STITES & HARBISON PLLC
ATTORNEYS

421 West Main Street
Post Office Box 634
Frankfort, KY 40602-0634
[502] 223-3477
[502] 223-4124 Fax
www.stites.com

July 28, 2006

RECEIVED
JUL 2 8 2006
PUBLIC SERVICE COMMISSION

Bruce F. Clark
(502) 209-1214
(502) 223-4386 FAX
bclark@stites.com

Ms. Beth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602

Re: PSC Case No. 2006-00307

Dear Ms. O'Donnell:

Please find enclosed an original and nine (9) copies of Kentucky Power Company's Application, Direct Testimony and Exhibits in Case No. 2006-00307.

If you have any questions concerning this filing, please let me know.

Sincerely,

STITES & HARBISON, PLLC

Bruce F Clark

Bruce F. Clark

cc: Elizabeth E. Blackford
Michael L. Kurtz
Errol K. Wagner

KE057:KE113:14474:1:FRANKFORT

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

JUL 28 2006

PUBLIC SERVICE
COMMISSION

IN THE MATTER OF:

| | | |
|---|---|---|
| THE APPLICATION OF KENTUCKY POWER COMPANY | ) | |
| FOR APPROVAL OF AN | ) | |
| AMENDED COMPLIANCE PLAN FOR PURPOSES | ) | CASE NO. |
| OF RECOVERING ADDITIONAL COSTS OF | ) | 2006-00307 |
| POLLUTION CONTROL FACILITIES AND TO AMEND ITS | ) | |
| ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF | ) | |

APPLICATION, DIRECT TESTIMONY AND EXHIBITS

**July 28, 2006**

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

| | | |
|---|---|---|
| THE APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF AN | ) | |
| AMENDED COMPLIANCE PLAN FOR PURPOSES | ) | CASE NO. |
| OF RECOVERING ADDITIONAL COSTS OF | ) | 2006-00307 |
| POLLUTION CONTROL FACILITIES AND TO AMEND ITS | ) | |
| ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF | ) | |

APPLICATION

Kentucky Power Company ("KPCo" or the "Company"), pursuant to KRS 278.183, hereby applies to the Public Service Commission for approval of its Third Amended Environmental Compliance Plan and its proposed Third Amended Environmental Surcharge Tariff (Tariff E.S.) to include the cost of pollution control projects that are required by the Federal Clean Air Act as amended and by other applicable laws relating to coal combustion wastes and borne by the Company pursuant to FERC-approved agreements between KPCo and certain of its sister American Electric Power Company, Inc. ("AEP") companies. In support of this application, KPCo states as follows:

1. **Address:** The applicant's full name and post office address is: Kentucky Power Company, 101A Enterprise Drive, P.O. Box 5190, Frankfort, Kentucky 40602-5190.

2. **Articles of Incorporation:** A certified copy of the Articles of Incorporation of Kentucky Power Company, and all amendments thereto, are on file with the Commission in Case No. 99-149 as Exhibit "J" and are incorporated by reference herein.

3. KPCo is a public utility engaged in generating, transmitting and distributing electric service in 20 counties in Eastern Kentucky. The proposed environmental surcharge will apply to the retail service provided to customers in KPCo's entire service area.

4. KPCo is a subsidiary of AEP and is a member of the integrated AEP System.

5. Pursuant to KRS 278.183, KPCo is entitled to the recovery of its costs of complying with the Federal Clean Air Act as amended and those federal, state or local environmental requirements which apply to coal combustion wastes and by-products from facilities used to generate electricity from coal in accordance with KPCo's compliance plan. KPCo's environmental costs include a reasonable return on construction and other capital expenditures and reasonable operating expenses for any plant, equipment, property, facility or other cost incurred to comply with applicable environmental requirements, including all costs of operating and maintaining environmental facilities, income taxes, property taxes other applicable taxes and depreciation expense.

6. The generation of electricity through the combustion of coal produces several wastes or by-products. The primary emissions in flue gases from coal-fired boilers are sulfur dioxide ($SO_2$), nitrogen oxide ($NO_x$) and fly ash. In addition, the operation of SCRs results in an increase of $SO_3$ emissions which, when combined with atmospheric $H_2O$, forms $H_2SO_4$ (sulfuric acid mist), which is a regulated pollutant under the CAA. Furthermore, the operation of the Flue Gas Desulphurization ("FGD" or "scrubber") facilities being constructed by Ohio Power Company, a sister company of KPCo, will create, as a waste byproduct, large quantities of CaSO4-2H20 (gypsum), the disposal of which is regulated by federal and state environmental laws.

7. KPCo's initial Environmental Compliance Plan (Case No. 96-489) ("Original Environmental Compliance Plan") consisted of the following components: (a) low $NO_x$ burners at Big Sandy Unit 2; (b) low $NO_x$ burners at Big Sandy Unit 1; (c) continuous emissions monitors at Big Sandy Plant; (d) scrubbers at Gavin Plant; (e) $SO_2$ allowances purchased; (f) Kentucky air emissions fee for Big Sandy Plant; (g) continuous emissions monitors at Rockport plant; and (h) Indiana air emission fees at Rockport Plant. Each component of the Environmental Compliance Plan is necessary in order for the Company to comply with the Federal Clean Air Act as amended and those federal, state or local regulations applicable to current combustion wastes and by-products from power plants.

8. KPCo's Amended Environmental Compliance Plan of 2002 (Case No. 2002-00169) ("First Amended Environmental Compliance Plan") consisted of the items contained in the Original Environmental Compliance Plan (filed in Case No. 96-489) plus the following additional components: (a) over-fire air with water injection and boiler tube overlays at Big Sandy Unit 1; (b) precipitator improvements at Big Sandy Unit 2; (c) selective catalytic reduction (SCR) at Big Sandy Unit 2; and (d) $NO_x$ allowances purchased. Each component of the First Amended Environmental Compliance Plan was necessary in order for the Company to comply with the Federal Clean Air Act as amended and those federal, state or local regulations applicable to current combustion wastes and by-products from power plants.

9. KPCo's Second Amended Environmental Compliance Plan of 2005 ("Second Amended Compliance Plan") consisted of the items contained in the Original Environmental Compliance Plan (filed in Case No. 96-489) and in the First Amended Compliance Plan (filed in Case No. 2002-00169) plus the additional NOx pollution control compliance

technology and Title V Air Emission Fees required at the other KPCo's sister utilities in the AEP System to the extent that KPCo is responsible for the cost of those facilities through either the FERC-approved Unit Power Agreement charges for the Rockport Units or the capacity equalization charges under the FERC-approved AEP Interconnection Agreement that governs the AEP System's Pool Capacity settlement.

10. KPCo's Third Amended Compliance Plan, Exhibit 1 hereto, consists of the items contained in the Original Environmental Compliance Plan (filed in Case No. 96-489), in the First Amended Compliance Plan (filed in Case No. 2002-00169), and in the Second Amended Compliance Plan (filed in Case No. 2005-00068), plus the installation of additional NOx pollution control compliance technology, the installation of $SO_3$ mitigation technology, the installation or expansion of solid waste disposal facilities, and coal blending facilities. These environmental projects are being installed by KPCo sister utilities, and KPCo is responsible for its appropriate portion of the cost of those facilities through either the FERC-approved Unit Power Agreement (for the Rockport Units) or the capacity equalization charges paid by KPCo under the FERC-approved Interconnection Agreement that governs the AEP System's Pool Capacity settlement.

11. The pollution control items set forth in Paragraph 10 and included in KPCo's Third Amended Environmental Compliance Plan are necessary for compliance with regulations promulgated by the United States Environmental Protection Agency pursuant to the Federal Clean Air Act ("the Act") as amended and with state regulations promulgated in conformity with the Act, as well as with federal, state and local regulations applicable to coal combustion wastes and by-products from power plants.

12. A detailed statement of the facts and compliance requirements supporting this application is set forth in the Company's direct testimony and exhibits of Company witnesses Errol K. Wagner and John M. McManus which accompany this application and by this reference are incorporated herein.

13. The proposed Revised Environmental Surcharge Tariff, the Third Amended Environmental Compliance Plan, and a complete copy of this Application and supporting testimony and exhibits are available for public inspection at the Frankfort, Ashland, Hazard and Pikeville offices of KPCo. The Company is giving notice to the public of the proposed environmental surcharge by newspaper publication. An initial Certificate of Notice and Publication is filed with this application (Exhibit 2, hereto) and a Certificate of Completed Notice and Publication will be filed with the Commission upon the completion of this notice.

14. The proposed Amended Tariff E.S.-First Revised Sheet Nos. 29-1, 29-4 and 29-5 will allow the Company to recover the costs of complying with the Federal Clean Air Act as amended and other applicable laws at facilities used to generate electricity from coal for KPCo in accordance with the Company's Third Amended Environmental Compliance Plan.

15. KPCo's total additional environmental cost for the projects at the AEP System plants in the Third Amended Environmental Compliance Plan is approximately $11.8 million. The projected annual revenue requirement for the new projects is approximately $8.3 million which represents an increase of approximately 2.05% for Kentucky retail customers.

WHEREFORE, pursuant to KRS 278.183, KPCo hereby requests the Commission to approve the proposed Third Amended Environmental Compliance Plan and proposed Tariff E. S., Sheet Nos. 29-1, 29-4 and 29-5 to become effective for bills rendered on and after August 28, 2006.

Respectfully submitted,

Bruce F. Clark

Bruce F. Clark
Michele M. Whittington
R. Benjamin Crittenden
STITES & HARBISON, PLLC
421 West Main Street
P.O. Box 634
Frankfort, Kentucky 40602-0634
Telephone: 502-223-3477

Kevin F. Duffy
American Electric Power Service Corporation
Legal Department, 29th Floor
One Riverside Plaza
Columbus, Ohio 43215
Telephone: 614-223-1000

COUNSEL FOR:
KENTUCKY POWER COMPANY

**Kentucky Power Company's**
**Third Amended Environmental Compliance Plan**
**Pursuant to KRS 278.183**



| Project | Pollutant | Description | Year | |
|---|---|---|---|---|
| 1 | NOx | Low NOx Burners at Big Sandy Unit 2 | 1994 | |
| 2 | NOx | Low NOx Burners at Big Sandy Unit 1 | 1998 | |
| 3 | $SO_2$/NOx | Continuous Emission Monitors at Big Sandy Plant | 1994 | |
| 4 | $SO_2$ | Scrubbers at Gavin Plant | 1995 | |
| 5 | $SO_2$ | $SO_2$ Allowances Purchased | 1995 | |
| 6 | $SO_2$/NOx/ Particulates | Kentucky Air Emissions Fee for Big Sandy Plant | Annual | |
| 7 | $SO_2$/NOx | Continuous Emission Monitors at Rockport Plant | 1994 | |
| 8 | $SO_2$/NOx/ Particulates | Indiana Air Emission Fee at Rockport Plant | Annual | |
| 9 | NOx | Over-Fire Air Water Injection w/Boiler Tubes Overlays at Big Sandy Unit 1 | 2002 | |
| 10 | Particulates | Precipitator Improvements at Big Sandy Unit 2 | 2002 | |
| 11 | NOx | Selective Catalytic Reduction at Big Sandy Unit 2 | 2003 | |
| 12 | NOx | NOx Allowances Purchased | 2004 | |
| | | **Kentucky Power's share of the Pool Capacity Costs associated with the following:** | | |
| 13 | $SO_2$/NOx/ Particulates | Amos Unit No. 3 CEMS, Low NOx Burners, SCR, FGD, Landfill, Coal Blending Facilities and SO3 Mitigation | 1995-98-2003-2007 | (T) |
| 14 | $SO_2$/NOx/ Particulates | Cardinal Unit No 1 CEMS, Low $NO_x$ Burners, SCR, FGD, Landfill and SO3 Mitigation | 1994-1998-2003-2004-2008 | (T) |
| 15 | NOx | Gavin Plant SCR, SCR Catalyst Replacement and SO3 Mitigation | 2005-2006 | (T) |
| 16 | NOx | Gavin Unit No 1 and 2 Low NOx Burners | 1999 | |
| 17 | $SO_2$/NOx/ Particulates | Kammer Unit Nos 1,2 and 3 CEMS, Over Fire Air and Duct Modification | 1999-2003 | |
| 18 | NOx | Mitchell Unit Nos 1 and 2 Water Injection, Low NOx Burners, Low NOx Burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and SO3 Mitigation | 1993-1994-2002-2007 | (T) |
| 19 | $SO_2$/NOx/ Particulates | Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypson Material Handling Facilities | 1993-2004-2007 | (T) |
| 20 | NOx | Muskingum River Unit No 1 Low NOx Ductwork, Over Fire Air, Over Fire Air Modification, Water Injection and Water Injection Modification | 2000-2003-2004 | |
| 21 | NOx | Muskingum River Unit No 2 Low Lox Ductwork, Over Fire Air, Over Fire Air Modification and Water Injection | 2000-2004 | |
| 22 | NOx | Muskingum River Unit 3 Over Fire, Over Fire Air Modification with NOx Instrumentation | 2000-2003-2004 | |
| 23 | NOx | Muskingum River Unit No 4 Over Fire Air with Modification | 2000-2004 | |

**Kentucky Power Company's**
**Third Amended Environmental Compliance Plan**
**Pursuant to KRS 278.183**



| Project | Pollutant | Description | Year | |
|---|---|---|---|---|
| 24 | $SO_2$/NOx | Muskingum River Unit No 5 Low NOx Burner with Modification and Weld Overlays, an SCR and SO3 Mitigation | 1994-2004-2005 | (T) |
| 25 | $SO_2$/NOx/ Particulates | Muskingum River Common CEMS | 1993 | |
| 26 | NOx | Phillip Sporn Unit No 2 Low NOx Burners with Modifications | 1997-2003 | |
| 27 | NOx | Phillip Sporn Unit No 4 and 5 Low NOx Burners and Modulating Inject. Air System with Modifications | 1998-1999-2004 | |
| 28 | $SO_2$/NOx/ Particulates | Phillip Sporn Common CEMS, SO3 Injection System and Landfill | 1994-2003-2008 | (T) |
| 29 | NOx | Rockport Unit No 1 and 2 Low NOx Burners,Over Fire Air amd Landfill | 2003-2008 | (T) |
| 30 | NOx | Tanners Creek Unit No 1 Low NOx Burners with Modifications and Low NOx Burners Leg Replacements | 1995-2004 | |
| 31 | NOx | Tanners Creek Unit No 2 and 3 Low NOx Burners with Modifications | 1998-1999-2003-2004 | |
| 32 | NOx/Particulates | Tanners Creek Unit No 4 Over Fire Air, Low NOx Burners and ESP Controls Upgrade | 2002-2004 | |
| 33 | $SO_2$/NOx/ Particulates | Tanners Creek Common CEMS and Coal Blending Station | 1995-1996-2006 | (T) |
| 34 | $SO_2$/NOx/ Particulates/VOC and etc. | Title V Air Emission Fees at Amos, Cardinal, Gavin, Kammer, Mitchell, Muskingum River, Phillip Sporn. Rockport and Tanners Creek plants | Annual | |

# NOTICE TO CUSTOMERS
# OF
# KENTUCKY POWER COMPANY
# PROPOSED CHANGES TO THE ENVIRONMENTAL SURCHARGE TARIFF

*PLEASE TAKE NOTICE* that on July 28, 2006, Kentucky Power Company (KPCo) will file with the Kentucky Public Service Commission (the Commission) in Case No. 2006-00307 an Application pursuant to Kentucky Revised Statutes 278.183 for authorization to make changes to the environmental surcharge for customer bills rendered on and after August 28, 2006 in accordance with proposed changes to Tariff E.S. KPCo is requesting the Commission to approve the proposed changes to the Tariff E.S. This tariff contains the environmental surcharge ratemaking formula and other terms and conditions. The proposed changes, if approved, will allow KPCo to apply a surcharge to all customer bills rendered on and after August 28, 2006 to recover additional cost of complying with the Federal Clean Air Act and other federal and state or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal in accordance with KPCo's environmental compliance plan.

The full terms and conditions and ratemaking formula of Tariff E.S. are set forth below:

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., S.G.S., M.G.S., M.G.S.-T.O.D., L.G.S., Q.P., C.I.P.-T.O.D., C.S.- I.R.P., M.W., O.L., and S.L.

RATE.

1. The environmental surcharge shall provide for monthly adjustments based on a percent of revenues equal to the difference between the environmental compliance costs in the base period as provided in Paragraph 3 below and in the current period according to the following formula:

$$\text{Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m)}}{\text{KY Retail R(m)}}$$

Where:

Net KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.

(For purposes of this formula, Total Company Revenues do not include Non-Physical Revenues.)

KY Retail R(m) = Kentucky Retail Revenues for the Expense Month.

2. Monthly Environmental Surcharge Gross Revenue Requirement, E(m)

$$E(m) = CRR - BRR$$

Where:

CRR = Current Period Revenue Requirement for the Expense Month.

BRR = Base Period Revenue Requirement.

3. Base Period Revenue Requirement, BRR

BRR = The Following Monthly Amounts:

| Billing Month | Base Net Environmental Costs |
|---|---|
| JANUARY | $ 2,531,784 |
| FEBRUARY | 3,003,995 |
| MARCH | 2,845,066 |
| APRIL | 2,095,535 |
| MAY | 1,514,859 |
| JUNE | 1,913,578 |
| JULY | 2,818,212 |
| AUGUST | 2,342,883 |
| SEPTEMBER | 2,852,305 |
| OCTOBER | 2,181,975 |
| NOVEMBER | 2,598,522 |
| DECEMBER | 1,407,969 |
| | $28,106,683 |

4. Current Period Revenue Requirement, CRR

$$CRR=[((RB_{KP(c)})(ROR_{KP(c)})/12) + OE_{KP(c)} + [((RB_{IM(c)})\ (ROR_{IM(c)})/12) + OE_{IM(c)}]\ (.15) - AS]$$

Where:

$RB_{KP(C)}$ = Environmental Compliance Rate Base for Big Sandy.

$ROR_{KP(C)}$ = Annual Rate of Return on Big Sandy Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.

$OE_{KP(C)}$ = Monthly Pollution Control Operating Expenses for Big Sandy.

$RB_{IM(C)}$ = Environmental Compliance Rate Base for Rockport.

$ROR_{IM(C)}$ = Annual Rate of Return on Rockport Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.

$OE_{IM(C}$ = Monthly Pollution Control Operating Expenses for Rockport.

AS = Net proceeds from the sale of $SO_2$ emission allowances, ERCs, and NOx emission allowances, reflected in the month of receipt. The $SO_2$ allowance sales can be from either EPA Auctions or the AEP Interim Allowance Agreement Allocations.

"KP(C)" identifies components from the Big Sandy Units – Current Period, and "IM(C)" identifies components from the Indiana Michigan Power Company's Rockport Units – Current Period.

The Rate Base for both Kentucky Power and Rockport should reflect the current costs associated with the 1997 Plan, the 2003 Plan and the 2005 Plan. The Rate Base for Kentucky Power should also include a cash working capital allowance based on the 1/8 formula approach, due to the inclusion of Kentucky Power's accounts receivable financing in the capital structure and weighted average cost of capital. The Operating Expenses for both Kentucky Power and Rockport should reflect the current operating expenses associated with the 1997 Plan, the 2003 Plan and the 2005 Plan.

The Rate of Return for Kentucky Power is the weighted average cost of capital as authorized by the Commission in Case No. 2005-00341.

The Rate of Return for Rockport should reflect the requirements of the Rockport Unit Power Agreement. Net Proceeds from the sale of emission allowances and ERCs that reflect net gains will be a reduction to the Current Period Revenue Requirement, while net losses will be an increase.

The Current Period Revenue Requirement will reflect the balances and expenses as of the Expense Month of the filing.

5. Environmental costs "E" shall be the Company's costs of compliance with the Clean Air Act and those environmental requirements that apply to coal combustion wastes and by-products, as follows:

(a) cost associated with Continuous Emission Monitors (CEMS)

(b) costs associated with the terms of the Rockport Unit Power Agreement

(c) the Company's share of the pool capacity costs associated with Gavin scrubber(s)

(d) return on $SO_2$ allowance inventory

(e) costs associated with air emission fees

(f) over/under recovery balances between the actual costs incurred less the amount collected through the environmental surcharge

(g) costs associated with any Commission's consultant approved by the Commission

(h) costs associated with Low Nitrogen Oxide ($NO_x$) burners at the Big Sandy Generating Plant

(i) costs associated with the consumption of $SO_2$ allowances

(j) costs associated with the Selective Catalytic Reduction (SCR) at the Big Sandy Generating Plant

(k) costs associated with the upgrade of the precipitator at the Big Sandy Generating Plant

(l) costs associated with the over-fire air with water injection at the Big Sandy Generating Plant

(m) costs associated with the consumption of $NO_x$ allowances

(n) return on $NO_x$ allowance inventory

(o) 25% of the costs associated with the Reverse Osmosis Water System (the amount is subject to adjustment at subsequent 6 month surcharge reviews based on the documented utilization of the RO Water System by the SCR.)

(p) costs associated with operating approved pollution control equipment

(q) costs associated with maintaining approved pollution control equipment including material and contract labor (excluding plant labor)

(r) the Company's share of the pool Capacity costs associated with the following:

- Amos Unit No. 3 CEMS, Low $NO_x$ Burners, SCR, FGD, Landfill, Coal Blending Facilities and SO3 Mitigation
- Cardinal Unit No 1 CEMS, Low $NO_x$ Burners, SCR, Catalyst Replacement, FGD, Landfill, and SO3 Mitigation
- Gavin Plant SCR and SCR Catalyst Replacement
- Gavin Unit No 1 and 2 Low $NO_x$ Burners and SO3 Mitigation
- Kammer Unit Nos 1, 2 and 3 CEMS, Over Fire Air and Duct Modification
- Mitchell Unit Nos 1 and 2 Water Injection, Low $NO_x$ burners, Low $NO_x$ burner Modification, SCR, FGD, Landfill, Coal Blending Facilities, and SO3 Mitigation
- Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsum Material Handling Facilities
- Muskingum River Unit No 1 Low $NO_x$ Ductwork, Over Fire Air , Over Fire Air Modification, Water Injection and Water Injection Modification
- Muskingum River Unit No 2 Low $NO_x$ Ductwork, Over Fire Air, Over Fire Air Modification and Water Injection
- Muskingum River Unit No 3 Over Fire Air, Over Fire Air Modification with $NO_x$ Instrumentation
- Muskingum River Unit No 4 Over Fire Air with Modification
- Muskingum River Unit No 5 Low $NO_x$ Burner with Modification and Weld Overlays and an SCR
- Muskingum River Common CEMS
- Phillip Sporn Unit No 2 Low $NO_x$ Burners with Modifications
- Phillip Sporn Unit No 4 and 5 Low $NO_x$ Burners and Modulating Injection Air system with Modifications
- Phillip Sporn Common CEMS, $SO_3$ Injection System, and Landfill
- Rockport Unit No 1 and 2 Low $NO_x$ Burners and Landfill
- Tanners Creek Unit No 1 Low $NO_x$ Burners, with Modifications and Low $NO_x$ Burners Leg Replacement
- Tanners Creek Unit No 2 and 3 Low $NO_x$ Burners with Modifications
- Tanners Creek Unit No 4 Over Fire Air, Low $NO_x$ Burners and ESP Controls Upgrade
- Tanners Creek Common CEMS and Coal Blending Facilities

- Title V Air Emission Fees at Amos, Cardinal, Gavin, Kammer, Mitchell, Muskingum River, Phillip Sporn, Rockport and Tanners Creek plants.

6. The monthly environmental surcharge shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

The changes to Tariff E.S. contained in this notice are proposed by KPCo. The estimated monthly effect of the proposed changes to the environmental surcharge tariff for the different customer classes are as follows:

| Customer Classification | Average Customer Consumption / Demand | Present Average Monthly Billing | Percent Change | Average Monthly Change |
|---|---|---|---|---|
| Residential Service | 1,353 KWH | $86.17 | 2.05% | $1.77 |
| Small General Service | 323 KWH | $33.58 | 2.05% | $0.69 |
| Medium General Service | 4,450 KWH / 19 KW | $326.74 | 2.05% | $6.70 |
| Large General Service | 77,667 KWH / 272 KVA | $4,652.25 | 2.05% | $95.37 |
| Quantity Power | 952,607 KWH / 2,343 KW | $41,362.08 | 2.05% | $847.92 |
| Commercial and Industrial Power Time-of-Day | 12,984,522 KWH / 22,766 KW | $472,833.69 | 2.05% | $9,693.09 |
| Municipal Waterworks | 28,879 KWH | $1,669.79 | 2.05% | $34.23 |
| Outdoor Lighting | 72 KWH | $9.53 | 2.05% | $0.20 |
| Street Lighting | 12,447 KWH | $1,418.21 | 2.05% | $29.07 |

However, the Public Service Commission may order changes to Tariff E.S. to be different from the proposed changes. Such action may result in a change in the environmental surcharge amount for customers to be different than the environmental surcharge amounts in this notice.

Any corporation, association, body politic or person may, by motion within thirty (30) days after publication or mailing of notice of the proposed changes to the environmental surcharge tariff, request leave to intervene in Case No. 2006-00307. That motion shall be submitted to the Public Service Commission, 211 Sower Boulevard, P.O. Box 615, Frankfort, Kentucky 40602-0614, and shall set forth the grounds for the request including the status and interest of the party.

Intervenors may obtain copies of the Application and testimony by contacting Kentucky Power Company at 101A Enterprise Drive, P.O. Box 5190 Frankfort, Kentucky 40602-5190, attention Errol K. Wagner. A copy of the Application and testimony is available for public inspection at KPCo's district service buildings located in Ashland, Hazard and Pikeville.

**TARIFF E.S.**
**(Environmental Surcharge)**

**APPLICABLE.**

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., S.G.S., M.G.S., M.G.S.-T.O.D., L.G.S., Q.P., C.I.P.-T.O.D., C.S.-I.R.P., M.W., O.L., and S.L.

RATE.

1. The environmental surcharge shall provide for monthly adjustments based on a percent of revenues equal to the difference between the environmental compliance costs in the base period as provided in Paragraph ~~6~~ *3* below and in the current period according to the following formula: (T)

$$\text{Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m)}}{\text{KY Retail R(m)}}$$

Where:

Net KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.

(For purposes of this formula, Total Company Revenues do not include Non-Physical Revenues.)

KY Retail R(m) = Kentucky Retail Revenues for the Expense Month.

2. Monthly Environmental Surcharge Gross Revenue Requirement, E(m)

E(m) = CRR - BRR

Where:

CRR = Current Period Revenue Requirement for the Expense Month.

BRR = Base Period Revenue Requirement.

3. Base Period Revenue Requirement, BRR

BRR = The Following Monthly Amounts:

| Billing Month | Base Net Environmental Costs |
|---|---|
| JANUARY | $ 2,531,784 |
| FEBRUARY | 3,003,995 |
| MARCH | 2,845,066 |
| APRIL | 2,095,535 |
| MAY | 1,514,859 |
| JUNE | 1,913,578 |
| JULY | 2,818,212 |
| AUGUST | 2,342,883 |
| SEPTEMBER | 2,852,305 |
| OCTOBER | 2,181,975 |
| NOVEMBER | 2,598,522 |
| DECEMBER | 1,407,969 |
| | $28,106,683 |

(Continued on Sheet 29-2)

# FOR REFERENCE ONLY NO CHANGES

**TARIFF E.S. (Cont'd)**
**(Environmental Surcharge)**

**RATE (Cont'd)**

4. Current Period Revenue Requirement, CRR

$$CRR=[((RB_{KP(c)})(ROR_{KP(c)})/12) + OE_{KP(c)} + [((RB_{IM(c)})\ (ROR_{IM(c)})/12) + OE_{IM(c)}]\ (.15) - AS]$$

Where:

| | | |
|---|---|---|
| $RB_{KP(C)}$ | = | Environmental Compliance Rate Base for Big Sandy. |
| $ROR_{KP(C)}$ | = | Annual Rate of Return on Big Sandy Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return. |
| $OE_{KP(C)}$ | = | Monthly Pollution Control Operating Expenses for Big Sandy. |
| $RB_{IM(C)}$ | = | Environmental Compliance Rate Base for Rockport. |
| $ROR_{IM(C)}$ | = | Annual Rate of Return on Rockport Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return. |
| $OE_{IM(C)}$ | = | Monthly Pollution Control Operating Expenses for Rockport. |
| AS | = | Net proceeds from the sale of $SO_2$ emission allowances, ERCs, and NOx emission allowances, reflected in the month of receipt. The $SO_2$ allowance sales can be from either EPA Auctions or the AEP Interim Allowance Agreement Allocations. |

"KP(C)" identifies components from the Big Sandy Units – Current Period, and "IM(C)" identifies components from the Indiana Michigan Power Company's Rockport Units – Current Period.

The Rate Base for both Kentucky Power and Rockport should reflect the current costs associated with the 1997 Plan and the 2003 Plan. The Rate Base for Kentucky Power should also include a cash working capital allowance based on the 1/8 formula approach, due to the inclusion of Kentucky Power's accounts receivable financing in the capital structure and weighted average cost of capital. The Operating Expenses for both Kentucky Power and Rockport should reflect the current operating expenses associated with the 1997 Plan, the 2003 Plan and the 2005 Plan.

The Rate of Return for Kentucky Power is the weighted average cost of capital as authorized by the Commission in Case No. 2005-00341.

(Cont'd on Sheet 29-3)

**FOR REFERENCE ONLY NO CHANGES**

**TARIFF E.S. (Cont'd)**
**(Environmental Surcharge)**

**RATE (Cont'd)**

The Rate of Return for Rockport should reflect the requirements of the Rockport Unit Power Agreement.

Net Proceeds from the sale of emission allowances and ERCs that reflect net gains will be a reduction to the Current Period Revenue Requirement, while net losses will be an increase.

The Current Period Revenue Requirement will reflect the balances and expenses as of the Expense Month of the filing.

5. Environmental costs "E" shall be the Company's costs of compliance with the Clean Air Act and those environmental requirements that apply to coal combustion wastes and by-products, as follows:

(a) cost associated with Continuous Emission Monitors (CEMS)

(b) costs associated with the terms of the Rockport Unit Power Agreement

(c) the Company's share of the pool capacity costs associated with Gavin scrubber(s)

(d) return on $SO_2$ allowance inventory

(e) costs associated with air emission fees

(f) over/under recovery balances between the actual costs incurred less the amount collected through the environmental surcharge

(g) costs associated with any Commission's consultant approved by the Commission

(h) costs associated with Low Nitrogen Oxide ($NO_x$) burners at the Big Sandy Generating Plant

(i) costs associated with the consumption of $SO_2$ allowances

(j) costs associated with the Selective Catalytic Reduction (SCR) at the Big Sandy Generating Plant

(k) costs associated with the upgrade of the precipitator at the Big Sandy Generating Plant

(l) costs associated with the over-fire air with water injection at the Big Sandy Generating Plant

(m) costs associated with the consumption of $NO_x$ allowances

(n) return on $NO_x$ allowance inventory

(o) 25% of the costs associated with the Reverse Osmosis Water System (the amount is subject to adjustment at subsequent 6 month surcharge reviews based on the documented utilization of of the RO Water System by the SCR)

(p) costs associated with operating approved pollution control equipment

(Cont'd on Sheet 29-4)

**TARIFF E.S. (Cont'd)**
**(Environmental Surcharge)**

(q) costs associated with maintaining approved pollution control equipment including material and contract labor (excluding plant labor)

(r) the Company's share of the pool Capacity costs associated with the following:

- Amos Unit No. 3 CEMS, Low $NO_x$ Burners, SCR, *FGD, Landfill, Coal Blending Facilities and $SO_3$ Mitigation* (T)
- Cardinal Unit No 1 CEMS, Low $NO_x$ Burners, SCR, *Catalyst Replacement, FGD, Landfill and $SO_3$ Mitigation* (T)
- Gavin Plant SCR and SCR Catalyst Replacement
- Gavin Unit No 1 and 2 Low $NO_x$ Burners *and $SO_3$ Mitigation* (T)
- Kammer Unit Nos 1, 2 and 3 CEMS, Over Fire Air and Duct Modification
- Mitchell Unit Nos 1 and 2 Water Injection, Low $NO_x$ burners, Low $NO_x$ burner Modification, *SCR, FGD, Landfill, Coal Blending Facilities and $SO_3$ Mitigation* (T)
- Mitchell Plant Common CEMS, Replace Burner Barrier Valves *and Gypsom Material Handling Facilities* (T)
- Muskingum River Unit No 1 Low $NO_x$ Ductwork, Over Fire Air , Over Fire Air Modification, Water Injection and Water Injection Modification
- Muskingum River Unit No 2 Low $NO_x$ Ductwork, Over Fire Air, Over Fire Air Modification and Water Injection
- Muskingum River Unit No 3 Over Fire Air, Over Fire Air Modification with $NO_x$ Instrumentation
- Muskingum River Unit No 4 Over Fire Air with Modification
- Muskingum River Unit No 5 Low $NO_x$ Burner with Modification and Weld Overlay, *an SCR and SO3 Mitigation* (T)
- Muskingum River Common CEMS
- Phillip Sporn Unit No 2 Low $NO_x$ Burners with Modifications
- Phillip Sporn Unit No 4 and 5 Low $NO_x$ Burners and Modulating Injection Air system with Modifications
- Phillip Sporn Common CEMS, $SO_3$ Injection System *and Landfill* (T)
- Rockport Unit No 1 and 2 Low $NO_x$ Burners *and Landfill* (T)

(Cont'd on Sheet 29-5)

**TARIFF E.S. (Cont'd)**
***(Environmental Surcharge)***

- Tanners Creek Unit No 1 Low $NO_x$ Burners, with Modifications and Low $NO_x$ Burners Leg Replacement
- Tanners Creek Unit No 2 and 3 Low $NO_x$ Burners with Modifications
- Tanners Creek Unit No 4 Over Fire Air, Low $NO_x$ Burners and ESP Controls Upgrade
- Tanners Creek Common CEMS *and Coal Blending Facilities* (T)
- Title V Air Emission Fees at Amos, Cardinal, Gavin, Kammer, Mitchell, Muskingum River, Phillip Sporn, Rockport and Tanners Creek plants.

6. The monthly environmental surcharge shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments which shall include data and information as may be required by the Commission.

# COMMONWEALTH OF KENTUCKY

# BEFORE THE

# PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

| | | |
|---|---|---|
| KENTUCKY POWER COMPANY'S THIRD AMENDED ENVIRONMENTAL COMPLIANCE PLAN AND THIRD REVISED TARIFF | ) ) ) | Case No. 2006-00307 |

## DIRECT TESTIMONY

## OF

## JOHN M MCMANUS

July 28, 2006

DIRECT TESTIMONY OF
JOHN M. MCMANUS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

**I. Introduction**

**Q: Please state your name, position and business address.**

A: My name is John M. McManus. I am Vice President of the Environmental Services Division of the American Electric Power Service Corporation. The American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP) the parent of Kentucky Power Company (KPCO). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

**Q: Please describe your work experience.**

A: I earned a Bachelor of Science Degree in Environmental Engineering from Rensselaer Polytechnic Institute in 1976 and undertook graduate studies at the same location from 1976-77. I joined the AEPSC Environmental Engineering Division in September 1977. After holding various positions in the environmental division over the years, I was appointed as Manager-Environmental Services in December 2002 and remained in that position until April 2003. I was appointed to my current position as Vice President of Environmental Services in April 2003. In my current position, I am responsible for oversight of environmental support for all AEP generation and energy delivery facilities. I am the Company's listed Designated Representative on Title IV Acid Rain Program matters and the listed

$NO_x$ Authorized Account Representative on $NO_x$ SIP Call Program matters. I am also a registered professional engineer in the State of Ohio.

**Q: What are your responsibilities as Vice President of Environmental Services?**

A: As Vice President of the Environmental Services Department (ESD), I am responsible for leading the Department by providing overall management guidance, as well as developing and implementing a Department business plan that will enable my staff to fulfill our Department's responsibilities. The ESD has the responsibility to provide policy and technical guidance in all aspects of environmental compliance for the AEP generation fleet and Transmission and Distribution (T&D) operations. The ESD provides cost-effective and timely compliance solutions and guidance on complex environmental permitting and regulatory issues in the areas of air emissions, water quality and waste management. ESD is also the primary contact with regulatory agency personnel to resolve compliance issues, new regulation development, and permit applications.

**Q: What is the purpose of your testimony in this proceeding?**

A: The purpose of my testimony is to describe the regulatory programs that govern the reduction or control of air emissions related to the operation of AEP's coal-fired power plants, as well as those regulatory programs related to coal combustion waste and by-products. Each AEP System company, other utilities and certain industrial companies are required to comply with the Clean Air Act (CAA) program and further such companies must meet standards relating to coal combustion waste and by-products (landfills and water pollution discharges).

Also, I will describe the projects that Ohio Power Company (OPCO), Indiana Michigan Power Company (I&M) and AEP Generating Company (AEG) have or will undertake to comply with these requirements.

**Q: Are you sponsoring any exhibits?**

A: Yes. I am sponsoring Exhibit No. JMM-1, which is a list of environmental control projects that OPCO, I&M, and AEG have undertaken or plan to undertake in the future to comply with the Rules and Regulations stemming from the CAA, including the requirements of the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). Some of the related projects are also required to comply with requirements under the Clean Water Act (CWA) and the Solid Waste Disposal Act (SWDA). I provided this information to Mr. Errol Wagner because OPCO's and I&M's environmental costs impact KPCO's cost under the AEP Interconnection Agreement. A portion of the environmental cost of AEG is borne by KPCO through a Unit Power Agreement.

**Q: Have you testified in a hearing before this Commission previously?**

A: Yes. I provided both written and oral testimony on behalf of Kentucky Power Company in Case Nos. 96-489, 2002-00169 and 2005-00068. Additionally, I have provided both written and oral testimony before the Virginia State Corporation Commission, and written testimony before the West Virginia Public Service Commission.

**Q: Please describe the regulatory programs that drive the necessity for the projects listed on Exhibit No. JMM-1.**

A: The primary federal statute that drives the need for these projects is the CAA.

The CAA is divided into several sections, or Titles, which contain different types of programs that address emissions into the atmosphere with the ultimate goal of reducing the impacts on public health and the ecosystem from such emissions. Current air program requirements of Title I (protection of ambient air quality) and Title IV (acid rain control program) resulted in the installation of electrostatic precipitators (ESP) to control particulate emissions, selective catalytic reduction (SCR) or alternative combustion technologies to control or reduce $NO_x$ emissions, and the installation of Flue Gas Desulfurization Systems (FGD or scrubbers) or the institution of fuel switching to control $SO_2$. Additional reductions in $SO_2$, stricter requirements for operating $NO_x$ controls, and reductions in mercury have been adopted under Title I and are contained in the CAIR and the CAMR.

The Title IV Acid Rain Program rules were developed in response to the Clean Air Act Amendments (CAAA) of 1990. The Acid Rain program established a two-phase, market-based system designed to lower $SO_2$ emission levels. Phase I of the $SO_2$ emission reduction program went into effect in 1995 and Phase II of the program went into effect in 2000. The program uses an allowance system to "cap" national emissions from all affected electric generating units. Emission allowances represent the legal right to emit a specific amount (1 ton) of a particular pollutant. Allowances can be used, banked, traded or sold, and this market-based mechanism is intended to encourage the most cost-effective emission reductions. The Acid Rain NOx reduction program was also implemented using a two-phase approach, with the first phase becoming effective in 1996 and the second phase in 2000. Under the NOx reduction program, the rules established annual NOx emission rates that vary depending on boiler-type. In addition, the rules allow companies to comply with the applicable standards by using system-wide averaging plans.

In October 1998, EPA finalized the Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone. (Commonly called the NOx SIP Call.) The NOx SIP Call was designed to eliminate significant transport of NOx, one of the precursors of ozone, from sources within the NOx SIP Call region, which includes all of the States in which KPCO's, OPCO's, I&M's, and AEG's facilities are located. The NOx SIP Call rules generally require electric generating units within each State to reduce NOx emissions to a level roughly equivalent to a 0.15-lb/MMBtu emission rate. The NOx SIP Call reductions are only applicable during the ozone season that runs from May 1st through September 30th each year. Like the Acid Rain $SO_2$ program, the NOx SIP Call uses a regional emission "cap" and a market-based allowance trading system to encourage the most cost-effective emission reductions. The initial compliance deadline for the NOx SIP Call emission reductions was May 31, 2004.

On March 10, 2005, the U.S. Environmental Protection Agency (EPA) issued the final Clean Air Interstate Rule (CAIR). The CAIR calls for significant additional reductions of $SO_2$ and NOx from electric generating units within a 28-state region that includes all of the States in which KPCO's, OPCO's, I&M's, and AEG's facilities are located. The CAIR program is intended to help States achieve and maintain new and stricter ambient air quality standards for ozone and fine particles, and actually incorporates three cap-and-trade subprograms:

- An Ozone Season NOx reduction program that will replace the NOx SIP Call program,
- An annual NOx reduction program, and
- An annual $SO_2$ reduction program that will be administered through the Title IV Acid Rain Program.

These three programs use emission allowances that are transferable between sources. With this approach, each source is allocated a certain number of emission allowances at a level to achieve a broad-based regional reduction in emissions. If a source does not reduce its actual emissions to the allowance allocation level, it must obtain additional allowances from another source.

These reduction programs use trading of emission allowances similar to the $SO_2$ allowance program in Title IV, allowing system facilities to meet their individual emission limits through a compliance plan of installing cost effective control technologies and allowance transfers.

All three programs are effective in the States where KPCO's, OPCO's, I&M's, and AEG facilities are located. The two CAIR NOx programs will be implemented with a two-phase process in 2009 and 2015. The CAIR $SO_2$ program will be implemented in a two-phase process in 2010 and 2015.

These provisions of the CAA require the U.S. EPA or state environmental agencies to develop regulations to implement and accomplish the goal of the statute. The state requirements are then applied to individual facilities and incorporated into their permits. In some cases, both the U.S. EPA and the state agencies develop regulations on the same subject and compliance is required with the applicable requirements of each regulation.

**Q: Please describe the type of environmental facilities that are the subject of this current testimony?**

A: AEP plans to install a number of environmental facilities to maintain compliance with existing CAA requirements, to achieve compliance with future CAA requirements, and to meet its obligations under the CWA and SWDA. The types of facilities that AEP plans to install to reduce $SO_2$ emissions are FGD Systems and a Fuel Switch Project. The FGD Systems include related projects for Balanced Draft Conversion, Coal Blending Systems, Steam Generator Slag Controls, Unit Controls Modernization, FGD Purge Stream Water Treatment Systems, Gypsum Material Handling Systems, and a Forced Draft (FD) Fan Motor Replacement. AEP plans to install SCR Systems for NOx control. There are also plans to install $SO_3$ Mitigation Systems to address increases in $SO_3$ emissions associated with the installation of SCR and FGD Systems and changes in coal sulfur content. Furthermore, additional capital projects are required to improve or maintain the performance of existing environmental controls for particulate matter (PM) and NOx. These projects include an Upgrade to an Electrostatic Precipitator (ESP) Control System, Replacement of Transformer Rectifier (T/R) Sets, and Replacement of SCR Catalysts. Finally, to accommodate the solid wastes associated with the new FGD projects and continued operation of existing ESPs, AEP plans to install or expand several Solid

Waste Disposal Facilities. The environmental facilities for which cost recovery is being pursued are listed in Exhibit No. JMM-1, and each is described briefly below.

**Q: Were the environmental facilities previously mentioned chosen as the least cost options of compliance?**

A: Yes. AEP performed analyses on the AEP fleet system-wide to determine the least-cost compliance plan for meeting environmental regulations. AEP has conducted its economic analysis using a state of the art model called the multi-emissions compliance optimization model or MECO (the model). The model was developed specifically to deal with the complexity of environmental compliance decisions under multi-emissions regulations or legislation which include caps or limits on $SO_2$, NOx, Hg (mercury) and $CO_2$ emissions. The model has been set up to minimize the net present value of costs to achieve environmental compliance.

The model was developed as part of an Electric Power Research Institute (EPRI) tailored collaboration project. Charles Rivers Associates (CRA), a leading economic, and energy consulting firm, built the model. CRA is the lead economic consultant and modeler for the Edison Electric Institute (EEI). AEP specifically tailored the model for its system characteristics and individual plant input characteristics.

The key inputs to the model include emission limits and allowance balances, fuel and power prices, engineering and technical costs and parameters for emission controls and related projects at existing plants and new plants (e.g.

capital, fixed O&M, variable O&M, heat rates, etc.), system load and generation demand and planned new builds and retirements. The key outputs include a least cost compliance plan, compliance costs and projected emissions.

While the majority of the projects described in this testimony were included in the system-wide analysis described above, there are a few projects that are required to meet unit-specific emission limits which are not amenable to the system approach. These include upgrades to ESPs, replacement of transformer/rectifier sets on ESPs, replacement of SCR catalyst and expansion of existing coal byproduct disposal landfills. Such projects are managed to meet the unit-specific requirements while minimizing the cost of compliance.

**Q. What is the cost of the AEP System's overall compliance program?**

A. The bulk of the cost of on-going and future compliance results from completing the $NO_x$ SIP Call compliance program, continuing to meet Title IV $SO_2$ requirements and meeting future requirements under CAIR and CAMR. The AEP System is currently projecting capital expenditures of approximately $3.89 billion for these programs through 2010. The AEP System's strategy for the design, engineering, procurement, construction and startup/commissioning of its environmental compliance projects has resulted in SCRs being built in a timely and cost effective manner. AEP continues to use and improve prudent project and construction management practices and quality control procedures. These practices and procedures take into consideration safety, quality, cost and schedule performance to ensure our ongoing environmental projects will also be built in a timely and cost effective manner to meet applicable environmental laws and regulations.

**II. $SO_2$ Controls**

**FGD Projects**

**Q: Please provide a general discussion of the FGD Projects listed on Exhibit No. JMM-1.**

A: The FGD Projects are currently in the construction phase at several plants. The design basis of an FGD system is to provide process equipment that allows a reagent to contact the flue gas and remove the sulfur dioxide through a chemical reaction. The byproduct of the chemical process is a gypsum product that must be landfilled or, if a market exists, can be sold as a raw material for use in manufacturing wallboard. I will discuss plans for use of gypsum as a raw material and disposal of gypsum in FGD system byproduct landfills later in my testimony.

**Q: Please identify where FGD systems are being designed and installed.**

A: The FGD systems that are currently being designed and/or constructed by 2008 at OPCo facilities are Amos Unit 3, Cardinal Unit 1, and Mitchell Units 1 and 2. In addition, the following FGD systems are planned and a part of AEP's system wide compliance plan but are not subject to this filing: Appalachian Power Company's (APCO) Amos Units 1 and 2, APCO's Mountaineer Plant, Columbus Southern Power Company's (CSPCO) Conesville Unit 4, OPCO's Muskingum River Unit 5 (scheduled for 2010), and CSPCO's Stuart Units 1 – 4 (which is co-owned by Dayton Power & Light, Duke Energy and Columbus Southern Power

Company). Additionally, the following AEP units are currently operating with a FGD system: OPCO's Gavin Units 1 and 2, CSPCO's Conesville Units 5 and 6, Southwestern Electric Power Company's Pirkey Plant, Texas North Company's Oklaunion Plant and CSPCO's Zimmer Plant (which is co-owned by Dayton Power & Light, Duke Energy and Columbus Southern Power Company).

**Q: Does the installation of pollution control equipment like FGD systems result in a need for additional capital investment in a power plant?**

A: Yes. Pollution control equipment like an FGD or SCR are complex systems that must be integrated into the existing electric generating unit in order for the resulting system to operate effectively. This can require significant modifications to or upgrades of portions of the existing unit as well as addition of ancillary equipment such as FGD byproduct processing systems that must be physically fit into the existing site. Projects of this nature are often referred to as "balance of plant" work and can include conversion of the boiler to balanced draft operation, coal blending equipment installation, steam generator slag controls, upgrades to unit operating controls, FGD purge stream water treatment systems, gypsum material handling systems, and replacement of existing fan motors. These projects would not be undertaken absent the requirement to comply with current and future regulations under Title IV, 40 CFR 72 – 78 and the CAIR Program, 40 CFR 96, which in turn necessitates the installation of pollution control technology. These projects are described below.

**Balanced Draft Conversion Projects**

**Q: Please provide a general discussion of the Balanced Draft Conversion**

**projects as a result of the FGD Projects listed on Exhibit JMM-1.**

A: The installation of FGD technology requires the installation of new induced draft fans to overcome the additional system pressure drop (resistance) caused by the FGD equipment. This provides the opportunity to balance the operation of the existing forced draft fans and the new induced draft fans and to convert the furnace and gas path to operate at slightly negative pressure (balanced draft condition). Converting to balanced draft design concurrent with the FGD retrofit enables the unit to burn a wider range of lower cost coals, provides a safer work environment, and assures continued reliable unit availability, while at the same time reducing the potential for fugitive emissions to the environment.

**Q: Please identify where Balanced Draft Conversion Projects are being constructed.**

A: The Balanced Draft Conversion Projects in this filing are being constructed at Amos Unit 3, Cardinal Unit 1, and Mitchell Units 1 and 2.

**Coal Blending Projects**

**Q: Please provide a general discussion of the Coal Blending Projects included in Exhibit JMM-1.**

A: The installation of FGD technology allows greater flexibility in the range of coal quality that can be used at a controlled unit. In order to take advantage of this flexibility, and to achieve subsequent savings in fuel cost, improvements to the current coal handling systems are needed at some units. The savings associated with the wider range of lower priced coals have been analyzed as part of the economic justification for the FGD projects.

**Q: Please identify where the Coal Blending Projects are being constructed.**

A: The Coal Blending Projects in this filing are being constructed at Amos Unit 3 and Mitchell Units 1 and 2.

**Steam Generator Slag Control Projects**

**Q: Please provide a general discussion of the Steam Generator Slag Control Projects listed on Exhibit JMM-1.**

A: The flexibility to burn a wider range of coals requires equipping the steam generator with additional furnace slag control devices (water cannons and soot blowers), slag monitoring devices (high temperature camera and temperature instrumentation) and furnace tube wall corrosion protection (weld overlay) to operate satisfactorily and maintain reliability.

**Q: Please identify where Steam Generator Slag Control Projects are being constructed.**

A: The Steam Generator Slag Control Projects in this filing are being constructed at Amos Unit 3, Cardinal Unit 1, and Mitchell Units 1 and 2.

**Unit Controls Modernization Projects**

**Q: Please provide a general discussion of the Unit Controls Modernization Projects listed on Exhibit JMM-1.**

A: The FGD technology comes equipped with a state of the art digital control system. Significant modernization of existing obsolete plant control systems will be required to enable integration of the new FGD controls. The FGD projects also include steam generator slag control projects for controlling boiler slag and new fans for balanced draft operation. Significant modernization of the steam generator control system is needed to integrate this new equipment in order to achieve the overall compliance requirement and associated environmental benefit (i.e. reduction of $SO_2$ emissions). Integration of new equipment controls, monitoring routines, and protection functions with the existing main control room operator interface must be accomplished in a manner that allows an operator to perform his/her duties safely and without confusion. Efficient operation of the new FGD controls and attaining the necessary compliance standards cannot be achieved without the modernization of these controls.

**Q: Please identify where Unit Controls Modernization Projects are being constructed.**

A: The Unit Controls Modernization Projects in this filing are being constructed at Amos Unit 3, Cardinal Unit 1, and Mitchell Units 1 and 2.

**FGD Purge Stream Water Treatment Systems**

**Q: Please provide a general discussion of the FGD Purge Stream Water Treatment Systems listed on Exhibit JMM-1.**

A: The installation of FGD technology necessitates the installation of a FGD Purge Stream Water Treatment System. Evaluation of the expected characteristics of the FGD purge stream water, our current water treatment systems, and the applicable CWA and related state requirements for controlling water discharges indicates that treatment for Total Suspended Solids (TSS) and pH will be required. This treatment system will produce a solid by-product that will be disposed of in a landfill.

**Q: Please identify where FGD Purge Stream Water Treatment Systems are**

**being constructed.**

A: The FGD Purge Stream Water Treatment Systems in this filing are being constructed at Amos Unit 3, Cardinal Unit 1, and Mitchell Units 1 and 2.

**Gypsum Material Handling Systems**

**Q: Please explain the Mitchell Wallboard Facility Conveyor System listed on Exhibit JMM-1.**

A: On March 11, 2005, AEP and British PlasterBoard (BPB) executed a 25-year supply agreement for the delivery of FGD synthetic gypsum to a new BPB wallboard manufacturing facility to be located adjacent to the Mitchell Plant. This agreement requires AEP to provide a base volume of 800,000 dry tons of gypsum per year. Approximately 600,000 tons will be supplied from the Mitchell Plant with the remaining volume to be supplied from the Cardinal Plant. This gypsum supply agreement will enable AEP to avoid the costs associated with the construction, operation, closure, and post-closure care of a solid waste landfill for the disposal of gypsum produced by the Mitchell FGD Projects and will reduce the total cost for gypsum disposal at Cardinal Plant.

Providing gypsum as a raw material to a wallboard facility close to the Mitchell site from various plants, including Mitchell, is overall the most economic means of handling the gypsum produced by the FGD Projects. This project includes performing the detailed engineering, procurement, construction and commissioning of an overland gypsum conveyor from the Mitchell site to the wallboard manufacturing facility, including changes to the presently designed

FGD gypsum system, gypsum storage facility, barge unloading equipment, and miscellaneous site infrastructure facilities.

**Q: Please explain the gypsum unloading and transfer equipment at Mountaineer Plant listed on Exhibit JMM-1.**

A: In order to comply with the Title IV Acid Rain Control Program and CAIR, FGD systems will be retrofitted on units at AEP's Mitchell and Cardinal Plants. These FGD systems will produce gypsum as a by-product. Some of this gypsum will be sent to a wallboard plant near Mitchell Plant and the remainder will be disposed of in landfills. Some gypsum produced at the Mitchell Plant may not be suitable for use in the wallboard production process, and alternate disposal arrangements will need to be made. In addition, construction at the Cardinal landfill will not be completed in time for initial FGD operation, but once it is fully operational it will receive gypsum from the Cardinal FGD Project. The least cost option for these disposal needs is to place the gypsum from Mitchell and Cardinal Plants in the Mountaineer Plant's landfill in West Virginia.

In addition to the gypsum produced at Mitchell and Cardinal, both FGD Systems will require an FGD Purge Stream Water Treatment System that will produce a solid filter cake from the water treatment process. The filter cake cannot be sent to the wallboard plant and will be disposed of in a landfill. The least cost option for disposal is to place the filter cake from the Mitchell and Cardinal water treatment systems in the Mountaineer Plant's landfill in West Virginia.

In order to receive these materials from the Mitchell and Cardinal Plants, AEP plans to install barge unloading equipment at Mountaineer Plant to unload Cardinal and Mitchell gypsum/filter cake from the river barges. Once unloaded, the gypsum/filter cake will be transported via an overland conveying system to the landfill. The design of the gypsum/filter cake unloading and conveying system was developed to minimize fugitive dust from these material handling operations in accordance with CAA requirements.

**FD Fan Motor Replacement Project**

**Q: Please provide a general discussion of the FD Fan Motor Replacement Project at Cardinal Plant listed on Exhibit JMM-1.**

A: The existing FD fans at Cardinal Unit 1 will require new motors to efficiently operate and accommodate the changed operating conditions resulting from the addition of the FGD Project and Balanced Draft Operation Project. The changes include installing a smaller horsepower and slower speed motor in the fans. These changes also will result in a significant savings of auxiliary power over the existing motors. Cardinal Unit 1 will operate more efficiently, allowing power to be produced with a lower heat input, reduced coal use and lower emissions for a given generation level.

**Fuel Switch Project**

**Q: Please provide a general description of the Fuel Switch Project at Tanner's Creek Unit 4 listed on Exhibit JMM-1.**

A: Providing facilities and equipment that allow Tanners Creek Unit 4 to accommodate a higher percentage blend of low sulfur Powder River Basin (PRB) coal has resulted in a significant reduction of both $SO_2$ and NOx emissions and is part of the AEP compliance plan to meet the requirements of the Title IV Acid Rain Program and CAIR. The scope of the fuel switch project included engineering, design, equipment and materials procurement, construction, startup and commissioning to allow Unit 4 to change its fuel blend from a 40% PRB / 60% Eastern bituminous coal blend to an 80% PRB / 20% Eastern bituminous coal blend, with provisions to stage PRB levels up to 100%. It is estimated that this fuel switch will reduce $SO_2$ emissions by 25,000 to 30,000 tons per year, and reduce NOx emissions by approximately 1,200 tons per year. It is also anticipated that fuel costs will be reduced. Implementation of this project was completed in the spring of 2006.

## III. NOx Controls

### SCR Projects

**Q: Please provide a general discussion of the SCR Projects listed on Exhibit No. JMM-1.**

A: An SCR system uses a catalyst that, in the presence of ammonia, will convert $NO_x$ to nitrogen gas and water vapor. This control method reduces the NOx after it is formed in the steam generator. The ammonia reagent is injected into the flue gas stream before it passes through a catalyst. The use of a catalyst provides a much higher reagent efficiency and high $NO_x$ control efficiency (greater than 85% $NO_x$ reduction).

**Q: Please identify where SCRs are being installed.**

A: The only SCR projects included in this filing are being constructed at Mitchell

Units 1 and 2. A SCR system is planned at CSPCO's Conesville Unit 4 as part of AEP's system wide compliance plan but are not included in this filing. Additionally, the following AEP units are currently operating with a SCR system: OPCO's Gavin Units 1 and 2, APCO's Amos Units 1 and 2 & APCO/OPCO's (2/3 owned by OPCO) Amos Unit 3, APCO's Mountaineer Unit 1, KPCO's Big Sandy Unit 2, CSPCO's Stuart Units 1-4, CSPCO's Zimmer, OPCO's Cardinal Unit 1, and OPCO's Muskingum River Unit 5.

**$SO_3$ Mitigation Projects**

**Q: Please provide a general discussion of the $SO_3$ Mitigation Projects listed on Exhibit JMM-1 and explain why the $SO_3$ *mitigation* systems are included for all of the SCR and FGD projects described in this testimony.**

A: Our experience to date with operation of SCRs indicates that the use of this technology to control $NO_x$ emissions results in an increase in formation of $SO_3$, or sulfur trioxide, in the flue gas. $SO_3$, when combined with water in saturated flue gas from an FGD, produces $H_2SO_4$, or sulfuric acid mist, which is a regulated pollutant under the New Source Review Programs in Title I of the CAA ( 40 CFR 52.21, 52.24 Federal NSR Program). Use of an $SO_3$ mitigation system will prevent an increase in $H_2SO_4$ emissions associated with the installation of SCRs and FGDs by reacting the $SO_3$ with ammonia, Trona or other suitable treatment chemicals to produce particulate matter that is then collected in the ESP. The design for the SCR and FGD projects included in this filing includes $SO_3$ mitigation systems.

**Q: Are there environmental requirements associated with increased formation of $SO_3$?**

A: Yes. For many years, US EPA excluded pollution control projects like the installation of FGD and SCR systems from any Title I New Source Review Program preconstruction review or additional permitting requirements under a regulatory exclusion known as the pollution control project exclusion. This exclusion was based on the conclusion that the significant emission reductions in $SO_2$ and NOx resulting from these projects were environmentally beneficial, even if the projects caused modest increases in other regulated pollutants, like $H_2SO_4$. All of AEP's SCR and FGD projects commenced prior to 2005 relied upon this exclusion and similar provisions of state law. In June of 2005, a federal appeals court vacated this exclusion, and determined that any significant emission increases associated with a pollution control project should be subject to the applicable permitting requirements under the Federal NSR Program. US EPA sought reconsideration of that decision, which was denied in December of 2005.

Because the installation of FGD systems creates a saturated flue gas, and units previously or simultaneously equipped with SCR controls have higher $SO_3$ emission rates, the combination of increased $SO_3$ and water may increase emissions of $H_2SO_4$. Installing $SO_3$ mitigation systems, and maintaining $SO_3$ concentrations at or below their pre-SCR/FGD levels, avoids any increase in $H_2SO_4$ emissions and does not trigger the Federal NSR Program requirements. Any significant increase in $H_2SO_4$ emissions would require additional permits and control equipment under the CAA, delaying implementation and increasing the costs of compliance with CAIR.

**Q: Please identify where $SO_3$ Mitigation Projects are being constructed.**

A: The $SO_3$ Mitigation Projects in this filing currently being constructed are at Amos Unit 3, Cardinal Unit 1, and Mitchell Units 1 and 2.

**Q: Please further explain the Gavin SO3 mitigation project listed on Exhibit JMM-1 since a FGD system has previously been installed.**

A: Although the Gavin SCR and FGD installations were completed before the D.C. Circuit Court's decision vacating the pollution control exclusion, there is some uncertainty regarding whether prior projects retain their exclusion. US EPA requested clarification of this aspect of the D.C. Circuit decision, but that request was denied. Therefore, assuring that $H_2SO_4$ emissions remain below pre-SCR/FGD levels is consistent with the D.C. Circuit decision.

The Gavin Plant's $SO_3$ mitigation system required further development of the Trona system to maintain reliable operation. The project includes installing perforated plate rappers at the ESP inlet and quench air pipes to mitigate agglomeration on both units. Additionally, Gavin installed additional turning vanes at the air heater exit to reduce flow along the bottom of the duct on both units. Along with completing the Trona system at Gavin, this Capital Improvement project included designing, engineering, procuring and constructing a common storage facility for Trona.

## IV. Existing Environmental Controls

### Upgrade ESP Control System

**Q: What is the purpose of the Upgrade to the Electrostatic Precipitator (ESP) Control System at Amos Unit 3?**

A: The Amos 3 ESP currently operates with a narrow margin of compliance, and has one of the most stringent opacity limits in the AEP System - opacity is limited to 10%, within a plant wide particulate emissions limit of 0.05 lb/MMBTU set by West Virginia. With the addition of an FGD, the $SO_3$ Mitigation system, Balanced Draft Operation, and a wider range of fuel flexibility to allow Unit 3 to comply with Title IV and CAIR, AEP predicts that the existing ESP equipment will experience higher particle loading, higher flue gas velocity, and stresses from operation under negative pressure that will compromise its ability to comply with particulate emission requirements. The ESP upgrade is necessary for the facility to maintain compliance with existing particulate emissions limits. The modifications include balanced draft reinforcement, upgraded T/R sets, replacement hoppers and rebuilding 50% of the fields.

**Replacement of Transformer Rectifier Sets**

**Q: Please explain the scope of the Transformer Rectifier Set replacement project at Mitchell Unit 1 and 2 listed on Exhibit JMM-1.**

A: The transformer / rectifier sets (T/R sets) are located on the ESP roof and are designed specifically to provide the high voltage necessary for proper operation of the ESP. They consist essentially of a high voltage transformer and a solid state rectifier bridge immersed in a coolant fluid of high dielectric strength. The T/R sets on Mitchell Unit 2 will be replaced by the end of 2006. The replacement program will assure continued reliable ESP performance, eliminate multiple controls, replace undersized power cabling, and address other electrical and operating issues. In addition, the existing T/R sets contain polychlorinated biphenyls (PCBs) and have been in service for 27 years. The possibility of a PCB release to the environment is rare, but the failure rate of a T/R set increases with age, and the cost to remediate a PCB release can be significant. One half of the existing T/R sets were removed and replaced with conventional design, non-PCB T/R sets in December of 2005. The other half of the T/R sets will be replaced with high frequency, non-PCB sets in Fall 2006.

**Replacement of Catalysts**

**Q: Please explain the catalyst replacement project at Cardinal Unit 1 listed on Exhibit JMM-1.**

A: As part of the $SO_3$ Mitigation Project at Cardinal Unit 1, the existing three layers of SCR catalysts will be replaced with three layers of low $SO_2$ to $SO_3$ conversion catalyst to reduce the amount of $SO_3$ converted in the SCR. The remaining $SO_3$ levels will be reduced to the control range via use of a dry sorbent injection system. The combination of lower conversion catalyst and the dry sorbent system will assure that no increase in $H_2SO_4$ emissions occurs as a result of the FGD Project.

## V. Solid Waste Disposal Facilities

**Installations of Solid Waste Disposal Facilities**

**Q: Please explain the scope and justification of the Conner Run Impoundment Expansion Project at Mitchell Plant and Expansion Project at Rockport's flyash landfill listed on Exhibit JMM-1.**

A: The Conner Run Impoundment is the common disposal site for fly ash from both Kammer and Mitchell Plants and coal wash slurry from Consol Energy's (Consol) McElroy coal preparation plant. A disposal site for generated fly ash is required for the continued operation of both Kammer and Mitchell Plants. These facilities are required, per WV CSR, Title 33, Series 1 of Solid Waste Management Rule, to dispose of the solid wastes generated by the ESPs that control particulate emissions as required by the CAA. The current facilities are approaching their permitted capacity, and expansion is needed to assure uninterrupted operation of the Plants.

In the current regulatory environment, there are no other financially viable alternatives for disposing of the fly ash generated at Kammer and Mitchell Plants. Any change in the disposal location would require both Kammer and Mitchell plants to convert to a dry fly ash collection, transport and disposal system which is estimated to cost $44M. There is no reasonable market for the quantity and quality of ash generated at both Kammer and Mitchell Plants, which means that the ash would have to be placed in a newly permitted landfill with a liner and a leachate collection system. The expansion of the current fly ash and mine refuse impoundment, which will be accomplished by raising the impoundment dam, is clearly the most economically favorable solution for the required increase in capacity. The necessary property is already owned by AEP or Consol. Access roads, power supply and other infrastructure improvements are currently in service and suitable for continued operation and construction.

Similarly, Rockport's fly ash landfill is the sole disposal site for

Rockport's fly ash. In order for Rockport to continue to comply with its particulate emission requirements, this facility must be expanded. This is the most economically favorable solution for the required increase in disposal capacity.

**Q: Please explain the scope and justification of Amos and Cardinal landfill projects listed on Exhibit JMM-1.**

A: These three projects include engineering, designing, and constructing landfills to support the FGD projects at Amos and Cardinal. The development of these landfills is the most economical solution for disposal of our gypsum and flyash waste. The scope of work for the FGD Landfill Projects is divided into Phases. Phase 1 is preliminary engineering and design, Phase 2 is detailed engineering and design and permitting, Phase 3 is construction.

**Q: Please explain the scope and justification of Sporn landfill project listed on Exhibit JMM-1.**

A: The Sporn landfill is a shared landfill between Mountaineer and Sporn plants. The facility is used to dispose of Mountaineer and Sporn flyash, as well as future FGD waste. The scope of work includes construction of two new landfill cells, engineering, design and permitting of four new landfill cells, and completing new siting studies, site assessments, permitting, land options, and procurement for the new landfill. Capacity is needed at the landfill to continue operation.

**Q: Please explain the scope and justification for the Plant Common Project at Amos Unit 3 listed on Exhibit JMM-1.**

A: The Amos Plant Common Project includes several other FGD resulting projects that have been grouped together for internal accounting purposes. These projects include gypsum dewatering equipment, limestone preparation, auxiallary pumping station, and river work.

**Q: What are the CAA regulations and legal requirements applicable to the previously listed projects at the various facilities?**

A: The applicable CAA regulatory program for each of the environmental facilities is indicated in Exhibit JMM-1.

**Q: Is KPCo seeking recovery for the aforementioned environmental facilities pursuant to KRS 278.183 in this proceeding?**

A: Yes. These projects are necessary for the AEP Pool surplus companies as well as KPCO's share of the Rockport generating facilities to be in compliance with state and federal statutory and regulatory requirements arising from the Clean Air Act as amended and to comply with requirements for disposal of coal combustion wastes and byproducts.

**Q: Does this conclude your testimony?**

A: Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

STATE OF OHIO

CASE NO. 2006-00307

COUNTY OF FRANKLIN

AFFIDAVIT

John M. McManus, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

John M. McManus

John M. McManus

Subscribed and sworn to before me by John M. McManus this 17 day of July, 2006.

Patrick R. Ott

Notary Public

My Commission Expires December 31, 2009

Patrick R. Ott
Notary Public, State of Ohio
My Commission Expires December 31, 2009

EXHIBIT JMM-1

Kentucky Power Company
AEP Pool Surplus Companies
Investment in Environmental Facilities

| Generating Unit | Project Description | In-Service Date | New Facilities Cost ($1000s) | Applicable CAA Program |
|---|---|---|---|---|
| Amos Unit 3 | FGD | 4Q - 07 | $346,121 | Title IV Acid Rain Program |
| Amos Unit 3 | Balance Draft Conversion | 4Q - 07 | $39,923 | Title IV Acid Rain Program |
| Amos Unit 3 | Controls Modernization | 4Q - 07 | $14,141 | Title IV Acid Rain Program |
| Amos Unit 3 | Steam Generator Modifications | 4Q - 07 | $6,091 | Title IV Acid Rain Program |
| Amos Unit 3 | SO3 Mitigation | 4Q - 07 | $14,066 | NOx SIP Call |
| Amos Unit 3 | FGD Purge Stream Water Treatment System | 4Q - 07 | $9,400 | Title IV Acid Rain Program |
| Amos Unit 3 | Plant Common | 4Q - 07 | $90,797 | Title IV Acid Rain Program |
| Amos Unit 3 | Coal Blending Station | 4Q - 07 | $5,740 | Title IV Acid Rain Program |
| Amos Unit 1, 2, & 3 | Landfill | 4Q - 07 | $33,263 | Title IV Acid Rain Program |
| Amos Unit 3 | Precip Modification | 4Q - 07 | $93,365 | NOx SIP Call |
| Cardinal Unit 1 | FGD | 4Q - 07 | $216,748 | Title IV Acid Rain Program |
| Cardinal Unit 1 | Controls Modernization | 4Q - 07 | $5,930 | Title IV Acid Rain Program |
| Cardinal Unit 1 | Boiler Modification | 4Q - 07 | $6,971 | Title IV Acid Rain Program |
| Cardinal Unit 1 | Balance Draft Conversion | 4Q - 07 | $30,530 | Title IV Acid Rain Program |
| Cardinal Unit 1 | FD Fan Modification | 4Q - 07 | $1,763 | Title IV Acid Rain Program |
| Cardinal Unit 1 | FGD Purge Stream Water Treatment System | 4Q - 07 | $12,821 | Title IV Acid Rain Program |
| Cardinal Unit 1 | SO3 Mitigation | 4Q - 07 | $7,292 | NOx SIP Call |
| Cardinal Unit 1 | Catalyst Replacement | 4Q - 07 | $3,606 | NOx SIP Call |
| Cardinal Unit 1 | Landfill | 2Q - 08 | $15,703 | Title IV Acid Rain Program |
| Gavin Plant Unit 1 & 2 | SO3 Mitigation | 4Q - 06 | $9,997 | NOx SIP Call |
| Mitchell Unit 1 | FGD | 2Q - 07 | $242,906 | Title IV Acid Rain Program |
| Mitchell Unit 1 | SCR | 2Q - 07 | $133,771 | NOx SIP Call |
| Mitchell Unit 1 | Balance Draft Conversions | 2Q - 07 | $24,431 | Title IV Acid Rain Program |
| Mitchell Unit 1 | Controls Modernization | 2Q - 07 | $3,026 | Title IV Acid Rain Program |
| Mitchell Unit 1 | Steam Generator Modifications | 2Q - 07 | $10,262 | Title IV Acid Rain Program |
| Mitchell Unit 1 | SO3 Modifications | 2Q - 07 | $14,827 | NOx SIP Call |
| Mitchell Unit 1 | FGD Purge Stream Water Treatment System | 2Q - 07 | $11,624 | Title IV Acid Rain Program |
| Mitchell Unit 1 | Coal Blending Station | 2Q - 07 | $12,280 | Title IV Acid Rain Program |
| Mitchell Unit 2 | FGD | 4Q - 06 | $236,154 | Title IV Acid Rain Program |

EXHIBIT JMM-1

Kentucky Power Company
AEP Pool Surplus Companies
Investment in Environmental Facilities

| Generating Unit | Project Description | In-Service Date | New Facilities Cost ($1000s) | Applicable CAA Program |
|---|---|---|---|---|
| Mitchell Unit 2 | SCR | 2Q - 07 | $137,557 | NOx SIP Call |
| Mitchell Unit 2 | Balance Draft Conversions | 2Q - 07 | $24,431 | Title IV Acid Rain Program |
| Mitchell Unit 2 | Controls Modernization | 2Q - 07 | $3,026 | Title IV Acid Rain Program |
| Mitchell Unit 2 | Steam Generator Modifications | 2Q - 07 | $10,262 | Title IV Acid Rain Program |
| Mitchell Unit 2 | SO3 Modifications | 2Q - 07 | $14,827 | NOx SIP Call |
| Mitchell Unit 2 | FGD Purge Stream Water Treatment System | 2Q – 07 | $11,624 | Title IV Acid Rain Program |
| Mitchell Unit 2 | Coal Blending Station | 2Q - 07 | $12,280 | Title IV Acid Rain Program |
| Mitchell Unit 1 & 2 | Impoundment | 4Q – 06 | $9,844 | Title 1 National Ambient Air Quality Standards |
| Mitchell Unit 1 & 2 | Gypsum Material Handling | 1Q – 07 | $33,228 | Title IV Acid Rain Program |
| Mitchell Unit 1 & 2 | Gypsum Material Handling | 4Q – 06 | $13,123 | Title IV Acid Rain Program |
| Mitchell Unit 1 & 2 | Transformer Rectifier Set Replacement | 4Q - 06 | $8,351 | Title 1 National Ambient Air Quality Standards |
| Sporn Unit 2, 4, & 5 | Landfill | 4Q - 08 | $6,546 | Title 1 National Ambient Air Quality Standards |
| Rockport Unit 1 | Landfill | 4Q - 08 | $1,250 | Title 1 National Ambient Air Quality Standards |
| Rockport Unit 2 | Landfill | 4Q - 08 | $1,250 | Title 1 National Ambient Air Quality Standards |
| Tanners Creek Common | Coal Blending Project | 2Q - 06 | $90,637 | NOx SIP Call |
| Total Net Investment | | | $2,2376,394 | |

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE**

**PUBLIC SERVICE COMMISSION OF KENTUCKY**

**IN THE MATTER OF**

| | | |
|---|---|---|
| **KENTUCKY POWER COMPANY'S THIRD AMENDED ENVIRONMENTAL COMPLIANCE PLAN AND THIRD REVISED TARIFF** | ) ) ) | **Case No. 2006-00307** |

**DIRECT TESTIMONY**

**OF**

**ERROL K WAGNER**

**July 28, 2006**

DIRECT TESTIMONY OF
ERROL K WAGNER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

Q: Please state your name, position and business address.

A: My name is Errol K. Wagner. My position is Director of Regulatory Services for Kentucky Power Company (KPCo or Company). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

Q: Please summarize your educational background and business experience.

A: I received a Bachelor of Science degree with a major in accounting from Elizabethtown College, Elizabethtown, Pennsylvania in December 1973. I am a Certified Public Accountant. I worked for two certified public accounting firms prior to joining the Pennsylvania Public Utility Commission Staff in 1976. In 1982, I joined the American Electric Power Service Corporation (AEPSC) as a Rate Case Coordinator. In 1986, I transferred from AEPSC to Kentucky as the Assistant Rates, Tariffs and Special Contracts Director for KPCo. In July 1987, I assumed my current position.

Q: What are your responsibilities as Director of Regulatory Services?

A: I supervise and direct the Regulatory Services of the Company, which has the responsibility for rate and regulatory matters affecting KPCo's Kentucky jurisdiction. This would include the preparation of and coordination of the

Company's exhibits and testimony in rate cases and any other formal filings before state and federal regulatory bodies. Another responsibility is assuring the proper application of the Company's rates in all classifications of business.

Q: To whom do you report?

A: I report to Kentucky Power President, Timothy C. Mosher also located in Frankfort, Kentucky.

Q: Have you previously testified before this Commission?

A: Yes. I have testified before this Commission in numerous regulatory proceedings involving the application of the general adjustment in electric base rates, the fuel adjustment clause, the operation of the environmental cost recovery mechanism, approval of certificates of public convenience and necessity and other regulatory matters including three prior environmental surcharge proceedings.

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony in this proceeding is to support the Company's Application of Approval of its Third Amended Environmental Compliance Plan. The testimony will present to the Commission the Company's annual costs expected to be incurred by KPCo as a result of new environmental facilities being added to the amended environmental compliance plan to comply with the Federal Clean Air Act Amendments (CAAA).

Q: Can you describe the type of environmental facilities which are the subject of this Application?

A: Yes. The types of environmental facilities we are discussing are Selective Catalytic Reduction (SCR), Flue Gasification Desulphurization (FGD or

Scrubber), Boiler Modifications, Balanced Draft Conversion, Control System Modernization, Waste Water Treatment, Coal Blending Facilities, $SO_3$ Flue Gas Conditioning System and Gypsum Material Handling (See Exhibit EKW-1). These costs are being incurred by KPCo under two Federal Energy Regulatory Commission (FERC) approved agreements. The cost represent KPCo's portion of the costs being incurred at the Rockport plant, and at certain AEP System plants (i.e., those owned by the AEP "surplus" companies, as explained below).

Q: How will the costs of these environmental facilities flow to KPCo?

A: The costs of these environmental facilities will flow to KPCo either pursuant to the AEP Interconnection Agreement or the Unit Power Agreement (for portion of Rockport that KPCo is responsible).

Q: Has the FERC approved these agreements?

A: Yes. The AEP Interconnection Agreement was last approved by FERC on November 1, 1980 and the Unit Power agreement was last approved on December 29, 2004. KPCo only incurs its proper share of the cost of these facilities under rates (i.e., capacity and energy) contained in these agreements.

Q: Are you sponsoring any exhibits in connection with your testimony?

A: Yes. I am sponsoring Exhibits EKW-1 through EKW-10.

## The AEP Interconnection Agreement

Q: As background, please briefly describe the AEP Interconnection Agreement.

A: KPCo, Appalachian Power Company (APCo), Columbus Southern Power Company (CSP), Indiana Michigan Power Company (I&M) and Ohio Power Company (OPCo) are the five AEP System operating companies that are members of the AEP Pool established pursuant to the FERC approved AEP Interconnection Agreement. Although each operating company owns specific generating facilities, the AEP System is designed, built and operated on an integrated system basis. The AEP Interconnection Agreement defines the obligations of the members and methodology for allocating the cost of generation among the operating companies. Significant aspects of the AEP Interconnection Agreement are as follows:

- Requires each operating company to provide adequate generating facilities (or resources) to meet its firm load requirement.
- Allocates capacity on the basis of each company's highest non-coincident peak in the preceding twelve months (i.e., Member Load Ratio, or MLR).
- Provides a Capacity Settlement that equalizes responsibility for installed capacity. The capacity settlement effectively equalizes reserve margins by assigning responsibility to each operating company for its MLR share of overall system capacity. To the extent that an operating company's capacity is less than its system responsibility, such deficit company is required to make up the shortfall by paying a capacity charge to the surplus companies. The capacity is based on the average embedded cost of capacity of each surplus company.

Q: Please describe the calculation of the capacity equalization settlement.

A: Exhibit EKW-2 demonstrates the AEP Pool monthly capacity equalization settlement calculation. First, the total Members' primary capacity installed is multiplied by each company's MLR to arrive at the Member's primary capacity reservation (See Exhibit EKW-2, Columns 1, 2 and 3). This reservation is then compared with the installed capacity contributed by each Member (See Exhibit EKW-2, Columns 1 and 3). If a Member's capacity reservation exceeds its capacity contribution, the difference is a capacity deficit to be met by the Member(s) having the surplus capacity. If a Member's installed capacity exceeds its reservation, the difference is a capacity surplus, which is supplied to the AEP System by its Members. The total capacity surplus in any given month for surplus Members always equals the total capacity deficit for the deficit Members (i.e., producing a zero surplus/deficit balance for the AEP System) (See Exhibit EKW-2, Column 4).

Q: On what basis are the surplus companies reimbursed by the deficit companies?

A: Exhibit EKW-3 demonstrates the AEP Pool capacity rate calculations. The capacity rate is made up of two components: the primary capacity investment rate and the fixed operating rate. The primary capacity investment rate reflects the surplus company's embedded cost of capacity times the carrying charge rate approved by FERC. The fixed operating rate reflects the surplus company's steam plant operations and one-half maintenance expense divided by its installed capacity. An example of the capacity rate calculations for the surplus companies (I&M and OPCo) is provided in Exhibit EKW-3. Also provided on Exhibit EKW-3 is the Pool's weighted average rate, which is paid by the deficit members.

Q: How is the deficit companies' capacity equalization settlement charges calculated?

A: A deficit company, such as KPCo, computes its capacity equalization settlement charge by multiplying its capacity deficit by the Pool's weighted average capacity rate of the surplus companies (See Exhibit EKW-2, Columns 5, 6 and 7).

Q: Would you please walk us through the AEP System Pool capacity equalization settlement calculations for KPCo?

A: Yes. KPCo's monthly MLR is calculated by dividing KPCo's highest non-coincident peak in the preceding twelve months by the total of all of the Members' highest non-coincident peaks (1,665 MW/22,194 MW) resulting in an MLR of 0.07502 (See Exhibit EKW-2, Ln 2, Column 2). KPCo's primary capacity reservation is determined by multiplying its MLR for the month (0.07502) times the members' total generating capacity (24,246,000 KW). This equals a primary capacity reservation for KPCo of 1,818,900 KW (See Exhibit EKW-2, Ln 2, Column 3). By comparing KPCo's reservation with its installed capacity, it is determined that KPCo has a capacity deficit of 368,900 KW (1,450,000 KW – 1,818,900 KW) for the month (See Exhibit EKW-2, Ln 2, Column 4). Multiplying the Pool's weighted average capacity rate of the surplus companies (I&M and OPCo) of $9.31 / KW times KPCo's capacity deficit of 368,900 KW produces a capacity equalization settlement charge for KPCo of $3,432,888 for the month (See Exhibit EKW-2, Ln 8, Column 7).

Q: Please explain how the fixed operating costs of the new environmental facilities of the surplus companies affect KPCo's capacity equalization settlement charges.

A: The fixed operating costs consist of the operation and one-half of the Maintenance Expense associated with the installed environmental facilities of the surplus companies (for example, the disposal and lime costs associated with the Amos Unit No. 3 FGD) are included in the surplus companies' fixed operating rate along with one-half of the Maintenance Expense associated with the FGD. As such, these costs are charged to KPCo, through the Pool's weighted average capacity rate, based on KPCo's capacity deficit. Exhibit EKW-4 provides a summary of these new environmental costs, and their affect on the monthly Pool's weighted average capacity rate.

Q: How soon after the new environmental facilities are placed in service do the costs associated with these new environmental facilities appear in the monthly capacity rate?

A: The Steam Plant Operation Expense and one-half of Maintenance Expense will appear in the fixed operating rate the month following the date on which the environmental facilities' operation and maintenance expenses are incurred by the surplus companies. The primary capacity investment rate reflects the level of Steam Production Plant in service as of December 31 of the prior year. For example, Mitchell Unit No. 1's FGD is expected to be placed into service March 2007. The fixed operating rate KPCo will pay in April 2007 will reflect the Steam Operation Expense plus one-half of the Maintenance Expense associated with Mitchell Unit No. 1's FGD. However, the primary capacity investment rate will not reflect the investment in Mitchell Unit No. 1's FGD until January 2008.

Q: Please briefly describe the background on the Gypsum Material Handling facilities at the Mitchell Generating Plant?

A: The FGD OPCo is currently building at its Mitchell Generating Plant will create, as a waste byproduct, large quantities of CaSO4-2H2O (gypsum), or filter cake. Filter cake is very similar to mined gypsum commonly used in the production of gypsum wallboard building materials. Ordinarily, the filter cake would be transported by the plant to a landfill for disposal at a cost of approximately $5-$7 per ton, excluding the capital investment of the landfill. Around 2004, AEP began discussions with BPB to utilize the filter cake in wallboard production as an alternative with lower economic and environmental costs.

Q: How much of this filter cake does OPCo expect to sell to the wallboard manufacture?

A: OPCo expects to sell approximately 800,000 tons of filter cake annually at $3.00 per ton.

Q: Explain how the proceeds realized from the sale of the filter cake will be recorded on OPCo's books.

A: The proceeds realized from the sale of the filter cake will be recorded as credits in Account 501 thereby reducing OPCo's expense. As prescribed by the FERC USofA, one of the items to be recorded in Account 501 is "Residual disposal expenses less any proceeds from the disposal of residuals. Currently Account 501 is used to record the cost of disposal of coal byproducts such as fly ash. The proceeds from the sale of filter cake will reduce OPCo's primary capacity fixed operating rate which in turn reduces the equalization capacity rate the deficit companies, like KPCo, will pay to the surplus companies.

Q: What is the proposed additional annual charge associated with these new environmental facilities of the surplus companies that will be incurred by KPCo through the AEP Interconnection Agreement?

A: Based on Exhibit EKW-4 calculations, the annualized charges associated with the surplus companies new environmental facilities incurred by KPCo through the AEP Interconnection Agreement are expected to be $11,819,556 (See Exhibit EKW-4).

**The KPCo Unit Power Agreement**

Q: As background, please briefly describe the Rockport Generating Plant located in Rockport, Indiana and the Unit Power Agreement (UPA).

A: The Rockport Generating Plant consists of two 1,300 MW generating units. Each unit is owns 50% by AEP Generating and 50% owned by I&I. KPCo has a FERC approved UPA with AEP Generating Company for 30% of AEP Generating Company's 50% interest in both units equating in total 390 MW ((1,300 X 50% X 50%) X 2). The UPA obligates KPCo to be responsible for 30% of AEP Generating Company's cost at the Rockport Units and in return KPCo receives 30% of AEP Generating Company's share of the generation output at these two generating facilities.

Q: What is the proposed additional annual charge associated with the new Rockport environmental facilities which will be incurred by KPCo through the Unit Power Agreement?

A: Exhibit EKW–9 demonstrates the estimated annual revenue requirement associated with the expansion of the landfill at both Rockport Unit No. 1 and No. 2 is $409,212.

**Rate of Return**

Q: Is KPCo seeking a rate of return on equity on the compliance related capital expenditures set forth in the Third Amended Environmental Compliance Plan?

A: No. KPCo is seeking only the recovery of new environmental costs it will incur to comply with the Federal Clean Air Act as a result of these federally-approved agreements.

**Estimated Annual Retail Effect**

Q: What is the estimated annual retail effect of the proposed changes to the environmental surcharge tariff?

A: The estimated annual retail effect of the proposed changes to the environmental surcharge tariff after these facilities are placed into service is approximately $8,346,134 (See Exhibit EKW-10, Ln 5). The effect on a residential customer using an average 1,353 kWh per month would be an increase to the monthly bill of approximately $1.77 or $21.24 annually. This equates to an approximately 2.05% increase (See Exhibit EKW-10, Ln 7).

Q: Will the retail jurisdictional customers experience the full 2.05% increase if the Commission approves the Third Amended Environmental Compliance Plan and the Third Revised Tariff?

A: No. There are several reasons for this conclusion. First, these environmental facilities will be phased into service over the next three years (See Exhibit EKW–

1, In-Service Dates). Second, there will be some retirements associated with some of these facilities, which will reduce the environmental investments. The Company has not included these retirements in its calculations due to the fact that the Company has not estimated or forecasted the associated retirements. In Case No. 2005–00068 the associated retirements equated to approximately 5% of the level of new environmental investment. If this same level of retirement would hold true in this case, the annual effect on Exhibit EKW–4, Ln 17 would be decreased by approximately $486,948. Third, with respect to KPCo's share of Rockport (Exhibit EKW–9), the Company has not yet forecasted the deferred federal income tax benefit. This would also reduce the annualized revenue requirement on Exhibit EKW–11, Ln 13.

Q: With respect to the three year phase-in of the environmental facilities, can you give us an annual estimate as to the effect on the average residential customer.

A: Yes. The chart below demonstrates the Company's best estimate by year as to the total jurisdictional annual revenue, percent increase and the effect on an average residential customer's monthly bill.

| | 2007 | 2008 | 2009 |
|---|---|---|---|
| Jurisdic. Annual Revenue | $1,571,000 | $6,496,000 | $279,000 |
| Percent Increase | 0.39% | 1.59% | 0.070% |
| Aver. Monthly Bill Effect | $0.34 | $1.37 | $0.06 |

Q: Does this conclude you testimony?

A: Yes it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

COMMONWEALTH OF KENTUCKY

CASE NO. 2006-000307

COUNTY OF FRANKLIN

AFFIDAVIT

Errol K. Wagner, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

Errol K Wagner

Errol K. Wagner

Subscribed and sworn to before me by Errol K. Wagner this 25th day of July, 2006.

Judy K Jackett

Notary Public

My Commission Expires January 14, 2009

Exhibit EKW - 1
Page 1

**Kentucky Power Company**
**AEP Pool Surplus Companies**
**Net Investment In**
**Environmental Facilities**
**in Thousand of Dollars**

| Ln. No. (1) | Generating Unit (2) | Description of Environmental Facilities (3) | In-Service Date (4) | Cost of Environmental Facilities (5) | Less Cost of Orginial (6) | OPCo or I & M Percentage (7) | OPCo's Envir. Invest. (9) | I&M's Envir. Invest. (10) |
|---|---|---|---|---|---|---|---|---|
| 1 | Amos Unit No. 3 | FGD | 4Q-07 | $346,121 | $0 | 66.67% | $230,779 | |
| 2 | Amos Unit No. 3 | Balance Draft Conversion | 4Q-07 | $39,923 | $0 | 66.67% | $26,613 | |
| 3 | Amos Unit No. 3 | Controls Modernization | 4Q-07 | $14,141 | $0 | 66.67% | $9,448 | |
| 4 | Amos Unit No. 3 | Steam Generator Modifications | 4Q-07 | $6,091 | $0 | 66.67% | $4,081 | |
| 5 | Amos Unit No. 3 | SO3 Mitigation | 4Q-07 | $14,066 | $0 | 66.67% | $9,398 | |
| 6 | Amos Unit No. 3 | FGD Purge Steam Water | 4Q-07 | $9,400 | $0 | 66.67% | $6,287 | |
| 7 | Amos Unit No. 3 | Plant Common Equipment | 4Q-07 | $90,797 | $0 | 29.89% | $27,159 | |
| 8 | Amos Unit No. 3 | Coal Blending Station | 4Q-07 | $5,740 | $0 | 66.67% | $3,847 | |
| 9 | Amos Unit Nos. 1, 2 & 3 | Landfill | 4Q-07 | $33,263 | $0 | 29.89% | $9,962 | |
| 10 | Amos Unit No. 3 | Precip Modification | 4Q-07 | $93,365 | $0 | 66.67% | $62,246 | |
| 11 | Sub-Total | | | $652,907 | $0 | | $389,820 | |
| 12 | Cardinal Unit No. 1 | FGD | 4Q-07 | $216,748 | $0 | 100.00% | $216,748 | |
| 13 | Cardinal Unit No. 1 | Controls Modernization | 4Q-07 | $5,930 | $0 | 100.00% | $5,930 | |
| 14 | Cardinal Unit No. 1 | Boiler Modification | 4Q-07 | $6,971 | $0 | 100.00% | $6,971 | |
| 15 | Cardinal Unit No. 1 | Balance Draft Conversion | 4Q-07 | $30,530 | $0 | 100.00% | $30,530 | |
| 16 | Cardinal Unit No. 1 | FD Fan Modification | 4Q-07 | $1,763 | | 100.00% | $1,763 | |
| 17 | Cardinal Unit No. 1 | FGD Purge Stream Water | 4Q-07 | $12,821 | $0 | 100.00% | $12,821 | |
| 18 | Cardinal Unit No. 1 | SO3 Mitigation | 4Q-07 | $7,292 | $0 | 100.00% | $7,292 | |
| 19 | Cardinal Unit No. 1 | Catalyst Replacement | 4Q-07 | $3,606 | $0 | 100.00% | $3,606 | |
| 20 | Cardinal Unit No. 1 | Landfill | 2Q-08 | $15,703 | $0 | 100.00% | $15,703 | |
| 21 | Sub-Total | | | $301,364 | $0 | | $301,364 | |
| 22 | Gavin Units Nos 1 & 2 | SO3 Mitigation | 4Q-06 | $9,997 | $0 | 100.00% | $9,997 | |
| 23 | Mitchell Unit No. 1 | FGD | 2Q-07 | $242,906 | $0 | 100.00% | $242,906 | |
| 24 | Mitchell Unit No. 1 | SCR | 2Q-07 | $133,771 | $0 | 100.00% | $133,771 | |
| 25 | Mitchell Unit No. 1 | Balance Draft Conversion | 2Q-07 | $24,431 | $0 | 100.00% | $24,431 | |
| 26 | Mitchell Unit No. 1 | Controls Modernization | 2Q-07 | $3,026 | $0 | 100.00% | $3,026 | |
| 27 | Mitchell Unit No. 1 | Steam Generator Modifications | 2Q-07 | $10,262 | $0 | 100.00% | $10,262 | |
| 28 | Mitchell Unit No. 1 | SO3 Mitigation | 2Q-07 | $14,827 | $0 | 100.00% | $14,827 | |
| 29 | Mitchell Unit No. 1 | FGD Purge Stream Water | 2Q-07 | $11,624 | $0 | 100.00% | $11,624 | |
| 30 | Mitchell Unit No. 1 | Coal Blending Station | 2Q-07 | $12,280 | $0 | 100.00% | $12,280 | |
| 31 | Sub-Total | | | $453,127 | $0 | | $453,127 | |

**Kentucky Power Company**
**AEP Pool Surplus Companies**
**Net Investment In**
**Environmental Facilities**
***in Thousand of Dollars***

**Exhibit EKW - 1**
**Page 2**

| Ln. No. (1) | Generating Unit (2) | Description of Environmental Facilities (3) | In-Service Date (4) | Cost of Environmental Facilities (5) | Less Cost of Orginial (6) | OPCo or I & M Percentage (7) | OPCo's Envir. Invest. (9) | I&M's Envir. Invest. (10) |
|---|---|---|---|---|---|---|---|---|
| 32 | Mitchell Unit No. 2 | FGD | 4Q-06 | $236,154 | $0 | 100.00% | $236,154 | |
| 33 | Mitchell Unit No. 2 | SCR | 2Q-07 | $137,557 | $0 | 100.00% | $137,557 | |
| 34 | Mitchell Unit No. 2 | Balance Draft Conversion | 2Q-07 | $24,431 | $0 | 100.00% | $24,431 | |
| 35 | Mitchell Unit No. 2 | Controls Modernization | 2Q-07 | $3,026 | $0 | 100.00% | $3,026 | |
| 36 | Mitchell Unit No. 2 | Steam Generator Modifications | 2Q-07 | $10,262 | $0 | 100.00% | $10,262 | |
| 37 | Mitchell Unit No. 2 | SO3 Mitigation | 2Q-07 | $14,827 | $0 | 100.00% | $14,827 | |
| 38 | Mitchell Unit No. 2 | FGD Purge Stream Water | 2Q-07 | $11,624 | $0 | 100.00% | $11,624 | |
| 39 | Mitchell Unit No. 2 | Coal Blending Station | 2Q-07 | $12,280 | $0 | 100.00% | $12,280 | |
| 40 | Sub-Total | | | $450,161 | $0 | | $450,161 | |
| 41 | Mitchell Unit Nos 1 & 2 | Impoundment | 4Q-06 | $9,844 | $0 | 100.00% | $9,844 | |
| 42 | Mitchell Unit Nos 1 & 2 | Gypsum Material Handling | 1Q-07 | $33,228 | $0 | 100.00% | $33,228 | |
| 43 | Mitchell Unit Nos 1 & 2 | Gypsum Material Handling | 4Q--06 | $13,123 | $0 | 100.00% | $13,123 | |
| 44 | Mitchell Unit Nos 1 & 2 | Transformer Rectifier Set | 4Q-06 | $8,351 | $0 | 100.00% | $8,351 | |
| 45 | Sub-Total | | | $64,546 | $0 | | $64,546 | |
| 46 | Sporn Unit Nos 2,4 & 5 | Landfill | 4Q-08 | $6,546 | $0 | 100.00% | $6,546 | |
| 47 | Rockport Unit No 1 | Landfill | 4Q-08 | $1,250 | $0 | 85.00% * | | $1,063 |
| 48 | Rockport Unit No 2 | Landfill | 4Q-08 | $1,250 | $0 | 65.08% * | | $814 |
| 49 | Sub-Total | | | $2,500 | $0 | | | $1,877 |
| 50 | Tanners Creek Common | Coal Blending | 2Q-06 | $90,637 | $0 | 100.00% | | $90,637 |
| 51 | Total Net Investment | | | $2,031,785 | $0 | | $1,675,561 | $92,514 |

* I&M's Share of Rockport Plant in the AEP Pool
Rockport Unit No. 1 = I&M 650 MW + AEGCo's 455MW (1105 MW / 1300 MW)
Rockport Unit No. 2 = I&M's 650 MW + AEGCo's 196 MW (846 MW / 1300MW)

**Exhibit EKW-2**

**Kentucky Power Company**
**AEP System Pool**
**Capacity Equalization Settlement**
**April 2006 Actual**

**Calculation of Member Capacity Surplus / (Deficit) (kw)**

| Ln No. | Company | Member Primary Capacity (kw) | Member Load Ratio | Primary Capacity Reservation (kw) | Capacity Surplus (Deficit) (kw) |
|---|---|---|---|---|---|
| | | (1) | (2) | (3)=Total kw*(2) | (4)=(1)-(3) |
| 1 | APCo | 6,254,000 | 31.284% | 7,585,100 | (1,331,100) |
| 2 | KPCo | 1,450,000 | 7.502% | 1,818,900 | (368,900) |
| 3 | I&M | 5,078,000 | 18.892% | 4,580,600 | 497,400 |
| 4 | OPCo | 8,043,000 | 23.826% | 5,776,900 | 2,266,100 |
| 5 | CSP | 3,421,000 | 18.496% | 4,484,500 | (1,063,500) |
| 6 | Total | 24,246,000 | 100.000% | 24,246,000 | 0 |

**Calculation of Member Capacity Settlement ($)**

| Ln No. | Company | Capacity Surplus (Deficit) (kw) | Capacity Rate ($/kw) | Credit (Charge) ($) |
|---|---|---|---|---|
| | | (5) | (6) | (7) |
| 7 | APCo | (1,331,100) | $9.31 | ($12,386,874) |
| 8 | KPCo | (368,900) | $9.31 | ($3,432,888) |
| 9 | I&M | 497,400 | $13.66 | $6,794,484 |
| 10 | OPCo | 2,266,100 | $8.35 | $18,921,935 |
| 11 | CSP | (1,063,500) | $9.31 | ($9,896,657) |
| 12 | Total | 0 | | $0 |

Exhibit EKW-3

**Kentucky Power Company**
**AEP Pool**
**Capacity Rate Calculations**
**I & M and OPCo Surplus Members**
**April 2006 Actual**

| Ln No. | | | | I&M | OPCo | |
|---|---|---|---|---|---|---|
| | | **Primary Capacity Investment Rate:** | | | | |
| 1 | | Steam Production Plant as of 12/31/05 | ($) | $3,497,240,549 | $3,436,351,970 | |
| 2 | | Steam Capability as of 12/31/05 | (kw) | 5,064,000 | 8,438,000 | |
| 3 | = (1)/(2) | Average Cost of Investment | ($/kw) | $690.61 | $407.25 | |
| 4 | | Times Carrying Charge (16.44% / 12 Months) | ($/kw/Month) | 0.0137 | 0.0137 | |
| 5 | = (3)*(4) | Primary Capacity Investment Rate | | $9.46 | $5.58 | |
| | | **(Monthly) Fixed Operating Rate:** | | | | |
| 6 | | Steam Plant Operation Expense | ($) | $15,189,509 | $16,686,592 | |
| 7 | | 1/2 Maintenance Expense | ($) | $6,081,111 | $6,719,782 | |
| 8 | = (6)+(7) | Subtotal - Fixed Operating Expense | ($) | $21,270,620 | $23,406,374 | |
| 9 | | Steam Capability | (kw) | 5,064,000 | 8,438,000 | |
| 10 | = (8)/(9) | Fixed Operating Rate | ($/kw) | 4.2 | 2.77 | |
| 11 | = (5)+(10) | **Capacity Rate** | ($/kw) | $13.66 | $8.35 | |
| | | **Calculate AEP Pool Average Capacity Rate ($/kw)** | | | | |
| 12 | | Surplus Capacity | (kw) | 497,400 | 2,266,100 | |
| 13 | | Member's Percent of Pool's Total Surplus | (%) | 18.00% | 82.00% | |
| 14 | | Surplus Member's Capacity Rate | ($/kw) | $13.66 | $8.35 | |
| 15 | | Surp. Memb. CAP Rate Recv. From Deficit Memb. | ($/kw) | 2.46 | 6.85 | |
| 16 | | AEP Pool's Average Capacity Rate | ($/kw) | | | $9.31 |

Exhibit EKW-4

# Kentucky Power Company
## AEP Pool Monthly
## Environmental Capacity Costs

| Ln. No. | Description | I&M | OPCo | KPCo |
|---|---|---|---|---|
| 1 | Net Cost of Envir.Facilities Investment Installed ($ Thousands) (See Exhibit EKW-1) | $92,514 | $1,675,561 | |
| 2 | Installed Capacity (kw) (See Exhibit EKW-3) | 5,064,000 | 8,438,000 | |
| 3 | Wgt. Ave. Installed Cost (Ln1/Ln2) ($/kw) | $18.27 | $198.57 | |
| 4 | Monthly Return on Investment (See Exhibit EWK-3) | 0.0137 | 0.0137 | |
| 5 | Envir. Member Cap. Invest. Rate ($/kw/month) | $0.25 | $2.72 | |
| | **Plus: Operations & 1/2 Maintenance** | | | |
| 6 | Amos Unit No. 3 FGD | | $0.11 | |
| 7 | Cardinal Unit No. 1 FGD | | $0.12 | |
| 8 | Mitchell Unit No. 1 FGD & SCR | | $0.12 | |
| 9 | Mitchell Unit No. 2 FGD & SCR | | $0.14 | |
| 10 | Sub-Total | $0.25 | $3.21 | |
| 11 | Surplus Company Weighting (See Exhibit EKW-3) | 18.00% | 82.00% | |
| 12 | Effect on Wgt. Ave. Rate (Ln11 * 12) | $0.04 | $2.63 | $2.67 |
| 13 | KPCo's Pool Capacity Deficit (See Exhibit EKW-2) | | | 368,900 |
| 14 | KPCo's Monthly Envir. Pool Cap. Charge | | | $984,963 |
| 15 | Number of months | | | 12 |
| 16 | Annual Effect of Envir. Pool Cap. Charge | | | $11,819,556 |

Exhibit EKW - 5

**Ohio Power Company**
**Amos Unit No. 3**
**Flue Gas Desulfurization (FGD)**
***12 Month Ending December 31, 2008***

| Ln. No. | Description | Jan 08 | Feb 08 | Mar 08 | Apr 08 | May 08 | Jun 08 | Jul 08 | Aug 08 | Sep 08 | Oct 08 | Nov 08 | Dec 08 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ***Operations*** | | | | | | | | | | | | | |
| 1 | Disposal (5010000) | $458,900 | $28,600 | $657,800 | $573,300 | $213,200 | $416,000 | $436,800 | $546,000 | $514,800 | $383,500 | $557,700 | $617,500 | |
| 2 | Trona (5020003) | $20,571 | $19,207 | $20,684 | $21,189 | $28,362 | $39,239 | $41,302 | $41,269 | $38,664 | $21,218 | $25,359 | $23,436 | |
| 3 | Lime Stone (5020004) | $345,049 | $322,180 | $346,948 | $355,419 | $237,869 | $329,099 | $346,395 | $346,118 | $324,270 | $355,906 | $425,365 | $393,111 | |
| 4 | Total Operations (Ln1 + Ln2 + Ln3) | $824,520 | $369,987 | $1,025,432 | $949,908 | $479,431 | $784,338 | $824,497 | $933,387 | $877,734 | $760,624 | $1,008,424 | $1,034,047 | |
| | **Maintenance** | | | | | | | | | | | | | |
| 5 | FGD ( Acct. No. 512 ) | $274,300 | $354,900 | $592,800 | $509,600 | $92,300 | $429,000 | $276,900 | $426,400 | $586,300 | $299,000 | $445,900 | $562,900 | |
| 6 | 1/2 Maintenance (Ln5/2) | $137,150 | $177,450 | $296,400 | $254,800 | $46,150 | $214,500 | $138,450 | $213,200 | $293,150 | $149,500 | $222,950 | $281,450 | |
| 7 | Total Fixed O&M (Ln4 + Ln6) | $961,670 | $547,437 | $1,321,832 | $1,204,708 | $525,581 | $998,838 | $962,947 | $1,146,587 | $1,170,884 | $910,124 | $1,231,374 | $1,315,497 | |
| 8 | OPCo's Percentage Ownership | 66.67% | 66.67% | 66.67% | 66.67% | 66.67% | 66.67% | 66.67% | 66.67% | 66.67% | 66.67% | 66.67% | 66.67% | |
| 9 | OPCo's Share of Fixed O&M (L7 * L8) | $641,145 | $364,976 | $881,265 | $803,179 | $350,405 | $665,925 | $641,997 | $764,430 | $780,628 | $606,780 | $820,957 | $877,042 | |
| 10 | OPCo Steam Capacity (kw) | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | |
| 11 | Amos Unit No 3 FGD Rate ($/kw) | $0.08 | $0.05 | $0.11 | $0.10 | $0.04 | $0.08 | $0.08 | $0.10 | $0.10 | $0.08 | $0.10 | $0.11 | |
| 12 | OPCo Surplus Weighting (%) | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | |
| 13 | Effect on Wt. Ave. Rate ($/kw) | $0.07 | $0.04 | $0.09 | $0.08 | $0.03 | $0.07 | $0.07 | $0.08 | $0.08 | $0.07 | $0.08 | $0.09 | |
| | **Kentucky Power's Share:** | | | | | | | | | | | | | |
| 14 | Portion of Wgt. Av. Cap. Rate Attributed to Amos No. 3 FGD | $0.07 | $0.04 | $0.09 | $0.08 | $0.03 | $0.07 | $0.07 | $0.08 | $0.08 | $0.07 | $0.08 | $0.09 | |
| 15 | KPCo's Pool Cap. Deficit | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | |
| 16 | KPCo's Share of Amos No. 3 FGD | $25,823 | $14,756 | $33,201 | $29,512 | $11,067 | $25,823 | $25,823 | $29,512 | $29,512 | $25,823 | $29,512 | $33,201 | $313,565 |

Exhibit EKW - 6

**Ohio Power Company**
**Cardinal Unit No. 1**
**Flue Gas Desulfurization (FGD)**
**12 Month Ending December 31, 2008**

| Ln. No. | Description | Jan 08 | Feb 08 | Mar 08 | Apr 08 | May 08 | Jun 08 | Jul 08 | Aug 08 | Sep 08 | Oct 08 | Nov 08 | Dec 08 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Operations** | | | | | | | | | | | | | |
| 1 | Disposal (5010000) | $211,094 | $13,156 | $302,588 | $263,718 | $98,072 | $191,360 | $200,928 | $251,160 | $236,808 | $176,410 | $256,542 | $284,050 | |
| 2 | Trona (5020003) | $70,000 | $71,196 | $76,330 | $73,893 | $140,717 | $139,665 | $147,357 | $147,240 | $136,471 | $72,170 | $70,008 | $76,154 | |
| 3 | Lime Stone (5020004) | $421,100 | $414,585 | $444,479 | $430,288 | $409,707 | $406,645 | $429,039 | $428,698 | $397,344 | $420,256 | $407,666 | $443,457 | |
| 4 | Total Operations (Ln1 Ln2 + Ln3) | $702,194 | $498,937 | $823,397 | $767,899 | $648,496 | $737,670 | $777,324 | $827,098 | $770,623 | $668,836 | $734,216 | $803,661 | |
| | **Maintenance** | | | | | | | | | | | | | |
| 5 | FGD ( Acct. No. 512 ) | $126,178 | $163,254 | $272,688 | $234,416 | $42,458 | $197,340 | $127,374 | $196,144 | $269,698 | $137,540 | $205,114 | $258,934 | |
| 6 | 1/2 Maintenance (Ln5/2) | $63,089 | $81,627 | $136,344 | $117,208 | $21,229 | $98,670 | $63,687 | $98,072 | $134,849 | $68,770 | $102,557 | $129,467 | |
| 7 | Total Fixed O&M (Ln4 + Ln6) | $765,283 | $580,564 | $959,741 | $885,107 | $669,725 | $836,340 | $841,011 | $925,170 | $905,472 | $737,606 | $836,773 | $933,128 | |
| 8 | OPCo Steam Capacity (kw) | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | |
| 9 | Card. Unit No. 1 FGD Rate ($/kw) | $0.10 | $0.07 | $0.12 | $0.11 | $0.08 | $0.10 | $0.10 | $0.12 | $0.11 | $0.09 | $0.10 | $0.12 | |
| 10 | OPCo Surplus Weighting (%) | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | |
| 11 | Effect on Wt. Ave. Rate ($/kw) | $0.08 | $0.06 | $0.10 | $0.09 | $0.07 | $0.08 | $0.08 | $0.10 | $0.09 | $0.07 | $0.08 | $0.10 | |
| | **Kentucky Power's Share:** | | | | | | | | | | | | | |
| 12 | Portion of Wgt. Av. Cap. Rate Attributed to Card. No. 1 FGD | $0.08 | $0.06 | $0.10 | $0.09 | $0.07 | $0.08 | $0.08 | $0.10 | $0.09 | $0.07 | $0.08 | $0.10 | |
| 13 | KPCo's Pool Cap. Deficit | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | |
| 14 | KPCo's Share of Card. No. 1 FGD | $29,512 | $22,134 | $36,890 | $33,201 | $25,823 | $29,512 | $29,512 | $36,890 | $33,201 | $25,823 | $29,512 | $36,890 | $368,900 |

Exhibit EKW - 7

**Ohio Power Company**
**Mitchell Unit 1**
**Flue Gas Desulfurization (FGD) and**
**Selective Catalytic Reduction (SCR)**
**12 Month Ending March 31, 2008**

| Ln. No. | Description | Apr 07 | May 07 | Jun 07 | Jul 07 | Aug 07 | Sep 07 | Oct 07 | Nov 07 | Dec 07 | Jan 08 | Feb 08 | Mar 08 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Operations** | | | | | | | | | | | | | |
| 1 | Disposal (5010000) | $352,800 | $131,200 | $256,000 | $268,800 | $336,000 | $316,800 | $236,000 | $343,200 | $380,000 | $282,400 | $17,600 | $404,800 | |
| 2 | Lime Stone (5020004) | $208,822 | $506,574 | $432,591 | $562,422 | $503,539 | $523,040 | $584,048 | $516,591 | $433,274 | $341,767 | $165,338 | $321,617 | |
| 3 | UREA (ACCT No 5020002) | $0 | $349,972 | $299,830 | $388,561 | $347,928 | $361,604 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 4 | TRONA (Acct No 5020003) | $13,846 | $67,176 | $57,365 | $74,582 | $66,773 | $69,360 | $38,725 | $34,252 | $28,728 | $23,101 | $11,175 | $21,739 | |
| 5 | Total Operations (Sum Ln1 - Ln4) | $575,468 | $1,054,922 | $1,045,786 | $1,294,365 | $1,254,240 | $1,270,804 | $858,773 | $894,043 | $842,002 | $647,268 | $194,113 | $748,156 | |
| | **Maintenance** | | | | | | | | | | | | | |
| 6 | FGD ( Acct. No. 512) | $313,600 | $56,800 | $264,000 | $170,400 | $262,400 | $360,800 | $184,000 | $274,400 | $346,400 | $168,800 | $218,400 | $364,800 | |
| 7 | SCR (Acct. No. 512) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 8 | Total Maintenance (Ln6 + Ln7) | $313,600 | $56,800 | $264,000 | $170,400 | $262,400 | $360,800 | $184,000 | $274,400 | $346,400 | $168,800 | $218,400 | $364,800 | |
| 9 | 1/2 Maintenance (Ln 8/2) | $156,800 | $28,400 | $132,000 | $85,200 | $131,200 | $180,400 | $92,000 | $137,200 | $173,200 | $84,400 | $109,200 | $182,400 | |
| 10 | Total Fixed O&M (Ln5 + Ln9) | $732,268 | $1,083,322 | $1,177,786 | $1,379,565 | $1,385,440 | $1,451,204 | $950,773 | $1,031,243 | $1,015,202 | $731,668 | $303,313 | $930,556 | |
| 11 | OPCo Steam Capacity (kw) | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | |
| 12 | Mitchell Unit No. 1 Rate ($/kw) | $0.09 | $0.13 | $0.15 | $0.17 | $0.17 | $0.18 | $0.12 | $0.13 | $0.13 | $0.09 | $0.04 | $0.12 | |
| 13 | OPCo Surplus Weighting (%) | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | |
| 14 | Effect on Wt. Ave. Rate ($/kw) | $0.07 | $0.11 | $0.12 | $0.14 | $0.14 | $0.15 | $0.10 | $0.11 | $0.11 | $0.07 | $0.03 | $0.10 | |
| | **Kentucky Power's Share:** | | | | | | | | | | | | | |
| 15 | Portion of Wgt. Av. Cap Rate Attributed to Mitchell No. 1 | $0.07 | $0.11 | $0.12 | $0.14 | $0.14 | $0.15 | $0.10 | $0.11 | $0.11 | $0.07 | $0.03 | $0.10 | |
| 16 | KPCo's Pool Cap. Deficit | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | |
| 17 | KPCo's Share of Mitchell Unit No. 1 | $25,823 | $40,579 | $44,268 | $51,646 | $51,646 | $55,335 | $36,890 | $40,579 | $40,579 | $25,823 | $11,067 | $36,890 | $461,125 |

Exhibit EKW - 8

**Ohio Power Company**
**Mitchell Unit 2**
**Flue Gas Desulfurization (FGD) and**
**Selective Catalytic Reduction (SCR)**
**12 Month Ending December 31, 2007**

| Ln. No. | Description | Jan 07 | FEB 07 | Mar 07 | Apr 07 | May 07 | Jun 07 | Jul 07 | Aug 07 | Sep 07 | Oct 07 | Nov 07 | Dec 07 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Operations** | | | | | | | | | | | | | |
| 1 | Disposal (5010000) | $282,400 | $17,600 | $404,800 | $352,800 | $131,200 | $256,000 | $268,800 | $336,000 | $316,800 | $236,000 | $343,200 | $380,000 | |
| 2 | Lime Stone (5020004) | $527,214 | $528,428 | $533,132 | $464,385 | $482,141 | $491,474 | $521,067 | $577,067 | $496,255 | $505,664 | $469,697 | $544,818 | |
| 3 | UREA (ACCT No 5020002) | $0 | $0 | $0 | $0 | $333,389 | $339,833 | $360,503 | $398,463 | $343,134 | $0 | $0 | $0 | |
| 4 | TRONA (Acct No 5020003) | $26,963 | $27,025 | $27,265 | $23,749 | $49,315 | $50,270 | $53,296 | $59,024 | $50,759 | $25,860 | $24,021 | $27,863 | |
| 5 | Total Operations (Sum Ln1 - Ln4) | $836,577 | $573,053 | $965,197 | $840,934 | $996,045 | $1,137,577 | $1,203,666 | $1,370,554 | $1,206,948 | $767,524 | $836,918 | $952,681 | |
| | **Maintenance** | | | | | | | | | | | | | |
| 6 | FGD ( Acct. No. 512) | $168,800 | $218,400 | $364,800 | $313,600 | $56,800 | $264,000 | $170,400 | $262,400 | $360,800 | $184,000 | $274,400 | $346,400 | |
| 7 | SCR (Acct. No. 512) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | |
| 8 | Total Maintenance (Ln6 + Ln7) | $168,800 | $218,400 | $364,800 | $313,600 | $56,800 | $264,000 | $170,400 | $262,400 | $360,800 | $184,000 | $274,400 | $346,400 | |
| 9 | 1/2 Maintenance (Ln 8/2) | $84,400 | $109,200 | $182,400 | $156,800 | $28,400 | $132,000 | $85,200 | $131,200 | $180,400 | $92,000 | $137,200 | $173,200 | |
| 10 | Total Fixed O&M (Ln5 + Ln9) | $920,977 | $682,253 | $1,147,597 | $997,734 | $1,024,445 | $1,269,577 | $1,288,866 | $1,501,754 | $1,387,348 | $859,524 | $974,118 | $1,125,881 | |
| 11 | OPCo Steam Capacity (kw) | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | 8,043,000 | |
| 12 | Mitchell Unit No. 2 Rate ($/kw) | $0.11 | $0.08 | $0.14 | $0.12 | $0.13 | $0.16 | $0.16 | $0.19 | $0.17 | $0.11 | $0.12 | $0.14 | |
| 13 | OPCo Surplus Weighting (%) | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | 82.00% | |
| 14 | Effect on Wt. Ave. Rate ($/kw) | $0.09 | $0.07 | $0.11 | $0.10 | $0.11 | $0.13 | $0.13 | $0.16 | $0.14 | $0.09 | $0.10 | $0.11 | |
| | **Kentucky Power's Share:** | | | | | | | | | | | | | |
| 15 | Portion of Wgt. Av. Cap Rate Attributed to Mitchell No. 2 | $0.09 | $0.07 | $0.11 | $0.10 | $0.11 | $0.13 | $0.13 | $0.16 | $0.14 | $0.09 | $0.10 | $0.11 | |
| 16 | KPCo's Pool Cap. Deficit | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | 368,900 | |
| 17 | KPCo's Share of Mitchell Unit No. 2 | $33,201 | $25,823 | $40,579 | $36,890 | $40,579 | $47,957 | $47,957 | $59,024 | $51,646 | $33,201 | $36,890 | $40,579 | $494,326 |

**Exhibit EKW-9**

**Kentucky Power Company**
**Rockport Landfill Expansion**
**Environmental Surcharge Calculations**
**Revenue Requirement**

| Ln No (1) | Cost Componment (2) | Unit No. 1 (3) | Unit No 2 (4) | Total (5) |
|---|---|---|---|---|
| 1 | Landfill Expansion | $1,250,000 | $1,250,000 | |
| 2 | Less: Accumulated Depreciation | $44,000 | $44,000 | |
| 3 | Less: Accum. Def. Income Tax | $0 | $0 | |
| 4 | Total Rate Base | $1,206,000 | $1,206,000 | $2,412,000 |
| 5 | May Weighted Average Cost of Capital | | 12.7703% | |
| 6 | Monthly Weighted Average Cost of Capital | | | 1.0642% |
| 7 | Monthly Return on Rate Base (Lns 4 X 6) | | | $25,669 |
| | Operating Expenses | | | |
| 8 | Monthly Depreciation Expense | | | $88,000 |
| 9 | Total Operating Expense | | | $88,000 |
| 10 | Total Revenue Requirement Associated with Rockport Landfill Expansion (Lns 7 + 9) | | | $113,669 |
| 11 | KPCo's Portion of Rockport's Landfill Expansion (Ln 10 X 30%) | | | $34,101 |
| 12 | Annualize | | | 12 |
| 13 | Annualized Revenue Requirement | | | $409,212 |

**Kentucky Power Company**
**New Environmental Costs Associated**
**with AEP Pool Charges**
**Effect on Residential Customer**

**Exhibit EKW - 10**

| Ln No | Description | | Annual Amount |
|---|---|---|---|
| 1 | Annual Effect of New Environmental Pool Capacity Charges | (EKW-4 Ln 16) | $11,819,556 |
| 2 | KPCo's Share of Rockport Landfill Expansion | (EKW-11 Ln 13) | $409,212 |
| 3 | Total Environmental Cost (Lns 1 + 2) | | $12,228,768 |
| 4 | KPCo's Twelve Months May 2006 Average Retail Allocation | | 68.25% |
| 5 | Net Annual Impact on the Kentucky Retail Customers | (Ln 3 X Ln 4) | $8,346,134 |
| 6 | May 2006 Twelve Months Billed Revenues After Increase | | $407,629,174 |
| 7 | Percent Increase | (Ln 5/Ln 6) | 2.05% |
| 8 | Monthly Effect on a Residential Customer using 1,353 kWh | | $1.77 |
| 9 | Annual Effect for a Residential Customer using 16,236 kWh | | $21.24 |