Coal (tons)	490,983	945,371	870,993	760,947	852,381
Oil (barrels)	5,401	8,854	8,422	8,161	8,199
Capacity Factor	17.1%	33.5%	32.2%	27.2%	31.4%
Heat Rate (Btu/kWh)	11,757	11,988	10,997	11,392	11,056

Mitchell

The Mitchell plant is located adjacent to Kammer in Moundsville. Mitchell consists of two units with a combined capacity of 1560 MW. 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. Ohio Power maintains both low and high sulfur coal piles at Mitchell which are largely blended through variable-speed feeders. [redacted].

Exhibit 2-13
Mitchell Plant



Recent plant operating statistics are provided in Exhibit 2-14. Generation and coal burn fell consistently across the audit period. In 2012 generation fell by 17 percent year over year, and in 2013 it fell by another 21 percent.

Exhibit 2-14
Historical Operating Statistics at Mitchell

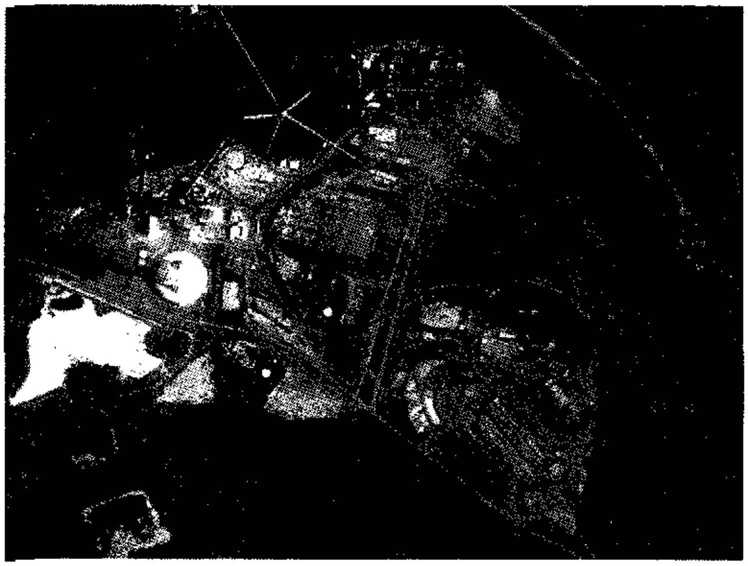
Plant	Units	Location	Ownership %	Total MW	Utility Share
Mitchell	1-2	Moundsville, WV	100	1,560	1,560

	2013	2012	2011	2010	2009
Generation (MWh)	5,956,991	7,544,338	9,124,435	10,242,061	9,389,850
Consumption					
Coal (tons)	2,418,715	3,035,147	3,619,091	4,033,432	3,678,634
Oil (barrels)	47,776	47,110	31,076	37,669	29,883
Capacity Factor	43.6%	55.5%	66.8%	75.0%	68.7%
Heat Rate (Btu/kWh)	10,035	10,029	9,828	9,756	9,811

Muskingum River

The Muskingum River plant is located in Beverly, Ohio. Muskingum River consists of five units. Two of the four smallest units are wet bottom boilers and two are cyclones, all of 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 have has been retrofit with scrubbers; Unit 5 was retrofit with an SCR.

Exhibit 2-15
Muskingum River Plant



All units at Muskingum River are on AEP's list of coal plant retirements. With the exception of Muskingun River 5, this is not surprising given their size, age, and boiler design and uncontrolled operation. However, Muskingum River 5 is a relatively new unit and has an SCR. Despite this fact, AEP has stated that it does not wish to invest additional capital in the unit in order to bring it up to standard with the MATS rule.

Recent plant operating statistics are provided in Exhibit 2-16. The plant's utilization fell dramatically in 2012. It recovered slightly in 2013, though did not come close to returning to the 45 percent and above rate of capacity utilization, as was typical before 2012.

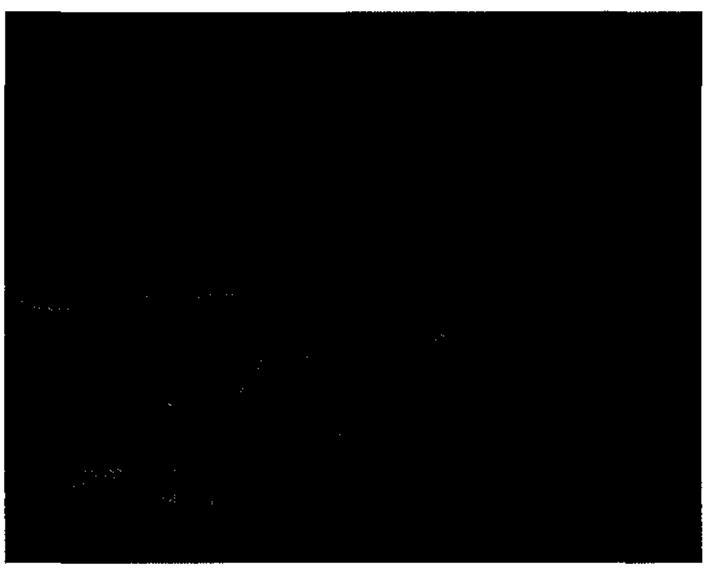
Picway

Picway is AEP Ohio's smallest coal plant. (Exhibit 2-17) 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 2-16
Historical Operating Statistics at Muskingum River

Plant	Units	Location	*Ownership* %	*Total* MW	*Utility* Share
Muskigum	1-5	Beverly, OH	100	1,440	1,440
	2013	**2012**	**2011**	**2010**	**2009**
Generation (MWh)	2,222,804	1,789,615	5,831,062	6,701,885	7,299,585
Consumption					
Coal (tons)	947,888	782,974	2,430,720	2,723,728	2,869,762
Oil (barrels)	21,131	19,452	32,665	30,856	34,094
Capacity Factor	17.6%	17.2%	46.7%	53.7%	58.5%
Heat Rate (Btu/kWh)	10,615	10,820	10,314	10,168	9,967

Exhibit 2-17
Aerial View of Picway Plant



Recent plant operating statistics are provided in Exhibit 2-18. Generation in 2012 was a small fraction of what it was in 2011. No generation was reported for 2013.

Exhibit 2-18
Picway Operating Statistics

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

	2013	2012	2011	2010	2009
Generation (MWh)	61,274	3,957	69,373	65,072	124,791
Consumption					
Coal (tons)	31,974	2,381	49,912	36,965	61,270
Oil (barrels)	828	165	402	1,382	2,490
Capacity Factor	7.0%	0.5%	7.9%	7.4%	14.3%
Heat Rate (Btu/kWh)	13,000	13,567	16,150	13,163	11,410

** 2013 Data Estimated from SNL*

3 FUEL PROCUREMENT AUDIT

The fuel supply arrangements for Ohio Power consist of commercial purchases comprised of long-term, short-term, and spot purchases.

Coal procurement performance during the audit periods is reviewed by year

2012 Coal Procurement Performance

Coal deliveries in 2012 by plant and contract type for Ohio Power are summarized in Exhibit 3-1.[9] The average price was [redacted] per MMBtu.[10]

Exhibit 3-1
Ohio Power Coal Deliveries, 2012

[redacted]

Source: EVA-2012/2013-1-12

There is considerable variation in the delivered price by plant with [redacted] having the lowest delivered prices and [redacted][11] the highest. The difference in the average delivered price between Gavin and Cardinal (which should have similar delivered prices) reflects the [redacted] under the [redacted] in 2011.

Ohio Power's delivered coal costs on a dollars per MMBtu basis (as reported to the Energy Information Administration [EIA] on Form 923) are compared to the 923 data for the other Ohio companies for which data are publicly available in Exhibit 3-2. Ohio Power's coal costs compare with the coal purchase expenses of the other Ohio utilities. According to the 923 data, Ohio Power had the second highest delivered costs in 2012. This comparison is indicative of

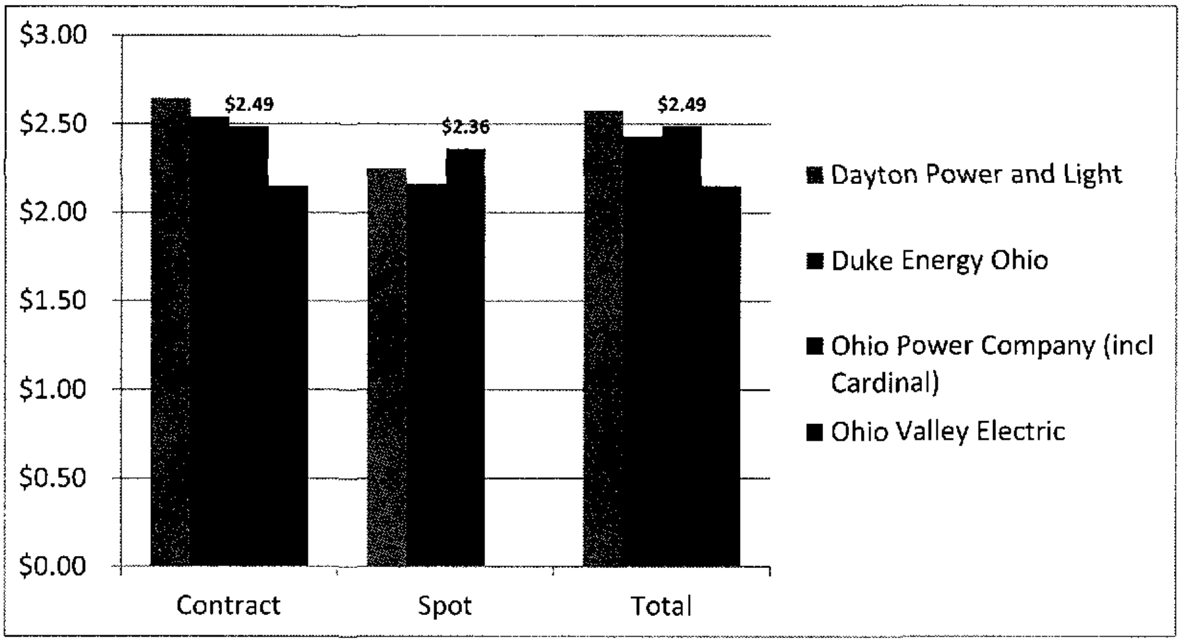
[9] This chart is developed from the data provided to EVA in 2012/2013-1-4.

[10] The calculated numbers are slightly different than those reported on EIA 923. The two known reasons are that the purchases from the Powder River Basin (PRB) that move through the Cook Coal Terminal do not contain the barge component of the price and the Cardinal numbers include all three plants.

[11] [redacted] is reported separately as it is a jointly-owned plant. [redacted] are wholly owned by Ohio Power.

performance but not dispositive as the utilities vary with respect to quality requirements and transportation.

Exhibit 3-2
Ohio Utility Coal Purchase Costs, 2012



Source: Form 923.

Some additional detail about the 2012 purchases by other companies with plants in Ohio 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, 2012

Utility Name	Contract					Spot					Total					%
	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Contract
DP & L	4,552,249	11,747	2.65%	$62.10	$2.64	953,767	11,910	2.09%	$53.46	$2.25	5,506,016	11,775	2.55%	$60.60	$2.58	83%
Duke Energy Ohio	4,750,508	11,886	3.45%	$60.51	$2.54	1,930,504	11,769	2.74%	$50.83	$2.16	6,681,012	11,852	3.25%	$57.71	$2.43	71%
Ohio Power Co	16,353,762	12,250	3.39%	$60.77	$2.49	71,022	12,003	2.30%	$56.72	$2.36	16,424,784	12,249	3.38%	$60.75	$2.49	100%
Ohio Valley Electric	2,190,318	12,248	4.17%	$52.47	$2.15	0	--	--	--	--	2,190,318	12,248	4.17%	$52.47	$2.15	100%

Source: Form 923.

2013 Coal Procurement Performance

Coal purchases in 2013 by AEPSC for Ohio Power are summarized in Exhibit 3-4.[12]

[12] This chart is developed from the data provided to EVA-2012/2013-1-4. It does not contain the barge costs associated with the purchase of coal from the Powder River Basin.

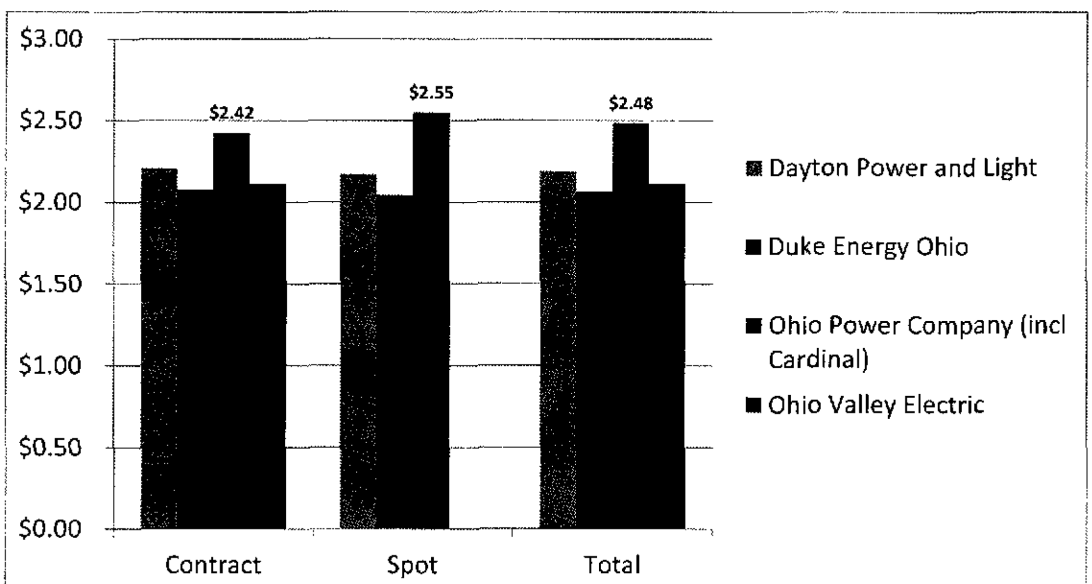
Exhibit 3-4
Ohio Power Coal Deliveries, 2013

[redacted]

There is considerable variation in the delivered price by plant with Cardinal having the lowest delivered prices and Conesville 4[13] the highest. The difference in the average delivered price between Gavin and Cardinal (which should have similar delivered prices) reflects the [redacted] contract in 2011, the [redacted], and the [redacted] contracts.

Ohio Power's delivered coal costs on a dollars per MMBtu basis (as reported to EIA) are compared to the other companies with Ohio power plants for which data are publicly available in Exhibit 3-5. The change in relative performance for Ohio Power in 2013 is striking. Ohio Power not only had the highest delivered costs in 2013, but it had the highest costs by a significant amount.

Exhibit 3-5
Ohio Utility Coal Purchase Costs, 2013



Source: Form 923.

[13] Conesville 4 is reported separately as it is a jointly-owned plant. All of the other plants are wholly owned by Ohio Power.

[14] [redacted]

Some additional detail about the 2013 purchases by the other companies with plants in Ohio is provided on Exhibit 3-6. Dayton Power & Light, Duke and OVEC all had lower costs in 2013 compared to 2012. Dayton's relative improvement is due to the effective complete conversion of Killen and Stuart to higher sulfur coals.

Exhibit 3-6
Ohio Utility Coal Purchase Details, 2013

Utility Name	Contract					Spot					Total					%
	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Tons	Btu/lb	Sulfur (%)	$/Ton	$/MMBtu	Contract
DP & L	3,307,225	11,844	2.47%	$52.29	$2.21	3,624,225	11,531	2.85%	$50.06	$2.17	6,931,450	11,680	2.67%	$51.13	$2.19	48%
Duke Energy Ohio	5,480,642	12,061	3.39%	$50.16	$2.08	3,245,872	11,517	2.87%	$47.15	$2.04	8,726,514	11,859	3.20%	$49.04	$2.07	63%
Ohio Power Co	15,616,938	12,000	3.19%	$59.44	$2.42	149,180	12,063	2.07%	$61.59	$2.55	15,766,118	12,278	3.25%	$60.95	$2.48	99%
Ohio Valley Electric	2,129,595	12,218	4.10%	$51.40	$2.11	0	--	--	--	--	2,129,595	12,218	4.10%	$51.40	$2.11	100%

Source: Form 923.

The decline in Ohio Power's absolute and relative performance is due a number of contract decisions made both prior to and during the audit periods which resulted in higher contract prices in 2013. These decisions, which are discussed in greater detail in Section 3, include:

- The [redacted] which resulted in the [redacted] in 2013.[15]
- The [redacted] which [redacted] for the years [redacted], causing [redacted] tons in [redacted] which EVA estimated to be priced approximately [redacted].
- The [redacted] contracts which had [redacted] shipments.
- The decision to [redacted] in 2012 and 2013
- The decision to [redacted].

Management And Organization

Responsibility for fuel and emission allowance procurement lies with the Senior Vice President Fuel Emissions and Logistics ("FEL"). There were significant changes in the FEL organization during the audit periods. In 2012 the Vice President of Fuel Procurement retired after a relatively short tenure in that position. On or about July 2012, the individual who had previously had responsibility for Ohio Power fuel procurement was transferred to a position that restored his responsibility for Ohio Power fuel procurement among other things.

The Company, with input from McKinsey & Company, reviewed Company processes in 2012 as part of its repositioning effort. As part of the repositioning effort, the Company eliminated the director level in FEL procurement which resulted in the termination of a long-term director in FEL who had responsibility over Ohio Power procurements. The net result was loss of

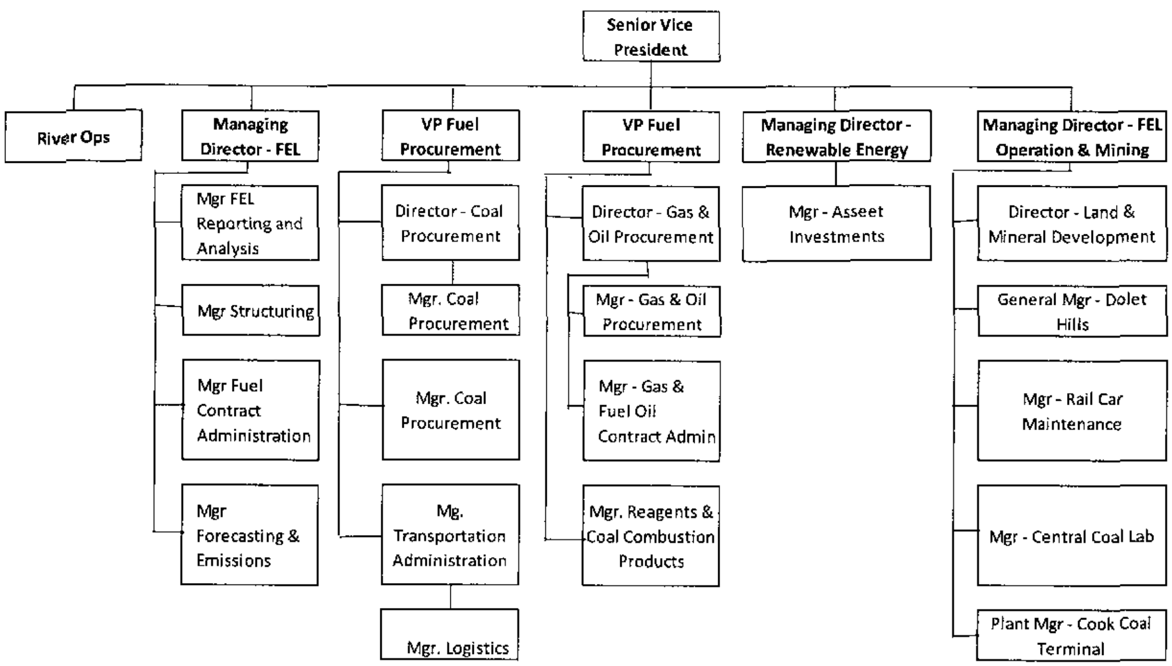
[15] The discussion about this contract decision can be found in the report of the audit of 2011.

management continuity during the audit periods as well as lack of corporate knowledge of key events.

During this period the Company moved forward with its plan for corporate separation wherein the Ohio Power-owned generating assets were to be transferred to AEP Generation Resources leaving Ohio Power as a transmission and distribution company. The activities related to Corporate Separation appeared to consume considerable management attention during the audit periods.

The organization chart provided by the Company is provided in Exhibit 3-7. With the completion of the corporate separation, the organization has changed and the individuals responsible for fuel procurement are now separated from the regulated fuel procurement organization.

Exhibit 3-7
Organization Chart for Fuel, Emissions And Logistics



Policies And Procedures

AEPSC updated its Fuel, Emissions & Logistics Procurement Policy in July 2012. The basic policy "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" remained the same.

The organization of the manual (which has a total of 12 pages with text) remained the same.

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 three audits the revised manual is very general and provides little of the guidance typically provided by such manuals.

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."

The inventory targets in effect during the audit periods are provided in Exhibit 3-8. The inventory targets for the plants on the retirement list (i.e., Kammer, Muskingum River, and Picway) have been reduced to [redacted] days. The inventory targets for the other plants ranges from [redacted] to [redacted] days.

Exhibit 3-8
Inventory Targets

[redacted]

End of year inventory by year and plant is shown Exhibit 3-9. Total end of year inventory was relatively unchanged between 2011 and 2013 but [redacted] between 2013 and 2012. The largest reductions were at the plants slated for retirement as AEPSC looks to bring down the tons at each of these plants.

Exhibit 3-9
End of Year Inventory Levels by Plant

[redacted]

The inventory levels by month and plant compared to inventory capacity and the new inventory targets are shown in Exhibit 3-10. Performance varied considerably by plant and year. Inventory levels at the plants were largely at or above target levels throughout most of the audit periods.

Exhibit 3-10
Inventory Levels At Ohio Power Plants (Tons)

[redacted]

[redacted]

[redacted]

[redacted]

In Exhibit 3-11, inventory levels at Ohio Power-operated plants are compared to actual and normal industry levels of East North Central utilities based upon EVA's proprietary stockpile report.[16] Because of Ohio Power's decision to have very low inventory targets for the retiring plants, two Ohio Power inventory levels were compared, one with all of the plants[17], the other without the plants slated for retirement[18]. During 2012, utility inventory levels at the East North Central utilities ballooned as low natural gas prices caused considerable displacement of coal generation by natural gas-fired combined cycle plants. Utilities made adjustments to their procurement strategies which allowed for inventory levels to return to normal. Higher natural gas prices and normal weather for most of 2013 resulted in a decline in inventory levels throughout the year as utilities burned more coal than expected at the start of the year.

[16] 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.
[17] Cardinal, Conesville, Gavin, Kammer, Mitchell, Muskingum River, Picway
[18] Cardinal, Conesville, Gavin, Mitchell

Exhibit 3-11
Ohio Power Inventory Days Versus East North Central

[redacted]

Ohio Power inventories also jumped by mid-2012. By the end of 2012, Ohio Power inventories had fallen almost back to the beginning of the year level. Ohio Power has continued to reduce inventory levels through mid 2013. Ohio Power inventory levels are considerably below either normal or actual inventory levels of East North Central power plants.

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. [redacted]

The information provided on the physical inventory survey adjustments at AEP Ohio-operated plants are summarized for 2012 in Exhibit 3-12 and for 2013 in Exhibit 3-13. Several of the [redacted] In 2012, adjustments exceeded [redacted] of book inventory at Cardinal 1&2, Conesville 3&4, and Kammer and [redacted] of burn at Cardinal 1&2, Kammer and Picway. In 2013, adjustments [redacted] at Cardinal 1&2 (twice) and Muskingum River 5.

19 [redacted]

Exhibit 3-12
Physical Inventory Survey Adjustments, 2012

[redacted]

Exhibit 3-13
Physical Inventory Survey Adjustments, 2013

[redacted]

The internal audit reports in both 2012 (of the 2011 surveys) and 2013 (of the 2012 surveys) found that [redacted]

Internal Audits

[redacted]

Coal Procurement

According to AEP's 2013 10-K filing, about 60 million tons of coal and lignite were delivered to the AEP System plants in 2012 and 51 million tons of coal and lignite were delivered to AEP System plants in 2013. 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 and Louisiana.

Coal Procurement Strategy

AEPSC's strategy is to layer in coal commitments to minimize market exposure at any one time. AEPSC enters into contracts based on the generation and consumption information available at the time of contract execution. AEPSC indicated that its strategy is changing in order to manage increased burn volatility. [redacted] With respect to procurement, AEPSC has increased its tolerance for open positions in order to decrease the risk of being over-supplied. AEPSC points out that the corollary to this procurement strategy is a greater market exposure should demand both for AEPSC and the market at large increase.[20] As noted above, AEPSC is not increasing inventory targets which is the strategy adopted by some utilities.

In both 2012 and 2013, AEPSC [redacted] for Ohio Power [redacted].

Exhibit 3-14
Coal Contracts Commitments versus Deliveries During Audit Periods

[redacted]

[redacted].

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

[20] DR EVA-2012/2013-1-50

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 2012 [redacted] and [redacted] coal solicitations in [redacted]

AEPSC purchased [redacted] off of the [redacted] RFP. This coal purchase supported that [redacted]. The [redacted] was also used to establish the market price for the [redacted] under the [redacted] From the [redacted] RFP, AEPSC entered into an [redacted] with [redacted] for [redacted] tons of coal for [redacted]. The [redacted] bid was the most competitive given the narrow quality required by [redacted]. Like the last contract with [redacted] for [redacted] this contract contained flexibility on tonnage which allowed AEPSC to make a purchase commitment without exceeding its requirements.

From the 2013 RFP's, AEPSC entered into [redacted] purchases, which are summarized in Exhibit 3-15. There were deliveries under only [redacted] of these agreements during the audit periods.

Exhibit 3-15
Coal 2013 RFP Results

[redacted]

In addition, in both 2012 and 2013, AEPSC purchased coal [redacted]. In 2012, AEPSC made substantial commitments to [redacted] for deliveries in [redacted] and [redacted] and possibly [redacted]. In 2012 and 2013, AEPSC purchased coal from [redacted].

Regardless of the manner in which coal is procured, a written justification is supposed to be procured 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. As noted below, EVA identified issues with several of the justifications.

Procurement Administration

AEP Ohio switched from its [redacted] system to the [redacted] system [redacted] in [redacted]. 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.

In prior audits, EVA has raised the issue that it 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).[21] EVA found a higher level of compliance with contract quality specifications in this audit. There continue to be a couple of suppliers, however, with chronic non-performance.

Spot Coal Procurements

Ohio Power purchased very little coal on a spot basis during the audit periods. This reflects primarily the declining demand. The agreements are listed by supplier in Exhibit 3-16. Most of the spot agreements were [redacted].

Exhibit 3-16
Spot Coal Agreements[22]

[redacted]

Contract Overview

AEPSC is a party to a number of long-term coal supply agreements. The agreements are listed in Exhibit 3-17. Note some of the agreements expired in 2012 and some did not commence deliveries until 2013.

[21] From [redacted] contract.
[22] EVA is using AEPSC's classifications with respect to which agreements are contract purchases and which agreements are spot purchases.

Exhibit 3-17
Ohio Power Coal Contracts

[redacted]

2012 Performance

During 2012, AEP Ohio received coal under [redacted] contracts. As shown in Exhibit 3-18, AEPSC had a combined commitment under these contracts of [redacted] tons. Deliveries in 2012 were [redacted] tons which was about [redacted]. The variance was due to a combination of supplier and utility performance as discussed below.

Exhibit 3-18
Ohio Power Contract Tonnage Performance, 2012

[redacted]

Coal under these contracts went to one or more plants as shown in Exhibit 3-19.

Exhibit 3-19
Ohio Power Contract Purchases, 2012

[redacted]

In 2012, [redacted][23] supplied [redacted] of Ohio Power contract tonnage. (Exhibit 3-20) [redacted] accounted for over [redacted] of contract purchases.

Exhibit 3-20
Ohio Power Contract Supplier Volume And Contract Market Share, 2012

[redacted]

2013 Performance

In 2013, Ohio Power received coal under [redacted] contracts. As shown in Exhibit 3-21, AEPSC had a combined commitment under these contracts of [redacted] tons. Deliveries in 2012 were [redacted] tons which was about [redacted]. More than [redacted] was under the [redacted] contracts. The balance was under the [redacted] contracts. The variance was due to a combination of supplier and utility performance as discussed below.

[23] [redacted]

Exhibit 3-21
Ohio Power Contract Tonnage Performance, 2013

[redacted]

Coal under these contracts went to one or more plants as shown in Exhibit 3-22.

Exhibit 3-22
Ohio Power Contract Purchases, 2013

[redacted]

The two largest suppliers in 2013 were [redacted]. Combined [redacted] accounted for [redacted] of Ohio Power's 2013 contract purchases, as shown in Exhibit 3-23. This level of concentration is a concern absent [redacted].

Exhibit 3-23
Ohio Power Contract Supplier Volume And Contract Market Share, 2013

[redacted]

Individual Contract Performance

Performance in 2012 and 2013 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 lower than the noted monthly specifications for Btu or higher than the noted specifications for sulfur, SO_2 and/or ash.

[redacted]

In [redacted], 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. The [redacted] coal was a new source for this plant. The basic terms of the contract are summarized in Exhibit 3-24. In addition, the contract gave AEPSC the [redacted] at the [redacted]

Exhibit 3-24
Summary of [redacted] Agreement

[redacted]

2012 Performance

In May 2012, after receiving the first [redacted], AEPSC exercised its [redacted].

Shipments under the [redacted] contract in 2012[24] are summarized in Exhibit 3-25. AEPSC elected to divert a portion of the coal to [redacted].

Exhibit 3-25
Shipments Under [redacted] Contract, 2012

[redacted]

The [redacted] contract is for [redacted]. The contract provided that the first [redacted] were to be at an annual rate of [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 [redacted].

In [redacted], the contract was amended to address a [redacted] over the [redacted] period.

2012 Performance

The contract was amended [redacted]. Amendments [redacted] were administrative addressing contractually-allowed price adjustments.

Amendment [redacted] addresses [redacted]. AEPSC's analysis of the [redacted] amendment states that the parties "agreed that [redacted] remained outstanding due to the Seller. It states that the [redacted] will be increased by that amount and that the [redacted] will be at the [redacted]. The focus of the analysis is [redacted]. This analysis considers two coals, neither of which is comparable to the contract. One coal is the [redacted] which is not appropriate because AEPSC purchases no [redacted] for [redacted] or [redacted]. The second coal is a [redacted] coal on the [redacted]

[24] The data provided by AEPSC showed the shipments as-priced in November and December of 2011. EVA was informed the coal delivered in 2012.

[redacted]. This coal commands a premium in the market above that calculated by doing SO2 and Btu adjustments.

This is the same issue raised in the prior audit when AEPSC was criticized for not including the most appropriate ICAP index which is for a [redacted]. The index price for this coal on the same date was [redacted]. While using this coal would have produced the same results, i.e., [redacted] is meritorious, it would have been the right basis for management to make its decision.[25]

Shipments under the [redacted] Contract in 2012 are summarized in Exhibit 3-26. In most months, the average Btu content was [redacted].

Exhibit 3-26

Shipments Under [redacted] Contract, 2012

[p[25] AEPSC is selective about when to use this index. AEPSC did use this index in its evaluation as to whether to take shortfall tons under the [redacted] agreement.(justification for Amendment [redacted]..

[redacted]

2013 Performance

The contract was amended [redacted]. Amendments [redacted] were administrative addressing contractually-allowed price adjustments.

Amendment [redacted] allowed [redacted] to ship [redacted]. For AEPSC, the goal of the amendment was to determine whether this [redacted]. For [redacted], it was to develop an additional market for its [redacted]. The amendment [redacted]. Rather it established a [redacted]

Amendment [redacted] addressed the [redacted] of [redacted]. The parties did not dispute that AEPSC was responsible for [redacted]. The amendment provided for the [redacted] in [redacted] with [redacted] tons [redacted].

[redacted] provided for [redacted] In order to obtain [redacted].

Shipments under the [redacted] in 2013 are summarized in Exhibit 3-27. In a number of months, the average Btu content was [redacted]. AEPSC [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 [redacted] tons per month and extended the contract, such that its current expiration date is [redacted].

2012 Performance

AEPSC was [redacted]. AEPSC [redacted] (Exhibit 3-28) The coal was [redacted] and, in fact, AEPSC had to [redacted]. In addition, AEPSC had [redacted].

Exhibit 3-27
Shipments Under [redacted] Contract, 2013

[26] By the end of the first quarter, the difference between actual tons and inventory capacity at [redacted] Plus there was another [redacted]. This coal could have been [redacted] if the piles could not be adjusted to accommodate more [redacted].

[redacted]

Exhibit 3-28
Inventory at [redacted] in 2012

[redacted]

The cost of [redacted], is estimated to be [redacted] as shown in Exhibit 3-29. This is based upon the delivered cost of the [redacted] compared to a cost based upon a [redacted] coal during the same months. Some of the additional cost was [redacted]. EVA recommends that the 2012 FAC be adjusted by the retail portion of the remaining cost charged [redacted] which was [redacted].

Exhibit 3-29
Incremental FAC Costs Due to [redacted] Coal in Q1 2012

[redacted]

AEPSC indicated that in early 2012, it had indicated that it initiated efforts to [redacted] contract in recognition of [redacted]. In addition, AEPSC recognized that the problems with the [redacted] would require [redacted]. The documents indicate that [redacted]

[redacted]

AEP personnel indicated in interviews that the [redacted][29] In fact the [redacted] This distinction is very important because of the [redacted]

The incremental cost of delivering the [redacted]

27 [redacted]

28 [redacted]

29 It is not clear whether they knew this all along.

30 [redacted]

Exhibit 3-30
Incremental FAC Costs Due to [redacted] in Q4 2012

[redacted]

Jurisdictional customers have been paying a high price for the [redacted] The price reflects all provisions in the contract including [redacted] Given AEP's apparent belief that this [redacted]

The [redacted] was amended [redacted]. Amendments [redacted], were related to contract-allowed price adjustments. Amendments [redacted] related to [redacted]. Amendment [redacted]

The [redacted], was a [redacted]. The amendment provided for a [redacted] in [redacted] Ohio Power did not [redacted]. Unlike Ohio Power's standard practice, a justification for this amendment was not prepared [redacted]

Shipments under the [redacted] contract in 2012 are summarized in Exhibit 3-31.

[redacted]

Exhibit 3-31
Shipments Under [redacted] Agreement, 2012

[redacted]

2013 Performance

AEPSC diverted significant tonnage under the [redacted] in [redacted] because of a combination of the [redacted] and the fact that AEPSC's decision to [redacted] contract into [redacted] eliminated the potential market for [redacted] at [redacted].[32]

For the same reasons discussed above and using the same methodology, EVA calculated the incremental cost of delivering the [redacted] was [redacted]. (Exhibit 3-32) Ohio Power's share of the [redacted].

[32] AEPSC indicated there was no technical reason this coal could not be [redacted].

Exhibit 3-32
Incremental FAC Costs Due [redacted] in 2013

[redacted]

EVA believes the correct way to determine the FAC adjustment for 2013 related to the [redacted] should consider [redacted]. However, EVA believes that the analysis should be based upon shipping the [redacted] as EVA believes that [redacted]. Had the [redacted] contract not been [redacted], AEPSC would have had a place to put the [redacted]. Assuming make-up deliveries began [redacted], the [redacted] would have been [redacted]. Assuming it [redacted] at the same delivered price [redacted], AEPSC would have paid approximately [redacted]. This does not take into account the [redacted] which would have considerably reduced the spread as the [redacted]. Ohio Power's share would have been [redacted].

Exhibit 3-33
Incremental Cost of Moving [redacted]

[redacted]

EVA recommends that the 2013 FAC be reduced by the difference of the retail portion of [redacted] which is the difference between the [redacted]

Shipments under the [redacted] contract in 2013 are summarized in Exhibit 3-33.

Exhibit 3-33
Shipments Under the [redacted] Contract, 2013

[redacted]

AEPSC entered into a new agreement with [redacted] in [redacted]. The agreement was for [redacted] of [redacted] for [redacted]. The [redacted] was for [redacted]; the [redacted]. The contract was [redacted].

2012 Performance

Shipments in 2012 are summarized in Exhibit 3-34.

Exhibit 3-34
Shipments Under [redacted] Agreement, 2012

[redacted]

The [redacted] agreement provided for [redacted] for [redacted] and [redacted] and provided a [redacted] for Ohio Power for [redacted]. The agreement also imposed some [redacted]. In [redacted], the parties amended the agreement [redacted]. The amendment provided a commitment [redacted]. The [redacted].

2012 Performance

This contract was amended [redacted]. Amendment [redacted] Amendment [redacted]

[redacted]. AEPSC concluded that it had [redacted], AEPSC had explored [redacted] AEPSC analyzed both options and concluded [redacted] The parties [redacted] EVA reviewed AEPSC's analysis and concurs with its decision.

Shipments under the [redacted] Agreement in 2012 are summarized in Exhibit 3-35.

Exhibit 3-35
Shipments Under [redacted] Agreement, 2012

[redacted]

[redacted]

AEPSC entered into an agreement with [redacted] coal given an expectation that by 2010 [redacted] would burn [redacted]. AEPSC subsequently determined that such high usage of [redacted]. As a result, AEPSC is limited to [redacted] coal in its [redacted]. AESPC informed [redacted] that AEPSC had the right to suspend performance and, as a result [redacted]. After review, [redacted] agreed. AEPSC also informed [redacted] of the [redacted].

Pursuant to these discussions, the parties agreed to revise their respective obligations. The annual tonnage was [redacted][33] The amended agreement [redacted]r.

2012 Performance

The agreement was amended [redacted] to allow [redacted] to pass through an increase of one percentage point in the [redacted] sales/use tax. (Change Order No. 3)

Shipments under the [redacted] agreement in 2012 are summarized in Exhibit 3-36.

Exhibit 3-36
Shipments Under [redacted] Agreement [redacted], 2012

[redacted]

[33]The end date is the later of [redacted] coal.

2013 Performance

The agreement was amended [redacted]. The [redacted] allowed [redacted] to [redacted]. The [redacted]

Shipments under the [redacted] Agreement in 2013 are summarized in Exhibit 3-37.

Exhibit 3-37
Shipments Under [redacted] Agreement [redacted] 2013

[redacted]

[redacted]

In [redacted], AEPSC and [redacted] entered into a complex contract for [redacted] coal [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 the [redacted] portion of the [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].

2012 Performance

The contract was amended [redacted]2. The first amendment addressed a [redacted] shortfall in deliveries in [redacted] which was deemed to be the responsibility of the Seller. The amendment provided for the entire shortfall to be shipped in [redacted] at the [redacted]. AEPSC compared the price of the coal to market and concluded that [redacted] The amendment increased the tonnage obligation in [redacted] to reflect the additional tons.

[redacted] amendment addressed the required [redacted] tons for delivery [redacted]. AEPSC indicated at the initiation of the renegotiation, the parties were far apart. AEPSC conducted an RFP in [redacted] to obtain market information[34] and, in the event the parties could not agree on price, to develop a back-up supply plan. The RFP produced competitive bids due in part to the depressed market that existed in [redacted] as a result of coal gas switching. AEPSC stated in its justification memorandum that the lowest *composite cost market prices for* [redacted][35] AEPSC ultimately settled on a [redacted] of [redacted]

In a situation when the utility is able [redacted] because the benefits of the third year do not flow to customers. Said differently, the price in [redacted] is [redacted], while the price in [redacted] is at a [redacted]. AEP is asking customers to pay the premium knowing they will not receive the discount. AEPSC's argument was that its decision-making focused on realizing the lowest cost, not which party would benefit. It is not clear why the shifting of costs was not a consideration.

EVA believes an adjustment in the FAC recovery is appropriate. As shown in Exhibit 3-38, [redacted], the delivered fuel costs for the [redacted] tons in [redacted] were [redacted] higher in cost than the market alternative. EVA recommends a [redacted] adjustment to the 2013 FAC as a result.

Shipments under the [redacted] agreement in 2012 are summarized in Exhibit 3-39. Deliveries in [redacted] were [redacted] the commitment. As discussed above, a significant share of the [redacted] was due to AEPSC's decision to [redacted].

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[34] The prior [redacted] was a subject in the audit of 2011 as AEPSC neglected to solicit bids from the market. EVA estimated that the outcome of the prior reopener was a price about [redacted] higher than the then prevailing market. Taking bids during this process was a definite improvement.

[35] *EVA identified a slight error in AEP's summary table based upon using the wrong tonnages for two of the* suppliers. In the actual analysis, AEP correctly adjusted the tons for Btu but did not reflect that adjustment in the summary table. The correct weighted averages would be [redacted].

Exhibit 3-38
Impact of [redacted] on 2013 FAC Costs

[redacted]

Exhibit 3-39
Shipments Under [redacted] Agreement, 2012

[redacted]

2013 Performance

The [redacted] contract was amended [redacted]. The [redacted] address the [redacted] shortfall which AEPSC indicated had been by mutual agreement. According to AEPSC, [redacted]. As part of the arrangement, it was recognized that Buyer would receive and accept any accumulated calendar year [redacted] in calendar year [redacted]" The [redacted] the [redacted] tonnage obligation by [redacted].

The [redacted] addressed the [redacted] tons for delivery [redacted]. AEPSC indicated at the initiation of the renegotiation, the parties were far apart. AEPSC conducted an RFP in [redacted] to obtain market information and, in the event the parties could not agree on price, to develop a back-up supply plan. The RFP produced multiple bids for each year. AEPSC developed the least cost composite alternative to [redacted] on a quality adjusted delivered price basis.[36] AEPSC was able to obtain equivalent pricing from [redacted]. The negotiated prices per ton were [redacted] EVA concurs with AEPSC's analysis. The amendment also adjusted the SO2 limits in the contract to reflect the revised SO2 forecast of the [redacted].

The [redacted] addressed a problem with calculating the SO2 adjustment for the first half of [redacted]. The formula was revised to be based upon the average [redacted]. The explanation provided by AEPSC was reasonable and EVA concurs with the amendment.

Shipments under the [redacted] agreement in 2013 are summarized in Exhibit 3-40. Deliveries in [redacted] tons [redacted]. As discussed above, a significant share of the [redacted].

[36] The [redacted] repricing is in stark contrast to what was done in [redacted]. There was [redacted] of the prices and the comparisons to market were all made on a delivered quality adjusted basis.

Exhibit 3-40
Shipments Under [redacted] Agreement, 2013

[redacted]

In [redacted], AEPSC entered into a [redacted] agreement with [redacted]. This contract obligates Ohio Power to [redacted] throughout the term but [redacted]. As such it provides considerable flexibility to Ohio Power and addresses the uncertain and volatile burn at [redacted].

2012 Performance

The agreement was modified in [redacted] to reflect a price adjustment related to Senate Bill 579 in which the [redacted] Legislature amended Section 22-3-11 (h)(i)(B) of the Code of [redacted], Surface Coal Mining and Reclamation Act to increase the Special Reclamation Tax by $0.135 per ton on [redacted] coal mining operations. The adjustment to the contract price was [redacted] as approximately [redacted].

Shipments under this agreement in 2012 are summarized in Exhibit 3-41.

Exhibit 3-41
Shipments Under [redacted] Agreement, 2012

[redacted]

2013 Performance

Shipments under this agreement in 2013 are summarized in Exhibit 3-42. The contract which was based upon [redacted].

Exhibit 3-42
Shipments Under [redacted] Agreement, 2013

[redacted]

[redacted]

In [redacted], AEPSC entered into an [redacted]. The basic terms of the contract are summarized in Exhibit 3-43. This contract obligates Ohio Power to buy its [redacted] for [redacted] but does not obligate a [redacted]. Ohio Power has to buy [redacted] tons over the term. As such it provides considerable flexibility to Ohio Power and addresses the uncertain and volatile burn at [redacted].

Exhibit 3-43
Overview of [redacted] Agreement

[redacted]

2013 Performance

Ohio Power made the required nominations which were converted into contract amendments. (Exhibit 3-44)

Exhibit 3-44
Tonnage Nominations Under [redacted] Agreement, 2013

[redacted]

The agreement was amended a [redacted] in [redacted] when the delivery point was changed from [redacted], located [redacted], located [redacted]. No justification was provided. With [redacted], this amendment would serve to lower the barge cost.

Shipments under this agreement in 2013 are summarized in Exhibit 3-45. With the exception of SO_2 [redacted], the quality of the deliveries was consistent with the contract specifications.

Exhibit 3-45
Shipments Under [redacted] Agreement, 2013

[redacted]

In [redacted], Ohio Power entered into [redacted] with [redacted] that collectively provide the basis for the [redacted]. The interest in [redacted]. [redacted] In order to qualify for the [redacted] As a result, in order to [redacted] Ohio Power must [redacted]

[redacted]

Under the [redacted], Ohio Power [redacted] provides for Ohio Power to [redacted]. The [redacted] provides for the [redacted].

Under the [redacted], Ohio Power receives what is referred to as [redacted]. [redacted] is summarized in Exhibit 3-46. In the deal summary prepared for management, AEP noted that it believes the [redacted].

Exhibit 3-46

[redacted]

Ohio Power indicated it would not be flowing any of [redacted] through the FAC. The reason provided is that "FAC ratepayers will realize a net benefit without cost through this arrangement because the savings in the cost of [redacted] by Ohio Power Company as a result of the [redacted] will be reflected in the FAC via [redacted] AEPSC also notes that the "decisions to [redacted] were made over a period of several months in the [redacted] Many corporate business units were involved in this process including: Fuels Emission & Logistics, Corporate Accounting, AEP Legal, AEP Regulatory and Ohio Power Company." To the best of the auditor's knowledge, AEPSC did not ask for or receive an opinion from the Commission or Staff regarding the appropriate accounting treatment.

Fundamentally, EVA believes that the only reason a [redacted] burns substantial quantities of coal, which were purchased on the behalf of jurisdictional customers. In other words, the asset (i.e., the coal) during the audit period effectively [redacted] Therefore, [redacted] received are inextricably tied to Ohio Power's ability to lever this asset into [redacted]. While not suggesting customers are due a residual payment over the life of the project, EVA is recommending that during the remaining term of the FAC the proceeds received should flow through the FAC. For 2013, EVA is recommending an adjustment to the FAC of the retail portion of [redacted].

With respect to the specific justification regarding [redacted] noted by AEPSC in its response to EVA-2012/13-3-8, EVA notes that AEPSC indicated that it included "no value for [redacted]" in its deal value because [redacted] will not be certifying that the required [redacted] have in fact been realized. In fact, EVA is aware of situations where utilities have decided to [redacted] because of higher operating costs and lower plant availability. Absent a clear demonstration of total savings, EVA is not convinced by AEPSC's arguments.

Finally, it is not at all clear that customers are not adversely affected in their cost of fuel. In the deal package, AEPSC notes that following a test burn at [redacted], the [redacted] yielded acceptable results [redacted]. This exclusion suggests that [redacted]. After the end of the FAC, this is no longer an issue. Prior to the end of the FAC, having the fee not flow through the FAC reduces the incentive to minimize fuel costs at the plant.

[redacted]

In [redacted] and [redacted] entered into a [redacted] for the supply of [redacted] to the [redacted] In addition, the agreement gives [redacted] each year provided such option is exercised no later than [redacted] prior to the commencement of [redacted]. The mine is located [redacted]. In [redacted], the agreement was [redacted] decided it best to each company having a stand-alone agreement. The new agreement was given the [redacted]

2012 Performance

The contract was amended [redacted] in [redacted]. Amendment [redacted] was price adjustment-related, based on the escalatable pricing components outlined in the terms and conditions of the contract. Amendment [redacted] changed the [redacted]. Amendment [redacted] was price adjustment-related, based on the escalatable pricing components outlined in the terms and conditions of the contract plus it [redacted] (which had no impact on the delivered price) and corrected the [redacted].

Shipments in [redacted] under the [redacted] are summarized in Exhibit 3-47. [redacted] was not in compliance with the SO2 specifications for [redacted].

Exhibit 3-47
Shipments Under [redacted] Agreement, 2012

[redacted]

2013 Performance

The contract was amended [redacted]. Amendment [redacted] was price adjustment-related, based on the escalatable pricing components outlined in the terms and conditions of the contract.

Amendment [redacted] primarily addressed the [redacted]. The amendment justification did not address the [redacted] other than stating the parties agreed they were equally responsible for [redacted]. The resolution was that the [redacted] would be delivered with [redacted] and [redacted]. The tonnage under the amendment is inconsistent with the tonnage actually shipped and nominated in [redacted] for unknown and unexplained reasons. Further, the amendment appears to reflect actions that had actually occurred in [redacted]. It is generally not good practice to amend contracts after the fact. Amendment [redacted] also allowed the [redacted].

Amendment [redacted] was price adjustment-related, based on the escalatable pricing components outlined in the terms and conditions of the contract.

Amendment [redacted] provided for the [redacted]. As part of [redacted] agreement, [redacted]

Amendment [redacted] addressed a change in [redacted]. AEPSC noted that Buyer's [redacted] AESPC concluded the [redacted]. As the only coal being burned at the time was from [redacted], AEPSC requested that [redacted]. [redacted]. AEPSC indicated its analysis (which was not provided) [redacted].

Shipments in [redacted] under the [redacted] are summarized in Exhibit 3-48. [redacted] was not in compliance with the SO2 specifications [redacted].

Exhibit 3-48
Shipments Under [redacted] Agreement, 2013

[redacted]

[redacted]

The initial contract with [redacted] was signed in [redacted] and provided for [redacted] tons of [redacted] and [redacted] tons per year of [redacted] through [redacted] with [redacted] for AEPSC. With [redacted], AEPSC could elect to [redacted]. [redacted] are described in Exhibit 3-49.

Exhibit 3-49

[redacted]

Subsequent amendments [redacted]. In [redacted], AEPSC amended the contract to [redacted] in [redacted] and [redacted] with an [redacted].

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

- The price for [redacted] which is [redacted]. According to AEPSC, this pricing structure produced an [redacted].[37]
- The price for the remaining will be set by an average of the following three [redacted]
  - [redacted]
- [redacted] will be added to the annual average the indexes. The [redacted]
- Adjust the calculated price to calculate the SO_2 cost.

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

EVA reviewed the justification and concluded that AEPSC wsa ill-advised in extending the [redacted] agreement *in the manner it did for the following reasons:*

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

- As previously discussed, AEPSC has a huge problem [redacted] because the plant dispatch is impaired due to the current high price of [redacted]. EVA believes that the availability of business at [redacted] provided some ability for negotiation on the [redacted] terms either with [redacted][38] or perhaps a third party that could have provided a comprehensive solution.
- [redacted], AEPSC made the decision [redacted]. Given the significant costs associated with the plant's closure, 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].
- By [redacted], it had become clear that AEPSC had on numerous occasions purchased more coal that it ultimately [redacted]. 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] 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] price relief [redacted] and [redacted]. AEPSC agreed to defer repayment in [redacted]. AEPSC agreed to allow [redacted] to ship tonnage shortfalls [redacted] At some point, AEPSC needs to consider whether continued support is consistent with the interest of its customers.

Given these findings, EVA recommended the following:

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

As of the date of this audit, the Commission has not ruled on these recommendations.

2012 Performance

The contract was amended [redacted]. Amendment [redacted] provided for a reduction of [redacted] because of lower projected demand from [redacted]. AEPSC indicated that the parties made this agreement in [redacted]. AEPSC agreed [redacted]

[38] AEPSC argues that using [redacted] would not been more expensive because these units do not need [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] to include additional tons for [redacted] could have been based upon alternative coals, not the coals moving [redacted] Further, there are procedures in place to accommodate the transfer of coal purchases from [redacted]

[redacted] for the [redacted] and [redacted] for the [redacted] of the year. AEPSC justified the higher price as a way to avoid having the producer experience financial harm. Of course, the higher price is simply a way to buy-down the contract volumes.[39] Given the agreed to contract price, the higher prices were effectively a buy-down payment of [redacted]. (Exhibit 3-50)

Exhibit 3-50

[redacted]

Amendment [redacted] also revised the pricing calculations for [redacted] through [redacted]. According to the new Schedule 5.1, the "determination of the Contract Price for [redacted] for each of Contract Years [redacted] will involve [redacted] to determine the annual market prices used in establishing the price per Ton which is the Contract Price." The three publications and reference markets shall be as follows:

[redacted]

All together, the amendment provides [redacted] steps to determine the market price. The last step is the subtraction of the agreed-to discount [redacted] from the Quality Adjusted Delivered Contract Price

By [redacted], AEPSC indicated it had realized the tonnage reductions in Amendment [redacted] were excessive. Amendment [redacted] modified the tonnage to reduce the reduction [redacted] tons and [redacted]. The amendment did provide for a price adjustment once the actual shipment level was known. The net result of Amendment [redacted] assuming [redacted] tons were shipped in the [redacted] was to reduce the buy-down payment to [redacted]. (Exhibit 3-51)

Exhibit 3-51

[redacted]

---

[39] AEP made a motion to FERC to allow recovery of what it refers to as "buy-down payment" to [redacted] In the entire presentation to FERC, AEP neglects to mention that the FAC auditor found the decision in 2011 to prematurely extend the [redacted] agreement imprudent for a number of reasons including the future over-commitment for coal.

[redacted]

Shipments in 2012under the [redacted] are summarized in Exhibit 3-52.

Exhibit 3-52
[redacted]

[redacted]

2013 Performance

The contract was amended [redacted]. Amendment [redacted] amended the tonnage and price for [redacted] and [redacted] based upon [redacted]. The price was increased to [redacted] per ton for the [redacted]. As a result, the final effective buy-down amount in [redacted] was [redacted] as shown in Exhibit 3-53. Amendment [redacted] also provided a reduction in the Federal Reclamation Fee from $0.315 to $0.280 consistent with the Office of Surface Mining's lower rate effective October 1, 2012.

Exhibit 3-53

[redacted]

[redacted]

Consistent with the recommendation from the prior audit, EVA recommends the 2012 FAC recovery be reduced by the retail portion of [redacted] associated with the [redacted]

Amendment [redacted] restated Amendment [redacted] without the Federal Reclamation Fee. The parties subsequently realized that the [redacted] [redacted] was not subject to any [redacted]. Amendment [redacted] also established the [redacted] price at [redacted] per ton. No back-up support was provided for the establishment of the [redacted] price.

Amendment [redacted] amended the contract to allow the contract [redacted]

Amendment [redacted] addressed the problem previously identified at [redacted]. AEPSC decided to divert sufficient coal to [redacted] in order to determine whether a [redacted] would meet the MATS limits. At the time of the test, [redacted]

Amendment [redacted] extends the date by which AEPSC can exercise its option to extend the contract beyond [redacted] for an additional [redacted]. No justification was provided.

Amendment [redacted] provides for [redacted] scheduled for [redacted] in [redacted]. The reduction was requested due to an [redacted]. The parties agreed that the tons would be [redacted]. At this price, the delivered price of the [redacted] would be less than what it was to [redacted] and Ohio Power could avoid an off-site storage charge of [redacted].

The problems with Amendment [redacted] are threefold. First, as previously discussed, Ohio Power should never have extended the [redacted] at the volume it did because of the potential for over-commitment. This was fully explained in the audit of 2011 [redacted]. Second, the transfer should not have been effectuated through a separate purchase order but through an amendment to the existing contract so that when/if the volumes changed there would not be an outstanding commitment for these incremental tons. And third, and most important, the [redacted] did not consider both sides of the equation. Ohio Power did not need coal for [redacted] and in fact [redacted] contributed to Ohio Power [redacted]. Therefore, the true cost of [redacted] is not the avoided inventory charge which never should have been a factor but the difference between the price of the [redacted] versus the alternative.

In the amendment justification, the Company represented the replacement coal would be a [redacted]. In fact, in the purchase order governing the amendment, the coal specification was [redacted] and the price was [redacted]. At the correct Btu, the conclusion of the amendment, i.e., that the [redacted] would have delivered to [redacted] at a lower price, was wrong. While the error may have simply have been a typographical error, it suggests that AEPSC was not performing the necessary quality control on its analyses that affect the flow of significant amounts of dollars.

According to the Company, the delivered price of the [redacted] was [redacted] per ton, as shown in Exhibit 3-54. From the provided information, it appears that only [redacted] tons of the [redacted] tons were delivered in [redacted] and a full [redacted] were delivered to [redacted] negating the need (and expense of this amendment).

Exhibit 3-54
Shipments By [redacted], 2013

[redacted]

As noted above, AEPSC did not consider the impact on fuel costs [redacted]. For the [redacted] tons delivered in [redacted], the incremental cost of this coal versus the deferred [redacted] coal was [redacted] as shown in Exhibit 3-55. This cost is effectively the [redacted] and as such EVA recommends that it not be recoverable through the FAC.[40] If tonnage under this agreement continues into 2014, a similar adjustment should be made for those tons. Interestingly, when considered in the context of these higher costs, the additional [redacted] is quite inexpensive when compared to the equivalent incremental cost per ton of the [redacted].

Exhibit 3-55
Incremental Fuel Cost at [redacted]

[40] EVA notes that even if the Commission decides that buy-down costs can be recovered, EVA recommends that this cost not be recovered because it was not necessary to commit to these for [redacted]

[redacted]

Shipments in [redacted] under the [redacted] are summarized in Exhibit 3-56. As can been seen, the full contract amount was taken to [redacted] in [redacted] making the [redacted] unnecessary and expensive.

Exhibit 3-56
Shipments Under [redacted] Agreement, 2013

[redacted]

[redacted], AEPSC entered into [redacted] with [redacted] with shipments beginning in [redacted]. The contract provided for deliveries [redacted] tons [redacted] and [redacted] tons each year thereafter.

2012 Performance

The [redacted] was amended [redacted], [redacted] were administrative in nature. Shipments under this contract [redacted] are shown in Exhibit 3-57. There was a [redacted] ton shortfall in [redacted]. In addition, [redacted] the Btu specification.

Exhibit 3-57
Shipments Under [redacted] Agreement, 2012

[redacted]

2013 Performance

The [redacted]Agreement was amended [redacted]. The [redacted]mendment was administrative.

The [redacted] amendment provided for [redacted] to accommodate the shipment of [redacted]. The contract was [redacted] and the price for the [redacted]. The amendment did not include the [redacted] which the parties agreed were the fault of the Seller. AEPSC compared the price under the contract to the market price and concluded it was not advantageous to [redacted]. EVA concurs with AEPSC's findings but is somewhat perplexed by why [redacted] were not resolved until [redacted].

The [redacted] amendment was a modification [redacted]

The [redacted] amendment provided for price and quality adjustments. According to AEPSC, [redacted]wanted to [redacted] and offered a [redacted] to do so. Since this coal is not needed and the [redacted] does not bring pricing anywhere close to market, it is unclear why AEPSC agreed to make this change as opposed to enforcing its contractual rights.

Shipments under the [redacted] Agreement in [redacted] are summarized in Exhibit 3-58.

Exhibit 3-58
Shipments Under [redacted] Agreement, 2013

[redacted]

[redacted]

AEPSC entered into a contract with [redacted] in [redacted] for [redacted] for [redacted] starting in [redacted]. The coal was purchased for [redacted] which uses [redacted].

2012 Performance

The [redacted] contract was amended [redacted]. The [redacted] amendment incorporated [redacted] tons Ohio Power wanted to purchase for [redacted]. [redacted] was selected in the [redacted] RFP to supply [redacted] tons to [redacted]. Rather than enter into a new contract, the parties agreed to amend the existing contract to add the existing tons. The parties further agreed that once the [redacted]. The tons covered by the original contract were to be priced based upon the [redacted]. The [redacted] amendment established the price for the [redacted] tons at [redacted] per ton.

Shipments under the [redacted]. Agreement in 2012 are summarized in Exhibit 3-59.

Exhibit 3-59
Shipments Under the [redacted] Agreement, 2012

[redacted]

2013 Performance

The [redacted] agreement was amended [redacted]. The amendment documented a decision in [redacted] and [redacted] of [redacted] to [redacted] due to [redacted]. The parties agreed to [redacted] tons and that the tons would [redacted].

Shipments under the [redacted] Agreement in 2013 are summarized in Exhibit 3-60.

Exhibit 3-60
Shipments Under the [redacted] Agreement, 2013

[redacted]

[redacted]

Ohio Power Company entered into agreement [redacted] with [redacted] in [redacted]. The terms of the agreement are summarized in Exhibit 3-61.

Exhibit 3-61
[redacted]

[redacted]

This agreement was [redacted]. Rather, according to AEPSC, the Seller approached Buyer about entering into this agreement with Ohio Power as well as another agreement with Ohio Power. It is highly unusual and not industry practice to enter into an agreement [redacted]. Another unusual aspect of this agreement is the [redacted].

AEPSC's analysis, summarized in Exhibit 3-62, showed a loss compared to market of [redacted]. Market is defined as the [redacted] It was only in the [redacted] year of the contract, did it become net favorable to market.

Exhibit 3-62
AEPSC Analysis of [redacted]

[redacted]

The calculations of the [redacted] and [redacted] costs are shown in Exhibit 3-63.

Exhibit 3-63
Derivation of [redacted] Contract versus Market Price

[redacted]

The analysis of the [redacted] value is opaque in the justification package.[41] From what is provided, it is clear that AEPSC based its analysis on the [redacted] as of [redacted]. Because of the volatility of forward price curves, analyses dependent on a forward price number will often use an average of several prices, not a single point. As shown in Exhibit 3-64, from the date the discussions with [redacted] first commenced until the date of the agreement, the forward price for Calendar Year [redacted] displayed significant volatility and the selected point on the curve was the highest point throughout the period. In fact had AEPSC used the forward price curve as of [redacted], there would have been considerably less value in [redacted]. While hindsight is not particularly relevant, the [redacted] for calendar year (CY) [redacted] is as of [redacted], [redacted] or over [redacted] per ton below the price used to justify this deal.

Exhibit 3-64
Derivation of [redacted] Contract versus Market Price

[redacted]

[41] Work papers were requested but AEPSC advised none existed.

While the selection of the [redacted] number is important, the bigger question is the justification of entering into an agreement in which the [redacted] years (and the only [redacted] years) show a [redacted]. This justification would be a challenge under any circumstance but is a particular challenge in the context of the end of fuel cost recovery through the FAC at the end of 2014. As the benefits of this agreement, should they in fact occur, are in [redacted], the pricing structure effectively has customers paying for benefits they will not realize.

In many ways, this contract is akin to a financial option for [redacted]. Ohio Power overpaid by its own calculations [redacted] more for coal in [redacted] in exchange for an option to purchase coal at [redacted]. The loss does not need to be written off from an accounting perspective because as structured customers paid for it. EVA believes this arrangement is in fact contrary to the hedging strategy outlined in the July 2012 FEL Procurement Policy which states the "FEL is not currently active in entering into financial fuel hedge transactions." FEL states while it will investigate doing so they would be "subject to the appropriate regulatory approvals."

2013 Performance

The agreement was amended [redacted]. The [redacted] amendment provided a change in approved alternative sources.

Shipments under [redacted] in [redacted] are summarized in Exhibit 3-39. Shipments were just [redacted] of the contracted volumes. EVA accepts AEPSC's analysis that it paid [redacted] per ton more in [redacted] for this coal than the market price even though there is an argument that the over-payment was even higher. EVA recommends that AEPSC's allowed fuel cost recovery in 2013 be reduced by [redacted] to align costs and benefits of the contract for jurisdictional customers. EVA further recommends a similar adjustment in 2014.

Shipments under the [redacted] Agreement in 2013 are summarized in Exhibit 3-65.

Exhibit 3-65
Shipments Under [redacted], 2013

[redacted]

Ohio Power Company entered into agreement [redacted] with [redacted] in [redacted]. The terms of the agreement are summarized in Exhibit 3-66.

Exhibit 3-66
[redacted]

This agreement was also [redacted]. Rather, according to AEPSC, the Seller approached Buyer about entering into this agreement. As noted above, it is highly unusual and not industry practice to enter into an agreement [redacted]

[redacted] Another unusual aspect of this agreement is the [redacted].

AEPSC's analysis of the offer, which is summarized in Exhibit 3-67, showed the [redacted] of the contract had a [redacted]. It was only in the [redacted] year of the contract, did it become net favorable to market.

Exhibit 3-67
AEPSC Analysis of [redacted] Agreement

[redacted]

The analysis itself is opaque.[42] Minimal components of AEPSC's analysis are contained in the justification package. From what is provided, it is clear that AEPSC based its analysis on [redacted] coal. AEPSC did not justify why the [redacted] has the same value as the [redacted] with a Btu and sulfur and ash adjustment.

Further, the basis for the sulfur and ash adjustment AEPSC includes, which is [redacted], is not provided. The contract has [redacted] Per the contract provisions that SO2 adjustment would be [redacted].[43]

More significantly, AEPSC is treating this deal as a financial hedge. AEPSC has historically not purchased financial hedges for its coal purchases. By over-paying in [redacted] for a [redacted] option is akin to buying a financial hedge. To the auditor's understanding, AEPSC has never asked the Commission for approval to utilize financial hedging strategies for coal in Ohio and, therefore, did not.

Finally, as a result of AEPSC's approach, the costs of the [redacted] contract are front-end loaded. Under normal circumstances, such an approach would require significant justification including a demonstration that the forward price curve is reflective of the actual market and that the option analysis is meritorious. Under the regulatory circumstances facing the Company, however, a further demonstration is required in that the excess costs of the [redacted] contract are being borne by jurisdictional customers while the benefits [redacted]

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[42] Work papers were requested but AEPSC said none existed.
[43] [redacted]

[redacted] Absent a compelling reason for such a transfer, which has not been provided, the transfer is inappropriate.

2013 Performance

This contract was amended [redacted]. According to AEPSC, following the "loading and receipt of the [redacted] shipments" under this agreement "it was evident Seller was going to have great difficulty meeting the contracted quality specifications." AEPSC agreed to a number of changes including a change in quality specifications [redacted] AEPSC in the justification for the amendment provides a financial analysis of the amendment, arguing that these changes [redacted]. (Exhibit 3-68)

Exhibit 3-68
AEPSC Analysis of [redacted] Agreement

[redacted]

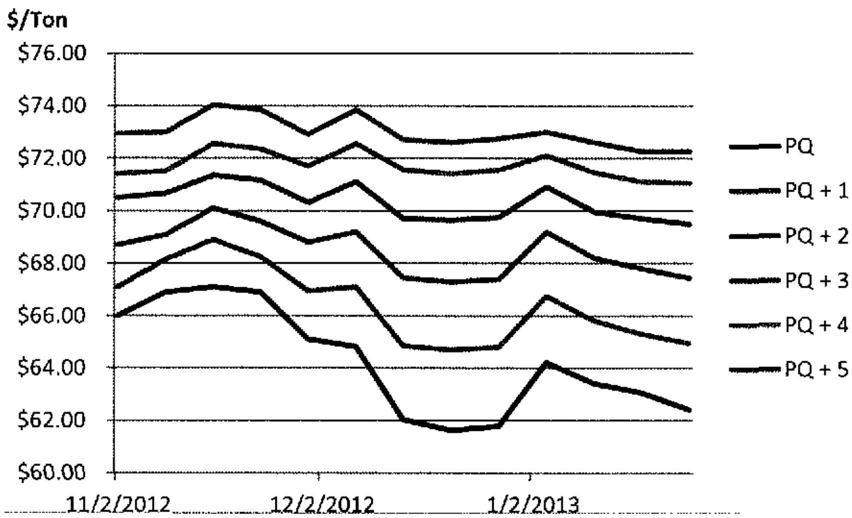
It is obvious that AEPSC increased the value of the deal in its analysis because it only changed the economics of [redacted] and failed to change the economics of the [redacted] despite the following [redacted]

Exhibit 3-69
Impact of Correcting [redacted]

[redacted]

Further, AEPSC uses the same [redacted] in the amendment that it used in the original deal despite the fact the prices had fallen between [redacted] from the date of the original economics. (Exhibit 3-70)

Exhibit 3-70
Change in Forward Price Curve for NYMEX Coal



[redacted]

Whatever AEPSC's reason for agreeing to the amendment, it was clearly not because of improved economics.

Deliveries under the [redacted] contract in [redacted] are summarized in Exhibit 3-71. Total deliveries equaled [redacted] tons resulting in a [redacted] tons. EVA accepts AEPSC's original analysis that it paid [redacted] per ton more for this coal than the market price. EVA recommends that its allowed fuel cost recovery in 2013 be reduced by [redacted] to align costs and benefits of the contract for jurisdictional customers. EVA further recommends a similar adjustment in 2014 if any of the shortfall is shipped.

Exhibit 3-71
Shipments Under [redacted] Agreement [redacted]

[redacted]

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.

AEPSC is a party to multiple rail contracts under which the rail coal is delivered. The contracts are listed in Exhibit 3-72.

Exhibit 3-72
Rail Contracts

[redacted]

AEPSC entered into [redacted] new contracts during the audit periods. The new contract with the [redacted] replaced the [redacted] which expired at the end of [redacted]. The new contract was for [redacted] with AEPSC having the right to extend [redacted] which it did at the end of [redacted]. The new contract with the [redacted] replaced the [redacted] which expired at the end of [redacted]. The new [redacted] contract has a [redacted] but no minimum obligations other than for [redacted] of purchases from the designated regions and any nominated tonnages. As Ohio Power's requirements from these supply regions are uncertain, the rail contract does not force purchases that may not be economic. The agreement caps total tons to be moved under the agreement. The agreement was amended to [redacted]. No justification package was provided for the new [redacted] contract. The new contract with the [redacted] was specifically for the [redacted] for ultimate movement by [redacted]. In [redacted], the movements from [redacted] were split between [redacted]. The rates provided in this new contract made [redacted] more economic.

Other Fuel Procurement

AEPSC acquires natural gas 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 2012 and 2013 are summarized by month on Exhibit 3-73.

Exhibit 3-73

[redacted]

The growth in gas consumption over the last five years has been significant as shown in Exhibit 3-74.

Exhibit 3-74

[redacted]

AEPSC indicated that it purchases its gas monthly for base periods and day to day for other requirements. The gas for Waterford must be delivered to a TETCO meter. As a result, there are not a lot of pipeline options for the last inch. However, there a lot of supply options for providing gas to TETCO. The supply options include the Gulf via TETCO, Rockies gas to Clarington via the REX pipeline connecting to TETCO, and Pennsylvania gas backhauled on TETCO. There are less options for Darby. Transportation must be via Columbia Gas or Dominion Transmission Inc.

AEP uses a competitive bidding process and selects the cheapest option. The bidders list is large and comprehensive. The RFP's are clear. Over time the RFP's have adapted to the availability of shales, particularly the Marcellus share. The focus is less source specific, allowing the market to dictate origin. The range in pricing confirms the value of the formal solicitation process.

AEPSC also purchases fuel oil for flame stabilization and start up. Purchases are relatively low and the agreements are for requirements. Like with gas, the bidding process is well structured. The bidders list was comprehensive. The assessment of the bids was systematic. The range in pricing confirms the value of the formal solicitation process.

Coal Sales

Ohio Power sold [redacted] in both [redacted] and [redacted].[44]

2012 Performance

In 2012, AEPSC indicated it had been approached by [redacted] as to the availability of [redacted] coal. AEPSC entered discussions with [redacted] because it realized it had a [redacted] AEPSC indicated its only options were looking at [redacted] The size of these numbers demonstrates the magnitude of the problem with [redacted].
A summary of the sales agreement in 2012 is summarized in Exhibit 4-1.

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[44] The terms of the sales to [redacted] were particularly difficult to extract from AEPSC. The initial data response to EVA-2012/2013-1-19 which requested information on third party saies provided only the accounting treatment and third-party sales.

Exhibit 3-75
2012 Agreement to [redacted]

[redacted]

The justification of this sale notably lacks any discussion of the [redacted] which based upon information discussed with [redacted] in [redacted] so was presumably known at this time. Given the early representations by AEPSC that it believed the [redacted]

2013 Performance

At the end of 2012, AEPSC entered into a [redacted] agreement with [redacted] for [redacted] In its justification, AEPSC repeated that it had a [redacted] AEPSC indicated its only options were [redacted] As the market for this quality of coal had softened between 2012 and 2013, [redacted] AEPSC estimated the damages to be [redacted] The size of these numbers demonstrates the magnitude of the problem with [redacted]. A summary of the sales agreement in 2013 is summarized in Exhibit 4-2.

Exhibit 3-76
2013 Agreement to [redacted]

[redacted]

[redacted]

The justification of this sale was identical to the earlier justification and notably lacks any discussion of the [redacted]. At the time of this justification, AEPSC was [redacted]

4 CONESVILLE COAL PREPARATION PLANT

Plant 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, 2, and 3 have been retired, and Unit 4 has been retrofit with a scrubber and AEPSC revised its contract for Unit 4 to a washed coal.

In 2010, AEPSC performed a study which concluded that the closure of the plant would be economic. AEPSC ceased operations at CCPP in 2011. AEPSC, however did not start the sales process for CCPP until 2012. In 2011, despite knowing there would be a sale process, AEPSC [redacted]. With the [redacted] contract for [redacted] and the [redacted], AEPSC knew that any buyer of CCPP would not have access to the [redacted] market until at least [redacted].

In EVA's audit of 2011, EVA found AEPSC's decision to decouple the marketing of the preparation plant with the post [redacted] supply decisions for [redacted] deeply flawed.[45] It is EVA's experience that assets have considerably more value when packaged with sales commitments.[46] In this instance, the tie in was even greater when one considered CCPP is located adjacent to the power plant and has no rail loading capability, therefore largely limiting the potential market to truck-served plants. EVA strongly recommended in 2011 that AEPSC offer to sell the plant prior to [redacted]. EVA believes that by failing to market CCPP in conjunction with an open coal position at [redacted] significantly reduced the value of the preparation.

Sales Process

In 2012, AEPSC initiated a standard sales process. [redacted]

[45] EVA was also concerned that AEPSC did not explore a possible solution to the high-priced [redacted] at the same time.

[46] 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."

[redacted]

The parties entered into an asset purchase agreement in [redacted]. The purchase price was [redacted] with [redacted] and the [redacted], and the assumption of the reclamation obligation. [redacted] noted in its 2013 10-K filing that it paid [redacted] and [redacted]

Given AEPSC's decision to take the [redacted] tonnage out of the equation, which is the most likely explanation for the lack of interest, the price paid by [redacted] cannot be evaluated. Further, [redacted] continues to be in a financially fragile situation as losses continue to mount. Should [redacted] not survive, there could be potential reach-back consequences at the plant.

Finally, [redacted] contract for [redacted] runs through [redacted] and AEPSC had deferred its decision to [redacted] on whether to [redacted]. In addition to presumably obvious concerns about the tonnage, AEPSC has determined that the [redacted] without changes to [redacted]

5 ENVIRONMENTAL PERFORMANCE

Environmental Requirements

Ohio Power coal plants are subject to air emission regulations through both state and federal programs. Throughout the audit period, these coal plants were required to comply with EPA's Clean Air Interstate Rule (CAIR).[47]

Under the Clean Air Interstate Rule (CAIR), power plants must surrender emission allowances each year to cover their annual emissions of both sulfur dioxide (SO2) and nitrogen oxides (NOx) as well as surrender additional allowances for their NOx emissions during the five-month ozone season (seasonal NOx). Each plant was initially given an allocation of SO2, annual NOx and seasonal NOx at no cost under an EPA distribution formula and is permitted to trade allowances (e.g. sell surplus, purchase to meet target) that can be used to meet their compliance requirement.

AEP has a stated policy on 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. Ohio Power was a party to the Interim Allowance Agreement (Modification 1) that provided the framework for the allocation of SO_2 purchases and sales among the AEP companies. The Interim Allowance Agreement ended at the end of 2013 and, therefore, was in effect throughout the audit periods. Seasonal and Annual NOx allowances are managed separately by AEP.

Ohio Power and [redacted] are parties to a NOx allowance agreement that was originally issued in 2004 and modified in November 2010. This agreement obligates Ohio Power to purchase any excess NOx allowances (annual and/or seasonal) from [redacted] at its fixed allowance carrying costs (capital, fixed O&M) plus [redacted] variable NOx control costs (energy consumption, urea, wages, catalyst depreciation, maintenance cost and plus other variable cost). Given the facility SCR equipment reduces NOx emissions towards its seasonal and annual NOx requirements, the full costs are spread between the two programs based each program emissions divided by the sum of its seasonal NOx plus annual NOx emissions. This contract accounts for the NOx allowances purchases at a high (above market) purchase price. These purchases increased the Ohio Power annual and seasonal NOx allowance carrying costs.

[47] Clean Air Interstate Rule (CAIR) was initially vacated but then reinstated pending an appropriate replacement rule. To replace CAIR, EPA signed the Cross State Air Pollution Rule (CSAPR) on July 6, 2011 which placed limits on state-wide emissions of NO_X and SO_2 beginning in 2012. However, 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. In a subsequent decision, the US Court of Appeals vacated CSAPR and returned to the CAIR program limitations. EPA appealed this decision to the US Supreme Court. Oral arguments were recently heard by the court; the court's decision is pending.

Ohio Power emissions for 2012-2013 are shown in Exhibit 5-1.

Exhibit 5-1
Ohio Power Emissions, 2012 and 2013

Plant	SO2 Tons		Seasonal NOx Tons		Annual NOx Tons	
	2012	2013	2012	2013	2012	2013
Amos 3	1,026	2,356	410	616	1,032	1,836
Beckjord 6	5,105	3,822	229	147	498	420
Cardinal 1	2,710	4,640	369	485	644	1,214
Conesville	11,588	5,590	3,930	4,653	7,855	9,377
Darby	-	-	59	-	59	-
Gavin	31,185	28,113	2,716	3,448	7,239	8,249
Kammer	19,691	10,458	1,915	860	3,849	1,941
Lawrenceburg	13	4	129	54	316	152
Mitchell	3,455	2,441	805	660	1,866	1,678
Muskingum River	36,104	33,019	1,012	849	2,650	1,956
Picway	67	1,031	11	166	11	166
Sporn 2,4, 5	4,758	3,771	299	300	714	603
Stuart	2,218	2,920	990	993	1,966	2,239
Waterford	9	9	85	71	187	154
Zimmer	2,998	4,582	487	1,077	1,598	2,737
Total	**120,927**	**102,756**	**13,446**	**14,379**	**30,484**	**32,722**

Source: EVA 2012/2013-1-30

These emission levels are below the plant emission allocations for each year of the audit period because of the large prior investments in post combustion controls. As shown in Exhibit 5-2, Ohio Power has ownership interests in 14 coal units with flue gas desulfurization controls to reduce SO2 emissions (Amos #3, Cardinal #1, Conesville #4-6, Gavin #1-2, Mitchell #1-2, Stuart #1-4 and Zimmer #1). All of the remaining Ohio Power coal plants without scrubbers are scheduled to retire because of the costs associated with complying with the new EPA Mercury and Air Toxics Standard (MATS). Unless CSAPR or an alternative is reinstated, the Ohio Power system will continue to accumulate excess allowances.

A similar story exists for the current NOx requirements. Ohio Power units also over-complied with their seasonal and annual NOx allocations during the audit period because of their large investment in post combustion selective catalytic reduction (SCR) controls. With the pending coal unit retirements, Ohio Power will be left with only two units (Conesville #5-6) without the advanced SCR controls. As discussed above, Ohio Power has determined that the [redacted]. AEP indicated it is still investigating solutions. With the future planned retirements, Ohio Power system will continue to over-comply with its existing seasonal and annual NOx requirements and the growth of their surplus NOx allowance banks will accelerate.

Exhibit 5-2
Status Of Environmental Retrofits On Ohio Power Units

Plant	Unit	SCR	FGD/ FGD Upgrade	Retirement
Amos	3	2002	2009	
Cardinal	1	2003	2008	
Conesville	3			2012
Conesville	4	2009	2009	
Conesville	5		2006	
Conesville	6		2008	
Gavin	1-2	2001	1995	
Kammer	1-3			2015
Mitchell	1-2	2007	2007	
Muskingum Rv	1-4			2015
Muskingum Rv	5	2005		2015
Picway	5			2015
Sporn	2			2015
Sporn	4	2008		2015
Sporn	5			2012

The emission banks for Ohio Power as of the start and end of each of the audit periods are summarized in Exhibit 5-3. [redacted]

Exhibit 5-3
End of Year Ohio Power Emission Allowance Banks

[redacted]

These inventory balances and value changes are primarily attributable to the emission trading activity. As is shown in Exhibit 5-4, Ohio Power was both selling and purchasing emission allowances throughout the audit period. Overall, Ohio Power [redacted] By the end of the audit period, Ohio Power still held [redacted] and maintained a little less than a [redacted] The allowance inventory had a [redacted]. However, given the continued depressed allowance market prices in [redacted] the Ohio Power inventory had a year-end current market value of [redacted].

Exhibit 5-4
Allowance Activity During Audit Period (Tons)

[redacted]

Given its [redacted], Ohio Power did not need to [redacted]. However, due to obligations created under the Interim Allowance Agreement (Modification 1), covering emissions from power trading and prior allowance trading contract activity, Ohio Power did have obligations for both selling and purchasing SO2 allowances. Overall, with [redacted]

AEP also sold [redacted] The monthly sales prices during this period closely matched [redacted]. Because Ohio Power received most allowances [redacted], the AEP inventory carrying costs were [redacted]. However, in [redacted], AEP-Ohio was [redacted] This purchase price was [redacted]. As a result, the [redacted]). Across the audit period, the net annual NOx trading activity resulted in a net [redacted]

AEP both sold [redacted] and purchased [redacted] seasonal NOx allowances during the audit period. Like the annual NOx allowances, its sales prices [redacted] The high purchase price under the [redacted].

At the end of 2013, the regulated Ohio Power generation assets including the emission allowance banks were transferred to an AEP Generation Resources. The emission allowance banks were transferred at the lower of book or market value.

Forecast of Consumption of Emission Allowances

Ohio Power's current forecast of SO_2 emission allowance consumption for 2014 is summarized on Exhibit 5-5 for its ownership share. Beginning in 2010, two allowances must be forfeited for each ton of SO_2 emitted. [redacted]

Exhibit 5-5
Forecast of SO_2 Emission Allowance Consumption

[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 [redacted] The material is delivered [redacted].

AEPSC has multiple consumable contracts in place. 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.

Exhibit 5-7
Consumable Contract Summary

[redacted]

6 POWER PLANT PERFORMANCE

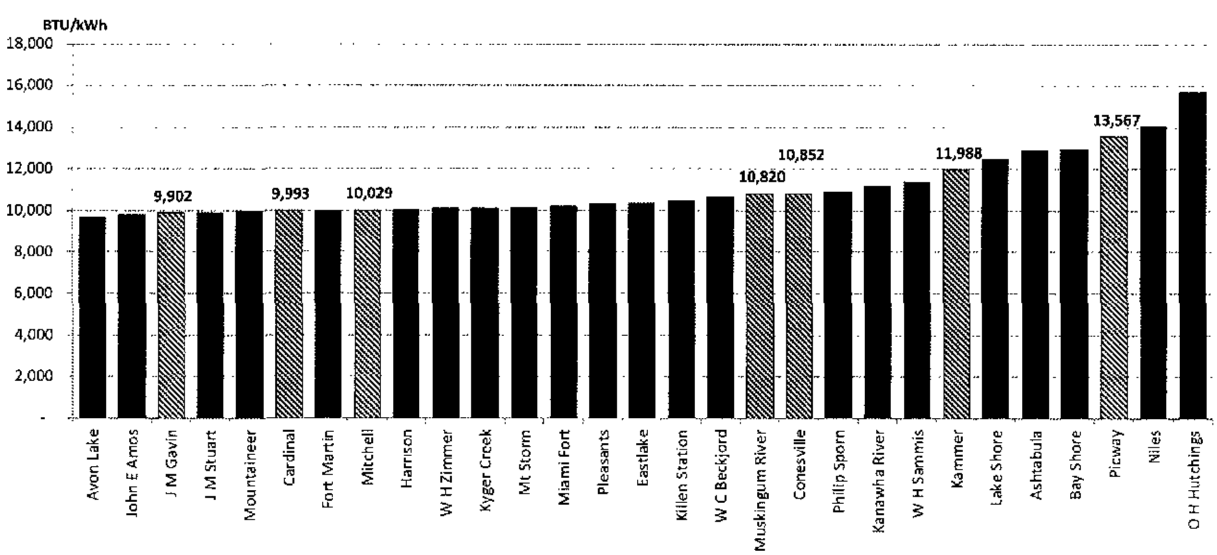
Benchmarking

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.

2012 Performance

The heat rates for the Ohio Power plants compared to the heat rates for the other coal-fired plants in Ohio and West Virginia is provided for 2012 in Exhibit 6-1.[48] The data used to generate these figures are from the Department of Energy.[49] The Ohio Power plants are highlighted. In 2012, Gavin had the third best heat rate out of the group and three of Ohio Power's plants were in the top 10.

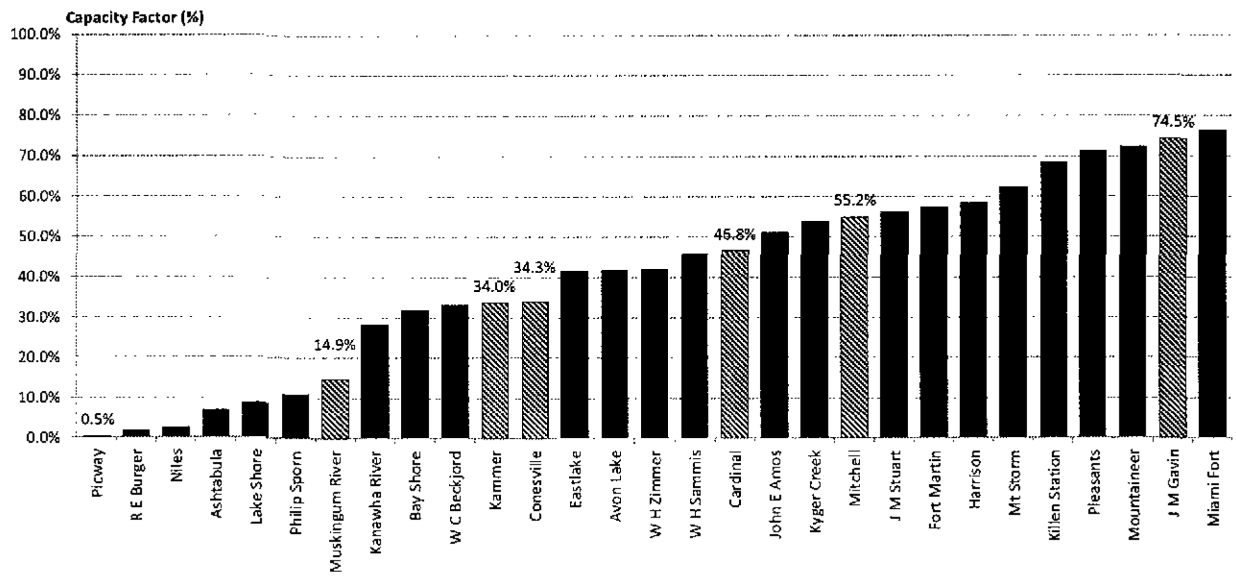
Exhibit 6-1
Coal-Fired Power Plant Heat Rates.[50] 2012



[48] Longview is not included.
[49] All of the data (AEP and other plants) come from 2012 EIA-923 (generation and MMBtu) and EIA-860 (capacity). Picway data is not reported to EIA.
[50] The heat rates are calculated based upon generation and MMBtu consumption from EIA 923.

The capacity factors for the same units for 2012 are provided in Exhibit 6-2. Gavin had the highest capacity factor of the Ohio Power unit at 74.5 percent with only one other plant above a 50 percent capacity factor. Cardinal's capacity factor is unusually low, down from 51 percent in 2012, due to the outage related to the scrubber, that were resolved in 2012. 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 suffered significantly 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.[51]

Exhibit 6-2
Coal-Fired Power Plant Capacity Factors 2012



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

Exhibit 6-3 provides the heat rates for all PJM coal-fired plants in 2012. Three Ohio Power plants fall in the top third indicating their competitiveness assuming competitively priced fuel.

The relative heat rate rankings for the Ohio Power units with respect to total generation are provided on Exhibit 6-4 for 2012. This graph is a better measure of the competitiveness of the Ohio Power units.

[51] 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.

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, Kammer, and Muskingum River are Ohio Power's marginal units.

Exhibit 6-3
PJM Coal-Fired Power Plant Heat Rates 2012

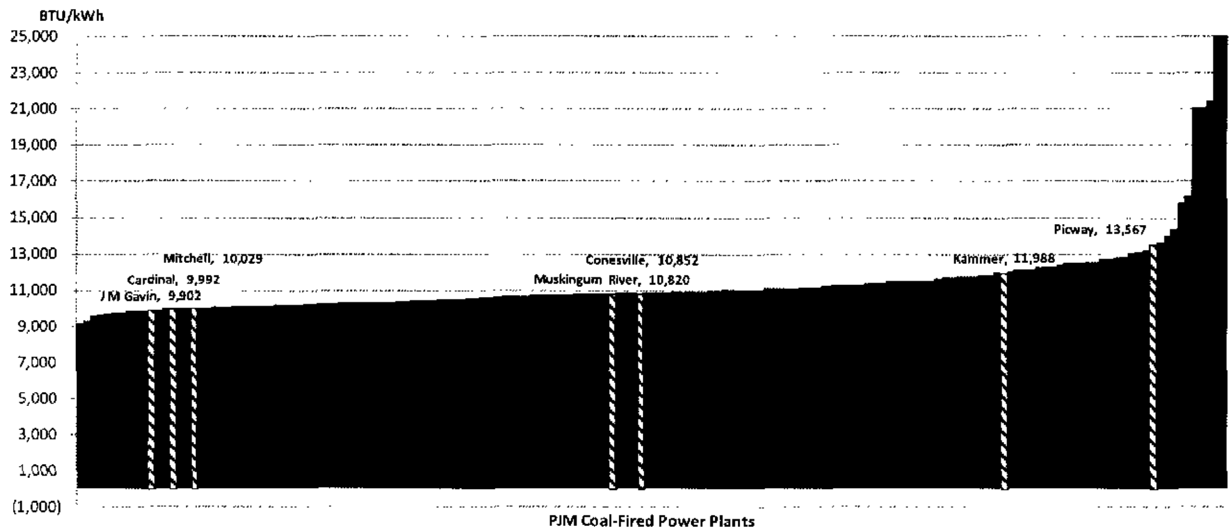
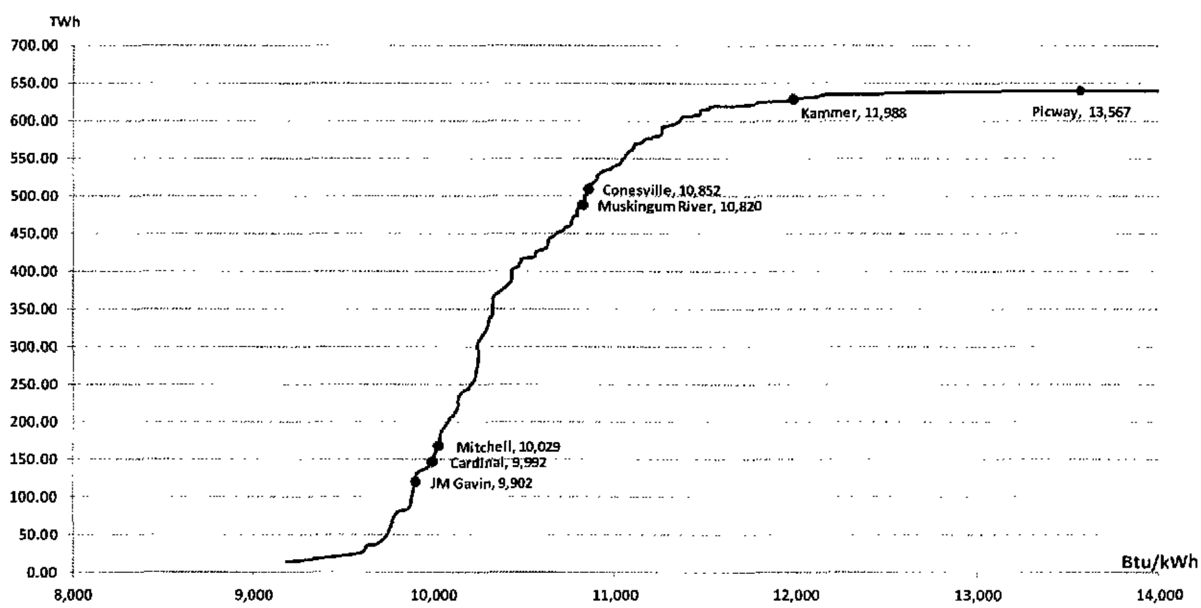


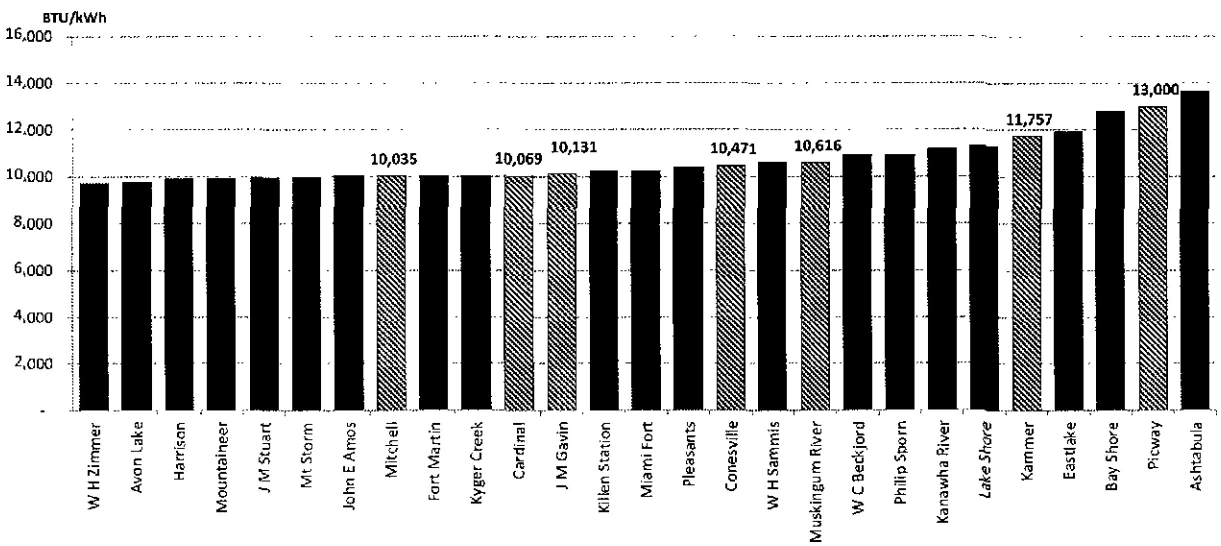
Exhibit 6-4
PJM Coal-Fired Power Plant Cumulative Generation by Heat Rate, 2012



2013 Performance

The heat rates for the AEP Ohio plants compared to the heat rates for the other coal-fired plants in Ohio and West Virginia are provided for 2013 in Exhibit 6-5.[52] The data used to generate these figures are from the Department of Energy.[53] The AEP Ohio plants are highlighted. In 2013, Mitchell had the best heat rate out of the AEP Ohio plants. Cardinal and Gavin saw average heat rates rise marginally in 2013, eroding each plant's competitiveness against other WV and OH plants, though both plants remain at the top of AEP-Ohio's stack of coal plants in terms of heat rate competitiveness.

Exhibit 6-5
Coal-Fired Power Plant Heat Rates.[54] 2013



The capacity factors for the same units for 2013 are provided in Exhibit 6-6. Cardinal had the highest capacity factor of the AEP Ohio unit at 69.8 percent, followed closely by Gavin at 67.8 precent. Cardinal's capacity factor is up from 2012., 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 suffered significantly 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.[55]

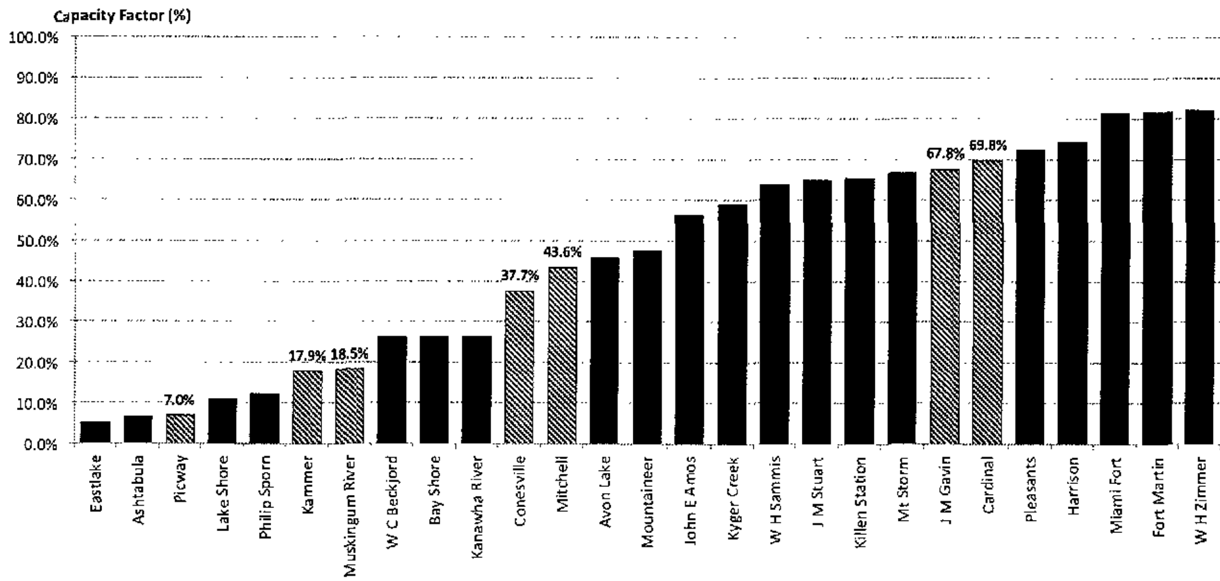
[52] *Longview is not included.*

[53] All of the data (AEP and other plants) come from 2013 EIA-923 (generation and MMBtu) and EIA-860 (capacity). Picway data is not reported to EIA.

[54] The heat rates are calculated based upon generation and MMBtu consumption from EIA 923.

[55] 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 6-6
Coal-Fired Power Plant Capacity Factors 2013



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 6-7 provides the heat rates for all PJM coal-fired plants in 2013. Three AEP Ohio plants fall in the first quartile, 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 6-8 for 2013. 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, Kammer, and Muskingum River are AEP Ohio's marginal units.

Exhibit 6-7
PJM Coal-Fired Power Plant Heat Rates 2013

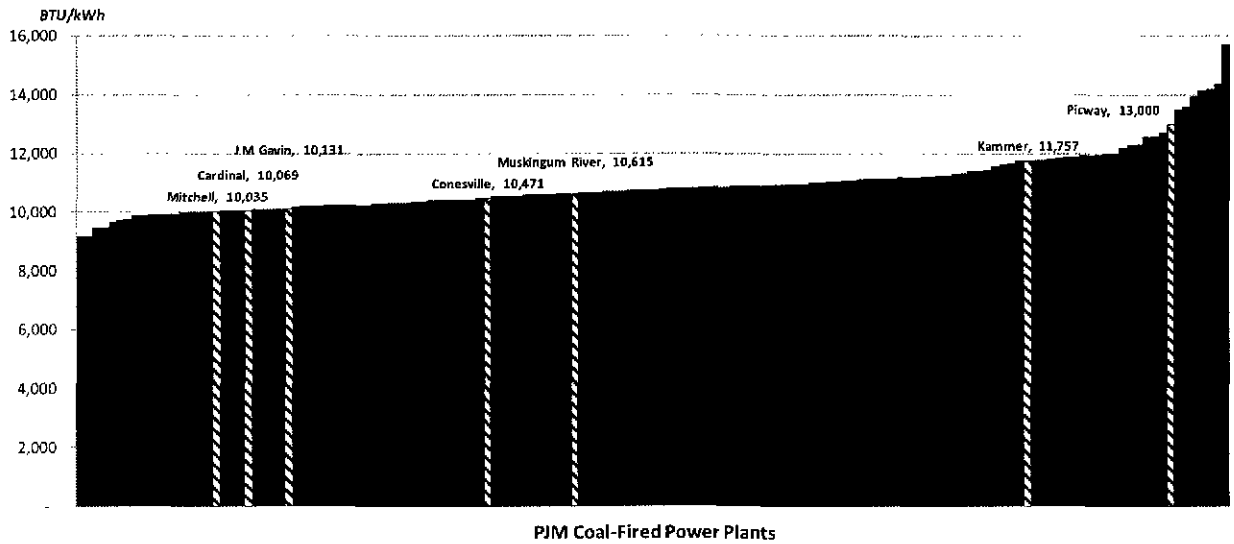


Exhibit 6-8
PJM Coal-Fired Power Plant Cumulative Generation by Heat Rate, 2013