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December 5, 2011

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HAND DELIVERED

RECEIVED
DEC 05 2011
PUBLIC SERVICE COMMISSION

Jeff R. Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Case No. 2011-00401

Dear Mr. Derouen:

Enclosed please find and accept for filing the original and ten copies of Kentucky Power Company's Application in this matter. Also enclosed for filing are the original and ten copies of the Company's motion for an informal conference.

Copies of the Application and motion also are being served today on counsel for Kentucky Industrial Utility Customers, Inc. and the Attorney General along with a copy of this letter.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

STITES & HARBISON, PLLC

Mark R. Overstreet

MRO
cc: Michael L. Kurtz
Jennifer Black Hans
Dennis G. Howard II
Lawrence W. Cook

COMMONWEALTH OF KENTUCKY

RECEIVED

DEC 05 2011

PUBLIC SERVICE
COMMISSION

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	)	CASE NO. 2011-00401

APPLICATION

Kentucky Power Company ("Kentucky Power," "Company," or "KPCo") applies to the Public Service Commission of Kentucky ("Commission") pursuant to KRS 278.020(1), KRS 278.183, and 807 KAR 5:001, Sections 8, 9, and 11, and all other applicable provisions for an order: (a) approving its 2011 Environmental Compliance Plan; (b) approving its amended Environmental Surcharge Tariff (Tariff E.S.); and (c) granting it a Certificate of Public Convenience and Necessity for construction and acquisition of certain facilities associated with the 2011 Environmental Compliance Plan. Approval of the 2011 Environmental Compliance Plan, amended Tariff E.S., and the related Certificate of Public Convenience and Necessity will enable Kentucky Power to comply with environmental requirements for coal-fired electric generating facilities imposed by "the Clean Air Act, as amended, and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal…." KRS 278.183(1) ("Environmental Requirements.")

Kentucky Power states:

A. Applicant And Related Parties.

1. Kentucky Power is a public utility organized as a corporation under the laws of the Commonwealth of Kentucky in 1919 and engaged in the generation, purchase, transmission, distribution, and sale of electric power. Its post office address is: 101A Enterprise Drive, P.O. Box 5190, Frankfort, Kentucky 40602-5190. Kentucky Power serves approximately 173,400 customers in the following 20 Kentucky counties: Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Johnson, Knott, Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike, and Rowan. Kentucky Power also supplies electric power at wholesale to other utilities and municipalities in Kentucky for resale. Kentucky Power is a utility within the meaning of KRS 278.010(3).

2. 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 1 to Kentucky Power's application, and are incorporated by reference pursuant to 807 KAR 5:001, Section 8(3).

3. Kentucky Power is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is a New York corporation having an address of 1 Riverside Plaza, Columbus, Ohio 43215. AEP is one of the largest investor-owned electric public utility holding companies in the United States. Its electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. AEP is not a utility within the meaning of KRS 278.010(3).

B. Kentucky Power Units And Applicable Agreements.

4. Kentucky Power is the owner of Big Sandy Unit 1 and Big Sandy Unit 2. Both units are located at 23000 Highway 23 North, Louisa, Lawrence County, Kentucky. Big Sandy Unit 1 is a 278 MW coal-fired steam electric generating unit completed in 1963. Big Sandy Unit 2 is an 800 MW coal-fired steam electric generating unit completed in 1969.

5. Kentucky Power is a party to an agreement dated July 6, 1951, as amended, by and between Appalachian Power Company ("APCo"), Kentucky Power, Columbus Southern Power Company ("CSPCo"), Indiana Michigan Power Company ("I&M"), and Ohio Power Company ("OPCo") that defines the sharing of costs and benefits of their respective generating plants ("AEP Power Pool"). The AEP Power Pool "is a tariff that contains rates and terms of service for the wholesale sale of power and is subject to regulation by … [the Federal Energy Regulatory Commission ("FERC")]. The members of the AEP [Power] Pool share generating capacity and either make or receive capacity-related payments pursuant to FERC-approved rates." Order, *In the Matter of: The Application of Kentucky Power Company for Approval of An Amended Compliance Plan for Purposes of Recovering Additional Costs of Pollution Control Facilities And To Amend Its Environmental Cost Recovery Surcharge Tariff*, Case No. 2006-00307 at 2-3 (Ky. P.S.C. January 24, 2007).

6. In December 2010, each member of the AEP Power Pool gave notice of its decision to terminate the Interconnection Agreement effective January 1, 2014, or such other date approved by the FERC, subject to state regulatory input. It is unknown at this time whether the AEP Power Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers, or if each company will operate independently. The

decision to terminate is subject to management's ongoing evaluation. The AEP Power Pool members may revoke their notices of termination.

7. Under a FERC-approved Unit Power Agreement with American Electric Generating Company ("AEGCo"), a wholly-owned subsidiary of AEP that is not a member of the AEP Power Pool, KPCo purchases 15% (or 393 MW) of the 2,620 MW Rockport Plant capacity ("Rockport Agreement"). The unit power agreement expires in December 2022. KPCo pays a demand charge for the right to receive the power.

8. Included within the charges paid by Kentucky Power under the Rockport Agreement and the AEP Power Pool are Kentucky Power's allocated portion of the costs of environmental projects and environmental charges at I&M (Rockport Agreement and AEP Power Pool) and OPCo (AEP Power Pool) facilities used for the production of energy from coal, including costs incurred to comply with the Environmental Requirements ("Environmental Compliance Costs.") Pursuant to KRS 278.183, Kentucky Power was authorized by prior orders of the Commission[1] to recover through its environmental surcharge Environmental Compliance Costs included within the charges paid by Kentucky Power under the Rockport Agreement and the AEP Power Pool.

C. Applicable Environmental Requirements.

9. Kentucky Power and the electric utility industry are facing new United States Environmental Protection Agency ("EPA") regulations arising under the federal Clean Air Act. These include the Cross-State Air Pollution Rule ("CSAPR") and the proposed Electric Generating Unit Maximum Achievable Control Technology Rule ("EGU MACT Rule"), In addition, Kentucky Power's Big Sandy Unit 1 and Big Sandy Unit 2 are subject to requirements

[1] *See e.g.* Order, *Application of Kentucky Power Company d/b/a American Electric Power To Assess A Surcharge Under KRS 278.183 to Recover Costs of Compliance with the Clean Air Act and Those Environmental Requirements Which Apply to Coal Combustion Waste and By-Products*, Case No. 96-00489 (Ky. P.S.C. May 27, 1997).

imposed by the Consent Decree entered by the United States District Court for the Southern District of New York in an action arising under the Federal Clean Air Act, *United States v. American Electric Power Service Corp.*, Civil Action C2-99-1250 ("Consent Decree"). (The CSAPR, EGU MACT Rule and Consent Decree are referred to collectively as the "Clean Air Act Requirements.") The Clean Air Act Requirements are among the environmental requirements listed in KRS 278.183.

10. The CSAPR requires reductions in emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) from power plants in 28 eastern, southern, and mid-western states (including Kentucky) and the District of Columbia. It establishes state obligations to reduce emissions of NO_X and SO_2 that, according to EPA, significantly contribute to another state's fine particulate and ozone nonattainment and maintenance areas. Each of the affected States and the District of Columbia is required to limit its emissions to a prescribed cap; each emission unit within these states is allotted a specific budget of NO_x and SO_2 allowances on an annual basis. The allowance allocations for Big Sandy Unit No. 1 and Big Sandy Unit No. 2 are described in more detail in the testimony of John McManus. The CSAPR has two compliance phases, the first beginning January 1, 2012, and the second beginning January 1, 2014.

11. The proposed EGU MACT Rule will impose stringent limits on the emissions of mercury and many other hazardous air pollutants (HAPS), including mercury, arsenic, lead, cadmium and selenium, various acid gases such as hydrochloric acid, and many organic HAPs, from coal-fired electric generating plants. The final version of the Rule is expected to be issued on or about December 16, 2011. Under the Clean Air Act, the final EGU MACT Rule will become effective three years following its publication, with a provision for a one-year extension upon the approval of the permitting authority. Under the proposed EGU MACT rule, KPCo

would be required to install environmental controls at the Big Sandy Unit 2 by the end of 2014 (or 2015 with the one-year extension), or the unit will be unable to operate.

12. As part of the Consent Decree, which covered all coal-fired units in the five eastern states of the AEP System, KPCo agreed in part to install flue gas desulfurization emissions control equipment on Big Sandy Unit 2 by December 31, 2015. The proposed compliance dates under the proposed EGU MACT rule and the final CSAPR rule will satisfy the compliance dates of the Consent Decree.

13. The CSAPR and the EGU MACT rule have short, strict compliance deadlines. Kentucky Power will violate the Clean Air Act Requirements if it operates Big Sandy Unit 1 and Big Sandy Unit 2 past the compliance dates without the installation of updated environmental technology.

APPLICATION FOR CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

A. The Environmental Projects.

14. To meet the Environmental Requirements, Kentucky Power proposes to retro-fit Big Sandy Unit 2 with a Dry Flue Gas Desulfurization System ("DFGD"). An illustration of the DFGD technology is filed with this application as **EXHIBIT 1**. The DFGD will include the installation or construction of the following equipment and facilities at or near Big Sandy Unit No. 2:

- Pebble lime truck unloading equipment and storage silos
- Reagent preparation system foundations, equipment, and building
- Absorber vessels or ductwork modules
- Induced draft fans and motors
- Tie-in ductwork

- Pulse jet fabric filter
- Ash recycle system foundations, equipment, and building
- Waste storage silo and truck loading equipment
- Equipment to supply electrical needs of new process equipment
- Balance of plant piping (fire protection, service water, sanitary, etc.)

15. In addition to retro-fitting Big Sandy Unit 2 with the DFGD, the Company will construct certain DFGD Associated Projects, construct a DFGD landfill, and a DFGD ash haul road. (The DFGD retro-fit of Big Sandy Unit 2, the Big Sandy DFGD Associated Projects, the Big Sandy DFGD landfill, and the Big Sandy DFGD ash haul road are referred to collectively as the "Big Sandy Unit 2 DFGD Project.") Kentucky Power currently anticipates retiring Big Sandy Unit 1 by January 1, 2015, and will make all requisite filings related to this retirement by separate application.

16. Kentucky Power's Big Sandy Unit 2 DFGD Project is the least cost and most cost-effective means of complying with the Environmental Requirements, and is required by the public convenience and necessity.

17. Kentucky Power is executing the Big Sandy Unit 2 DFGD Project using the phased approach described in the direct testimony of Robert Walton. The project is currently in Phase 1, with initial planning and conceptual engineering completed. Kentucky Power proposes to commence site construction activities at the Big Sandy Generating Station on or about July 1, 2013. Kentucky Power requests that the Commission issue its Certificate of Public Convenience and Necessity by June 5, 2012.

B. Information Provided Pursuant To 807 KAR 5:001, Section 9.

18. There are no utilities, corporations, or persons with whom the proposed new construction is likely to compete.

19. Kentucky Power will submit requests to modify existing Title V operating permits to reflect all of the proposed Big Sandy construction. Kentucky Power will seasonably file applications for the needed Title V permit changes, and will file a copy of the applications with the Commission when they are available. Kentucky Power will also seek any applicable construction permits. Kentucky Power is not required to seek any franchises in connection with the Big Sandy Unit 2 DFGD Project.

20. The projected capital cost of the Big Sandy Unit 2 DFGD Project is $940,300,067. The cost will be financed through short term debt, long-term debt, and equity. Separate application for approval of financing will be made as required by KRS 278.300.

21. The estimated annual cost of operation of the proposed Big Sandy Unit 2 DFGD Project after the proposed facilities are completed is $46,067,000. The estimated annual maintenance expense associated with the Big Sandy Unit 2 DFGD Project after the proposed facilities are completed is $2,600,000.

22. In conformity with 807 KAR 5:001, Section 9, three sets of maps to suitable scale showing the location of the proposed new construction and the location and identification of the ownership of any like facilities owned by others located within the map area are filed with this Application as EXHIBIT 2.

REQUEST FOR APPROVAL OF KENTUCKY POWER'S 2011 ENVIRONMENTAL COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE

23. Kentucky Power is entitled to the current recovery of its Environmental Compliance Costs, including a reasonable return on construction and other capital costs, in accordance with its Commission-approved plan for complying with Environmental Requirements ("Environmental Compliance Plan.")

A. Kentucky Power's Prior Environmental Compliance Plans.

24. KPCo's Environmental Compliance Plan first was approved by the Commission by Order dated May 27, 1997, in Case No. 1996-00489[2] ("Original Environmental Compliance Plan"). The Company's Original Environmental Compliance Plan included the following projects:

(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 the Rockport Plant.

Kentucky Power is responsible for its contractual share of the OPCo and I&M environmental costs under the FERC-approved AEP Power Pool and the FERC-approved Rockport Agreement. The costs associated with Kentucky Power's Original Environmental Compliance Plan are

[2] *In the Matter of: Application of Kentucky Power Company d/b/a American Electric Power to Assess A Surcharge Under KRS 278.183 to Recover Costs of Compliance With the Clean Air Act and Those Environmental Requirements Which Apply To Coal Combustion Wastes and By-Products,*

reasonable. The Original Environmental Compliance Plan, including each of its components, is a reasonable and cost-effective means for the Company to comply with the Environmental Requirements.

25. KPCo's First Amended Environmental Compliance Plan ("2003 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.

The 2003 Environmental Compliance Plan was approved by the Commission by Order dated March 31, 2003, in Case No. 2002-00169.[3] The costs associated with Kentucky Power's 2003 Environmental Compliance Plan are reasonable. The 2003 Environmental Compliance Plan, including each of its components, is a reasonable and cost-effective means for the Company to comply with the Environmental Requirements.

26. KPCo's Second Amended Environmental Compliance Plan ("2005 Environmental Compliance Plan"), consisted of the items contained in the Original Environmental Compliance Plan (filed in Case No. 96-489), the items contained in the 2003 Compliance Plan (filed in Case No. 2002-00169), plus certain environmental costs associated with 53 environmental projects at OPCo and I&M generating plants. Kentucky Power is responsible for its contractual share of the OPCo and I&M environmental costs under the FERC-approved AEP Power Pool and the FERC-approved Rockport Agreement. The Commission

[3] *In the Matter of: The Application of Kentucky Power Company d/b/a American Electric Power for Approval of an Amended Compliance Plan for Purposes of Recovering the Costs of New and Additional Pollution Control Facilities and to Amend Its Cost Recovery Surcharge Tariff.*

approved Kentucky Power's 2005 Environmental Compliance Plan (except for certain costs related to four SO_3 mitigation projects) by Orders dated September 7, 2005, and October 17, 2005, in Case No. 2005-00068.[4] The costs associated with the 2005 Environmental Compliance Plan are reasonable. The 2005 Environmental Compliance Plan, including each of its components, is a reasonable and cost-effective means for the Company to comply with the Environmental Requirements.

27. KPCo's Third Amended Environmental Compliance Plan, ("2007 Environmental Compliance Plan"), consisted of the items contained in the Original Environmental Compliance Plan (filed in Case No. 96-489), the items contained in the 2003 Compliance Plan (filed in Case No. 2002-00169), the items contained in the 2005 Environmental Compliance Plan (filed in Case No. 2005-00068), plus the expense associated with 44 environmental projects at OPCo and I&M generating plants. Kentucky Power is responsible for its contractual share of the OPCo and I&M environmental costs under the FERC-approved AEP Power Pool and the FERC-approved Rockport Agreement. The 2007 Environmental Compliance Plan was approved by the Commission in an order dated January 24, 2007, in Case No. 2006-00307.[5] The costs associated with Kentucky Power's 2007 Environmental Compliance Plan are reasonable. The 2007 Environmental Compliance Plan, including each of its components, is a reasonable and cost-effective means for the Company to comply with the Environmental Requirements.

B. <u>Kentucky Power's 2011 Environmental Compliance Plan</u>.

28. KPCo's Fourth Amended Environmental Compliance Plan, ("2011 Environmental

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[4] *In the Matter of: Application of Kentucky Power Company for Approval of an Amended Compliance Plan for Purposes of Recovering Additional Costs of Pollution Control Facilities and to Amend Its Environmental Cost Recovery Surcharge.*

[5] *The Application of Kentucky Power Company for Approval of an Amended Compliance Plan for Purposes of Recovering Additional Costs of Pollution Control Facilities and to Amend Its Environmental Cost Recovery Surcharge Tariff.*

This 5th day of December, 2011.

Respectfully submitted,

Mark R. Overstreet
R. Benjamin Crittenden
Laura S. Crittenden
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421 West Main Street
P.O. Box 634
Frankfort, KY 40602-0634
Telephone: (502) 223-3477

COUNSEL FOR KENTUCKY POWER
COMPANY

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by first class mail, postage prepaid, upon the following persons this 5th day of December, 2011.

David F. Boehm
Michael L. Kurtz
Kurt J. Boehm
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

Jennifer Black Hans
Dennis G. Howard II
Lawrence W. Cook
Assistant Attorneys General
Office of Rate Intervention
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601-8204

Mark R. Overstreet

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of: APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	CASE NO. 2011-00401

Exhibits To Application

1. ILLUSTRATION OF THE DFGD TECHNOLOGY;

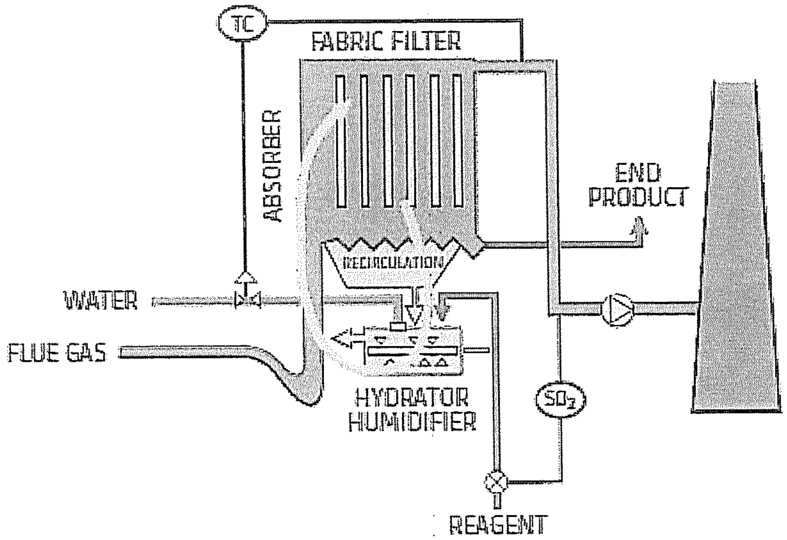
2. MAPS TO SUITABLE SCALE SHOWING THE LOCATION OF THE PROPOSED NEW CONSTRUCTION AND THE LOCATION AND IDENTIFICATION OF THE OWNERSHIP OF ANY LIKE FACILITIES OWNED BY OTHERS LOCATED WITHIN THE MAP AREA;

3. KENTUCKY POWER'S 2011 ENVIRONMENTAL COMPLIANCE PLAN;

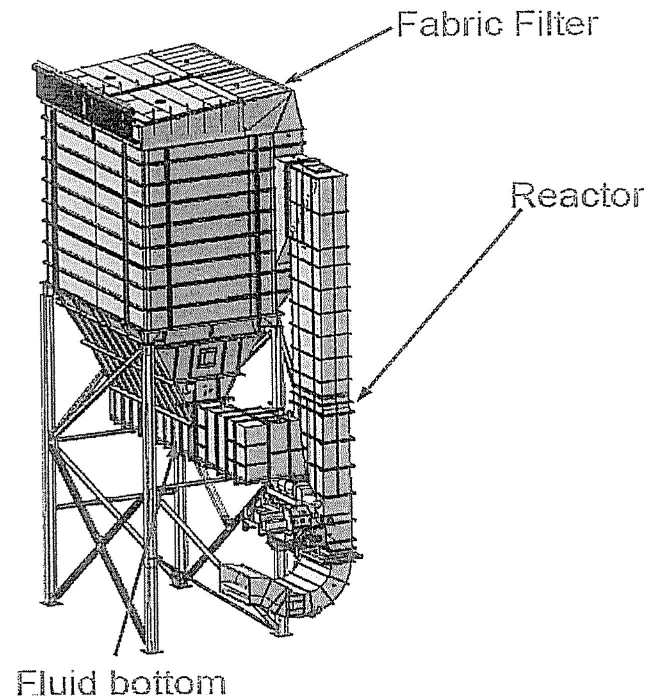
4. PROPOSED TARIFF E.S. (ENVIRONMENTAL SURCHARGE);

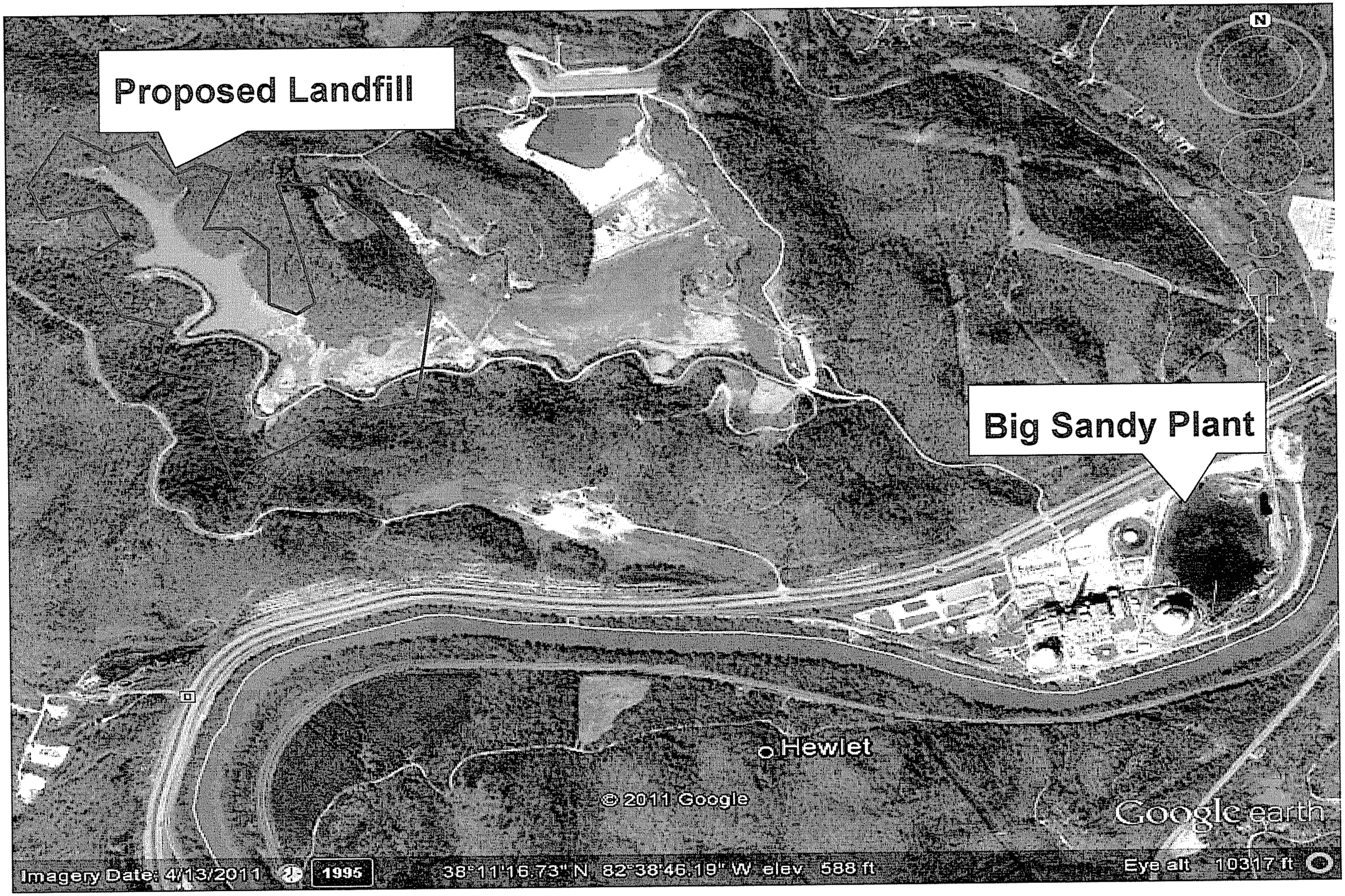
5. CERTIFICATE OF PUBLICATION AND PUBLIC NOTICE.

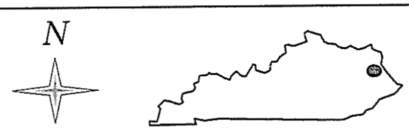
Big Sandy Unit 2
SO_2 Technology Selection



RECIRCULATION CONCEPT





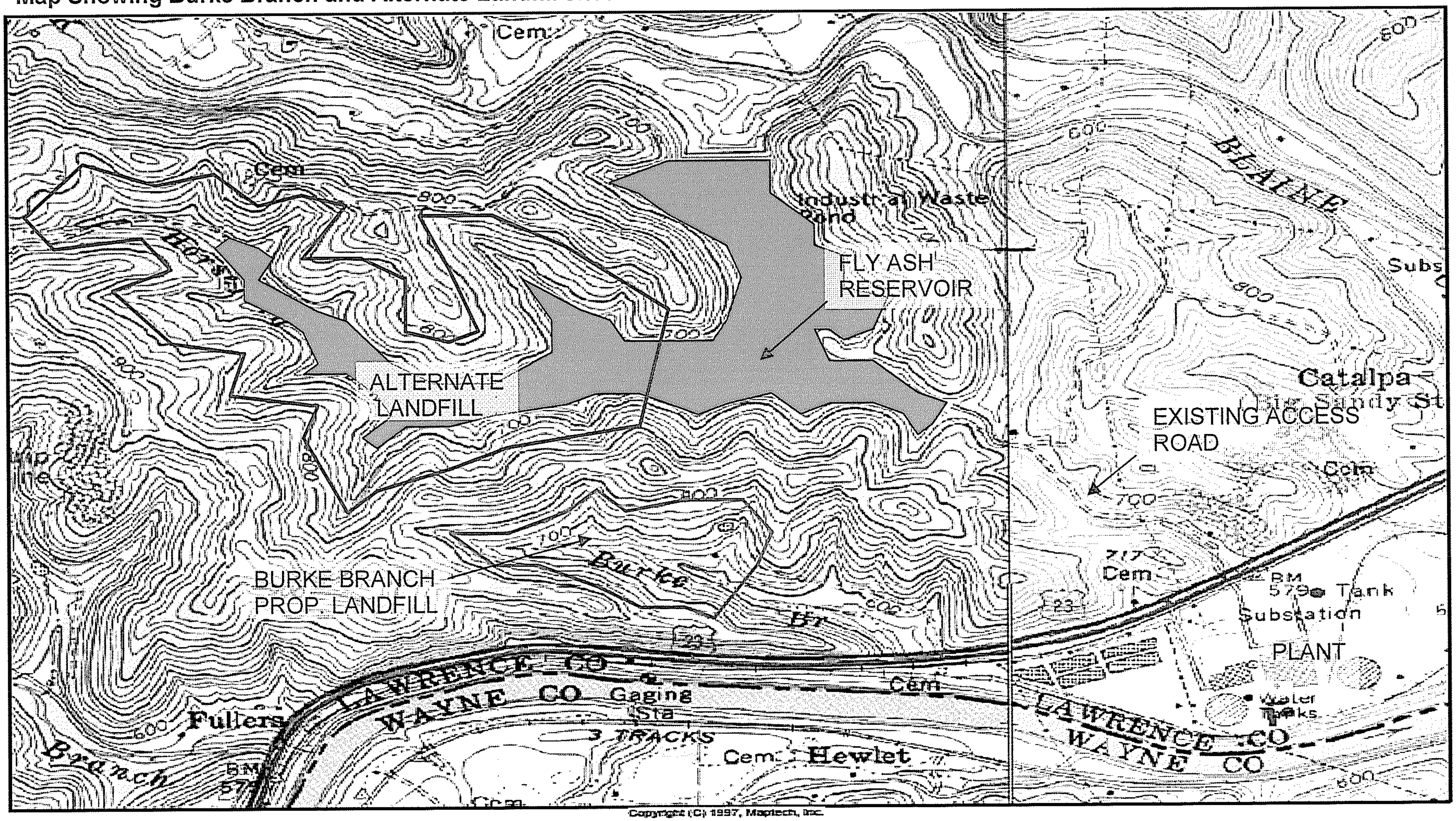


American Electric Power -Projects

Proposed Landfill – Horseford Creek

Site Location Map

Map Showing Burke Branch and Alternate Landfill sites



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Kentucky Power Company
Fourth Amended Environmental Compliance Plan
2011 Plan
Pursuant to KRS 278.183

Project	Pollutant	Description	Year
1	SO_2	Dry Flue Gas Desulfurization System - Big Sandy Unit 2	2016
2	SO_2	Dry Flue Gas Desulfurization System Associated Projects - Big Sandy Unit	2016
3	SO2, Particulate	Dry Flue Gas Desulfurization System Landfill - Big Sandy Unit 2	2016
4	SO2, Particulate	Dry Flue Gas Desulfurization System Ash Haul Road - Big Sandy Unit 2	2016
		Kentucky Power's share of the Pool Capacity Costs associated with the following:	
5	Particulates	Dry Fly Ash Disposal Conversion- Amos Unit 3	2010
6	Mercury, Selenium	Ash Pond Discharge Diffuser - Amos Unit 0	2012
7	Mercury	Flue Gas Desulfurization Mercury Waste Water Treatment - Amos Unit 0	2012
8	Mercury	Mercury In-Pond Chemical Treatment - Amos Unit 0	2011
9	Mercury	Activated Carbon Injection (ACI) - Rockport Units 1 & 2	2009
10	NO_X	Selective Non-Catalytic Reduction (SNCR) - Tanners Creek Units 1-3	2009
11	SO_2 / NO_X	Costs associated with the SO_2 and NO_x Allowances required by CSAPR	2012
		Kentucky Power's Previously Approved Projects:	
12	NO_X	Low NO_x Burners - Big Sandy Unit 2	1994
13	NO_X	Low NO_x Burners - Big Sandy Unit 1	1998
14	SO_2 / NO_X	Continuous Emission Monitors (CEMS) - Big Sandy Plant	1994
15	SO_2	SO_2 Allowances Purchased	1995
16	SO_2 / NO_X / Particulates	Kentucky Air Emissions Fee - Big Sandy Plant	Annual
17	SO_2 / NO_X	Continuous Emission Monitors (CEMS) - Rockport Plant	1994
18	SO_2 / NO_X / Particulates	Indiana Air Emissions Fee - Rockport Plant	Annual
19	NO_X	Over-Fire Air Water Injection w/Boiler Tubes Overlays - Big Sandy Unit 1	2002
20	Particulates	Precipitator Improvements - Big Sandy Unit 2	2002
21	NO_X	Selective Catalytic Reduction (SCR) - Big Sandy Unit 2	2003
22	NO_X	Rockport Units 1 and 2 Low NOx Burners, Over Fire Air and Landfill	2003-2008
23	NO_X	NO_x Allowances Purchased	2004
		Kentucky Power's share of the Previously Approved Pool Capacity Costs associated with the following:	
24	SO_2 / NO_X / Particulates	Amos Unit 3 CEMS, Low NOx Burners, SCR, FGD, Landfill, Coal Blending Facilities, Electrostatic Precipitator (ESP) Modifications, and SO_3	1995-98-2003-2007
25	SO_2 / NO_X / Particulates	Cardinal Unit 1 CEMS, Low NOx Burners, SCR, FGD, Landfill, Catalyst Replacement, and SO_3 Mitigation	1994-1998-2003-2004-2008
26	SO_2	Scrubbers - Gavin Plant	1995
27	NO_X	Gavin Plant SCR, SCR Catalyst Replacement, and SO_3 Mitigation	2005-2006
28	NO_X	Gavin Units 1 and 2 Low NOx Burners	1999

Kentucky Power Company
Fourth Amended Environmental Compliance Plan
2011 Plan
Pursuant to KRS 278.183

Project	Pollutant	Description	Year
29	SO_2 / NO_X / Particulates	Kammer Units 1, 2 and 3 CEMS, Over Fire Air and Duct Modification	1999-2003
30	NO_X	Mitchell Units 1 and 2 Water Injection, Low NOx Burners, Low NOx Burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and SO_3 Mitigation	1993-1994-2002-2007
31	SO_2 / NO_X / Particulates	Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypson Material handling Facilities	1993-2004-2007
32	NO_X	Muskingum River Unit 1 Low NOx Ductwork, Over Fire Air, Over Fire Air Modification, Water Injection, and Water Injection Modification	2000-2003-2004
33	NO_X	Muskingum River Unit 2 Low NOx Ductwork, Over Fire Air, Over Fire Air Modification, and Water Injection	2000-2004
34	NO_X	Muskingum River Unit 3 Over Fire Air, Over Fire Air Modification with NOx Instrumentation	2000-2003-2004
35	NO_X	Muskingum River Unit 4 Over Fire Air, Over Fire Air Modification	2000-2004
36	SO_2 / NO_X	Muskingum River Unit 5 Low NOx Burners, Low NOx Burner Modification and Weld Overlays, SCR, and SO_3 Mitigation	1994-2004-2005
37	SO_2 / NO_X / Particulates	Muskingum River Common CEMS	1993
38	NO_X	Phillip Sporn Unit 2 Low NOx Burners, Low NOx Burner Modification	1997-2003
39	NO_X	Phillip Sporn Unit 4 Low NOx Burners, Low NOx Burner Modifications and Modulating Injection Air System	1998-1999-2004
40	NO_X	Phillip Sporn Unit 5 Low NOx Burners and Modulating Injection Air System	1998-1999-2004
41	SO_2 / NO_X / Particulates	Phillip Sporn Common CEMS, SO_3 Injection System and Landfill	1994-2003-2008
42	NO_X	Tanners Creek Unit 1 Low NOx Burners, Low NOx Burner Modifications and Low NOx Burners Leg Replacements	1995-2004
43	NO_X	Tanners Creek Unit 2 Water Injection, Low NOx Burners,and Low NOx Burner Modifications	1998-1999-2003-2004
44	NO_X	Tanners Creek Unit 3 Low NOx Burners	1998-1999-2003-2004
45	NO_X / Particulates	Tanners Creek Unit 4 Over Fire Air, Low NOx Burners, Coal Blending Project and ESP Controls Upgrade	2002-2004
46	SO_2 / NO_X / Particulates	Tanners Creek Common CEMS and Coal Blending Station	1995-1996-2006
47	SO_2 / NO_X / 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

KENTUCKY POWER COMPANY

Original Sheet No. 29-1
Canceling _______ Sheet No. 29-1

P.S.C. ELECTRIC NO. 9

TARIFF E.S.
(Environmental Surcharge)

APPLICABLE. (T)

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., Experimental S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., 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	$ 3,991,163
FEBRUARY	3,590,810
MARCH	3,651,374
APRIL	3,647,040
MAY	3,922,590
JUNE	3,627,274
JULY	3,805,325
AUGUST	4,088,830
SEPTEMBER	3,740,010
OCTOBER	3,260,202
NOVEMBER	2,786,040
DECEMBER	4,074,821
	$44,185,079

(I)
(I)

(Continued on Sheet 29-2)

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Bunt Kirtley
EFFECTIVE
6/29/2010
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

DATE OF ISSUE July 16, 2010 DATE EFFECTIVE Service rendered on and after
ISSUED BY E.K. Wagner E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No.2009-00459 dated June 28, 2010

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, the 2005 Plan, the 2007 Plan, and the 2011 Plan. (T)

The Rate of Return for Kentucky Power is 10.5% rate of return on equity as authorized by the Commission in its June 28, 2010 Order in Case No. 2009-00459 at page 6.

(Cont'd on Sheet No. 29-3)

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 No. 29-4)

DATE OF ISSUE July 16, 2010 DATE EFFECTIVE Service rendered on and after Ju

ISSUED BY E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT
NAME TITLE ADDRESS

Issued by authority of an order of the Public Service Commission in Case No. 2009-00459 dated June 28, 2010

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Brent Kirtley
EFFECTIVE
6/29/2010
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

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

RATE (Cont'd)

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

(r) costs associated with installing, operating, and maintaining a Dry Flue Gas Desulfurization Unit (DFGD), DFGD Ash Haul Road and Landfill, at the Big Sandy Generating Plant Unit No. 2. (N)

(s) The Company's share of the pool Capacity costs associated with the following: (T)

- Amos Unit No. 3 CEMS, Low NO_x Burners, SCR, FGD, Landfill, Coal Blending Facilities, SO_3 Mitigation, Electrostatic Precipitator Modification (ESP),and Dry Fly Ash Disposal Conversion (T)
- Amos Plant Common FGD Hg Waste Water Plant Treatment, Hg In-Pond Chemical Treatment, and Ash Pond Discharge Diffusers (N)
- Cardinal Unit No 1 CEMS, Low NO_x Burners, SCR, Catalyst Replacement, FGD, Landfill and SO_3 Mitigation
- Gavin Plant SCR and SCR Catalyst Replacement
- Gavin Unit No 1 and 2 Low NO_x Burners and SO_3 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 SO_3 Mitigation
- Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsom 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 Overlay, an SCR and SO3 Mitigation
- Muskingum River Common CEMS
- Phillip Sporn Unit No 2 Low NO_x Burners with Modifications

(Cont'd on Sheet No. 29-5)

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

RATE (Cont'd)

- 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, Landfill, and Activated Carbon Injection (ACI) (T)
- Tanners Creek Unit No 1 Low NO_x Burners, with Modifications, Low NO_x Burners Leg Replacement, and Selective Non-Catalytic Reduction (T)
- Tanners Creek Unit No 2 and 3 Low NO_x Burners with Modifications and Selective Non-Catalytic Reduction (T)
- Tanners Creek Unit No 4 Over Fire Air and 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.
- Costs associated with the SO_2 and NO_x allowances required by the Cross-State Air Pollution Rule (CSAPR). (N)

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

APPLICATION OF KENTUCKY POWER COMPANY	)	
FOR APPROVAL OF ITS 2011 ENVIRONMENTAL	)	
COMPLIANCE PLAN, FOR APPROVAL OF ITS	)	
AMENDED ENVIRONMENTAL COST RECOVERY	)	Case No. 2011-00401
SURCHARGE TARIFF, AND FOR THE GRANT OF A	)	
CERTIFICATE OF PUBLIC CONVENIENCE AND	)	
NECESSITY FOR THE CONSTRUCTION AND	)	
ACQUISITION OF RELATED FACILITIES	)	

Certification of Publication And Public Notice

I, Lila P. Munsey, Manager, Regulatory Services, Kentucky Power Company, hereby certify that the attached notice will be published once a week for three consecutive weeks in the identified newspapers of general circulation in Kentucky Power Company's service territory. The first publication was made the week of November 28, 2011, with subsequent publications in each newspaper the weeks of December 5, 2011 and December 12, 2011.

Proof of publication will be seasonably filed with the Commission following the completion of publication.

A copy of the application and testimony in this proceeding, including the revised Tariff E.S., also will be made available for public inspection at Kentucky Power Company's district service buildings in Ashland, Pikeville and Hazard, Kentucky, and will be provided upon request.

Lila P. Munsey

Lila P. Munsey

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF FRANKLIN)

The foregoing instrument was subscribed and sworn to before me this 5th day of December, 2011, by Lila P. Munsey.

My commission expires: January 23, 2013

Judy K Rosquist
NOTARY PUBLIC

[SEAL]

KENTUCKY POWER®
A unit of American Electric Power

Kentucky Power
101A Enterprise Drive
P O Box 5190
Frankfort, KY 40602-5190
KentuckyPower.com

November 21, 2011

KENTUCKY PRESS ASSOCIATE

ATTN: Rachael McCarty

FAX 502-875-2624

Dear Ms. McCarty:

As you requested, we are faxing information to be published in the Classified Section under "Legal Notices" in the following "legal" newspapers in the Kentucky Power service area:

The Daily Independent
P.O. Box 311
Ashland, KY 41105-0311

Big Sandy News
P.O. Box 766
Louisa, KY 41230

Grayson Journal-Enquirer
113 Hord Street
Grayson, KY 41143

Greenup News Times
P.O. Box 724
Greenup, KY 41144

The Morehead News
722 West First Street
Morehead, KY 40351

Lewis County Herald
260 Main Street
Vanceburg, KY 41179

The Manchester Enterprise
103 Third Street
Manchester, KY 40962

The Jackson Times
1003 College Avenue
Jackson, KY 41339

The Mountain Eagle
P.O. Box 808
Whitesburg, KY 41858

Leslie County News
P.O. Box 917
Hyden, KY 41749

Hazard Herald-Voice
P.O. Box 869
Hazard, KY 41702

Troublesome Creek Times
P.O. Box 700
Hindman, KY 41822

The Booneville Sentinel
P.O. Box 129
Booneville, KY 41314

Appalachian News-Express
P.O Box 802
Pikeville, KY 41502

Floyd County Times
P.O. Box 391
Prestonsburg, KY 41653

The Mountain Citizen
P.O. Box 1029
Inez, KY 41224

The Salyersville Independent
P.O. Box 29
Salyersville, KY 41465

Elliott County News
P.O. Box 187
West Liberty, KY 41472

The Paintsville Herald
West Third Street
Paintsville, KY 41240

Licking Valley Courier
P.O. Box 187
West Liberty, KY 41472

In accordance with 807 KAR 5:001 Section 10 (4) (c) (3) the company is requesting publishing the notice once a week for three (3) consecutive weeks beginning November 28, 2011.
A copy of the final ad after it is reset should be "faxed" to the below address for our approval.

As we discussed, immediately following publication, your office will prepare a notarized affidavit and forward it along with the tear sheet, to the address below

The invoice for any costs associated with the service should be mailed to the address below.

JUDY K. ROSQUIST
KENTUCKY POWER COMPANY
REGULATORY SERVICES
P.O. BOX 5190
FRANKFORT, KY 40602

If you have any questions, please call Judy at 502-696-7011.

Thank you,

Lila P. Munsey

Lila P. Munsey
Manager Regulatory Services

COPY OF AD ON FOLLOWING SHEET

NOTICE TO CUSTOMERS

OF

KENTUCKY POWER COMPANY

PROPOSED CHANGES TO THE ENVIRONMENTAL SURCHARGE TARIFF

PLEASE TAKE NOTICE that Kentucky Power Company (KPCo) will file an Application with the Kentucky Public Service Commission (the Commission) in Case No. 2011-00401 on December 5, 2011. Pursuant to Kentucky Revised Statute 278.183, the Application will request approval of an amended compliance plan (2011 Environmental Compliance Plan) for the purpose of recovering the capital and operation and maintenance costs associated with new pollution control facilities through an increase in the environmental surcharge on customers' bills rendered on and after July 31, 2012, under KPCo's Tariff E.S., also known as the environmental surcharge. 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 July 31, 2012, to recover additional costs of complying with the Federal Clean Air Act, as amended, 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.

Federal, state, and local environmental regulations require KPCo to build and upgrade equipment and facilities to operate in an environmentally sound manner. Specifically, KPCo is seeking Commission approval of a Certificate of Public Convenience and Necessity (CPCN) to build a Dry Flue Gas Desulfurization (DFGD) system for Unit 2 at its Big Sandy Generating Station in Lawrence County, Kentucky. The 2011 Environmental Compliance Plan also includes KPCo's share of an Activated Carbon Injection (ACI) system put in-service in September 2009 at Rockport Generating Station Units 1 and 2; Selective Non-Catalytic Reduction (SNCR) systems put in-service in December 2009 at Tanners Creek Generating Station Units 1, 2 and 3; Dry Fly Ash Disposal Conversion put in-service in August 2010 at Amos Generating Station Unit 3; Mercury In-Pond Chemical Treatment put in-service in July 2011, as well as Ash Pond Discharge Diffusers and Flue Gas Desulfurization Mercury Waste Water Treatment facilities to be built by the fourth quarter of 2012 at Amos Generating Station Common Plant. Additional required environmental allowances to meet the Cross State Air Pollution Rule are also included in this filing. The capital cost of the new pollution control facilities for which KPCo will seek cost recovery at this time is estimated to be $1.07 billion. Additional operation and maintenance expenses will be incurred for these projects and are costs that KPCo is requesting to recover through the environmental surcharge in its application.

The impact on KPCo's electric customers is estimated to be a 0.20% increase in 2012 with a maximum increase of 31.41% in 2016. For a KPCo residential customer using an average of 1,000 kWh per month, the initial monthly increase is expected to be $0.20 in 2012, with a maximum monthly increase expected to be $30.76 in 2016.

The Environmental Surcharge Application and tariff change described in this Notice is proposed by KPCo. However, the Public Service Commission may issue an order modifying or denying KPCo's application and proposed tariff change. Such action may result in a change in the environmental surcharge amount for a customer that is 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. 2011-00401. That motion shall be submitted to the Public Service Commission, 211 Sower Boulevard, P.O. Box 615, Frankfort, Kentucky 40602-0615, 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 supporting testimony by contacting Kentucky Power Company at 101A Enterprise Drive, P.O. Box 5190, Frankfort, Kentucky 40602-5190, attention Ranie K. Wohnhas. A copy of the Application and testimony is available for public inspection at KPCo's district service buildings located in Ashland, Hazard, and Pikeville.

KENTUCKY PRESS SERVICE

101 CONSUMER LANE
FRANKFORT, KY 40601
(502) 223-8821
FAX (502) 875-2624

List of newspapers running the Notice to Kentucky Power Company customers. *Attached tear sheets provide proof of publication:*

Ashland Daily Independent
Booneville Sentinel
Elliott County News
Grayson Journal-Enquirer
Greenup News
Hazard Herald
Hindman Troublesome Creek Times
Hyden Leslie Co. News
Inez Mountain Citizen
Jackson Times
Louisa Big Sandy New
Manchester Enterprise
Morehead News
Paintsville Herald
Pikeville Appalachian News-Express
Prestonsburg Floyd County News
The Salyersville Independent
Vanceburg Lewis County Herald
West Liberty Licking Valley Courier
Whitesburg Mountain Eagle

November 21, 2011

The Kentucky Press Service
Business Affiliate of the Kentucky Press Association
Attn: Rachael McCarty
101 Consumer Lane
Frankfort, KY 40601
Phone: 502-223-8821
FAX: 502-875-2624

I hereby agree to plan for publication of the Notice attached per Kentucky Public Service Commission Rules and Regulations 807 KAR 5:001 (10) (4) (c) (3) and acknowledge same by returning a signed copy of this form to Ms. Lila P. Munsey, Kentucky Power Company, Frankfort, KY, FAX: 505-696-7009.

Receipt of and Intent to Comply
Acknowledged by:

Rachel McCarty 11-21-11

The Kentucky Press Service Date

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY	)	
FOR APPROVAL OF ITS 2011 ENVIRONMENTAL	)	
COMPLIANCE PLAN, FOR APPROVAL OF ITS	)	
AMENDED ENVIRONMENTAL COST RECOVERY	)	Case No. 2011-00401
SURCHARGE TARIFF, AND FOR THE GRANT OF A	)	
CERTIFICATE OF PUBLIC CONVENIENCE AND	)	
NECESSITY FOR THE CONSTRUCTION AND	)	
ACQUISITION OF RELATED FACILITIES	)	

DIRECT TESTIMONY

OF

JOHN M. MCMANUS

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

CASE NO. 2011-00401

TABLE OF CONTENTS

**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 employed by American Electric Power Service Corporation as Vice President - Environmental Services. 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 or the Company). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A: I earned a Bachelor of Science Degree in Environmental Engineering from Rensselaer Polytechnic Institute in 1976 and undertook graduate studies there from 1976-77. I joined AEPSC's 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 - Environmental Services in April 2003. I am also a registered professional engineer in the State of Ohio.

Q: **WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT-ENVIRONMENTAL SERVICES?**

A: I am responsible for oversight of environmental support for all generation and energy delivery facilities owned by AEP operating companies. I am AEP's listed Designated Representative on Title IV Acid Rain Program matters and the listed NO_X Authorized Account Representative on NO_X State Implementation Plan (NO_X SIP Call) Program matters. Environmental Services provides permitting and compliance support, guidance, procedures, recommendations and training for AEP's operating companies in order to maintain and improve their environmental programs and enhance compliance with environmental laws, regulations, and policies. As part of this effort, Environmental Services is also involved in the development process for environmental regulations, coordinating with operating company staffs to support AEP's corporate strategies and values concerning the environment.

Q: **HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

A: Yes, I have testified before the Kentucky Public Service Commission on a number of occasions as well as before the Virginia State Corporation Commission, Indiana Utility Regulatory Commission, Public Service Commission of West Virginia, Public Utilities Commission of Ohio and have submitted testimony before the Public Utility Commission of Texas.

III. PURPOSE OF TESTIMONY

Q: **WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A: The purpose of my testimony is to describe the applicable environmental rules that drive the need and timing to retrofit an environmental project on Big Sandy Unit 2. These controls are being installed at Unit 2 to comply with requirements of the final Cross-State Air Pollution Rule (CSAPR) as they apply to KPCo facilities and the proposed Electric Generating Unit Maximum Achievable Control Technology (EGU MACT) Rule recently noticed by the United States Environmental Protection Agency (USEPA or EPA). I will also review other future environmental requirements that could result in cost and operational impacts to Big Sandy Plant and outline the required permitting needed to install the environmental controls that are the subject of this request for a certificate of public convenience and necessity. Further, I will describe the regulatory programs that govern the reduction or controls of air emissions related to the operation of AEP's coal-fired plants, as well as those regulatory programs related to coal combustion waste and by-products. Each AEP System company, as well as other utilities, 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). Finally, 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 KPCo, 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 final CSAPR and the proposed EGU MACT Rule. Some of the related projects are also required to address compliance requirements for coal combustion wastes and by-products under the Clean Water Act (CWA) and the Resource Conservation and Recovery Act (RCRA). I provided this project information to Company witness Munsey because OPCo's and I&M's environmental costs impact KPCo's cost under the AEP Interconnection Agreement. Also, a portion of the environmental cost of AEG is borne by KPCo through a Unit Power Agreement as discussed by Company witness Munsey.

IV. USEPA ENVIRONMENTAL REGULATIONS

Q: **PLEASE DESCRIBE THE REGULATORY PROGRAMS THAT DRIVE THE NEED FOR THE BIG SANDY UNIT 2 ENVIRONMENTAL CONTROL.**

A. The following major known and emerging federal rulemakings, and previously-established requirements, create the need for the Big Sandy Unit 2 environmental retrofit in this CPCN filing:

1. **Cross-State Air Pollution Rule (CSAPR)** – CSAPR was initially proposed by the USEPA in August 2010 as the Clean Air Transport Rule (CATR). This rule serves as a replacement for the Clean Air Interstate Rule (CAIR), which was remanded to EPA in 2008 by the D.C. Circuit Court of Appeals. The CSAPR addresses National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter, and is focused on the reduction of emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) within 28 eastern, southern and mid-western states—including

Kentucky.[1] Along with other requirements, the final CSAPR establishes state-specific annual emission "budgets" for SO_2 and NO_X. The EPA's approach for obtaining these emission reductions requires each state to limit its emissions to a prescribed cap. Based on this cap, each emitting unit within affected states has been allocated a specified budget of NOx and SO_2 allowances for the applicable compliance period, whether annual or ozone season. An annual cap for SO_2 and NOx and an ozone season cap for NOx emissions apply for Kentucky. Allowance trading within and between states is allowed on a regional basis. However, if a state's annual NO_X or SO_2 emissions exceed its annual allocation by 18% or more, those units within the state that have also emitted 18% or more above their allocations will be subject to an allowance penalty. The assurance level is the margin above the budget that states are permitted to exceed. The assurance provisions go into effect in 2012 based on the final rule, but EPA has proposed delaying the effective year to 2014.

2. **Electric Generating Unit Maximum Achievable Control Technology (EGU MACT) Rule** -- The EGU MACT Rule was proposed as a replacement for the Clean Air Mercury Rule (CAMR), which was vacated in 2008 by the D.C. Circuit Court of Appeals. The proposed EGU MACT Rule was issued by the USEPA in March 2011, and final rulemaking was originally required under a consent decree by November 16, 2011; however, EPA has been granted a one-month extension of this deadline. Designed to address the reduction of: 1) emissions of mercury; 2) other hazardous air pollutants (HAPs) in the form of toxic metals such as arsenic, lead, cadmium and selenium; 3) various acid gases including hydrochloric acid; and 4) many organic HAPs, the proposed EGU MACT rulemaking would establish emission standards for those pollutants applicable to coal and oil-fired units.

---

[1] Final CSAPR issued by the USEPA on July 6, 2011 and published in the Federal Register on August 8, 2011.

3. **NSR Consent Decree** -- In December 2007, AEP, KPCo and its affiliated eastern Operating Companies entered into a Consent Decree that settled outstanding litigation with the U.S. Department of Justice, EPA, numerous states, and other litigants that stemmed from differences in interpretation of various New Source Review requirements associated with coal unit maintenance practices. The AEP Companies admitted no violations of law and all claims against them were released. For KPCo's Big Sandy units, the Consent Decree called for the following schedule of NOx and SO_2 controls:
   - Big Sandy Unit 2: Install FGD for SO_2 by December 31, 2015
   - Big Sandy Unit 2: Continue to operate the existing Selective Catalytic Reduction (SCR) system to minimize NOx emissions
   - Big Sandy Unit 1: Install Low-NO_X Burner technology *and* limit the sulfur content of its coal to no greater than 1.75 lb. per million British thermal units (MMBtu), on an annual average basis, by the effective date of the Consent Decree.

Q. **ARE BIG SANDY UNITS 1 AND 2 THE ONLY GENERATING UNITS CITED BY THE 2007 CONSENT DECREE THAT WILL IMPACT KPCO?**

A. No. Rockport Units 1 and 2, from which KPCo receives a 30 percent purchase entitlement from the 50-percent portion of each unit that is owned/leased by affiliate AEG, are required to install FGD and SCR technology by 12/31/2017 and 12/31/2019, respectively. The KPCo relationship to Rockport Units 1 and 2 is addressed in the testimony of Company witness Munsey.

Q: **PLEASE DESCRIBE THE ORIGIN OF THE CSAPR AND PROPOSED EGU MACT RULE.**

A. The CSAPR and proposed EGU MACT Rule are federal air emissions statutes which originated from the CAA. The CAA is divided into several sections, or

Titles, which address anthropogenic emissions into the atmosphere with the ultimate goal of reducing impacts on public health and the ecosystem from man-made pollutants. In addition to the well-known CAA Title IV (Acid Rain Program) Phase I and II emission requirements for SO_2 and NO_X, additional rules regarding atmospheric emissions have stemmed from the CAA and include the NO_X State Implementation Plan (SIP) Call, and the Clean Air Visibility Rule (CAVR).

Q. HAS THE FINAL CSAPR BEEN REVIEWED BY THE COMPANY?

A. Yes. The Company has performed a review of the 1,323 page CSAPR, and is continuing to analyze its impacts on the AEP fleet. Generally speaking, for KPCo, the final rule has become more stringent than the proposed rule issued as the Clean Air Transport Rule (CATR).

Q. WHAT COMPLIANCE TIMELINES ARE STIPULATED IN THE CSAPR?

A. The CSAPR sets forth two compliance phases. The first compliance phase will begin on January 1, 2012 for SO_2 and annual NO_X with a May 1, 2012 start date for ozone season NO_X. The second phase follows two years later with January 1, 2014 and May 1, 2014 effective dates respectively[2] [3]. Allowance allocations are reduced in each phase as the rule becomes more stringent.

---

[2] By way of definition, "state-specific" SO2 and NOX emission budgets/limits are applicable to facilities physically located within that state. Therefore, any future defined Kentucky-specific requirements from CSAPR applicable to KPCo would center on the Big Sandy units which are located in Kentucky. KPCo's purchase entitlement share of the Rockport units would likewise be exposed to CSAPR SO2 and NOX emission limits; however, those limits would be established based on the EPA state emission budget assigned to the state of Indiana.

[3] NOX budget limits are established effective January 1, 2012 and do not change. Such NOX limits include both an "annual" reduction requirements as well as "(ozone) seasonal" (May-September) requirements. Further, certain of the 28 states may have requirements limited to only seasonal NOX. Kentucky's requirements are applicable to SO2, annual NOX and ozone seasonal NOX.

Q. PLEASE EXPLAIN THE PROPOSED REVISIONS BY THE USEPA TO THE FINAL CSAPR RULE AND THE IMPACTS TO KPCO.

A. The USEPA proposed changes to the CSAPR on October 6, 2011. Following the submission of additional data by states and Companies, and further review of the rule by the EPA, the proposed changes could ease some of the rule's impacts. The EPA proposed to revise some unit level allocations in six states including Indiana, Kentucky, and Ohio. The final proposed change to the CSAPR changes the effective date of the assurance penalty provisions, increasing the opportunity for market-based compliance options until January 2014.

Q. DID KPCO GAIN ADDITIONAL ALLOWANCES DUE TO THE PROPOSED OCTOBER 6, 2011 REVISIONS TO THE CSAPR?

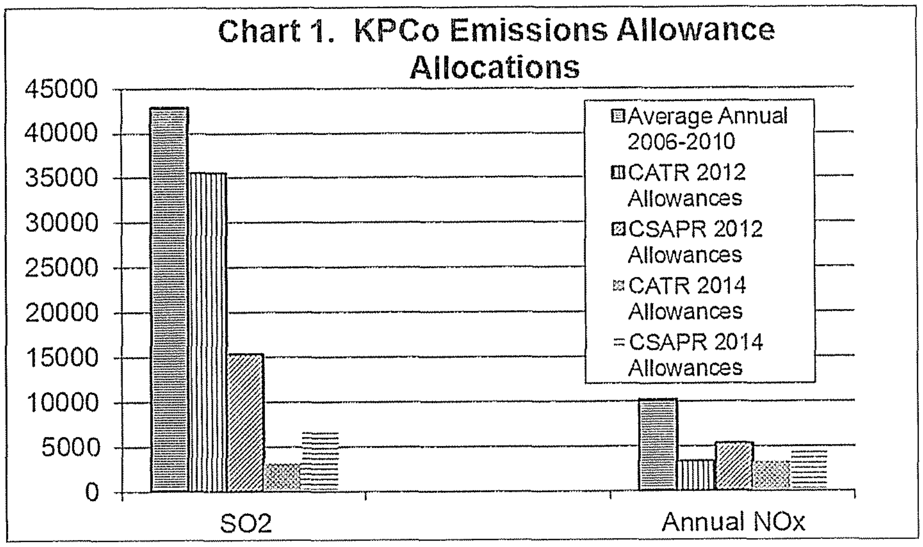
A. No. The allowances allocated by the USEPA for Big Sandy did not change from the original final CSAPR.

Q. COULD THE PROPOSED REVISIONS TO THE FINAL CSAPR RESULT IN A LONGER TIMELINE FOR THE INSTALLATION OF THE FGD SYSTEM ON BIG SANDY UNIT 2?

A. No. The proposed revisions to the CSAPR do not meaningfully change the SO_2 reduction requirements of the rule.

Q: WHAT ARE THE ALLOWANCE ALLOCATIONS FOR KPCo's UNITS IN EACH PHASE?

A. **Chart 1** below shows the SO_2 and NO_X allowances allocated to KPCo's units in the proposed CATR and the now finalized CSAPR. For reference, the historical annual average emissions from these units from 2006-2010 are included.



As can be seen in the chart, the allowance caps in the originally proposed CATR called for reductions in both 2012 and 2014 compliance phases for both SO_2 and NO_X. In the CSAPR, the USEPA significantly reduced the allocation totals for many states, including Kentucky, and as a result individual unit allocations were made even more stringent in 2012 for SO_2.

Q **PLEASE PROVIDE MORE DETAIL ON THE STRINGENCY OF THE CSAPR ALLOCATIONS.**

A. The Phase 1 SO_2 allocations for Big Sandy Plant represent an approximate 64% reduction from recent SO_2 emission levels, with the Phase 2 requirements representing a nearly 85 percent reduction from recent historical SO_2 emission levels. The final allocation of SO_2 allowances for Big Sandy Units 1 and 2, in "Phase 2", are equal to approximately 6,600 annual tons—reduced from approximately 15,300 annual tons in "Phase 1". KPCo will be unable to achieve such reductions without either very significant curtailment of the operation of both Big Sandy units and/or the installation of some form of significant SO_2 control technologies on either or both of these units. As a point of reference, the

Big Sandy units collectively emitted approximately 42,918 tons of SO_2 in 2010; and on average, 42,848 tons per year over the 5-year period, 2006-2010.

Q. WHAT ARE THE IMPLICATIONS OF THE BIG SANDY COMPLIANCE TIMELINES AND ALLOWANCE ALLOCATIONS FOR THE OPERATION OF THE BIG SANDY UNIT 2?

A. The CSAPR sets forth aggressive compliance timelines and restrictive emissions caps with which it will be difficult to comply. At a minimum, the largest of the Big Sandy units, the 800-MW Unit 2, would either be severely curtailed, retired or retrofitted to achieve massive SO_2 reductions through the installation of efficient FGD technology, as discussed by Company witness Weaver, in order to approach the Phase 1 and ultimately, the Phase 2 CSAPR thresholds. CSAPR also provides the Company with the option to acquire SO_2 or NO_X allowances to offset Phase I and Phase II emission levels that exceed annual EPA-budgeted allowance allocations. In addition, as supported by Company witness Weaver, the extraordinarily brief compliance window will require KPCo to operate Big Sandy Unit 2 in an uncontrolled fashion, but under a potentially constrained dispatch. This is due to the fact that the timeframe to permit and install an FGD system is beyond the proposed compliance window as discussed by Company witness Walton. In essence, the timing contained in the rule already puts us behind schedule.

Q. WHAT ARE THE IMPLICATIONS OF THE EGU MACT EMISSIONS LIMITS FOR ENVIRONMENTAL RETROFITS AT BIG SANDY UNIT 2?

A. The proposed EGU MACT Rule emission limits for mercury, particulate matter

(PM), and hydrochloric acid will likely require some combination of FGD, SCR, dry sorbent injection (DSI), fabric filter baghouses, activated carbon injection (ACI) and upgrades of existing electrostatic precipitators (ESP) to comply. Big Sandy Unit 2 has an SCR and an existing ESP, but will need additional control technology to be installed.

Q. WHAT ARE THE COMPLIANCE TIMELINES IN THE PROPOSED EGU MACT RULE?

A. The USEPA entered into a consent decree that set a deadline for a final rule to be issued by November 16, 2011, but this was recently extended one month to December 16. The CAA specifies a three-year period after the final MACT Rule becomes effective for sources to come into compliance. There is a provision for a one-year extension upon approval of the permitting authority. Based on the current rulemaking schedule, compliance would be required by roughly the end of 2014 with a possible extension to the end of 2015. Like the CSAPR, the extremely short compliance timeframe in this instance will prove to be an enormous challenge. As Company witness Walton discusses, the timeframe to retrofit major environmental equipment is measured in years, not months. For planning purposes, it has been assumed that the one-year "extension" to the end of 2015 will be available if the intent is to retrofit a unit for the purposes of achieving compliance with EGU MACT.

Q. HAS KPCO DETERMINED IF BIG SANDY UNIT 2 WOULD BE ABLE TO OPERATE WITHIN THE CSAPR ALLOCATION BUDGET AND IN COMPLIANCE WITH THE EGU MACT RULE?

A. As I discussed earlier, Big Sandy Unit 2 will need to operate in an uncontrolled and potentially constrained dispatch mode for the early phases of the CSAPR implementation. The proposed EGU MACT Rule does not afford KPCo with the same type of operational flexibility since this rule would impose emission rate limitations on each affected unit. Under the proposed EGU MACT rule, KPCo would be required to install environmental controls at Unit 2 by the end of 2014 (or 2015 with the one-year extension), or the unit will be unable to operate in compliance.

Q. DOES THE REQUIRED COMPLIANCE DATE OF THE PROPOSED EGU MACT RULE CREATE A CONFLICT WITH THE COMPLIANCE DATE AS SET BY THE 2007 CONSENT DECREE?

A. No. As previously stated in my testimony, the Consent Decree requires installation of a FGD system on Unit 2 by the end of 2015. This aligns with the compliance schedule for the MACT rule assuming an additional year for a major retrofit. While the CSAPR program will result in having to reduce SO_2 emissions from the unit prior to that time, it can be achieved with curtailment of operation and supplementing the allowance allocation with allowances from other sources.

Q. DO OTHER PROPOSED ENVIRONMENTAL REGULATIONS EXIST THAT MAY CREATE A NEED FOR ADDITIONAL ENVIRONMENTAL CONTROL RETROFITS AT BIG SANDY UNIT 2 IN THE FUTURE?

A. Yes, the following proposed and emerging federal rulemaking requirements will have future impacts on Big Sandy Unit 2 environmental control requirements:

1. **Coal Combustion Residuals (CCR) Rule** – The proposed CCR rule

published by the EPA in June 2010, with final rulemaking anticipated in late 2012 or early 2013, is intended to address the disposal of byproducts of combustion of coal in power plants (coal ash, etc.). A new CCR rule could require the conversion of all "wet" ash systems to dry systems; the possible relining or closing of ash ponds; as well as the possible construction of waste water treatment facilities by approximately the end of 2017. Based on the preliminary assumption that these residual materials may be categorized as "Subtitle D", or non-hazardous materials[4], it would be anticipated that each coal unit in the AEP fleet, including KPCo's Big Sandy generating units, would require plant modifications and capital expenditures to address these requirements.

2. **Clean Water Act "316(b)" Rule** -- The proposed 316(b) rule was published by the USEPA on March 28, 2011, with final rulemaking expected by mid-2012. The rule's intent is to establish technology standards around the need for, and construction of, cooling water intake structures that would lessen the impact of impingement and entrainment on fish and other aquatic organisms. The most severe cost impact would be the construction of some form of closed-loop cooling structure. However, since KPCo's Big Sandy units utilize natural draft, hyperbolic cooling towers, the most significant potential impact to KPCo could be the potential need to install improved screens at the front of the water intake structure to further reduce impingement. While representing a potential

[4] As set forth under the current Resource Conservation and Recovery Act (RCRA)

exposure, it is generally anticipated that this new program would not become effective until the latter part of this decade.

3. **Carbon and Greenhouse Gas (GHG) Legislation** – For many years, the potential for requirements to reduce greenhouse gas emissions, including carbon dioxide, has existed. Currently, the Company faces no mandatory or state level emission reduction requirements for greenhouse gas (GHG) emissions in the U.S. However, the Company anticipates that federal legislation or GHG regulation mandating such reductions will likely occur over the next several years. Given that there are currently no cost-effective post-combustion control technologies available, the standards are anticipated to focus on energy efficiency opportunities, but the substantive requirements of an EPA proposal are not yet known.

V. BIG SANDY UNIT 2 ENVIRONMENTAL PERMITTING

Q. WILL PERMITTING ACTIVITIES NEED TO BE COMPLETED PRIOR TO STARTING CONSTRUCTION OF THE BIG SANDY UNIT 2 ENVIRONMENTAL PROJECT?

A. Yes. Big Sandy's existing Kentucky Department of Environmental Protection (KDEP) operating permit regulating air emissions will need to be modified and a permit for the DFGD landfill will need to be obtained. In addition, construction activities associated with Big Sandy's environmental projects will require receiving permits from the U.S. Army Corps of Engineers for the DFGD landfill, and for the potential construction of facilities in waters of the United States, from KDEP for control of storm water runoff, and from local authorities. Furthermore, the Big Sandy Plant's NPDES wastewater discharge permit may require modification.

Q. HOW LONG WILL IT TAKE FOR THE AIR PERMIT TO BE PROCESSED SO THAT KPCO CAN BEGIN CONSTRUCTION?

A. As Company witness Walton discusses, KPCo and AEPSC are currently performing preliminary engineering work on the Big Sandy Unit 2 Environmental Projects. One of the products of this work will be data necessary for air permitting, such as the location and height of a new stack if one is necessary, and key flue gas parameters. From this data, a permit application should be completed and submitted in 2012. After submittal of the application, we have assumed for planning purposes that it will potentially take up to 18 months for issuance of the modified air permit.

VI. KPCO AND AEP POOL SURPLUS COMPANIES PROJECTS

Q. PLEASE DESCRIBE THE REGULATORY PROGRAMS THAT DRIVE THE NEED FOR THE PROJECTS LISTED ON EXHIBIT NO. JMM-1.

A. The primary federal statute that drives the need for the projects listed on Exhibit No. JMM-1 is the Clean Air Act (CAA). Other statutes that contribute to environmental requirements applicable to coal combustion wastes and by-products include the Resource Conservation and Recovery Act (RCRA) and the Clean Water Act (CWA).

As stated earlier in my testimony, the CAA is divided into several sections, or Titles, which address emissions into the atmosphere with the ultimate goal of reducing impacts from man-made pollutants on public health and the environment. Current and future air program requirements for SO_2, NOx and hazardous air pollutants have, and will likely, result in the installation of selective non-catalytic reduction (SNCR) technology to control or reduce NOx emissions, and Dry Flue Gas Desulfurization (DFGD) technology to reduce or control SO_2 and HAPs. The Clean Air Interstate Rule (CAIR) and the vacated Clean Air Mercury Rule (CAMR) were also drivers for some projects placed in-service prior to 2012. Additional reductions in SO_2, stricter requirements for operating NOx controls, and reductions in mercury are contained in the recently finalized CSAPR and proposed EGU MACT Rule.

The RCRA establishes requirements for the handling of solid wastes such as coal combustion by-products and flue gas desulfurization by-products at landfills to protect the land and groundwater from contamination. The Act also contains provisions for the management of nonhazardous solid wastes, and focuses upon active and future facilities.

The CWA's goal is to reduce industrial pollutant discharges into rivers and streams. The EPA's National Pollutant Discharge Elimination System (NPDES) permit program controls discharges. Point sources are discrete conveyances such as waste disposal ponds.

These statutes require the U.S. Environmental Protection Agency (EPA) or state environmental agencies to develop regulations to implement and accomplish the goal of the respective statute. The state regulations are then applied by regulation or by permit. 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 provisions of each regulation.

Q. WHAT IS THE CURRENT STATUS OF THE CAIR?

A. While CAIR was remanded to EPA for revision, it remains in effect until the CSAPR becomes effective in 2012.

Q. PLEASE SUMMARIZE THE MAJOR TYPES OF PROJECTS THAT ARE NEEDED TO MEET THE ENVIRONMENTAL REQUIREMENTS.

A. The major types of environmental projects to control air emissions are: installation of SNCRs for NO_X; construction of an FGD for SO_2 and HAPs control; upgrades to Continuous Emission Monitors for the monitoring of SO_2, NOx, and other emissions; and the installation of Activated Carbon Injection (ACI) technology for emission reduction of mercury. To meet water discharge requirements, we are continuously evaluating and improving infrastructure such as new waste water treatment systems and ponds. To comply with solid waste handling requirements, storage areas such as landfills are developed as needed.

Q. PLEASE PROVIDE A SUMMARY OF THE INVESTMENT IN ENVIRONMENTAL FACILITIES INCLUDED IN EXHIBIT NO. JMM-1.

A. Exhibit No. JMM-1 provides a summary of the environmental control projects that have been or may be placed in-service by KPCo and AEP Pool Surplus Companies I&M and OPCo in accordance with the aforementioned environmental regulatory programs. The KPCo environmental projects are expected to be in-service no later than mid-2016. The AEP Pool Surplus Company environmental projects are planned for in-service no later than December 31, 2013. The projects included in the exhibit are:

Activated Carbon Injection

An activated carbon injection (ACI) system was placed in-service in September 2009 at Rockport Units 1&2. In this system, powdered activated carbon is injected into the ductwork prior to the ESP, absorbing the mercury into its pores. The resultant particulate is collected through the existing ESP, which functions as the primary fly ash particulate control device. Installation of this system was initiated for compliance with requirements of the CAMR before it was vacated.

SNCR Systems

SNCR systems achieve NO_X reduction for a coal-fired boiler by injecting urea into the furnace at a location where the flue gas temperature ranges between 1600°F and 2200°F. Urea decomposes to ammonia in this temperature range and reacts with NO_X to form nitrogen and water. SNCR can potentially achieve 20-40% NO_X reduction from baseline NO_X levels in the flue gas. NO_X reductions are necessary in the overall compliance strategy for the NO_X SIP Call, the CAIR, and the NSR Consent Decree. SNCR's were placed in-service at Tanners Creek Units 1, 2, and 3 in December 2009 to comply with the requirements of the New Source Review Consent Decree and the CAIR.

DFGD System

The DFGD process is comprised of the absorber vessel or duct integrated with a pulse jet fabric filter (PJFF). The DFGD system that is proposed for installation at Big Sandy Unit 2 will be designed to remove 98% of the SO_2 in the flue gas. Lime is used as the reagent and calcium sulfite is formed as a result of the chemical reaction. The DFGD relies on the scrubbing reactions to take place as the flue gas intermingles with the lime inside the vessel or ductwork and also collects the reaction byproducts directly in the downstream fabric filter. A DFGD will be installed on Big Sandy Unit 2, and placed in-service in 2016 to comply with the requirements of the New Source Review Consent Decree, CSAPR, and the proposed EGU MACT Rule.

DFGD Associated Projects

Other equipment must be installed in support of the functionality of the DFGD system for Big Sandy Unit 2. Such equipment plans include, but are not limited to, balanced draft conversion; steam generator pressure part modifications; additional soot blowers; water cannons and cameras; coal yard modifications; distributed control system (DCS) for new process equipment; and continuous emissions monitors (CEMS) upgrades. These systems are expected to be in-service at the same time as the DFGD system during 2016 for compliance with like environmental regulations.

DFGD Solid Waste Landfill

Landfills are used for the disposal of coal combustion byproducts and are necessary for compliance with the RCRA. To support the Big Sandy Unit 2 DFGD system installation, a landfill is planned for construction along with its associated permitting and engineering. The new DFGD landfill is expected to be in-service in 2016.

Landfill-Related Projects

To support the on-site disposal of DFGD waste at Big Sandy Unit 2, the construction of an ash haul road is required. The haul road work is expected to be in service in 2016.

Various Other Projects

Many smaller scale environmental compliance projects were identified for Amos Unit 3 and Rockport Unit 2 including FGD mercury waste water management, mercury in-pond chemical treatment, and an ash pond discharge diffuser installation.

An FGD Mercury (Hg) Waste Water Treatment system is planned for installation at the Amos Plant as common equipment to be shared between the Plant's three units. The installation will include chemical injection systems for Hg reduction along with the implementation of upgrades that would include the replacement of Lamella Clarifiers with solids contact clarifiers, separating train operations, and the implementation of other operations and maintenance improvements. The project will satisfy compliance requirements of the CWA and is expected to be in-service by December 2012.

The installation of an ash pond discharge diffuser, common to the three Amos Plant units, is planned to be placed in-service near the end of 2012. An extended pipeline with a diffuser into the Kanawha River would be installed that will allow for improved mixing of wastewater with river water and compliance with requirements in the plant's wastewater discharge permit.

The Hg In-Pond Chemical Treatment project, placed in-service at Amos Plant during the third quarter of 2011, installed chemical injection systems for in-pond treatment for mercury reduction. The Hg in-pond treatment is also needed for compliance with the Hg requirements of the plant's wastewater discharge permit.

Fly Ash handling equipment was installed at Amos Unit 3 to remove dry fly ash from existing precipitator hoppers and to convey ash to a silo storage location for load-out into trucks for final disposal. The project also closed the normal water outfall in the existing fly ash pond and installed pumping and a pipe system to dispose of rainwater collected in the pond. The fly ash disposal project went into service in 2010 and satisfied wastewater discharge permit requirements. The project was implemented as a result of having converted the fly ash system from a wet to a dry system.

Q. ARE THE PROJECTS LISTED IN KPCO'S 2011 ENVIRONMENAL COMPLIANCE PLAN, INCLUDING THOSE LISTED IN JMM-1, REQUIRED TO COMPLY WITH THE ENVIRONMENTAL STATUTES AND REGULATIONS IN THIS PROCEEDING?

A. Yes. The projects are required to comply with the Federal Clean Air Act as amended (CAAA) and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal.

VII. CONCLUSION

Q. PLEASE SUMMARIZE THE REQUIREMENTS FOR RETROFITTING ENVIRONMENTAL PROJECTS ON BIG SANDY UNIT 2.

A. The environmental regulations facing KPCo are stringent and will require reductions in the emissions of several air pollutants. The extremely short compliance timeframes contained in the CSAPR, the proposed EGU MACT Rule, and the 2007 NSR Consent Decree require the Company to move quickly on the retrofit of equipment for Big Sandy Unit 2 in order to ensure that it remains a source of reliable, low-cost electricity for KPCo's customers.

Q. **PLEASE SUMMARIZE THE REQUIREMENTS FOR THE NEW PROJECTS LISTED IN THE KENTUCY ENVIRONMENTAL SURCHARGE TARIFF FOR THIS FILING.**

A. The new projects added to the tariff, as listed in JMM-1, will meet the compliance requirements of federal statutes that include the Clean Air Act (CAA), the Resource Conservation and Recovery Act (RCRA), and the Clean Water Act (CWA). The placement in-service of these projects will allow the Company to remain in compliance with environmental regulations and permitting in order to maintain KPCo's generating units as operational.

Q. **DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

VERIFICATION

The undersigned, John M. McManus being duly sworn, deposes and says he is the Vice President of Environmental Services for American Electric Power that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

John M McManus

JOHN M. MCMANUS

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John M. McManus, this the 28 day of November, 2011.

Janet L. White

Notary Public

JANET L. WHITE
Notary Public, State of Ohio
My Commission Expires: My Commission Expires 08-09-2013

Kentucky Power Company
and
AEP Pool Surplus Companies
Investment in Environmental Projects

Generating Unit	Project Description	In-Service Date (Actual/Proposed)	Applicable Environmental Program
Amos Unit Common	Ash Pond Discharge Diffuser	4th Qtr 2012	CWA NPDES
Amos Unit Common	FGD Hg Waste Water Treatment	4th Qtr 2012	CWA NPDES
Amos Unit Common	Hg In-Pond Chemical Treatment	3rd Qtr 2011	CWA NPDES
Amos Unit 3	Dry Fly Ash Disposal Conversion	3rd Qtr 2010	CWA NPDES
Big Sandy Unit 2	DFGD System	2nd Qtr 2016	CSAPR/Proposed EGU MACT/NSR Consent Decree
Big Sandy Unit 2	DFGD Associated Projects	2nd Qtr 2016	CSAPR/Proposed EGU MACT/NSR Consent Decree
Big Sandy Unit 2	DFGD System Landfill	2nd Qtr 2016	RCRA Solid Waste
Big Sandy Unit 2	DFGD Ash Haul Road	2nd Qtr 2016	RCRA Solid Waste
Rockport Units 1&2	ACI	3rd Qtr 2009	Former CAMR
Tanners Creek Units 1-3	SNCR System	4th Qtr 2009	NSR Consent Decree/CAIR

Legend:
Hg - Mercury
FGD - Flue Gas Desulfurization
DFGD - Dry Flue Gas Desulfurization
ACI - Activated Carbon Injection
SNCR - Selective Non-Catalytic Reduction

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY	)	
FOR APPROVAL OF ITS 2011 ENVIRONMENTAL	)	
COMPLIANCE PLAN, FOR APPROVAL OF ITS	)	
AMENDED ENVIRONMENTAL COST RECOVERY	)	Case No. 2011-00401
SURCHARGE TARIFF, AND FOR THE GRANT OF A	)	
CERTIFICATE OF PUBLIC CONVENIENCE AND	)	
NECESSITY FOR THE CONSTRUCTION AND	)	
ACQUISITION OF RELATED FACILITIES	)	

DIRECT TESTIMONY

OF

LILA P. MUNSEY

DIRECT TESTIMONY OF
LILA P MUNSEY, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2011-00401

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DIRECT TESTIMONY OF
LILA P MUNSEY, 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 Lila P. Munsey. My position is Manager of Regulatory Services, Kentucky Power Company (Kentucky Power, KPCo or Company). My business address is 101A Enterprise Drive, Frankfort, Kentucky 40601.

II. Background

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A: I received a Bachelor of Science in Civil Engineering degree from Purdue University, West Lafayette, Indiana in May 1978 and began my career with Appalachian Power Company (APCo) as a Civil Engineer in the Hydroelectric Department. In August 1983, I was promoted to the position of Cost Allocation Analyst for APCo where I conducted numerous studies to support retail rate filings and regulatory interactions with the West Virginia and Virginia regulatory commissions. In November 1985, I transferred to the Rate Department in American Electric Power Service Corporation, a subsidiary of American Electric Power Company, Inc. (AEP), in Columbus, Ohio, as an Associate Rate Analyst where I developed and supported operating company retail rate filings within AEP's seven eastern states. I was promoted to Rate Analyst in November 1989 where I developed, supported, and testified in retail filings concerning cost of service issues.

In January 1998, I moved to the newly formed transmission pricing group as a Transmission Contracts & Regulatory Specialist for AEP. In this capacity, I prepared AEP's FERC transmission rate filings, including transmission cost-of-service studies, rate design, and tariff development in support of the Regional Transmission Organization (RTO) developmental filings and negotiations for the Alliance TransCo and ultimately AEP's entrance into PJM's RTO on October 1, 2004. I also prepared long-term reservation contracts with other utilities and developed a contract management tracking system, provided expertise on AEP's Open Access Transmission Tariff and tariff revisions as necessary, and developed the merger-related FERC filings required for AEP's merger of the operating companies in the seven eastern states with those in the four western states previously known as Central & Southwest (CSW). In June of 2000, I was promoted to Senior Regulatory Consultant in the Transmission & Interconnections department, which became part of the Regulated Tariffs department in 2005. In 2010, I transferred to Kentucky Power where I assumed my current responsibilities and position.

Q: WHAT ARE YOUR RESPONSIBILITIES AS MANAGER OF REGULATORY SERVICES?

A: I supervise and direct the Regulatory Services of the Company, which has the responsibility for rate and regulatory matters for KPCo. 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.

Q. DO YOU HOLD ANY PROFESSIONAL LICENSES?

A. Yes, I am registered as a Professional Engineer in the State of Ohio and in the Commonwealth of Virginia.

Q: HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A: Yes. I have testified before this Commission for Kentucky Power in Case No. 91-066, a regulatory proceeding involving the application of the general adjustment in electric base rates; environmental surcharge 6-month review proceedings in Case Nos. 2010-00318 and 2011-00031; and fuel adjustment clause review hearings in Case Nos. 2010-00490 and 2011-00245. I have also presented testimony for Wheeling Power Company before the West Virginia Public Service Commission and for Appalachian Power Company before the Commonwealth of Virginia State Corporation Commission.

III. Purpose of Testimony

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 for Approval of its Fourth Amended Environmental Compliance Plan (2011 Plan). The testimony will present to the Commission the Company's annual costs expected to be incurred by KPCo as a result of placing in-service new environmental projects being added to the Company's amended environmental compliance plan to comply with the Federal Clean Air Act as amended and other environmental requirements ("Environmental Requirements").

Q: ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A: Yes. I am sponsoring the following exhibits:

- Exhibit LPM-1 – Dry Flue Gas Desulfurization (DFGD) facility for Big Sandy (BS) Unit 2
- Exhibit LPM-2 – Big Sandy Unit 2 Annual Revenue Requirement Calculation
- Exhibit LPM-3 – Big Sandy Unit 2 Weighted Cost of Capital Calculation for August 2011
- Exhibit LPM-4 –Estimated Property Taxes Associated with Big Sandy Unit 2 Pollution Control Facilities
- Exhibit LPM-5 – Revenue Allocation Percentages for 12-months ended August 31, 2011
- Exhibit LPM-6 – AEP Pool Surplus Companies Net Investment in Environmental Facilities
- Exhibit LPM-7 – AEP System Pool Capacity Equalization Settlement
- Exhibit LPM-8 – AEP System Pool Capacity Rate Calculations for Surplus Member Companies August 2011
- Exhibit LPM-9 – Annual Effect on AEP System Pool Capacity Charge
- Exhibit LPM-10 – AEP System Pool - Ohio Power Environmental Upgrades
- Exhibit LPM-11 – AEP System Pool - I&M Environmental Upgrades

- Exhibit LPM-12 – Rockport Environmental Surcharge Revenue Requirement Calculation
- Exhibit LPM-13 – New Environmental Allowance Inventory Costs
- Exhibit LPM-14 – Anticipated Effect on Residential Customers
- Exhibit LPM-15 – Revised Tariff E.S. (Environmental Surcharge) 1st Revised Sheet Nos. 29-2, 29-4, and 29-5, and Original Sheet Nos. 29-1 and 29-3.

Q: DESCRIBE THE GENERATING FACILITIES, WHICH WILL BE THE PREDOMINANT SUBJECT OF THE 2011 ENVIRONMENTAL COMPLIANCE PLAN PRESENTED IN THIS PROCEEDING.

A: The coal-fired Big Sandy Generating Plant consists of two units with a total nominal capacity of 1,078 MW. Big Sandy Unit 1 has a nominal capacity of 278 MW and Big Sandy Unit 2 has a nominal capacity of 800 MW. The units came online in 1963 and 1969, respectively. Kentucky Power currently anticipates retiring Big Sandy Unit 1 by January 1, 2015. However, Big Sandy Unit 2 and the modifications planned for Unit 2 are a major focus of this proceeding.

Q: WHAT TYPE OF ENVIRONMENTAL PROJECTS, WHICH ARE THE SUBJECT OF THIS APPLICATION, IS KPCO INSTALLING AT THE BIG SANDY GENERATING PLANT TO COMPLY WITH THE FINAL AND PROPOSED ENVIRONMENTAL REQUIREMENTS?

A: To meet its environmental requirements, Kentucky Power proposes to retro-fit Big Sandy Unit 2 with a Dry Flue Gas Desulfurization (DFGD) system. Details of this project may be found in Witness Robert L. Walton's testimony.

Q: ARE THERE ENVIRONMENTAL PROJECTS INCLUDED IN THIS APPLICATION THAT HAVE BEEN OR ARE BEING INSTALLED AT OTHER AEP GENERATING PLANTS TO COMPLY WITH THE ENVIRONMENTAL REQUIREMENTS THAT COULD AFFECT KPCO'S ENVIRONMENTAL SURCHARGE RATE?

A: Yes. The environmental projects being installed on Ohio Power Company (OPCo) and Indiana and Michigan Power Company (I&M) plants could increase the environmental charges to KPCo.

Q: WHAT TYPE OF ENVIRONMENTAL PROJECTS HAVE BEEN INSTALLED ON OHIO POWER AND INDIANA AND MICHIGAN POWER COMPANY PLANTS FOR WHICH YOU ARE REQUESTING RECOVERY IN THIS FILING?

A: The types of environmental projects being installed on OPCo and I&M plants include:

- OPCo Amos Unit 3 – Dry Fly Ash Disposal Conversion;
- OPCo Amos Common Plant - FGD Hg Waste Water Treatment, Hg In-Pond Chemical Treatment, and the associated Ash Pond Discharge Diffuser;
- I&M Rockport Units 1 & 2 - Activated Carbon Injection (ACI) system; and
- I&M Tanners Creek Units 1, 2, and 3 – Selective Non-Catalytic Reduction (SNCR) system.

These costs, outlined in Exhibit LPM-6, are being incurred by KPCo under two Federal Energy Regulatory Commission (FERC) approved agreements. In addition to the cost to retrofit Big Sandy Unit 2, these costs represent KPCo's portion of the costs being incurred at the Rockport plant, and at certain AEP plants (i.e., those owned by the AEP "surplus" companies, as explained below). These environmental projects are consistent with those described in the testimony of Witness John M. McManus. Exhibit LPM-6 lists the expected in-service dates and the projected installed capital costs. The annual expected non-fuel operation and maintenance expenses associated with the newly installed pollution control environmental projects can be found on Exhibits LPM-10 and LPM-11.

Q: WHEN IS THE COMPANY PROPOSING TO INCORPORATE THE COSTS ASSOCIATED WITH THESE POLLUTION CONTROL ENVIRONMENTAL PROJECTS INTO THE ENVIRONMENTAL SURCHARGE REPORT?

A: With respect to the four projects that have already been placed in service, Amos Unit 3 – Dry Fly Ash Disposal Conversion on August 8, 2010, Amos Common Plant Hg In-Pond Chemical Treatment facility on July 15, 2011, Rockport Units 1 and 2 Activated Carbon Injection on September 28, 2009, and Tanners Creek Units 1, 2, and 3 Selective Non-Catalytic Reduction (SNCR) on December 11, 2009, the Company is requesting to incorporate the costs in the monthly Environmental Surcharge Report effective the month following the Commission's order in this proceeding. With respect to the proposed pollution control projects in this filing, the in-service dates are expected to be after the Commission's order in this proceeding; therefore, the Company is requesting to incorporate the associated costs of these projects in the monthly Environmental Surcharge Reports two months following their in-service date, when the O&M costs begin to be recorded in the

Company books. For example, if a project is placed in service in June 2016, then the costs associated with the project would be included in the August 2016 monthly Environmental Surcharge Report which would be applied to the customer's monthly electric bill for the billing month of September 2016.

Q: WHAT METHODOLOGY IS THE COMPANY PROPOSING TO USE TO INCORPORATE THE COSTS ASSOCIATED WITH THE ADDITIONAL POLLUTION CONTROL ENVIRONMENTAL PROJECTS INTO THE MONTHLY ENVIRONMENTAL SURCHARGE REPORT?

A: The Company is proposing to use the same methodology as authorized by this Commission in Case No. 2000-00107 (the two-year review of the Company's current environmental surcharge), more recently in Case No. 2010-00318 (the six-month review of the Company's current environmental surcharge), and as has most recently been filed in Case No. 2011-00031. Exhibit LPM-5, line 15 demonstrates the Commission's revenue allocation methodology for the twelve months ended August 31, 2011, and each revenue group's allocation percentage factor.

Q: WHAT IS THE COMPANY'S BEST ESTIMATE OF THE ANNUAL REVENUE REQUIREMENT THAT SHOULD BE ALLOCATED TO THE KENTUCKY RETAIL JURISDICTION FOR THE ADDITIONAL BIG SANDY ENVIRONMENTAL PROJECTS?

A: Exhibit LPM-2, line 15, column 5, demonstrates the Company's best estimate of the Kentucky retail jurisdiction revenue requirement associated with the installation of the pollution control environmental projects that are at issue in this proceeding for the Big Sandy Generating Plant. There are two differences between columns 3 and

4 on Exhibit LPM-2. The first difference can be found on line 9, titled "Annual Non-Fuel O&M Expense", where the column 4 amount is one-half of the maintenance expense included in column 3. The reason for this difference is that the other half of maintenance expense is considered a variable cost and is recovered from the rates charged to the Associated Utilities by way of the FERC-approved rate schedule. The second difference in column 4 is on line 14, which allocates the annual revenue requirement between the Kentucky retail and FERC wholesale full-requirement customers based upon the revenue of the full-requirement customers, as shown on Exhibit LPM-5, line 14, column 3.

Q: WILL THE MONTHLY SURCHARGE FILING BE BASED ON THESE ESTIMATES?

A: No, the actual monthly environmental filings will reflect the Company's actual costs incurred after the pollution control environmental projects are placed in-service.

Q: WOULD YOU PLEASE EXPLAIN THE REST OF EXHIBIT LPM-2?

A: Yes, Exhibit LPM-2, line 1, shows the proposed investment to install pollution control environmental projects net of any environmental projects retired which were included in the Company's last base rate proceeding. Line 2, accumulated depreciation and line 3, accumulated deferred income taxes are deducted from line 1, to arrive at the net utility plant on line 4. The product of the weighted average cost of capital on line 5 and the net utility plant amount on line 4 yields the allowed return on rate base on line 6.

Q: HOW WAS THE ANNUAL DEPRECIATION EXPENSE ON EXHIBIT LPM-2 CALCULATED?

A: The Company's utility plant 15-year depreciation rate of 6.67% was multiplied by the net utility plant installed.

Q: WAS A 15-YEAR DEPRECIATION RATE USED ON THE OTHER ENVIRONMENTAL PROJECTS IN THIS FILING?

A: No. In Exhibit LPM-12, the depreciation rate for Rockport plant is 3.52%, the same percentage approved in previous filings.

Q: WHY WERE DIFFERENT DEPRECIATION RATES USED FOR THESE PROJECTS?

A: The facilities being placed on Big Sandy and those being attached to Rockport are very different facilities. The higher depreciation rate for Big Sandy will help ensure that KPCo recovers its expenses. A more detailed explanation can be found in the testimony of Witness Ranie K. Wohnhas.

Q: HOW WAS THE WEIGHTED AVERAGE COST OF CAPITAL CALCULATED?

A: Exhibit LPM-3 demonstrates how the weighted average cost of capital was calculated. Using the April 30, 2010 balance sheet, based on Case No. 2010-00318 dated September 7, 2010, each category of capital was divided by the Company's total capital to determine the capital structure percentages in column 4. There was no short-term debt balance on April 30, 2010. To calculate the weighted average cost of capital in column 6, the cost of capital rate in column 5 is multiplied by the capital structure percentage in column 4. The common equity portion of the weighted average cost of capital is based upon the Commission's order in Case No. 2010-00020, where the Company was granted 10.5% return on common equity multiplied by the common equity capital structure percentage. That result is then multiplied by the gross revenue conversion factor in column 7 to determine the weighted average cost of common equity in column 8. The gross revenue conversion factor is used in calculating the weighted average cost of capital for the common equity portion because the cost associated with common equity is taxable. The gross revenue conversion factor computation is shown at the bottom of this Exhibit, on lines 1 through 21. This is the same factor approved by the Commission in KPCo's last order in Environmental Case No. 2010-00318.

Q: HOW WAS THE ANNUAL PROPERTY TAX EXPENSE ON EXHIBIT LPM-2 CALCULATED?

A: Exhibit LPM-4 details the calculation of the annual increase in property tax expense by taking the net in-service investment of the pollution control environmental projects installed at the Big Sandy Generating Plant and deducting accumulated depreciation. That result is multiplied by the state property tax rate of 0.15% to derive the expected property tax.

Q: WILL THE ANNUAL NON-FUEL OPERATION AND MAINTENANCE EXPENSE ON EXHIBIT LPM-1, LINE 8 FLOW THROUGH THE MONTHLY ENVIRONMENTAL SURCHARGE CALCULATIONS?

A: The amount on lines 6 through 8 of Exhibit LPM-1 is the Company's estimate of non-fuel operation and maintenance expense associated with the proposed DFGD facility being installed at the Big Sandy Generating Plant. Only the Company's actual non-fuel operational and maintenance expenses associated with these pollution control environmental projects will flow through the monthly environmental surcharge calculations.

Q: HOW WAS THE TOTAL REVENUE REQUIREMENT ASSOCIATED WITH THE BIG SANDY ENVIRONMENTAL COSTS ON EXHIBIT LPM-2 CALCULATED?

A: First, the annual expenses for depreciation, property tax, and the non-fuel operation and maintenance were summed to arrive at the total operating expense on line 10. Then the annual return on rate base from line 6 was added to the total operating expense to arrive at the total revenue requirement associated with Big Sandy pollution control environmental projects found on line 11.

Q: HOW WAS THE AVERAGE KENTUCKY RETAIL ALLOCATION FACTOR ON EXHIBIT LPM-2 CALCULATED?

A: Exhibit LPM-5 uses the methodology ordered by the Commission in Case No. 2000-00107. The twelve monthly Kentucky revenue amounts in each revenue group for the test year ended August 31, 2011, were summed to derive a twelve month Total Revenue for Surcharge Purposes amount for each revenue group. The result was divided by the twelve month total revenue to determine the twelve month revenue allocation percentage for each revenue group on line 15. Line 14 shows the percentage of the Total Kentucky Full Requirement Revenues for the retail and FERC wholesale groups.

Q: HOW WAS THE TOTAL KENTUCKY RETAIL REVENUE REQUIREMENT ON EXHIBIT LPM-2 CALCULATED?

A: The total revenue requirement associated with the Big Sandy pollution control environmental projects on line 11 was multiplied by the average Kentucky retail allocation factor for the twelve months ended August 31, 2011, on line 12 to arrive at the total Kentucky retail revenue requirements on line 13. As discussed previously, a further adjustment is required to determine the Kentucky retail jurisdiction share of costs allocated to the Associated Utilities revenues.

Q: WHAT IS THE COMPANY'S ESTIMATE AS TO THE PERCENTAGE CHANGE IN THE KENTUCKY RETAIL JURISDICTION TWELVE-MONTH REVENUES AS A RESULT OF INCORPORATING THE COSTS ASSOCIATED WITH THE POLLUTION CONTROL ENVIRONMENTAL PROJECTS AT THE BIG SANDY GENERATING PLANT INTO THE ENVIRONMENTAL SURCHARGE CALCULATIONS?

A: As demonstrated on Exhibit LPM-2, column 5, line 17, the Company estimates a 31.20% increase in Kentucky annual retail revenue as a result of incorporating the pollution control environmental projects at the Big Sandy Generating Plant into the environmental surcharge calculations.

Q: HOW WILL THE COSTS OF ENVIRONMENTAL PROJECTS INSTALLED AT OTHER AEP GENERATING FACILITIES FLOW TO KPCO?

A: The costs of these environmental facilities will flow to KPCo pursuant to two agreements. There are some costs of the environmental projects that flow to KPCo by way of the AEP Interconnection Agreement and some costs of the environmental projects that flow to KPCo by way of the AEP Generating Company (AEGCo) and

KPCo Unit Power Agreement (UPA) for the portion of Rockport for which KPCo is responsible.

Q: HAS 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.

IV. The AEP Interconnection Agreement

Q: AS BACKGROUND, PLEASE BRIEFLY DESCRIBE THE AEP INTERCONNECTION AGREEMENT.

A: KPCo, Appalachian Power Company (APCo), Columbus Southern Power (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 LPM-7 demonstrates the AEP Pool monthly Capacity Equalization Settlement calculation. First, the sum of the five Members' primary capacity installed in column 5 is multiplied by each company's MLR in column 4 to derive each Member's primary capacity reservation in column 6. This reservation is then compared with the installed capacity contributed by each Member in column 5. 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 to be used to cover the deficit members' load. The total capacity surplus in any given month for surplus Members always equals the total capacity deficit for the deficit Members, thereby producing a zero surplus/deficit balance for the AEP System, as shown in column 7. Kentucky

Power, normally a deficit member, was deficit 283,900 kW as of the August 2011 settlement.

Q: ON WHAT BASIS ARE THE SURPLUS COMPANIES REIMBURSED BY THE DEFICIT COMPANIES?

A: Exhibit LPM-8 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 LPM-8. Also provided on line 16 of this exhibit is the Pool's weighted average rate, which is paid by the deficit members.

Q: HOW ARE 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 as seen in Exhibit LPM-7, columns 7, 8, and 9.

Q: WOULD YOU PLEASE WALK US THOUGH THE AEP SYSTEM POOL CAPACITY EQUALIZATION SETTLEMENT CALCULATIONS FOR KPCO?

A: Yes. Exhibit LPM-7 shows 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 (1,596 MW / 24,188 MW) resulting in an MLR of 0.06598 (line 2, column 4). KPCo's primary capacity reservation is determined by multiplying its MLR times the members' total generating capacity (26,598,000 kW). This equals a primary capacity reservation for KPCo of 1,754,900 kW (line 2, column 6). By comparing KPCo's reservation with its installed capacity, it is determined that KPCo has a capacity deficit of 283,900 kW (1,471,000 kW – 1,754,900 kW) for the month (line 2, column 7). Multiplying the Pool's weighted average capacity rate of the surplus companies (I&M and OPCo) of $13.6032/kW times KPCo's capacity deficit of 283,900 kW produces a Capacity Equalization Settlement charge for KPCo of $3,861,944 for the month (line 8, column 9).

Q: PLEASE EXPLAIN HOW THE FIXED OPERATING COSTS OF THE NEW ENVIRONMENTAL PROJECTS OF THE SURPLUS COMPANIES AFFECT KPCO'S CAPACITY EQUALIZATION SETTLEMENT CHARGES.

A: The fixed operating costs consist of the Operation Expense and one-half of the Maintenance Expense associated with the installed environmental projects of the surplus companies (for example, disposal, urea, trona, and lime stone costs associated with the Amos Unit 3 FGD) are included in the surplus companies' fixed operating rate along with the weighted average installed cost times a carrying charge rate. As such, these costs are charged to KPCo, through the Pool's weighted average capacity rate, based on KPCo's capacity deficit. Exhibit LPM-9 provides a summary of these new environmental costs, and their effect on the monthly Pool's weighted average capacity rate.

Q: HOW SOON AFTER THE NEW ENVIRONMENTAL PROJECTS ARE PLACED IN SERVICE DO THE COSTS ASSOCIATED WITH THESE NEW ENVIRONMENTAL PROJECTS 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 projects' 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, if an environmental project was placed into service the third quarter of 2012, the fixed operating rate KPCo would pay in October 2012 would reflect the Steam Operation Expense plus one-half of the Maintenance Expense associated with this environmental project. However, the primary capacity investment rate would not reflect the investment in this environmental project until January 2013.

Q: WHAT IS THE PROPOSED ADDITIONAL ANNUAL CHARGE ASSOCIATED WITH THESE NEW ENVIRONMENTAL PROJECTS OF THE SURPLUS COMPANIES THAT WILL BE INCURRED BY KPCO THROUGH THE AEP INTERCONNECTION AGREEMENT?

A: Based on Exhibit LPM-9 calculations, the annualized charges associated with the surplus companies new environmental projects incurred by KPCo through the AEP Interconnection Agreement are expected to be $306,612 annually.

V. 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 one 1,300 MW generating unit and one 1,320 MW generating unit. Each unit is owned 50% by AEP Generation and the remaining 50% is owned by I&M, therefore they each own a total of 1,310 MW of the plant (or 650 MW + 660 MW). KPCo has a FERC approved UPA with AEP Generating Company for 30% of AEP Generating Company's interest in both units equating to a total of 393 MW (1,310 MW X 30%). 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 portion of the generation output at these two generating units (30% of 650 + 660 MW).

Q: WHAT IS THE PROPOSED ADDITIONAL ANNUAL CHARGE ASSOCIATED WITH THE NEW ROCKPORT ENVIRONMENTAL PROJECTS WHICH WILL BE INCURRED BY KPCO THROUGH THE UNIT POWER AGREEMENT?

A: Exhibit LPM-12 demonstrates the estimated annual revenue requirement associated with the Activated Carbon Injection (ACI) system installed at both Rockport Units 1 and 2 is $480,780.

VI. SO_2 Allowances

Q: DOES THE 2011 PLAN INCLUDE THE COSTS TO PURCHASE ADDITIONAL ALLOWANCES THAT ARE REQUIRED?

A: Yes. In addition to the allowances required by the Federal Clean Air Act, the CSAPR requires the purchase of additional allowances as estimated on Exhibit LPM-13 and described in the testimony of Witness Wohnhas.

Q: WHAT IS THE ESTIMATE OF THE COST OF THOSE ALLOWANCES?

A: KPCo has estimated the allowances will cost $6,212,000 in 2012, of which the retail customers' share is $524,110, or 0.09% of current revenues.

Q: IF THE COMPANY DETERMINES THAT IT IS APPROPRIATE TO SELL ANY NOX OR SO2 ALLOWANCES, WOULD THE NET REVENUES REALIZED FROM THE SALE OF THE NOX OR SO2 ALLOWANCES BE INCORPORATED INTO THE MONTHLY ENVIRONMENTAL SURCHARGE FILING?

A: Yes, any net revenues realized by the Company from the sale of NO_x or SO_2 allowances would be applied to the monthly surcharge calculations. However additional allowances will be required under the new rules and as shown in Exhibit LPM-13, the allowances are being offset by estimated gains.

VII. Estimated Annual Retail Effect

Q: WHAT IS THE ESTIMATED ANNUAL RETAIL EFFECT OF THE PROPOSED CHANGES TO THE ENVIRONMENTAL SURCHARGE TARIFF?

A: Exhibit LPM-14, line 8 shows the estimated annual retail effect of the proposed changes to the environmental surcharge tariff after these projects are placed into service is approximately $178,844,850. The effect on a residential customer using an average 1,000 kWh per month would be an increase to the monthly bill of approximately $31 or $369 annually. This is approximately a 31% increase to the total bill of a typical residential customer using 1,000 kWh per month as seen on line 10 of that exhibit.

Q. Line 10 of Exhibit LPM-14 shows an increase of 31.40%. Is that the same value set out in the legal notice filed with your certification as Exhibit 5 to the Application?

A. Essentially, yes. Although the legal notice employs a value of 31.41% and not 31.40%, the legal notice describes the value as an estimate. There is no material difference between an estimate of 31.41% and an estimate of 31.40%, particularly in terms of estimated costs to be incurred over four to five years. Kentucky Power takes seriously its obligations to be accurate and candid in its communications with its customers and the Commission. That is why 31.40% was used in Exhibit LPM-14 to my testimony. Certainly, the difference, which represents a decrease over what was previously estimated, does not prejudice or mislead the public receiving the notice.

Q: **WILL THE RETAIL JURISDICTIONAL CUSTOMERS IMMEDIATELY EXPERIENCE THE FULL 31% INCREASE IF THE COMMISSION APPROVES THE 2011 PLAN?**

A: No, these environmental projects will be phased into service over the next five years, as shown on Exhibits LPM-1 and LPM-6, so the full increase will not be seen by the customers until 2016.

Q: CAN YOU PROVIDE AN ANNUAL ESTIMATE OF THE EFFECT ON A RESIDENTIAL CUSTOMER USING 1,000 KWH PER MONTH?

A: Yes, the following table demonstrates the Company's best estimate by year of the total jurisdictional annual revenue, percent increase and the effect on the monthly bill for a residential customer using 1,000 kWh per month.

	2012	2013	2014	2015	2016
Jurisdictional Annual Revenue Increase	$1,118,558	$26,883	$0	$0	$177,699,409
Percent Increase	0.20%	0.00%	0.00%	0.00%	31.20%
Monthly Bill Effect with 1,000 kWh usage	$0.20	$0.00	$0.00	$0.00	$30.55

VIII. Tariff

Q: WHAT ARE THE CHANGES TO THE COMPANY'S ENVIRONMENTAL SURCHARGE TARIFF REQUESTED IN THIS PROCEEDING?

A: Exhibit LPM-15 is an annotated version of the tariff demonstrating the changes to the Company's Environmental Surcharge Tariff E.S. requested in this proceeding. There are no changes to Original Sheet Nos. 29-1 and 29-3, which became effective June 29, 2010, as shown on Exhibit LPM-15 pages 1 and 3 of 5. The change to Tariff E.S. 1st Revised Sheet No. 29-2, as shown on Exhibit LPM-15 page 2 of 5, is a text change from "the 2005 Plan, and the 2007 Plan." to "the 2005 Plan, ~~and~~ the 2007 Plan, *and the 2011 Plan.*"

The changes to Tariff E.S. 1st Revised Sheet No. 29-4, as shown on Exhibit LPM-15 page 4 of 5, are as follows:

- revise the current text labeled paragraph from "(r)" to "*(s)*",
- add a new paragraph "(*r*)" as follows: "*costs associated with installing, operating and maintaining a Dry Flue Gas Desulfurization (DFGD) system, DFGD System Ash Haul Road and Landfill at the Big Sandy Generating Plant Unit No. 2*",
- change the first bullet from "Amos Unit No. 3 CEMS, Low NO_x Burners, SCR, FGD, Landfill, Coal Blending Facilities, and SO_3 Mitigation" to "Amos Unit No. 3 CEMS, Low NO_x Burners, SCR, FGD, Landfill, Coal Blending Facilities, ~~*and*~~ SO_3 Mitigation, *Electrostatic Precipitator (ESP) Modification, and Dry Fly Ash Disposal Conversion*",
- add a new bullet between the first and the second that states "*Amos Plant Common FGD Hg Waste Water Plant Treatment, Hg In-Pond Chemical Treatment, and Ash Pond Discharge Diffuser*", and
- revise the last bullet from "Rockport Unit No. 1 and 2 Low NO_x Burners and Landfill" to "Rockport Unit No. 1 and 2 Low NO_x Burners*,* ~~*and*~~ Landfill, *and Activated Carbon Injection (ACI)*".

The revisions to Tariff E.S. 1st Revised Sheet No. 29-5, as shown on Exhibit LPM-15 page 5 of 5, are as follows:

- change the current first bullet from "Tanners Creek Unit No. 1 Low NO_x Burners, with Modifications, and Low NO_x Burners Leg Replacement" to "Tanners Creek Unit No. 1 Low NO_x Burners, with Modifications, ~~and~~

Low NO_x Burners Leg Replacement, *and Selective Non-Catalytic Reduction (SNCR)*";

- change the current second bullet from "Tanners Creek Unit No. 2 and 3 Low NO_x Burners with Modifications" to "Tanners Creek Units No. 2 and 3 Low NO_x Burners with Modifications, *and Selective Non-Catalytic Reduction (SNCR)*", and
- add a new bullet before paragraph 6 that states "*costs associated with the SO_2 and NO_x allowances required by the Cross-State Air Pollution Rule (CSAPR)*".

Q: ARE THERE ANY CHANGES TO THE ENVIRONMENTAL SURCHARGE REPORT MONTHLY SCHEDULES REQUIRED TO INCORPORATE THE COSTS ASSOCIATED WITH THE CHANGES TO THE ENVIRONMENTAL SURCHARGE TARIFF THE COMPANY IS REQUESTING IN THIS PROCEEDING?

A: No.

IX. Conclusion

Q: WHAT ACTION IS THE COMPANY REQUESTING THE COMMISSION TAKE IN THIS PROCEEDING?

A: Kentucky Power Company respectfully requests the Commission issue an Order approving the Company's 2011 Plan and the revisions to Tariff E.S. (Environmental Surcharge), 1st Revised Sheet Nos. 29-2, 29-4, and 29-5.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes it does.

VERIFICATION

The undersigned, Lila P. Munsey, being duly sworn, deposes and says she is the Manager, Regulatory Services for Kentucky Power Company, that she has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of her information, knowledge, and belief.

Lila P. Munsey

LILA P. MUNSEY

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by, Lila P. Munsey, this the 30th day of November, 2011.

Judy K Rosquist

Notary Public

My Commission Expires: January 23, 2013

Kentucky Power Company
Pollution Control Environmental Facilities
Big Sandy Plant
Dry Flue Gas Desulfurization (DFGD)

Line No. (1)	Big Sandy Unit #2 Description (2)	Dry Flue Gas Desulfurization Unit (DFGD) (3)
	In-Service Date: Second Quarter of 2016	
1	Total Capital Environmental Costs	$ 940,300,067
2	Preliminary Scrubber Analysis 2004-2006	$ 15,212,425
3	Capital Costs Not Associated with CAA	$ -
4	Capital Booked in Last Base Case	$ -
5	KPCo's Net In-Service Investment (L1 + L2 - L3 - L4)	$ 955,512,492
6	Annual Operation Expense	$ 46,067,000
7	Annual Maintenance Expense	$ 2,600,000
8	Total Operation & Maintenance Expense	$ 48,667,000

Kentucky Power Company
Pollution Control Environmental Facilities
Annual Revenue Requirement
Associated with Big Sandy Plant

Line No. (1)	Description (2)	Capital Costs of KY Retail Revenues (3)	Capital Costs of Associated Utility Revenues (4)	Capital Total KY Retail (5)=(3)+(4)
	Return on Rate Base			
1	Utility Plant Installed Net (Exhibit LPM-1, L5)	$ 955,512,492	$ 955,512,492	
2	Less: Accumulated Depreciation	$ 63,732,683	$ 63,732,683	
3	Less: Accumulated Deferred Income Taxes	$ 23,505,607	$ 23,505,607	
4	Net Utility Plant (L1- L2 - L3)	$ 868,274,202	$ 868,274,202	
5	Annual Weighted Average Cost of Capital (Exhibit LPM-3, L5, C8)	10.69%	10.69%	
6	Annual Return on Rate Base (L4 X L5)	$ 92,818,512	$ 92,818,512	
	Operating Expenses			
7	Annual Depreciation (L2)	$ 63,732,683	$ 63,732,683	
8	Annual Property Tax Expense (Exhibit LPM-4, L5)	$ 1,337,670	$ 1,337,670	
9	Annual Non-Fuel O&M Expense (Exhibit LPM-1, L8)	$ 48,667,000	$ 1,300,000 [1]	
10	Total Operating Expenses (L7 + L8 + L9)	$ 113,737,353	$ 66,370,353	
11	Total Revenue Requirement Associated with BS Env. Facilities (L6 + L10)	$ 206,555,865	$ 159,188,865	
12	Annual Revenue Allocation Factor (Exhibit LPM-5, L15, C3 or C6)	78.91%	9.34%	
13	Subtotal (L11 X L12)	$ 162,993,233	$ 14,868,240	
14	KY Jurisdiction Revenue Allocation Factor (Exhibit LPM-5, L14, C3)		98.91%	
15	Total KY Retail Revenue Requirement (L13 X L14)	$ 162,993,233	$ 14,706,176	$ 177,699,409
16	KY Jurisdiction 12-month Revenue (Exhibit LPM-5, L13, C3)			$ 569,593,245
17	Percent Change (L15 / L16)			31.20%

[1] This amount is one half of the maintenance expense included in Exhibit LPM-1, Line 7.

Kentucky Power Company
Pollution Control Environmental Facilities
Weighted Cost of Capital Calculations for August 2011

Line No. (1)	Description (2)	Capital Balance as of April 30, 2010 [2] (3)	Capital Structure (4)	Cost of Capital Rates (5)	WACC Net of Tax (6)	Gross Revenue Conversion Factor (7)	WACC Pre Tax (8)
1	Long-term Debt	$ 550,000,000	51.941%	6.48%	3.37%		3.37%
2	Short-term Debt	$ -	0.000%	0.83%	0.00%		0.00%
3	A/R Financing	$ 43,588,933	4.116%	1.22%	0.05%		0.05%
4	Common Equity	$ 465,314,088	43.943%	**10.50%** [1]	4.61%	1.5762 [3]	7.27%
5	Total	$ 1,058,903,021	100.000%		8.03%		10.69%

1 Weighted Average Cost of Capital (WACC) ROR on Common Equity per Case No. 2010-00020.
2 WACC Balances As of 4/30/2010 based on Case No. 2010-00318, dated September 7, 2010.
3 Gross Revenue Conversion Factor Calculations per Order in Case No. 2010-00318:

1	OPERATING REVENUE	100.0000
2	UNCOLLECTIBLE ACCOUNTS EXPENSE (0.24%)	0.2400
3	Kentucky Public Service Commission Assessment (0.15%)	0.1500
4	STATE TAXABLE PRODUCTION INCOME BEFORE 199 DEDUCTION	99.6100
5	STATE INCOME TAX EXPENSE, NET OF 199 DEDUCTION (SEE BELOW)	5.6384
6	FEDERAL TAXABLE PRODUCTION INCOME BEFORE 199 DEDUCTION	93.9716
7	199 DEDUCTION PHASE-IN	5.6372
8	FEDERAL TAXABLE PRODUCTION INCOME	88.3344
9	FEDERAL INCOME TAX EXPENSE AFTER 199 DEDUCTION (35%)	30.9171
10	AFTER-TAX PRODUCTION INCOME	57.4173
11	GROSS-UP FACTOR FOR PRODUCTION INCOME:	
12	AFTER-TAX PRODUCTION INCOME	57.4173
13	199 DEDUCTION PHASE-IN	5.6372
14	UNCOLLECTIBLE ACCOUNTS EXPENSE	0.2400
15	Kentucky Public Service Commission Assessment (0.15%)	0.1500
16	TOTAL GROSS-UP FACTOR FOR PRODUCTION INCOME (ROUNDED)	63.4445
17	BLENDED FEDERAL AND STATE TAX RATE:	
18	FEDERAL (LINE 9)	30.9171
19	STATE (LINE 5)	5.6384
20	BLENDED TAX RATE	36.5555
21	GROSS REVENUE CONVERSION FACTOR (100 / Line 16)	1.5762

STATE INCOME TAX CALCULATION:

1	PRE-TAX PRODUCTION INCOME	100.0000
2	COLLECTIBLE ACCOUNTS EXPENSE (0.24%)	0.2400
3	Kentucky Public Service Commission Assessment (0.15%)	0.1500
4	STATE TAXABLE PRODUCTION INCOME BEFORE 199 DEDUCTION	99.6100
5	*LESS: STATE 199 DEDUCTION*	5.6372
6	STATE TAXABLE PRODUCTION INCOME BEFORE 199 DEDUCTION	93.9728
7	STATE INCOME TAX RATE	6.0000
8	STATE INCOME TAX EXPENSE (LINE 6 X LINE 7)	5.6384

Kentucky Power Company
Pollution Control Environmental Facilities
Estimated Property Taxes
Associated with Big Sandy Plant Pollution Control Facilities

Line No. (1)	Description (2)	Installed Costs (3)
1	DFGD Installed Capital at BS#2 (LPM-2, L1, C3)	$ 955,512,492
2	Less: Accumulated Depreciation (LPM-2, L2, C3)	$ 63,732,683
3	Net Plant Investment Assessed Value (L1 - L2)	$ 891,779,809
4	Property Tax Rate	0.15%
5	Increase in Property Tax (L3 X L4)	$ 1,337,670

Kentucky Power Company
Pollution Control Environmental Facilities
Revenue Allocation Percentages
12-months ended August 31, 2011

Line No. (1)	Month (2)	KY Retail Jurisdiction (3)	FERC Wholesale (4)	Total KY Full Requirement Revenues (5)=(3)+(4)	Associated Utilities (6)	Non-Associated Utilities (7)	Total Rev for Surcharge Purposes (8)=(5)+(6)+(7)
1	September 2010	$ 40,903,323	$ 495,401	$ 41,398,724	$ 6,337,586	$ 5,270,698	$ 53,007,008
2	October 2010	$ 39,106,852	$ 386,166	$ 39,493,018	$ 6,800,222	$ 4,192,455	$ 50,485,695
3	November 2010	$ 40,488,923	$ 410,737	$ 40,899,660	$ 4,661,941	$ 3,884,802	$ 49,446,403
4	December 2010	$ 56,106,329	$ 639,267	$ 56,745,596	$ 2,533,257	$ 5,561,003	$ 64,839,856
5	January 2011	$ 65,952,346	$ 603,837	$ 66,556,183	$ 5,085,114	$ 6,199,202	$ 77,840,499
6	February 2011	$ 58,755,458	$ 529,203	$ 59,284,661	$ 4,720,801	$ 5,024,766	$ 69,030,228
7	March 2011	$ 44,307,469	$ 459,737	$ 44,767,206	$ 5,691,192	$ 5,445,168	$ 55,903,566
8	April 2011	$ 42,540,201	$ 427,836	$ 42,968,037	$ 4,530,299	$ 6,578,375	$ 54,076,711
9	May 2011	$ 40,424,987	$ 784,420	$ 41,209,407	$ 6,373,043	$ 4,536,768	$ 52,119,218
10	June 2011	$ 46,953,714	$ 462,091	$ 47,415,805	$ 6,987,065	$ 10,149,681	$ 64,552,551
11	July 2011	$ 46,534,433	$ 530,987	$ 47,065,420	$ 8,031,761	$ 13,076,250	$ 68,173,431
12	August 2011	$ 47,519,210	$ 525,287	$ 48,044,497	$ 5,676,708	$ 8,673,690	$ 62,394,895
13	12-month Total	$ **569,593,245**	$ 6,254,969	$ 575,848,214	$ 67,428,989	$ 78,592,858	$ 721,870,061
14	Rev. Alloc. %s	**98.91%**	1.09%	100.00%			
15	Rev. Alloc. %s	**78.91%**	0.87%		**9.34%**	10.88%	100.00%

Kentucky Power Company
Pollution Control Environmental Facilities
AEP Pool Surplus Companies
Net Investment in
Environmental Facilities

Line No. (1)	Generating Unit (2)	Description of Environmental Facilities (3)	In-Service Date (4)	Cost of Environmental Facilities (5)	Less Original Facility Cost in Base Rates (6)	OPCo or I&M Percentage (7)	I&M's Environmental Investment (8)=[(5)-(6)]x(7)	OPCo's Environmental Investment (9)=[(5)-(6)]x(7)
	Surplus Companies							
1	Amos Unit 3	Dry Fly Ash Disposal Conversion	8/3/2010	$ 58,717,352	$ -	66.67%		$ 39,146,859
2	Amos Common	Hg In-Pond Chemical Treatment	7/15/2011	$ 2,484,972	$ -	29.89%		$ 742,758
3	Amos Common	FGD Hg Waste Water Treatment	4th Qtr 2012	$ 12,827,197	$ -	29.89%		$ 3,834,049
4	Amos Common	Ash Pond Discharge Diffuser	4th Qtr 2012	$ 2,447,711	$ -	29.89%		$ 731,621
5	Amos Subtotal	Sum of Lines 1 to 4		$ 76,477,232	$ -			$ 44,455,287
6	Rockport Units 1 & 2	Activated Carbon Injection (ACI)	9/28/2009	$ 23,405,482	$ -	85%	$ 19,894,660	
7	Tanners Creek Units 1, 2, & 3	Selective Non-Catalytic Reduction (SNCR) System	12/11/2009	$ 14,152,243	$ -	100%	$ 14,152,243	$ -
8	Total Surplus Companies	L5 + L6 + L7		$ 114,034,957	$ -		$ 34,046,903	$ 44,455,287

Kentucky Power Company
Pollution Control Environmental Facilities
AEP System Pool
Capacity Equalization Settlement for
August 2011

Calculation of Member Capacity Surplus / (Deficit) (kW)

Line No.	Generating Company	Internal (MLR) Max 60-Minute Integrated Demand in 12 ME 8/31/11 (MW)	Member Load Ratio	Member Primary Capacity (kW)	Primary Capacity Reservation (kW)	Capacity Surplus (Deficit) (kW)
(1)	(2)	(3)	(4)	(5)	(6)=Total kW x (4)	(7)=(5)-(6)
1	APCo	7,542	31.181%	6,377,000	8,293,500	(1,916,500)
2	KPCo	1,596	6.598%	1,471,000	1,754,900	(283,900)
3	I&M	4,837	19.998%	5,428,000	5,319,100	108,900
4	OPCo	5,544	22.920%	8,465,000	6,096,300	2,368,700
5	CSP	4,669	19.303%	4,857,000	5,134,200	(277,200)
6	Total	24,188	100.000%	26,598,000	26,598,000	-

Calculation of Member Capacity Settlement

	Generating Company	Capacity Surplus (Deficit) (kW)	Capacity Rate ($/kW)	Estimated Credit (Charge) ($)
	(2)	(7)=(5)-(6)	(8)=(9) / (7)	(9)
7	APCo	(1,916,500)	$13.60	(26,070,502)
8	KPCo	(283,900)	$13.60	(3,861,944)
9	I&M	108,900	$14.76	1,607,364
10	OPCo	2,368,700	$13.55	32,095,885
11	CSP	(277,200)	$13.60	(3,770,803)
12	Total	-		$ -

Equalization capacity rate (The is the average $/kW rate paid by deficit members.): **13.6032**

Kentucky Power Company
Pollution Control Environmental Facilities
AEP System Pool
Capacity Rate Calculations for
Surplus Member Companies
August 2011

Line No.	Description	Formula	Units	I&M	OPCo	
(1)	(2)	(3)	(4)	(5)	(6)	
	Primary Capacity Investment Rate:					
1	Steam Production Plant as of 12-mo ended 12/31/10		($)	4,040,461,038	6,654,950,782	
2	Steam Capacity as of 12-mo ended 12/31/10		(kW)	5,414,000	8,440,000	
3	Average Cost of Investment	L1 / L2	($/kW)	$746 30	$788.50	
4	Carrying Charge (16.44% / 12 months)		($/kW/Month)	0.0137	0.0137	
5	Primary Capacity Investment Rate	L3 X L4		$10.22	$10 80	
	Monthly Fixed Operating Rate:					
6	Steam Plant Operation Expense (less: fuel)		($)	18,440,310	17,311,512	
7	1/2 Maintenance Expense		($)	6,117,393	5,856,913	
8	Subtotal - Fixed Operating Expense	L6 + L7	($)	24,557,703	23,168,425	
9	Steam Capability	L2	(kW)	5,414,000	8,440,000	
10	Fixed Operating Rate	L8 / L9	($/kW)	$4 54	$2.75	
11	**Capacity Rate**	L5 + L10	($/kW)	$14.76	$13.55	
	Calculate AEP Pool Average Capacity Rate:					
12	Surplus Capacity	Exhibit LPM-7, C7, L3 or L4	(kW)	108,900	2,368,700	
13	Member's Percent of Pool's Total Surplus		(%)	4.40%	95.60%	
14	Surplus Member's Capacity Rate	L11	($/kW)	$14.76	$13 55	
15	Surpl. Memb. CAP Rate Recv. From Deficit Memb.	L13 X L14	($/kW)	$0.65	$12.95	
16	**AEP Pool's Average Capacity Rate**		($/kW)			$13.60

Kentucky Power Company
Pollution Control Environmental Facilities
AEP System Pool Monthly
Environmental Capacity Costs

Line No.	Description	Exhibit or Formula	I&M	OPCo	KPCo
(1)	(2)	(3)	(4)	(5)	(6)
1	Net Cost of Environmental Facilities Investment Installed	Exhibit LPM-6, L8	$ 34,046,903	$ 44,455,287	
2	Installed Capacity (kW)	Exhibit LPM-8, L2	5,414,000	8,440,000	
3	Weighted Average Installed Cost ($/kW)	L1 / L2	$6.29	$5.27	
4	Monthly Return on Investment	Exhibit LPM-8, L4	0.0137	0.0137	
5	Envir. Member Capacity Investment Rate ($/kW/Mo.)	L3 X L4	$0.09	$0.07	
	Plus: Operations & 1/2 Maintenance				
6	OPCo's Amos Unit No. 3 & Common Plant	Exhibit LPM-10, L21, C14		$0.01	
7	I&M's: Rockport & Tanners Creek Units	Exhibit LPM-11, L15, C14	$0.06		
8	Subtotal	L5 + L6 + L7	$0.15	$0.08	
9	Surplus Company Weighting	Exhibit LPM-8, L13	4.40%	95.60%	
10	Surplus Capacity	L8 X L9	$0.01	$0.08	$0.09
11	KPCo's Pool Capacity Deficit	Exhibit LPM-7, L2, C7	283,900	283,900	283,900
12	KPCo's Monthly Envir. Pool Capacity Charge	L10 X L11	$ 2,839	$ 22,712	$ 25,551
13	Number of months				12
14	**Annual Effect of Envir. Pool Capacity Charge**	L12 X L13			$ 306,612

Kentucky Power Company
Pollution Control Environmental Facilities
Ohio Power Company

Line No.	Description	Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11	Month 12	Annual
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Operations:													
1	Amos Unit #3 Dry Fly Ash Disposal Conversion	$ 3,042	$ 3,042	$ 3,041	$ 3,042	$ 3,042	$ 3,041	$ 3,042	$ 3,042	$ 3,041	$ 3,042	$ 3,042	$ 3,041	$36,500.00
2	Amos Common - FGD Hg Waste Water Treatment	$ 86,125	$ 86,125	$ 86,125	$ 86,125	$ 86,125	$ 86,125	$ 86,125	$ 86,125	$ 86,125	$ 86,125	$ 86,125	$ 86,125	$1,033,500.00
3	Amos Common - Hg In-Pond Chemical Treatment	$ 138,125	$ 138,125	$ 138,125	$ 138,125	$ 138,125	$ 138,125	$ 138,125	$ 138,125	$ 138,125	$ 138,125	$ 138,125	$ 138,125	$1,657,500.00
4	Amos Common - Ash Pond Discharge Diffuser	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.00
5	Total Common Plant Operations (L2 + L3 + L4)	$ 224,250	$ 224,250	$ 224,250	$ 224,250	$ 224,250	$ 224,250	$ 224,250	$ 224,250	$ 224,250	$ 224,250	$ 224,250	$ 224,250	$2,691,000.00
	Maintenance:													
6	Amos Unit #3 Dry Fly Ash Disposal Conversion	$ 3,042	$ 3,042	$ 2,867	$ 762	$ 20,802	$ 1,706	$ 4,042	$ 3,896	$ (4,704)	$ 22,701	$ 4,431	$ 877	$63,463.44
7	1/2 Amos Unit #3 Maintenance (L6 / 2)	$ 1,521	$ 1,521	$ 1,433	$ 381	$ 10,401	$ 853	$ 2,021	$ 1,948	$ (2,352)	$ 11,350	$ 2,216	$ 439	$31,732.00
8	Amos Common - FGD Hg Waste Water Treatment	$ 2,208	$ 2,208	$ 2,209	$ 2,208	$ 2,208	$ 2,209	$ 2,208	$ 2,208	$ 2,209	$ 2,208	$ 2,208	$ 2,209	$26,500.00
9	Amos Common - Hg In-Pond Chemical Treatment	$ 3,542	$ 3,542	$ 3,541	$ 3,542	$ 3,542	$ 3,541	$ 3,542	$ 3,542	$ 3,541	$ 3,542	$ 3,542	$ 3,541	$42,500.00
10	Amos Common - Ash Pond Discharge Diffuser	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.00
11	Total Common Plant Maintenance (L8 + L9 + L10)	$ 5,750	$ 10,313	$ 10,050	$ 6,893	$ 36,953	$ 8,309	$ 11,813	$ 11,594	$ (1,306)	$ 39,801	$ 12,397	$ 7,066	$159,632.44
12	1/2 Common Plant Maintenance (L11 / 2)	$ 2,875	$ 5,157	$ 5,025	$ 3,446	$ 18,477	$ 4,154	$ 5,906	$ 5,797	$ (653)	$ 19,900	$ 6,199	$ 3,533	$79,816.00
13	Total Amos Unit #3 Fixed O&M (L1 + L7)	$ 4,563	$ 4,563	$ 4,474	$ 3,423	$ 13,443	$ 3,894	$ 5,063	$ 4,990	$ 689	$ 14,392	$ 5,258	$ 3,480	$68,232.00
14	OPCo's % Ownership (Exh. LPM-6, L1, C7)	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%	66.67%	
15	OPCo's Share of Amos #3 Fixed O&M (L13 X L14)	$ 3,042	$ 3,042	$ 2,983	$ 2,282	$ 8,962	$ 2,596	$ 3,376	$ 3,327	$ 459	$ 9,595	$ 3,506	$ 2,320	$45,490.00
16	Total Amos Common Plant Fixed O&M (L5 + L12)	$ 227,125	$ 229,407	$ 229,275	$ 227,696	$ 242,727	$ 228,404	$ 230,156	$ 230,047	$ 223,597	$ 244,150	$ 230,449	$ 227,783	$2,770,816.00
17	OPCo's % Ownership (Exh. LPM-6, L2, C7)	29.89%	29.89%	29.89%	29.89%	29.89%	29.89%	29.89%	29.89%	29.89%	29.89%	29.89%	29.89%	
18	OPCo's Share of Common Pl Fixed O&M (L16 X L17)	$ 67,888	$ 68,570	$ 68,530	$ 68,058	$ 72,551	$ 68,270	$ 68,794	$ 68,761	$ 66,833	$ 72,976	$ 68,881	$ 68,084	$828,196.00
19	OPCo's Share of Fixed O&M (L15 + L18)	$ 70,930	$ 71,612	$ 71,513	$ 70,340	$ 81,513	$ 70,866	$ 72,170	$ 72,088	$ 67,292	$ 82,571	$ 72,387	$ 70,404	$873,686.00
20	OPCo Steam Capacity (kW) (Exh LPM-9, L2, C5)	8,440,000	8,440,000	8,440,000	8,440,000	8,440,000	8,440,000	8,440,000	8,440,000	8,440,000	8,440,000	8,440,000	8,440,000	
21	OPCo Rate ($/kW) (L19 / L20)	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	
22	OPCo Surplus Weighting (%) (Exh LPM-9, L9, C5)	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	95.60%	
23	Effect on Wt. Ave. Rate ($/kW) (L21 X L22)	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	
24	Portion of Weighted Average Capacity Rate Attributed to OPCo Facilities (L23)	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	
25	KPCo's Pool Capacity Deficit (Exh. LPM-7, L2, C7)	283,900	283,900	283,900	283,900	283,900	283,900	283,900	283,900	283,900	283,900	283,900	283,900	283,900
26	KPCo's Share of OPCo (L24 X L25)	$ 2,839	$ 2,839	$ 2,839	$ 2,839	$ 2,839	$ 2,839	$ 2,839	$ 2,839	$ 2,839	$ 2,839	$ 2,839	$ 2,839	$34,068

Kentucky Power Company
Pollution Control Environmental Facilities
Indiana and Michigan Power Company

Line No. (1)	Description (2)	Month 1 (3)	Month 2 (4)	Month 3 (5)	Month 4 (6)	Month 5 (7)	Month 6 (8)	Month 7 (9)	Month 8 (10)	Month 9 (11)	Month 10 (12)	Month 11 (13)	Month 12 (14)	Total (15)
	Operations:													
1	Rkpt1&2 Activated Carbon Injection (ACI)	$ 471,649	$ 613,139	$ 463,686	$ 536,123	$ 448,647	$ 290,791	$ 288,112	$ 165,345	$ 30,592	$ 165,068	$ 134,893	$ 379,076	$3,987,119.48
2	TC 1, 2, &3 Selective Non-Catalytic Reduction (SNCR)	$ 1,235	$ 26	$ (392)	$ (32)	$ 5	$ 8	$ (16)	$ 20	$ 26	$ (43)	$ 2	$ 107	$945.14
	Maintenance:													
3	Rkpt1&2 Activated Carbon Injection (ACI)	$ 2,314	$ -	$ 558	$ 1,349	$ 650	$ -	$ -	$ 4,047	$ 8,642	$ 32,485	$ 23,769	$ 279	$74,093.50
4	1/2 Rockport Maintenance (L3 / 2)	$ 1,157	$ -	$ 279	$ 675	$ 325	$ -	$ -	$ 2,024	$ 4,321	$ 16,243	$ 11,884	$ 139	$37,047.00
5	TC 1, 2, &3 Selective Non-Catalytic Reduction (SNCR)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0
6	1/2 Tanners Creek Maintenance (L5 / 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0
7	Total Rockport Fixed O&M (L1 + L4)	$ 472,806	$ 613,139	$ 463,965	$ 536,798	$ 448,972	$ 290,791	$ 288,112	$ 167,369	$ 34,913	$ 181,311	$ 146,777	$ 379,215	$4,024,166.48
8	I&M's Percentage Ownership (Exh. LPM-6, L6, C7)	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
9	I&M's Share of Rockport Fixed O&M (L7 X L8)	$ 401,885	$ 521,168	$ 394,370	$ 456,278	$ 381,626	$ 247,172	$ 244,895	$ 142,264	$ 29,676	$ 154,114	$ 124,761	$ 322,333	$3,420,542.00
10	Total Tanners Creek Fixed O&M (L2 + L6)	$ 1,235	$ 26	$ (392)	$ (32)	$ 5	$ 8	$ (16)	$ 20	$ 26	$ (43)	$ 2	$ 107	$945.14
11	I&M's Percentage Ownership (Exh. LPM-6, L7, C7)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
12	I&M's Share of TC Fixed O&M (L10 X L11)	$ 1,235	$ 26	$ (392)	$ (32)	$ 5	$ 8	$ (16)	$ 20	$ 26	$ (43)	$ 2	$ 107	$946.00
13	I&M's Share of Fixed O&M (L9 + L12)	$ 403,120	$ 521,194	$ 393,978	$ 456,246	$ 381,631	$ 247,180	$ 244,879	$ 142,284	$ 29,702	$ 154,071	$ 124,763	$ 322,440	$3,421,488.00
14	I&M Steam Capacity (kW) (Exh. LPM-9, L2, C4)	5,414,000	5,414,000	5,414,000	5,414,000	5,414,000	5,414,000	5,414,000	5,414,000	5,414,000	5,414,000	5,414,000	5,414,000	
15	Indiana Rate ($/kW) (L13 / L14)	$0.07	$0.10	$0.07	$0.08	$0.07	$0.05	$0.05	$0.03	$0.01	$0.03	$0.02	$0.06	
16	I&M Surplus Weighting (%) (Exh LPM-9, L9, C4)	4.40%	4.40%	4.40%	4.40%	4.40%	4.40%	4.40%	4.40%	4.40%	4.40%	4.40%	4.40%	
17	Effect on Wt. Ave. Rate ($/kW) (L15 X L16)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
18	Portion of Weighted Average Capacity Rate Attributed to I&M Environmental Controls	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
19	KPCo's Pool Capacity Deficit (Exh. LPM-7, L2, C7)	283,900	283,900	283,900	283,900	283,900	283,900	283,900	283,900	283,900	283,900	283,900	283,900	
20	KPCo's Share: ACI & SNCR (L18 X L19)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0

Kentucky Power Company
Pollution Control Environmental Facilities
Rockport Environmental Surcharge Calculations
Revenue Requirement

Line No.	Cost Component	Formula	Rockport Total
(1)	(2)	(3)	(4)
1	Rockport #1 & #2 Activated Carbon Injection (ACI)	Exhibit LPM-6, L6, C5	$23,405,482
2	Less: Accumulated Depreciation	L1 X 3.52%	$823,873
3	Less: Accumulated Deferred Income Tax	L1 X 1.3%	$304,271
4	Total Rate Base	L1 - L2 - L3	$22,277,338
5	Weighted Average Cost of Capital for Aug. 2011	Exhibit LPM-3, L5, C8	10.69%
6	Monthly Weighted Average Cost of Capital	L5 / 12	0.8908%
7	Monthly Return on Rate Base	L4 X L6	$198,447
	Operating Expenses		
8	Monthly Depreciation Expense	L2 / 12	$68,656
9	Total Operating Expense		$68,656
10	Total Revenue Requirement Associated with Rockport ACI	L7 + L9	$267,103
11	KPCo's Percentage of Rockport's upgrades	100% - Exhibit LPM-6, L6, C7	15%
12	KPCo's Portion of Rockport's upgrades	L10 X L11	$40,065
13	Annualize		12
14	**Annualized Revenue Requirement**	L12 X L13	$ 480,780

Kentucky Power Company
Pollution Control Environmental Facilities
New Environmental Costs Associated with
Allowance Inventory

Line No.	Description	Formula	Capital Costs of KY Retail Revenues	Capital Costs of Associated Utility Revenues	Capital Total KY Retail
(1)	(2)	(3)	(4)	(5)	(6)=(4)+(5)
1	Estimated Allowance Inventory Required by CSAPR	Wohnhas Testimony	$ 6,212,000	$ 6,212,000	
2	Less: Estimated NO_x Gains	Wohnhas Testimony	$ 650,000	$ 650,000	
3	Net Allowances required by CSAPR	L1 - L2	$ 5,562,000	$ 5,562,000	
4	Annual Weighted Average Cost of Capital	Exhibit LPM-3, L5, C8	10.69%	10.69%	
5	Carrying Cost	L3 X L4	$ 594,578	$ 594,578	
6	Annual Revenue Allocation Factor	Exhibit LPM-5, L15, C3 or C6	78.91%	9.34%	
7	Subtotal	L5 X L6	$ 469,181	$ 55,534	
8	KY Jurisdiction Revenue Allocation Factor	Exhibit LPM-5, L14, C3		98.91%	
9	Total KY Retail Revenue Requirement	L7 X L8	$ 469,181	$ 54,929	$ 524,110
10	KY Jurisdiction 12-month Revenue	Exhibit LPM-5, L13, C3			$ 569,593,245
11	Percent Change	L9 / L10			0.09%

Kentucky Power Company
Pollution Control Environmental Facilities
New Environmental Costs
Effect on Residential Customers

Line No.	Description	Formula	Annual Amount	Percent Increase
(1)	(2)	(3)	(5)	(6)
1	Annual Effect of New Environmental Pool Capacity Charges	Exhibit LPM-9, L14	$306,612	
2	KPCo's Share of Rockport	Exhibit LPM-12, L14	$480,780	
3	Total Environmental Cost	L1 + L2	$787,392	
4	KPCo's Average Retail Allocation for 12 months ended August 2011	Exhibit LPM-5, L.15, C3	78.91%	
5	Net Annual Impact on the Kentucky Retail Customers	L3 X L4	$621,331	0.11%
6	KY Retail Allowances	Exhibit LPM-13, L9, C6	$524,110	0.09%
7	KY Retail Revenue Requirement for Big Sandy Environmental Additions	Exhibit LPM-2, L15, C5	$177,699,409	31.20%
8	Total Environmental Projects in this Filing	L5 + L6 + L7	$178,844,850	31.40%
9	Billed Revenues for 12 months ended August 2011	Exhibit LPM-5, L13, C3	$569,593,245	
10	Percent Increase	L8 / L9	31.40%	
		Usage in kWh:	**1,000**	
11	Monthly Effect on a Residential Customers		$ 30.75	
12	Annualize		12	
13	**Annual Effect on a Residential Customers**	L11 X L12	$ 369.00	

KENTUCKY POWER COMPANY

Original Sheet No. 29-1
Canceling ______ Sheet No. 29-1

P.S.C. ELECTRIC NO. 9

TARIFF E.S.
(Environmental Surcharge)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., Experimental S.G.S.-T.O.D., M.G.S. M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., Q.P., C.I.P.-T.O.D., C.S.-I.R.P., M.W., O.L., and S.L. (T)

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	$ 3,991,163
FEBRUARY	3,590,810
MARCH	3,651,374
APRIL	3,647,040
MAY	3,922,590
JUNE	3,627,274
JULY	3,805,325
AUGUST	4,088,830
SEPTEMBER	3,740,010
OCTOBER	3,260,302
NOVEMBER	2,786,040
DECEMBER	4,074,321
	$44,185,079

(I)
(I)

(Continued on Sheet 29-2)

DATE OF ISSUE July 16, 2010 DATE EFFECTIVE Service rendered on and after

ISSUED BY E.K. Wagner E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No.2009-00459 dated June 28, 2010

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Brent Kirtley
EFFECTIVE
6/29/2010
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

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, the 2005 Plan, the 2007 Plan, and the 2011 Plan. (T)

The Rate of Return for Kentucky Power is 10.5% rate of return on equity as authorized by the Commission in its June 28, 2010 Order in Case No. 2009-00459 at page 6.

(Cont'd on Sheet No. 29-3)

KENTUCKY POWER COMPANY

Original Sheet No. 29-3
Canceling ______ Sheet No 29-3

P.S.C. ELECTRIC NO. 9

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 eq[uipment]

(Cont'd on Sheet No. 29-4)

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Bunt Kirtley
EFFECTIVE
6/29/2010
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

DATE OF ISSUE July 16, 2010 DATE EFFECTIVE Service rendered on and after Ju[ne 29, 2010]

ISSUED BY E. K. Wagner E. K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFO[RT, KY]
NAME TITLE ADDRESS

Issued by authority of an order of the Public Service Commission in Case No. 2009-00459 dated [June 28, 2010]

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

RATE (Cont'd)

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

(r) costs associated with installing, operating, and maintaining a Dry Flue Gas Desulfurization Unit (DFGD), DFGD Ash Haul Road and Landfill, at the Big Sandy Generating Plant Unit No. 2. (N)

(s) The Company's share of the pool Capacity costs associated with the following: (T)

- Amos Unit No. 3 CEMS, Low NO_x Burners, SCR, FGD, Landfill, Coal Blending Facilities, SO_3 Mitigation, Electrostatic Precipitator Modification (ESP),and Dry Fly Ash Disposal Conversion (T)
- Amos Plant Common FGD Hg Waste Water Plant Treatment, Hg In-Pond Chemical Treatment, and Ash Pond Discharge Diffusers (N)
- Cardinal Unit No 1 CEMS, Low NO_x Burners, SCR, Catalyst Replacement, FGD, Landfill and SO_3 Mitigation
- Gavin Plant SCR and SCR Catalyst Replacement
- Gavin Unit No 1 and 2 Low NO_x Burners and SO_3 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 SO_3 Mitigation
- Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsom 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 Overlay, an SCR and SO3 Mitigation
- Muskingum River Common CEMS
- Phillip Sporn Unit No 2 Low NO_x Burners with Modifications

(Cont'd on Sheet No. 29-5)

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

RATE (Cont'd)

- 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, Landfill, and Activated Carbon Injection (ACI) (T)
- Tanners Creek Unit No 1 Low NO_x Burners, with Modifications, Low NO_x Burners Leg Replacement, and Selective Non-Catalytic Reduction (T)
- Tanners Creek Unit No 2 and 3 Low NO_x Burners with Modifications and Selective Non-Catalytic Reduction (T)
- Tanners Creek Unit No 4 Over Fire Air and 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.
- Costs associated with the SO_2 and NO_x allowances required by the Cross-State Air Pollution Rule (CSAPR). (N)

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

APPLICATION OF KENTUCKY POWER COMPANY	)
FOR APPROVAL OF ITS 2011 ENVIRONMENTAL	)
COMPLIANCE PLAN, FOR APPROVAL OF ITS	)
AMENDED ENVIRONMENTAL COST RECOVERY	) Case No. 2011-00401
SURCHARGE TARIFF, AND FOR THE GRANT OF A	)
CERTIFICATE OF PUBLIC CONVENIENCE AND	)
NECESSITY FOR THE CONSTRUCTION AND	)
ACQUISITION OF RELATED FACILITIES	)

DIRECT TESTIMONY

OF

ROBERT L. WALTON

DIRECT TESTIMONY OF
ROBERT L. WALTON, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2011-00401

TABLE OF CONTENTS

DIRECT TESTIMONY OF
ROBERT L. WALTON, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert L. Walton, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the American Electric Power Service Corporation (AEPSC) as Managing Director of Projects and Controls. AEPSC supplies engineering, financing, accounting, project management and planning and advisory services to the eleven electric operating companies of the American Electric Power System, one of which is Kentucky Power (KPCo) Company.

II. BACKGROUND

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated from The Ohio State University in Columbus, Ohio in 1974 with a Bachelor of Science Degree in Mechanical Engineering. From 1975 to 1978 I was employed by the Babcock and Wilcox Company (B&W) as a Field Service Engineer. From 1978 to 1985, I was employed by the B&W Construction Company in various positions of increasing responsibility including Site Project Engineer, Site Construction Manager, and ultimately Regional representative, responsible for all aspects of Company business in a five-state area.

I joined American Electric Power (AEP) in 1985 as a Senior Engineer progressing to Assistant Manager in 1987 and then to Manager of Maintenance Planning in 1988. In 1993, I was named Manager of Steam Generation Engineering and became Manager, Selective Catalytic Reduction (SCR) Engineering in 1999. In 2000, I became the Director, Engineering & Consulting Services West. In 2003, I was named Director, Environmental Projects and subsequently named Managing Director, Plant and Environmental Retrofit Projects in April 2006. During this tenure, I was involved in or responsible for the installation of 13 individual Flue Gas Desulfurization (FGD) systems and 10 individual Selective Catalytic Reduction (SCR) systems on AEP and AEP affiliate facilities. In November 2010 I was named to my current position of Managing Director of Projects and Controls with expanded additional responsibility for project scheduling and monitoring services as well as cost analysis and control services.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have submitted written testimony on behalf of Indiana Michigan Power Company before the Indiana Utility Regulatory Commission in Cause Nos. 43636, 43636 ECR 1 and Cause No. 44033, as well as written testimony before the Michigan Public Service Commission in Case No. U-16801. I have also submitted written testimony on behalf of Appalachian Power Company in Case No. PUE-2008-00045 before the Virginia State Corporation Commission.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe the process that is being performed by the

AEPSC, on behalf of KPCo, to retrofit Big Sandy Unit 2 with a flue gas desulfurization (FGD) system to reduce the plant's emissions of sulfur dioxide (SO_2). I will also describe AEPSC's efforts to select the best SO_2 reduction technology for Big Sandy Unit 2, the expected performance of the technology, and the current cost estimate to retrofit the technology on the unit.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes, I am sponsoring Exhibit RLW-1 – Project Schedule.

IV. <u>ENVIRONMENTAL PROJECTS EXECUTION</u>

Q. PLEASE DESCRIBE THE PLANNING ACTIVITIES CONDUCTED BY THE COMPANY FOR THE RETROFIT OF ENVIRONMENTAL CONTROLS AT BIG SANDY UNIT 2.

A. The Company has acted to identify the most economical SO_2 reduction technology, and has also developed an associated cost estimate in order to perform analyses to determine if the project is economically beneficial for KPCo customers.

Q. PLEASE PROVIDE AN OVERVIEW OF THE CURRENT PROJECT PLAN FOR THE BIG SANDY UNIT 2 FGD.

A. The Big Sandy Unit 2 FGD retrofit project will be executed using the same phased approach that has been successfully employed by AEP on many past projects. The phased approach begins with Phase I, which consists primarily of a feasibility study. Phase IIa is the preliminary engineering and design stage, while Phase IIb provides for detailed engineering, design, and initial site construction activities. Full-scale construction, startup, and commissioning are undertaken in Phase III. A detailed review, followed by financial authorization, is required before the project can proceed from one phase to the next. A graphical timeline showing the phased approach as well as major project milestones is provided in Exhibit RLW-1.

Since 2004, AEP has implemented this phased approach in the installation of FGD systems on over 8,400 MW of generation and SCR systems on approximately 2,400 MW. At the height of construction activity in 2007, *Engineering News-Record* identified AEP's overall construction program as the largest in the utility industry and the second largest in the nation, based on capital invested. The Big Sandy Unit 2 FGD retrofit will positively benefit from years of valuable lessons learned and best practices.

This past experience will be invaluable, as the timeline for installing the FGD system on Big Sandy Unit 2 to meet the requirements of the Cross State Air Pollution Rule (CSAPR) and Electric Generating Unit Maximum Achievable Control Technology (EGU MACT) Rule will be challenging as discussed by Company witness McManus.

Q. **IN WHAT PHASE IS THE BIG SANDY UNIT 2 FGD PROJECT CURRENTLY?**

A. The project is currently in Phase I. The project has been initiated and the project planning and conceptual engineering required to support this filing have been completed. Next, a Project Charter and a Project Plan will be developed which will include a detailed execution strategy for the engineering, design, procurement, permitting, construction, startup and commissioning of the FGD system.

Q. **PLEASE DESCRIBE THE ACTIVITIES THAT OCCUR DURING PHASE I.**

A. The formal process begins with the preparation and approval of a Capital Improvement Requisition (CI) after which an architect/engineer (A/E) is engaged to perform the engineering, design, and feasibility studies for Phase I and the ensuing phases of the project. The intent of the Phase I feasibility studies is to investigate the technical options and factors driving the project cost and schedule. During Phase I, the architect/engineer, with input from a team of AEPSC engineers and managers, defines the scope of the project, prepares work plans, and develops a budgetary cost estimate and schedule for implementation. In addition, preliminary environmental permitting activities begin and the FGD supplier is released to begin conceptual engineering. The results of the Phase I conceptual engineering and feasibility studies are presented to senior management and authorization is sought to proceed to Phase IIa via a Phase IIa CI revision. Formal approval of the CI revision by AEPSC and KPCo management allows the project to proceed to Phase IIa.

Q. **PLEASE DESCRIBE THE ACTIVITIES THAT TAKE PLACE IN PHASE IIA.**

A. Phase IIa consists of preliminary engineering, design, permitting and procurement work. During this phase, we finalize the project scope, refine the cost estimate and schedule, award the Original Equipment Manufacturer (OEM) contract, procure long lead time equipment, and develop drawings to the point that detailed design work can begin. During Phase IIa, modifications to existing air, water and waste environmental permits are submitted to the Kentucky Department for Environmental Protection to begin the review and approval process and we assemble the construction and site management teams to begin design reviews to ensure that the proposed scope of work is optimized for constructability. We also define site preparation plans, determine which, if any, facilities will need to be relocated, select a site preparation contractor, and complete studies to support the various permitting activities that will be required. Upon completion of Phase IIa, the project is again reviewed and a Phase IIb CI is prepared for approval by AEPSC and KPCo management.

Q. PLEASE DESCRIBE PHASE IIB OF THE PROJECT PROCESS.

A. Phase IIb consists of detailed engineering, design, contracting and initial site construction work. During this phase, as detailed design progresses, construction bid packages are prepared and major equipment is specified, bid, and purchased. The construction and site management teams are mobilized and begin site construction work, including the development of new access roads, contractor parking areas and material storage areas, as well as the relocation of existing underground piping and electrical utilities to facilitate the installation of new foundations and equipment pads. We proceed through the process of selecting and awarding the major construction contracts. Upon completion of Phase IIb, the project is reviewed once again, and a Phase III CI is prepared for approval by AEPSC and KPCo management.

Q. WHAT TAKES PLACE DURING PHASE III?

A. Phase III consists of the full-scale construction and startup and commissioning of the project. Construction, start-up, testing, check out and commissioning are the key activities associated with Phase III. The principal construction contractors mobilize and begin the major construction effort. Engineering and design continues in support of the project throughout the construction and testing activities, including the validation of the design, the preparation of as-built drawings, and the evaluation and approval of necessary design changes. Phase III is complete when the project is complete and the equipment is commissioned and placed in service.

Q. WHAT ARE THE MAJOR BENEFITS DERIVED FROM THIS PHASED APPROACH TO CONSTRUCTION PROJECTS?

A. The phased approach provides structured control of the project scope and costs. It provides a minimum of three specific decision points (the end of Phases I, IIa, and IIb) where engineering and design, cost and schedule are reviewed to ensure they are meeting the intent and expectations of the project. Starting major construction activities when the detailed discipline design is substantially complete allows construction to proceed, in many cases, on a fixed or target price basis, since many of the design changes that might otherwise result in additional work and cost will have been identified and remedied. Participation by the construction team during the design phases assures that the equipment layout and modularization allows for optimized constructability and provides for a smooth transition into the major construction phase of the project.

Q. PLEASE GENERALLY DESCRIBE THE PROCESS FOR SELECTING A SPECIFIC TECHNOLOGY AND OEM VENDOR FOR THE ENVIRONMENTAL CONTROLS TO BE INSTALLED AT ANY UNIT.

A. AEP maintains an updated list of technologies that have been proven effective in removing emissions from power plant effluent streams. When a generic control (e.g., wet or dry scrubber) has been identified as the best type of control for a specific unit burning an identified range of fuel, an OEM Evaluation Team determines, on a unit-specific basis, which OEMs provide control technologies that can be used on that unit. The OEM Evaluation Team then determines the Total Evaluated Cost (TEC) over the life of the project for each technology. If there is no significant difference between or among the TECs or analyzed business risk, the OEM that presents the lowest Total Installed Cost (TIC) is preferred.

Q. PLEASE GENERALLY DESCRIBE THE PROCESS USED TO SELECT A CONSTRUCTION CONTRACTOR FOR THE ENVIRONMENTAL CONTROLS

AT ANY UNIT.

A. AEP maintains a list of construction contractors that have the capability to perform work of the type and scope envisioned with a demonstrated record of safe focus and performance. Proposals are requested from two or more of the contractors on that list. The final award is based on the TEC and safety performance of those bidders, along with ancillary considerations such as a financial risk assessment, any pricing discounts offered for multiple-unit awards, negotiated shared risk/reward programs, and similar factors.

Q. WHAT STEPS DOES AEP TAKE TO ENSURE THAT PROJECT COSTS ARE REASONABLE AND NECESSARY?

A. The three-phase process enables periodic and structured technical and cost reviews throughout each phase. The Phase I feasibility study assesses technical options and costs. Phase IIa and IIb engineering produces preliminary, then detailed designs to refine the associated costs.

As previously discussed, contracting for construction activities when the detailed discipline design is substantially complete allows construction to proceed, in many cases, on a fixed or target price basis. This serves to mitigate KPCo's and our customers' exposure to upside cost risks. As Phase III construction and startup and commissioning proceeds, we use prudent construction management practices and cost and schedule controls to ensure that the projects are accomplished in a safe, as well as professional, and cost-effective manner. To that end, AEP has developed a robust Quality Assurance/Quality Control manual that includes Standard Operating Procedures for such activities as Work Management, Preparation of Estimates, Procurement, Project Schedule Control, Project Cost Control, Corrective and Preventive Actions, and, above all, Safety.

Q. PLEASE DESCRIBE AEP'S PROJECT COST MANAGEMENT PROCESS.

A. Project cost management involves the planning, estimating, budgeting, and controlling processes and metrics to be utilized during each phase of the project. The initial refinement of the conceptual cost estimates developed for the project during Phase I is derived from several inputs, including the feasibility studies and recent market information.

At the end of Phase II engineering and design activities, the cost estimate is based on a well-defined scope of work which has been developed by completing a sufficient level of engineering and design to provide greater cost certainty in support of the project schedule. The schedule of activities for this phase incorporates a design review plan required by AEPSC Engineering Services. The inclusion of the design review plan bolsters scope definition and increases certainty in the cost estimate. A total project cost estimate is then developed by AEPSC to include the Balance of Plant (BOP) scope, FGD System Equipment Supply, construction costs and owner's costs. A detailed risk analysis is also completed to better determine the level of contingency required by the project for risk mitigation.

Q. PLEASE DESCRIBE AEP'S PROJECT SCHEDULE MANAGEMENT PROCESS.

A. Schedule management ensures that the overall project is executed in accordance with the needs of the interfacing groups to ensure that work is completed in support of the initial operation date. This is accomplished through the use of scheduling tools, the monitoring of critical milestones and through the establishment and monitoring of specific performance and production metrics.

An integrated project schedule is developed using activities and criteria for planning, structuring, and control. The project schedule development involves activity sequencing and activity duration estimating to develop detailed project schedules so monitoring and controls are in place to complete the project on or ahead of schedule. The scope of work for the project is subdivided into manageable work packages using a project Work Breakdown Structure (WBS). The WBS is used to facilitate project cost estimating, scheduling, and controlling activities.

AEPSC assumes the primary responsibility for schedule management as the Schedule Integrator for the project. In that role, we integrate the activities of the A/E, the FGD Supplier and the Constructors into our own for the development of a fully integrated schedule. The A/E, Contractors and vendors provide us with monthly reports on the project schedule along with weekly comprehensive process submittals that include an update of their project schedule, a 30-day look ahead, a status of major activities, cost/schedule status updates, and other pertinent data.

Q. PLEASE DESCRIBE AEP'S PROJECT PROCUREMENT/CONTRACT MANAGEMENT PROCESS.

A. The FGD System Equipment Supplier is selected through a competitive evaluation process based on AEPSC performance and technical specifications. A similar process is utilized for the selection of construction labor companies to perform the field installation of the equipment.

Q. PLEASE DESCRIBE AEP'S PROJECT RISK MANAGEMENT PROCESS.

A. A full risk analysis is generated for the project as part of the Phase I activities. This is completed to identify, quantify, and mitigate project risks and to develop a risk register. The critical project risks are prioritized so that project resources can be efficiently focused on mitigation efforts. The risk register is included in the Project Risk Management Plan and is updated quarterly.

Q. **PLEASE DESCRIBE AEP'S PROJECT SAFETY MANAGEMENT PROCESS.**

A. The project will follow AEP Generation's Safety Program – Target Zero. Target Zero distills safety into a simple idea – each employee, regardless of work location, is encouraged to ask themself how to make activities safer. The initiative is aimed at targeting and maintaining a zero accident goal and focusing on the job at hand, to look for and think about safety hazards before the job starts, and working smarter during the job and stopping work if necessary to avoid unsafe conditions.

All contractors will be required to adhere to AEP's safety policies and procedures as a minimum and implement the plans, programs, and requirements included in AEP's Supplemental Safety Terms & Conditions. Safety performance oversight will be provided by AEPSC during construction. Routine meetings will be held with contractors at the site to assure communication of, and adherence to, AEP's requirements.

Q. **PLEASE DESCRIBE AEP'S PROJECT QUALITY MANAGEMENT PROCESS.**

A. AEPSC Engineering Services develops a Statement of Work (SOW), which includes design criteria and specifications for the FGD system, equipment, materials, and process functionality.

The project team works with AEP Quality Control in the development of a Quality Oversight Plan (QOP) for the SOW in accordance with our Operating Instructions. The QOP will determine what inspections will be conducted, their frequency, and the responsible person(s). In addition, it will specify the frequency of independent surveillances to be conducted by AEP Quality Control. The QOP is reviewed by the project team for any needed updates every 6 months, at a minimum.

The AEPSC Site Construction Manager will assure field inspections are performed both independently and concurrently with any contractor's inspections. All assessments will be documented in a database, and the information will be reviewed monthly by AEP Quality Control to assure that inspections are conducted per the QOP.

Q. **WILL THE PHASE I FEASIBILITY STUDIES COVER THE ENTIRE SCOPE OF THE BIG SANDY UNIT 2 FGD PROJECT?**

A. Yes. AEP will establish a Division of Work (DOW) clearly defining the responsibilities of the assigned parties not only for the FGD technology, but also site development, reagent and material unloading and handling systems, any required switchyard modifications and the identification of all permitting requirements. AEP design criteria will be clearly communicated to the A/E and the OEM to ensure the benefits of our knowledge and experience in owning, maintaining and operating similar systems is carried forward on the Big Sandy Unit 2 project.

Q. **CAN YOU PROVIDE A GRAPHICAL SUMMARY OF THE PHASED APPROACH TO CONSTRUCTION?**

A. Yes. Exhibit RLW-1 shows a preliminary project schedule for the various activities that will take place during this phased approach to construction.

Q. **WHEN IS EACH PHASE ESTIMATED TO BEGIN?**

A. Each phase and subsequent activities are displayed in Exhibit RLW-1. Phase I has already commenced and activities are expected to be completed in the third quarter of 2012 with Phase IIa to start in the same time frame. Phase IIb is estimated to begin in the first quarter of 2013 and be completed by the end of the fourth quarter of 2013. We are currently planning on commencing site construction activities on or about July 1, 2013, predicated upon the receipt of the Permit to Install (PTI), often referred to as the air permit, from the issuing agency.

V. TECHNOLOGY SELECTION

Q. WHAT FGD SYSTEMS WERE CONSIDERED AND HOW DO THEY WORK TO REDUCE SO_2 EMISSIONS?

A. A variety of SO_2 control processes and technologies are in use within the industry, but two commercialized processes emerged for comparative study on Big Sandy Unit 2: Limestone Forced Oxidation (LSFO) Spray Tower Wet FGD and Lime Dry FGD with Recycle. These processes are typically referred to in the industry as wet FGD (WFGD) and dry FGD (DFGD) systems, respectively.

In a WFGD system, alkaline reagent slurry (usually lime or limestone) is injected into a vessel, where it reacts with the flue gas to collect the SO_2. A WFGD absorber utilizes a high volume of liquid slurry continuously circulating in the absorber vessel and collecting in the absorber reaction tank where the scrubbing reaction occurs. A DFGD is comprised of the absorber vessel or duct integrated with a pulse jet fabric filter (PJFF), often referred to as a baghouse. The DFGD does not utilize a liquid filled reaction tank, but instead relies on the scrubbing reactions to take place as the flue gas intermingles with the lime inside the vessel or ductwork and also in the highly reactive dust cake on the surface of the downstream fabric filter media.

Q. WHAT ARE THE KEY OPERATIONAL DIFFERENCES BETWEEN A WET FGD AND A DRY FGD SYSTEM?

A. In most WFGD systems, limestone slurry is used as the reagent and a gypsum byproduct is formed as a result of the chemical reaction. In DFGD systems, lime is used as the reagent and calcium sulfite is formed as a result of the chemical reaction.

The WFGD process requires an additional step not required of a DFGD. A WFGD requires dewatering of the reaction byproducts for solids handling, landfill suitability, and water reuse or disposal; a DFGD collects the reaction byproducts directly in a downstream fabric filter. Thus, solids dewatering or wastewater treatment is not required for a DFGD system.

On a comparable inlet SO_2 concentration, water consumption, auxiliary power usage, solid waste disposal, and equipment footprint are higher for a WFGD than for a DFGD. Co-benefit emissions control for mercury and other Hazardous Air Pollutants (HAPs) is better with a DFGD versus a WFGD due to the integral fabric filter (baghouse) associated with the DFGD technology. Plants with WFGD operate with a "wet stack" or a visible thick water vapor plume exiting the stack under all ambient conditions. The stack plume from a DFGD is typically not visible because it operates above the flue gas saturation temperature. A slight water vapor plume might become visible under certain ambient conditions of temperature and humidity.

Q. DID THE COMPANY CONDUCT A STUDY TO COMPARE THE USE OF A WFGD TO A DFGD FOR BIG SANDY UNIT 2?

A. Yes. The Projects and Controls group provided technology performance parameters and cost estimates for the initial high level overview of reasonable SO_2 compliance options available to KPCo. Technical and economic evaluations were performed to compare and contrast the WFGD and DFGD technology options that may be applied while burning coals with different sulfur content up to 4.5 lb SO_2/mmBtu. The evaluation of the FGD technology options considered environmental and technical performance, retrofit constraints, collateral environmental and technical impacts associated with the evaluated technologies, and economics, as outlined in Company witness Weaver's testimony.

An original equipment manufacturer (OEM) proprietary NID™ DFGD system was compared to a Spray Dryer Absorber (SDA) technology, Circulating Dry Fluidized Bed Scrubber (CDS) technology, and the Limestone Forced Oxidized (LSFO) Spray Tower WFGD technology. Considering equivalent SO_2 removal efficiencies among the evaluated FGD technology options for the aforementioned design basis, the proprietary NID™ DFGD technology is the favored FGD technology based on the following:

- Lowest total evaluated cost on 30-year cumulative present worth basis (capital and O&M).
- Lowest water consumption
- Lowest auxiliary power usage
- Lowest reagent usage
- Smallest equipment footprint
- Best supports Activated Carbon Injection (ACI) for mercury removal
- Best supports SO_3 removal
- Best supports other hazardous air pollutants (HAPs) removal
- Best supports future NPDES permit compliance

Q. **WHAT ARE THE COST COMPARISONS BETWEEN A DFGD AND A WFGD?**

A. Our initial Big Sandy Unit 2 cost comparison supports the industry expectation that DFGD is less capital intensive than WFGD. DFGD uses less exotic materials of construction than a WFGD, which not only reduces the initial capital costs but also future maintenance and equipment replacement costs. In addition, the use of a DFGD technology also eliminates the need for and the capital installation and ongoing O&M cost of a waste water treatment system associated with the WFGD process.

Q. IS ONE OF THE FGD TECHNOLOGIES A CLEAR FRONT RUNNER TO BE SELECTED FOR INSTALLATION AT BIG SANDY UNIT 2?

A. Yes. Based on what I have discussed above, the OEM proprietary NID™ DFGD will be the technology of choice to meet the required emission limits. The NID™ DFGD project cost estimate will be refined as engineering and design progresses, but the DFGD is expected to continually be the lowest reasonable cost option, especially when considering multi-pollutant reduction performance compared to WFGD. While both systems would meet the necessary emission limits imposed by the CSAPR and EGU MACT Rule, a DFGD system is expected to remain the choice for Big Sandy Unit 2 from both a technical and cost perspective.

Q. WHAT ARE THE PROJECTED EMISSION REDUCTIONS ASSOCIATED WITH THE PROPOSED DFGD SYSTEM?

A. The NID™ DFGD system that is proposed for installation at Big Sandy Unit 2 will be designed to remove 98% of the SO_2 in the flue gas.

Q. PLEASE PROVIDE AN OVERVIEW OF THE EQUIPMENT THAT WILL BE INSTALLED AS PART OF THE DFGD SYSTEM.

A. The following equipment would be installed as part of a DFGD system installation at Big Sandy Unit 2. This list is not all-inclusive.

- Pebble lime truck unloading equipment and storage silos
- Reagent preparation system foundations, equipment, and building

- DFGD Absorber modules
- Induced draft fans and motors
- Tie-in ductwork
- Pulse jet fabric filter (baghouse)
- Ash recycle system foundations, equipment, and building
- Waste storage silo and truck loading equipment
- Equipment to supply electrical needs of new process equipment
- Distributed control system (DCS) for new process equipment
- Balance of plant piping (fire protection, service water, compressed air, sanitary, etc.)

VI. BIG SANDY UNIT 2 PROJECT COST ESTIMATE

Q. WHAT IS THE ESTIMATED PROJECT COST FOR THE INSTALLATION OF THE DFGD ON UNIT 2 AT THE BIG SANDY PLANT?

A. KPCo's cost of the FGD system installation, excluding AFUDC, is currently estimated at $839 million. This cost estimate includes the installation of the DFGD, landfill development work that is necessary to dispose of the product from the DFGD, and other associated upgrades to existing plant equipment.

Q. HOW WAS THE COST ESTIMATE FOR THE BIG SANDY UNIT 2 PROJECT DEVELOPED?

A. The current cost estimate was developed based upon the actual cost incurred for our most recent WFGD installation project and cross referenced for comparative purposes with the actual cost of two other recent WFGD projects. The cost of the most recent project was converted into an equivalent dollar per kilowatt ($/KW) value which was then modified to reflect a DFGD installation on Big Sandy Unit 2 with an assumed in-service date occurring during the second quarter of 2016.

Q. WHAT IS THE LEVEL OF ACCURACY CONTAINED IN THE COST ESTIMATE PRESENTED IN THIS TESTIMONY?

A. Because the current level of site-specific project definition is less than 15%, the cost estimate for the Big Sandy Unit 2 DFGD retrofit project would be categorized as a Class 4 cost estimate by the Association of Advancement of Cost Engineering (AACE). Typical accuracy ranges for Class 4 estimates are -15% to -30% on the low side, and +20 to +50% on the high side. However, based upon our vast experience in executing projects such as this and our utilization of actual cost data from recent projects, as outlined above, we believe our range of accuracy to favor more toward the -15% to +20% range. Our confidence is further bolstered when we look at our past record of accuracy. On the most recent project, the final cost was within 5% of the initial estimate and on the two reference projects; our final cost was within 3% of our Phase IIb estimates. We would be somewhat naïve to presume that all site-specific anomalies have been both recognized and accounted for in our estimate methodology and thus have chosen to apply a 20% contingency to our estimate. We believe this to be prudent at this stage of the project.

Q. WHAT OTHER ACTIVITIES MUST BE COMPLETED PRIOR TO THE DEVELOPMENT OF A MORE DETAILED COST ESTIMATE?

A. As outlined above, the project is currently in Phase I engineering and design. Further project planning and conceptual engineering will be performed and the cost estimate will be refined before proceeding to Phase IIa in the third quarter of 2013. During Phase IIa, the cost estimate will be further refined. This work is currently scheduled to be completed in the first quarter of 2013 before the project can enter Phase IIb. Phase IIb will continue through the fourth quarter of 2013 and will result in a highly detailed cost estimate.

Q. **PLEASE DESCRIBE HOW KPCO HAS ACCOUNTED FOR ESCALATION OF LABOR AND MATERIALS IN THE COST ESTIMATE.**

A. KPCo has included escalation of labor and materials in the cost estimate. The estimate takes into consideration AEP's past experience in procuring labor and materials and the actual annual escalation/de-escalation rates experienced year-over-year during 2006 through 2010. It is expected that very similar fluctuations will be experienced during the 2012 through 2016 timeframe as the build out of multiple utility environmental projects across the eastern U.S. experiences a similar boom/bust cycle.

Q. **DOES KPCO EMPLOY ANY METHODS TO MITIGATE THE RISK OF ESCALATION OF COSTS THAT MAY AFFECT THE CONSTRUCTION OF THE BIG SANDY UNIT 2 DFGD?**

A. Yes. KPCo and its customers will be benefitted by having access to AEPSC's Business Intelligence group. One of the key functions of this group is to analyze past, current and projected future market conditions and recommend alternatives to minimize the risks of volatility present in labor, equipment and material markets. AEPSC's strategy of being first to market, locking in queues in production facilities, entering into procurement arrangements such as Discount Cooperative Agreements with major equipment vendors and procuring materials and commodities in bulk at fixed prices serves to mitigate the risk of market price spikes. The continuation of this strategy on the Big Sandy Unit 2 project will benefit KPCo's customers as many others in the industry will be undertaking similar large-scale construction projects to comply with the environmental regulations.

Q. **IS IT YOUR PROFESSIONAL OPINION THAT KPCO HAS DEVELOPED A REASONABLE COST ESTIMATE FOR CONSTRUCTION OF THE PROJECT?**

A. Yes. The cost estimate for the Big Sandy Unit 2 project is reasonable considering the development basis and the degree of site-specific engineering and design work to date.

Q. **HAS THE OEM PROPRIATARY NID™ DFGD TECHNOLOGY BEING CONSIDERED FOR BIG SANDY UNIT 2 BEEN SUCCESSFULLY INSTALLED AT OTHER AEP UNITS?**

A. No. To date, AEP has exclusively installed WFGD technology on its retrofit units. However, the proprietary technology has been successfully installed on over 6,300 MW of generation worldwide, with approximately 1,800 MW deployed in the U.S. AEP has performed a significant due diligence of the technology and we find no reason to question its ability to perform as specified. AEP has a proven track record of successfully managing the design and construction of many major environmental projects and it is expected that the DFGD installation at Big Sandy will be another success.

Q. **WILL THE BIG SANDY UNIT 2 DFGD PROJECT ALLOW THE UNIT TO CONTINUE TO OPERATE IN COMPLIANCE?**

A. Yes. As described in the testimony of Company witness McManus, absent these environmental controls, Big Sandy Unit 2 would not be able to operate in compliance with the proposed Electric Generating Unit Maximum Achievable Control Technology (EGU MACT) Rule. The installation of these controls will allow Big Sandy Unit 2 to operate beyond the end of 2014 (or 2015 with a one-year compliance extension), meaning that Big Sandy 2 will continue to provide value to KPCo's customers.

Q. **HAS AEPSC CONDUCTED PAST WORK ASSOCIATED WITH A FGD RETROFIT FOR BIG SANDY UNIT 2?**

A. Yes. As a part of the Clean Air Interstate Rule (CAIR) compliance strategy, AEPSC began preliminary Phase I feasibility analyses on Big Sandy Unit 2 in the third quarter of 2004. The analyses indicated that the retrofit of Big Sandy Unit 2 with a WFGD was part of the AEP least cost compliance plan. The dry FGD technology that existed in this timeframe could not accommodate the required SO_2 reduction efficiencies when burning a 4.5 lb/mmBTU sulfur coal. After preliminary feasibility studies, conceptual engineering, and a competitive selection of the WFGD OEM, the Phase I activities ceased in second quarter of 2006. A refined assessment indicated that the costs to retrofit Big Sandy Unit 2 had increased substantially.

Q. **WHAT WERE THE PRIMARY DRIVERS OF THE ESTIMATED INCREASED COST TO RETROFIT BIG SANDY UNIT 2 WITH A WFGD?**

A. The increase in the cost estimate of the WFGD was primarily attributed to increases in labor and material costs, which was a reflection of the changing marketplace for environmental controls. Additionally, the preliminary cost estimates were refined to better reflect the total scope of the project as additional engineering and design was accomplished.

Q. **WHAT OTHER FACTORS SUPPORTED THE DECISION TO END PHASE I WORK ASSCIATED WITH THE BIG SANDY UNIT 2 WFGD?**

A. There was a decrease in the projected price spread between low and high sulfur coals that effectively eliminated any fuel savings associated with using a higher sulfur coal, further making the retrofit less attractive.

Q. **WHAT WAS THE COST OF THE BIG SANDY UNIT 2 WORK PRIOR TO THE SUSPENSION?**

A. Prior to the suspension, approximately $15.2M of cost associated with the WFGD project was incurred.

Q. **IN VIEW OF THE SUSPENSION OF THE BIG SANDY UNIT 2 WORK, DO YOU CONSIDER THESE COSTS TO HAVE BEEN PRUDENTLY INCURRED?**

A. Yes. The costs incurred represent the best efforts at that time to address the federally mandated CAIR requirements in an economical manner. The performance of this work generated the necessary information that allowed us to conclude that the project would be more complex and expensive than originally anticipated and led to the conclusion that suspending the project was what provided the most benefit to KPCo and our customers. The suspension of the original project and subsequent costs also allowed time for new co-beneficial technology to develop in the marketplace that is more suitable to comply with final and proposed EPA regulations generating even more benefit for KPCo's customers.

Q. **WHAT OTHER DEVELOPMENTS HAVE OCCURRED SINCE 2006 THAT ARE CONSIDERED IN THIS CPCN FILING?**

A. On October 9, 2007 AEP entered into a the New Source Review (NSR) consent decree with the Department of Justice to settle all complaints filed against AEP and its affiliates of which KPCo is included. KPCo is bound by this decree to retrofit a FGD on Big Sandy Unit 2 by December 31, 2015. Based upon our experience and knowledge, it is known that the FGD retrofit will require 54 to 60 months to be placed into service. With the above in consideration, AEPSC restarted the conceptual and analytical work in support of the CPCN application filing in the first quarter of 2010. The Company felt it was prudent to reexamine our previous efforts which had resulted in our selection of a WFGD technology for Big Sandy 2 as the least cost and most beneficial compliance option for Kentucky Power and Kentucky Power customers.

But since the first quarter of 2010, several developments have occurred which have strongly affected and are reshaping the power industry and our ongoing analyses. These developments have played an integral part in the decision making process for Big Sandy Unit 2 and include the discovered abundance of shale gas, a new cost-effective DFGD technology, and final and proposed environmental regulations.

Q. GIVEN THE DISCOVERED RECENT ABUNDANCE OF SHALE GAS, DID KPCO EVALUATE ANY GAS ALTERNATIVES VERSUS THE RECOMMENDED DFGD FOR BIG SANDY UNIT 2?

A. The discovery of the purported abundance of shale gas has served to reduce and stabilize both the near term and long range forecast of natural gas prices. With the market reaction to the discovery, we were even further compelled to perform a comparative analysis of the differing potential gas options and felt providing cost estimates as accurate as possible to be necessary obligation. As a means of validation of our in-house developed project cost estimates and again, understanding the critical nature of the result of this decision-making process, AEPSC employed an independent team of professionals from Sargent & Lundy, LLC and Kiewit Industrial Company to examine and determine the cost of two different gas-based solutions as alternatives to the retrofit of a DFGD on Big Sandy Unit 2. The first alternative was the construction of a new combined cycle facility at Big Sandy. The second alternative considered the repowering of Big Sandy Unit 1 utilizing combustion turbine generators and heat recovery steam generators (HRSGs) integrated into the maximum amount of the existing Unit 1 steam cycle equipment. These options were evaluated against the scrubber options and are more thoroughly discussed by Company witness Weaver.

VII. SUMMARY

Q. PLEASE SUMMARIZE THE BIG SANDY UNIT 2 PROJECT.

A. The installation of the DFGD system at Big Sandy Unit 2 is necessary for compliance with the final and proposed environmental regulations to insure continued operation of this unit as a cost-effective source of generation for KPCo's customers. AEP's phased strategy for the design, engineering, procurement, construction, and startup/commissioning of its environmental compliance projects has resulted in its completed projects 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, combined with our experienced staff focused on safety, quality, cost and schedule performance provide us with a high level of confidence that the Big Sandy Unit 2 DFGD project will be another success.

Q. DOES THIS CONCLUDE YOUR PRE-FILED VERIFIED DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Robert L. Walton being duly sworn, deposes and says he is the Managing Director Projects and Controls for American Electric Power that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Robert L Walton

ROBERT L. WALTON

STATE OF OHIO	)	
	)	CASE NO. 2011-00401
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Robert L. Walton, this the 12 day of November, 2011.

A G. MYERS
Notary Public
irfield County
State of Ohio
My Commission Expires May 29, 2012

Notary Public

My Commission Expires: 5-29-2012

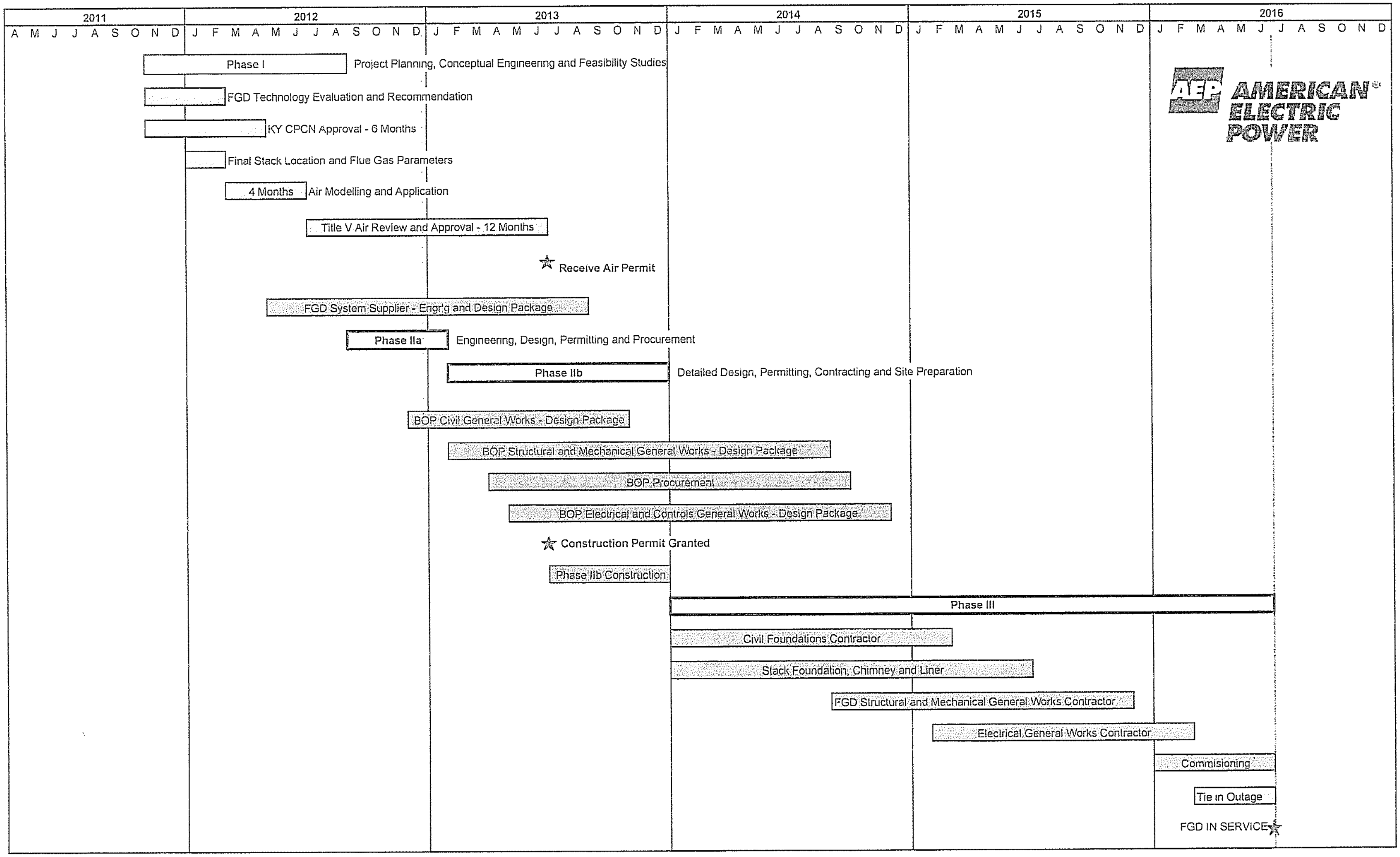

Exhibit RLW-1
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COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES	)	Case No. 2011-00401

DIRECT TESTIMONY

OF

SCOTT C. WEAVER

DIRECT TESTIMONY OF
SCOTT C. WEAVER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2011-00401

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**DIRECT TESTIMONY OF
SCOTT C. WEAVER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION?

A. My name is Scott C. Weaver, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation (AEPSC) as Managing Director-Resource Planning and Operational Analysis. AEPSC supplies engineering, financing, accounting and similar planning and advisory services to the eleven electric operating companies of the American Electric Power System (collectively, AEP).

II. BACKGROUND

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Business Administration Degree in Accounting from Ohio University in 1981, and a Master of Business Administration from the same university in 1985. In addition, in 1996 I completed both the American Electric Power System Management Development Program at The Ohio State University, as well as The Darden Partnership Program at the Darden Graduate School of Business Administration, University of Virginia.

I was employed by AEPSC in 1980 as an Associate Forecast Analyst in the Controllers Department (now Corporate Planning and Budgeting Department), and was subsequently named Assistant Financial Analyst in 1983, Financial Analyst in 1986, Senior Financial Analyst in 1987, and Senior Administrative Assistant II in 1990. In 1991, I transferred to the AEPSC Fuel Supply Department as Manager-Administration. I was subsequently named Manager-Administration and Purchasing in 1994 and Director of Power Generation Business Planning and Financial Management in 1996. I transferred to the AEP Wholesale business unit in 2000 as Manager-Business Planning and in January, 2003 transferred back to the Corporate Planning and Budgeting Department as Director of Operational Analysis. I assumed my present position in May 2003.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR–RESOURCE PLANNING AND OPERATIONAL ANALYSIS?

A. I am responsible for the supervision and administration of long-term generation resource planning and supply-side operational analysis for AEP. In such capacity, I coordinate the use of short- and long-term generation production costing and other resource planning models used in the ultimate development of operating and capital budget forecasts for Kentucky Power Company (KPCo, or "the Company") and its parent, AEP, regularly monitor actual performance, and review the preparation of forecasted information for use in regulatory proceedings.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS REGULATORY COMMISSION?

A. Yes. I offered testimony before this Commission on behalf of the Company's most recent base rate case (Case No. 2009-00459); as well as its recent renewable energy purchase agreement filing (Case No. 2009-00545). In addition, over the last six years I have offered resource planning-related testimony on behalf of AEP operating company affiliates before eight other state commissions: Arkansas, Indiana, Louisiana, Michigan, Oklahoma, Texas, Virginia, and West Virginia.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS FILING?

A. The purpose of this testimony is to:

1) Discuss the available disposition options at KPCo's Big Sandy coal-fired generating station that are being driven by known and emerging environmental regulations and legal requirements beginning in the year 2012 and continuing through the decade;

2) describe the modeling process undertaken to evaluate the relative economics of those alternative Big Sandy unit disposition options, including a discussion around the major issues, input parameters and key drivers; chief among them the anticipated long-term price of natural gas, as well as the inclusion and timing of an allowance price/tax associated with the emission of carbon dioxide (CO_2)/carbon;

3) discuss the results of these economic modeling analyses and the determination that a decision to retire Big Sandy Unit 1 by January 1, 2015 and **retrofit Big Sandy Unit 2 by approximately June 1, 2016 with Dry Flue Gas Desulfurization (DFGD)** technology, for reduced sulfur dioxide (SO_2) and, via co-benefits with the previously-installed Selective Catalytic Reduction (SCR) equipment, for mercury removal,

respectively, would offer the optimum result for KPCo and its customers; and

4) offer a validation of these results that assesses attendant commodity pricing, construction cost, and other economic risk factors.

Q. WERE YOUR EXHIBITS USED TO SUPPORT YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes they were. As I will describe in this testimony, it is important to realize, however, that numerous functional organizations within KPCo and AEPSC were involved in this process. The role I served was one of coordinating the attendant economic modeling effort and, ultimately, validating, documenting, and internally communicating this process and the results.

Q. DO THESE EXHIBITS INCORPORATE AN "APPENDIX" THAT SUMMARIZES OTHER RELEVANT INFORMATION?

A. Yes. Exhibit SCW-1 offers a broader overview of some of the other resource planning-related criteria that are necessarily introduced as part of this evaluation of alternative options surrounding the Big Sandy unit dispositions at issue in this filing. In addition, this "appendix" offers information surrounding additional risk analyses that were undertaken to further validate the results. The following direct testimony focuses more specifically on the discrete economic evaluations performed that led to the Company's conclusions and recommendations.

IV. PLANNING PROCESS AND IMPENDING ENVIRONMENTAL REQUIREMENTS

Q. WHAT ARE THE OVERALL OBJECTIVES AND OBLIGATIONS OF KPCO'S RESOURCE PLANNING PROCESS?

A. The best response can be found in the Company's most recent Integrated Resource Plan (IRP) filed with this Commission in Case No. 2009-00339, on August 17, 2009. In keeping with Kentucky statute 807 KAR 5:058 Sec. 8.5.a. and Sec. 8.5.c, the opening sub-section of the "Section 4 Resource Forecast" from that filing states (excerpted in its entirety):

> The primary objective of power system planning is to assure the reliable, adequate and economical supply of electric power and energy to the consumer, in an environmentally compatible manner. Implicit in this primary objective are related objectives, which include, in part: (1) maximizing the efficiency of operation of the power supply system, and (2) encouraging the wise and efficient use of energy.
>
> Other objectives of a resource plan include planning flexibility, creation of an optimum asset mix, adaptability to risk and affordability. In addition, given unique impact on generation of environmental compliance, the planning effort **must be in concert with anticipated long-term requirements as established by the environmental compliance planning process**. (emphasis added)

Q. PLEASE DESCRIBE THE IMPLICATIONS ON KPCO'S RESOURCE PLANNING PROCESS DUE TO EACH OF THE KNOWN OR CURRENTLY-EMERGING ENVIRONMENTAL CHALLENGES FACING THE COMPANY.

A. Company witness John McManus will offer more detailed descriptions and discussions surrounding the environmental challenges facing KPCo's coal generating assets, but the following offers a summary overview of the major known and emerging federal rulemaking and previously-established requirements, and the possible implications of each on the Company's long-term planning process:

I. **Cross-State Air Pollution Rule (CSAPR)** Implications on Planning – As described by Company witness McManus, it would be anticipated that, based on the allocation utilized by EPA in the establishment of, particularly, an SO_2 "budget" for AEP's Kentucky-domiciled coal units (Big Sandy Units 1 and 2), such proposed CSAPR reductions are very significant—with Phase 2 requirements being reduced by nearly *85 percent* from recent historical SO_2 emission levels. He further indicates that the Big Sandy units, particularly the 800-MW Big Sandy Unit 2, would then likely either have to be retired, significantly curtailed, or would be required to achieve large SO_2 emission reductions through installation of efficient FGD technology in order to approach the (CASPR-Group 1) Phase 1 (January 1, 2012) and, particularly, the Phase 2 (January 1, 2014) CSAPR threshold amounts. CSAPR does provide for a regulated generator to acquire SO_2 (or oxides of nitrogen [NO_X]) allowances to offset any emission levels that may exceed annual EPA-budgeted allowance allocations. However, not yet knowing either the allowance market availability "depth", or the attendant market pricing of such allowances, from a longer-term planning perspective, it would be reasonable to continue to assume that either retirement or, *minimally*, significant Big Sandy unit generation curtailments would also have to occur in the interim period beginning 1/2012 that would lead up to the ultimate achievable 2016 installation date for a Big Sandy 2 FGD retrofit (Option #1 in TABLE 1, to follow) *or* a (combined cycle) unit replacement alternative (Option #2 or Option #3 in TABLE 1).

II. **Electric Generating Unit Maximum Achievable Control Technology (EGU MACT) Rule** Implications on Planning -- As described by Company witness McManus, the EGU MACT rule:

> "…will likely require some combination of FGD, SCR, dry sorbent injection (DSI), fabric filter baghouses, activated carbon injection (ACI) and upgrades of existing electrostatic precipitators (ESP) to comply."

He further indicates that the Clean Air Act (CAA) specifies compliance within three (3) years subsequent to the issuance of final rulemaking, or by, roughly, <u>near the end-of-2014 (effectively assumed by January 1, 2015)</u>; but also provides for a possible one-year extension which could shift implementation to the end-of-2015, if specific criteria are satisfied. Therefore, for planning purposes, it has been assumed that this one-year "extension" (to approximately January 1, 2016) would be applicable if the intent is to either retrofit (or retire and replace) a unit for purposes of achieving compliance with EGU MACT.

III. **Coal Combustion Residuals (CCR) Rule** Implications on Planning – As described by Company witness McManus, it would be anticipated that—based even on the preliminary assumption that these residual materials may be categorized as "Subtitle D", or *non*-hazardous materials—each and every coal unit in the AEP fleet, including KPCo's Big Sandy generating units, would require plant modifications and capital expenditures—including possible waste water treatment facilities and relining of bottom ash ponds—to address these requirements by, approximately, the <u>end of the 2017 timeframe</u>. Although not specifically a component of the Environmental Projects being set forth as part of this CPCN filing, such future CCR-related costs—totaling approximately $48 million as reflected in TABLE 2 of my testimony—have nonetheless been incorporated into the relative study period economics supporting "Option #1" (Retrofit Big Sandy Unit 2) so as to fairly and completely assess the costs associated with that alternative over the long-term.

IV. **Clean Water Act "316(b)" Rule** Implications on Planning -- As also indicated in Company witness McManus' testimony, since KPCo's Big Sandy units utilize natural draft, hyperbolic cooling towers, the most significant potential impact to KPCo could be the potential need to install additional fish screening at the front of the water intake structure to further reduce impingement and entrainment. While representing a potential exposure, it is generally anticipated that such fish screening mechanisms would likely not be required until the decade of the 2020's, with any capital expenditures leading up to that point being relatively minor in nature.

V. **NSR Consent Decree** -- As described by Company witness McManus, KPCo is required under the NSR Consent Decree to perform the following:

- Big Sandy Unit 2: Install FGD for SO_2 by December 31, 2015
- Big Sandy Unit 2: Continue to operate the existing SCR system to minimize NO_X emissions
- Big Sandy Unit 1: Install Low-NO_X Burner technology *and* limit the sulfur content of its burn coal to no greater than 1.75 lb. per million British thermal units (MMBtu), on an annual average basis, by the effective date of the Consent Decree.

Q. IN SUMMARY, FROM A PLANNING PERSPECTIVE, WHAT IMPACTS WOULD THE ENVIRONMENTAL REQUIREMENTS HAVE ON KPCO'S COAL GENERATING ASSETS?

A. There are significant environmental exposures surrounding the future operations of the Big Sandy generating units. The known and emerging U.S. EPA requirements summarized above would indicate additional environmental remediation would need to be taken *over-and-above* what was established under the previously-established NSR Consent Decree.

V. AVAILABLE ALTERNATIVES

Q. WHAT ARE THE ALTERNATIVES THAT ARE AVAILABLE TO KPCO TO ADDRESS THESE IMPENDING ENVIRONMENTAL REQUIREMENTS AT THE BIG SANDY FACILITY?

A. As represented on the following **TABLE 1**, four (4) alternative options were assumed to be available to KPCo to address the unit disposition decisions facing the Big Sandy units ("UD Analyses"):

TABLE 1

Option #1: Retrofit Big Sandy Unit 2 with DFGD technology by approximately June 1, 2016 (and, subsequently, CCR-related equipment by January 1, 2018); and **Retire Big Sandy Unit 1 by January 1, 2015** (with incrementally-required capacity and energy needs purchased for calendar 2015—and prospectively—from the PJM market)…

… to ensure ultimate compliance with EGU MACT-based emission requirements, state-specific SO_2 emission limitations under CSAPR, and be in-keeping with the requirements of the NSR Consent Decree as well as anticipated future EPA CCR rulemaking

Option #2: Retire both Big Sandy Units 1 & 2 by January 1, 2015 and January 1, 2016, respectively, and **Replace that combined capacity with a nominally-rated 762-MW (904-MW for peaking purposes with duct-firing) New-Build natural gas Combined Cycle (CC) facility**, to be located at the Big Sandy site, **by January 1, 2016** (with incrementally-required capacity and energy needs purchased for calendar 2015—and prospectively—from the PJM market)

Option #3: Retire Big Sandy Unit 2 by January 1, 2015, and **Repower Big Sandy Unit 1 as a nominally-rated 745-MW (780-MW for peaking purposes with duct-firing) natural gas Combined Cycle unit by January 1,**

2016 (with incrementally-required capacity and energy needs purchased for calendar 2015—and prospectively—from the PJM market)

Option #4: <u>Retire both Big Sandy Units 1 & 2</u> by January 1, 2015, and <u>Replace both units entirely with purchased capacity and energy</u> assuming *all* capacity and energy replacement purchases from available (PJM) markets…

Option #4A: Acquire replacement market capacity and energy for a **<u>period of 5 years</u> (up to 2020)**, when replacement CC capacity would then be built/acquired

Option #4B: Acquire replacement market capacity and energy for a **<u>period of 10 years</u> (up to 2025)**, when replacement CC capacity would then be built/acquired

Q. UNDER OPTION #1 YOU INDICATE A BIG SANDY 2 RETROFIT SOLUTION BY APPROXIMATELY JUNE 1, 2016, AND UNDER OPTIONS #2 AND #3 YOU INDICATE A BIG SANDY 2 RETIRE/REPLACE SOLUTION BY JANUARY 1, 2016, YET COMPANY WITNESS MCMANUS ALSO INDICATES THAT THE FINAL CSAPR SETS FORTH "MORE STRINGENT" UNIT EMISSION ALLOWANCE ALLOCATIONS FOR WHICH "… IT WILL BE DIFFICULT TO COMPLY", BEGINNING WITH THE RULE'S INITIAL PHASE ON JANUARY 1, 2012. HOW WOULD THIS POTENTIALLY IMPACT THE BIG SANDY UNITS' OPERATION DURING THAT *INTERIM* (2012-2015) PERIOD?

A. As previously summarized, although the CSAPR does provide generators with the potential to purchase (market) allowances to fulfill its obligations under the rule, that prospect is speculative from the standpoint of ensuring that any non-controlled coal unit would be able to operate fully-unconstrained beginning in 2012. As such, it was also summarized that KPCo may be unable to achieve such SO_2 emission reductions required under Phase 1 and, particularly, Phase 2 of the CSAPR without either the retirement or significant operational curtailments of both Big Sandy units, or the installation of some form of significant SO_2 control technology on, particularly, the larger Unit 2. Therefore, given the anticipated necessary timeframe—through approximately June 1, 2016—required to obtain Commission approvals, permit, engineer, procure materials and components, construct and commission a DFGD retrofit, as indicated by Company witness Robert Walton, it is reasonable to assume that the operation of these Big Sandy units would likely be required to be curtailed in that CSAPR SO_2 "Phase 1" (2012-13) period. That prospect for such Big Sandy unit generation constraints is amplified in the rule's subsequent SO_2 "Phase 2" (2014 and beyond) period leading up to that June 1, 2016 approimated Unit 2 retrofit in-service date, due particularly to the assumed introduction of the CSAPR assurance provision requirements.[1]

Q. PLEASE ALSO RECONCILE AND DISCUSS THE "INTERIM" IMPACTS OF AN ASSUMED BIG SANDY 2 RETROFIT IN-SERVICE DATE OF APPROXIMATELY JUNE 1, 2016, IN THE CONTEXT OF THE PREVIOUSLY-DISCUSSED REQUIRED IMPLEMENTATION DATES SET FORTH UNDER THE PROPOSED EPA-EGU MACT RULEMAKING—AS WELL AS THE NSR CONSENT DECREE—OF JANUARY 1, 2016 (OR, DECEMBER 31, 2015).

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[1] Note: On page 19 of Company witness Walton's testimony, he indicates the assumed Big Sandy Unit 2 DFGD in-service date would occur "during the second quarter of 2016". So as to provide a specific date for economic modeling purposes, a date <u>within that timeframe</u> of June 1, 2016 was utilized; with June 1 also coinciding with the beginning of a PJM fiscal "planning year".

A. As indicated above, it is anticipated that the necessary time to obtain Commission approvals, permit, engineer, procure materials and components, construct and commission a DFGD retrofit would place the in-service date, for economic modeling purposes, at approximately June 1, 2016. Given that, and the limiting factors associated with the EGU MACT rule and the NSR Consent Decree, it was then assumed that, for modeling purposes, Big Sandy 2 would be removed from service effective January 1, 2016 for the period leading up to the beginning of the normal retrofit "tie-in" outage which would occur in approximately the April/May 2016 timeframe.

Q. AS SUMMARIZED IN EXHIBIT SCW-1, KPCO RECEIVES 15 PERCENT, OR (APPROXIMATELY) 390-MW OF THE CAPACITY AND ENERGY FROM THE CURRENTLY ENVIRONMENTALLY-UNCONTROLLED ROCKPORT UNITS 1 AND 2 AS PART OF ITS PURCHASE AGREEMENT WITH AFFILIATE AEG. WHAT UNIT DISPOSITION ASSUMPTIONS HAVE BEEN MADE AROUND THOSE UNITS FOR PURPOSE OF THIS BIG SANDY UNIT DISPOSITION MODELING?

A. For purpose of establishing a modeling baseline, it is assumed that a single Rockport unit will be retrofitted with DFGD and SCR technology by January 1, 2016 and the other Rockport unit would be retrofitted with an FGD technology capable to produce sufficient SO_2 reductions to satisfy the more aggressive "Phase 2" of the CSAPR (for Indiana) by January 1, 2014, and an SCR by end-of year 2019; all in-keeping with the CSAPR, EGU MACT rule, as well as the Rockport units' unique NSR Consent Decree requirements. However, this in no way serves as a commitment to this course of action for environmental control equipment—or its attendant timing—on those Rockport units. Rather it simply serves as, again, a going-in "baseline" for KPCo's overall resource portfolio that, in turn, impacts the modeling process for this KPCo-Big Sandy unit disposition analysis.

VI. ECONOMIC MODELING PROCESS

Q. HOW WERE THESE IDENTIFIED ALTERNATIVES ANALYZED?

A. The Company utilized a proprietary long-term resource optimization tool known as Strategist® to perform these evaluations. The initial economic evaluations were performed from the perspective of a "stand-alone" KPCo; meaning there were assumed to be no capacity and energy costs or credits flowing to/from affiliate AEP operating companies by virtue of the current AEP Interconnection Agreement (AEP Pool). This was done partly in recognition of—as discussed in Exhibit SCW-1—the prospect that the AEP Pool could be terminated *prior to* the respective in-service dates of the alternatives analyzed. Further, these evaluations were performed over a 30-year economic study period (2011 through 2040) in the Strategist® tool so as to emulate the potential life-cycle of the respective asset alternatives as well as in recognition of the various "down-stream" impacts on KPCo overall resource planning needs.

As will be described in more detail, the alternative-specific, generation-related costs/revenue requirements were then discounted to today's (2011) dollars and, as such, reflected on a Cumulative Present Worth (CPW) basis. It is also critical to understand that the framework for these evaluations was focused not on the "absolute" CPW results, but rather the *comparative* view of the alternative options' results. In other words, the objective of this exercise was to identify the **<u>relative least-cost alternative</u>** among those identified in TABLE 1. Finally, the results from Strategist® offer a view of these relative economics over the full, 30-year economic study period and thereby do not constitute an isolated "test-year" cost-of-service view. Company witness Lila Munsey will offer the estimated annual retail effect of the proposed changes to the KPCo environmental surcharge tariff after those facilities are placed into service.

Q. PLEASE DESCRIBE THE STRATEGIST® MODELING APPLICATION.

A. Strategist® is a proprietary software tool under lease to AEP from Ventyx, an industry software and data-services provider. Strategist® has been serving the utility industry for over 25 years. As indicated, it is a long-term resource optimization model that offers multiple objective functions; including determination of alternative solutions that offer the lowest utility cost. In this case, determining a lowest "G(eneration)" cost-of-service, or revenue requirement. Among other features, Strategist's® PROVIEW module contains a probabilistic, hourly dispatch algorithm—similar to its sister tool PROMOD®—so that unique alternative impacts on production-related variable costs-of-service can be modeled. Further, that module provides for the ability to import (purchase) or export (sell) capacity and energy into a "market" based on user-defined long-term market commodity pricing profiles. Finally, using it's forward-looking capability, Strategist® also seeks to establish, over the 30-year study period, an optimum overall capacity and energy resource plan that considers user-input constraints such as requisite reserve margins, as well as fleet-wide or unit-specific effluent (e.g. SO_2) emission limitations.

Q. HAS THE STRATEGIST® APPLICATION BEEN UTILIZED BY THE COMPANY IN CASES BEFORE THIS COMMISSION?

A. Yes. Strategist® served as the basis for the establishment of the "Resource Forecast" section provided with Kentucky Power Company's most recent Integrated Resource Planning filing (Case No. 2009-00339).[2] Additionally, the Ventyx-PROMOD® "sister tool" described above, has been utilized for many years as part of the Company's biannual Fuel Adjustment Clause filings.[3] Further, Strategist® has been utilized by other AEP operating companies in recent years to support resource planning options before Commissions in the states of Oklahoma, Arkansas, Texas Indiana, West Virginia and Virginia.

Q. YOUR TESTIMONY DESCRIBES THAT THE STRATEGIST MODEL CREATES A PROXY FOR A LONG-TERM "G(ENERATION)" REVENUE REQUIREMENT. WHAT ARE THE MAJOR MODEL OUTPUTS THAT DETERMINE THAT?

A. Those model outputs include annual:

Consumed Fuel Costs (+ attendant variable production costs), all (KPCo) units, including the purchase entitlement share of Rockport Units 1&2

Plus: Replacement cost of emission allowances consumed for all KPCo units

Plus: <Sales> / Purchases of Market Energy for KPCo

Plus: <Sales> / Purchases of Market Capacity for KPCo

Plus: Fixed Carrying Charges of Major *Incremental* KPCo "G" Capital Investment *

Plus: Fixed O&M for all KPCo units

= Total Annual Costs

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[2] See page 4-13 and 4-14 of that filing for a description of how Strategist® was utilized in KPCo's 2009 IRP.

[3] Most recently in Case No. 2010-00490.

* Any on-going 'return-on' *and* 'return-of' (depreciation/amortization) capital associated with pre-existing generation plant-in-service are ignored, as such costs/revenue requirements would be assumed to be consistent across all alternatives analyzed.

These annual cost streams are then "present-valued" using a proxy for an estimated KPCo-weighted average cost of capital, to create a CPW of (incremental) "G" revenue requirements.

Q. SPECIFICALLY, HOW DID THE STRATEGIST® MODEL PERFORM THE KPCO "UD ANALYSES" PREVIOUSLY SUMMARIZED?

A. The model "locked-in" the respective existing KPCo unit disposition outcomes—and timing—as described earlier in my testimony. For instance, under the first alternative listed in TABLE 1 (Option #1), Big Sandy Unit 2 was assumed to be retrofitted with DFGD by approximately June 1, 2016, while Big Sandy Unit 1 was assumed to be retired by January 1, 2015. The model was set-up to reflect these results with the necessary input parameters required, such as: capital cost to retrofit, attendant fuel switch cost data, modifications to variable and fixed O&M, etc. From that, beginning in the years 2015 and 2016, the modeling was then capable of recognizing any relative change in overall KPCo generation when considering the respective Big Sandy unit "options" identified in TABLE 1. Moreover, the (capacity) resource planning aspect of the tool recognized the MW-capability of these units when determining capacity needs for KPCo beyond 2015 and 2016 as it modeled throughout the long-term (30-year) economic study period.

Q. SO YOU ARE INDICATING THAT—IN ADDITION TO THE "DIRECT" COSTS ATTRIBUTABLE TO ANY UNIQUE UNIT DISPOSITION ALTERNATIVE SURROUNDING THE BIG SANDY UNITS—THE MODEL

ALSO FACTORS IN THE IMPLICATION THAT DECISION WOULD HAVE ON KPCO'S FUTURE RESOURCE REQUIREMENTS BEYOND THAT (UNIT DISPOSITION) YEAR?

A. Yes. This is an important aspect of this modeling process. Given that resource alternative options may not be of either equal "size" or "term", it is critical that in this case such unit disposition decisions be viewed holistically; that is in terms of that decision's implications on the whole of KPCo's capacity (and energy) resource needs. The Strategist® model's dynamic resource optimization capabilities affords such a holistic, overall resource planning view.

For example, a hypothetical UD Analyses "Alternative A" proposes to retire a coal unit with 800 MW of generating capability producing 5,200 Gwh of energy in any given year (roughly 75 percent average capacity factor), and replace that capacity with a smaller 650-MW gas-fired generating unit but generating only 2,900 Gwh of energy due to a lower, roughly 50 percent average capacity factor. Contrastingly, another hypothetical UD Analyses "Alternative B" would seek to retrofit and maintain that 800 MW coal unit. One clearly cannot perform a one-off comparison of the *unit-specific* absolute fixed and variable "G" costs associated with alternatives with such unique attributes. Rather, those respective alternatives would need to be viewed holistically, from an overall utility portfolio perspective. In this simple hypothetical, clearly "Alternative A" would ultimately require additional capacity (sooner) to be added to the generator's portfolio to maintain prior reserve margin levels, and would potentially be exposed to larger and more frequent "short" energy positions that would have to be purchased from an available energy market. The

Strategist® tool and the approach being taken as part of these UD Analyses ensures an appropriate alternative cost comparison by way of "leveling the (analytical) playing field".

Q. COULD YOU PLEASE IDENTIFY SOME OF THE MORE CRITICAL INPUT PARAMETERS FOR THE UD ANALYSES AND WHERE THAT INFORMATION WAS SOURCED?

A. Two of the major underpinnings in this process are long-term forecasts of KPCo's energy sales and customer (peak) demand, as well as the price of various generation-related commodities, such as energy, capacity, coal, natural gas, and emission allowances, including carbon/CO_2. Both views were created internally within AEPSC. The load forecast, including projected KPCo energy sales and demand summaries offered in the Exhibit SCW-1 information appendix, was created by the AEP Economic Forecasting organization; while the long-term commodity pricing forecast was created by the AEP Fundamental Analysis group. Exhibit SCW-2 offers charts and tables that summarize several of the key long-term fundamental commodity pricing projections utilized in these UD Analyses. These groups have had years of experience forecasting KPCo and AEP system-wide demand & energy requirements and fundamental pricing for both internal operational and regulatory purposes. Moreover, the Fundamental Analysis group constantly performs peer review by way of comparing and contrasting its commodity pricing projections versus "consensus" pricing on the part of outside forecasting entities such as IHS CERA, PIRA and the U.S. Department of Energy-Energy Information Administration (EIA).

Other critical input parameters include the installed cost of both environmental retrofits required and replacement capacity-build options, as well as the attendant operating costs associated with those options; data which was sourced from Company witness Walton and the AEP Engineering Projects & Field Services (EP&FS) organization he is part of.

Q. COULD YOU PLEASE OFFER AN OVERVIEW OF THE FGD RETROFIT ALTERNATIVES CONSIDERED FOR BIG SANDY UNIT 2 FOR "OPTION #1", ALONG WITH THE ATTENDANT FUEL SUPPLY OPTIONS?

A. The Company as well as the AEP EP&FS and AEP Fuel, Emissions & Logistics (FEL) organizations ultimately identified and economically-screened a combination of <u>14</u> FGD technology and fuel-type options to be utilized at Big Sandy Unit 2. Exhibit SCW-3 lists those options, but they can be generally broken down into four generation technology types; a traditional "wet" FGD and three forms of "dry" FGD technology. As described by Company witness Walton, the three dry technologies evaluated were a sorbent-injection (SDA) system, along with a circulating dry scrubber (CDS) technology; with the third being an OEM proprietary DFGD technology ("NID™" design). As also described by Company witness Walton, there were also certain design, operational and ancillary advantages associated with the NID™ DFGD design that, when coupled with the screening economics, warranted the selection of that particular FGD option for further review.

The other critical factor considered was the relative sulfur content of the coal to be utilized. In that regard, this FGD technology screening assessed fuel alternatives covering proxies for lower-sulfur 1.7 lb. per MMBtu (SO_2 emitting) coal products, as well as an intermediate 3.0 lb. per MMBtu, and higher-emitting 4.5 lb. per MMBtu coal types/blends. As described by Company witness Ranie Wohnhas, an issue faced by the Company was the potential availability and price variability associated with a near-compliance, 1.7 lb. coal product. For that reason, as also discussed by Company witness Walton, a Big Sandy Unit 2 DFGD technology design alternative was considered that could utilize up to a 4.5 lb. SO_2 per MMBtu blended coal product. This alternative was viewed as one that would afford the Company with greater fuel sourcing and procurement optionality as well as operational flexibility going-forward.

Based on that consideration and the alternative economic screening performed and also summarized in Exhibit SCW-3, it was determined that the optimum FGD "retrofit/fuel" alternative to be utilized for further modeling purposes within Strategist® in conjunction with "Option #1", was the modular NID™ DFGD technology solution that could utilize a higher-SO_2 emitting blended coal product of 4.5 lb. per MMBtu coal (*i.e.*, "Case 23" from that Exhibit SCW-3 screening analysis results summary) that Company witness Walton has further described in his direct testimony.

Q. PLEASE PROVIDE AN OVERVIEW OF THE REPLACEMENT <u>NEW-BUILD GAS COMBINED CYCLE</u> ALTERNATIVE AVAILABLE TO KPCO THAT YOU HAVE IDENTIFIED AS "<u>OPTION #2</u>"?

A. The Strategist® modeling to proxy this option was based on the assumed utilization of a Mitsubishi 2x1 M-501-GAC[4] design that would be nominally-rated at approximately 762-MW. Given that this CC facility would also be designed with duct-firing and chillers, the maximum capability of the unit has been determined to be 904-MW. It was further assumed to be located at the existing Big Sandy site, thereby utilizing existing transmission interconnections. Additionally, the modeling assumed indicative cost estimates and performance parameters received from the AEP EP&FS and AEP Fuel Emissions Logistics (FEL) organizations associated with the necessary gas pipeline infrastructure, pressuring and metering equipment to receive the delivered (firm) gas supply from the Tennessee-Eastern transmission pipeline.

Q. LIKEWISE, COULD YOU ALSO PLEASE OFFER AN OVERVIEW OF THE REPLACEMENT <u>BIG SANDY UNIT 1 GAS COMBINED CYCLE REPOWERING</u> ALTERNATIVE AVAILABLE TO KPCO THAT YOU HAVE IDENTIFIED AS "<u>OPTION #3</u>"?

A. The Strategist® modeling to proxy this option was based on the assumed utilization of the existing Big Sandy Unit 1 steam turbine and piping, as well as the conjoining of two (2) new Mitsubishi 501-G combustion turbines and Heat Recovery Steam Generators (HRSG). The nominal rating of this CC facility then being approximately 745-MW—with duct-firing capability of up to 780-MW. As with Option #2, this modeled alternative reflected the cost and performance parameters sourced from AEP EP&FS and FEL organizations, including the necessary gas pipeline infrastructure, pressuring and metering equipment to receive the delivered gas supply from the

[4] This represents two (2) natural gas turbines in combination with heat recovery steam generators (HRSG), and single steam turbine.

Tennessee-Eastern transmission pipeline. Company witness Walton will also offer an overview of the rigor and utilization of 3rd-party expertise in the development of each of these natural gas alternative estimates.

Q. WHAT ARE THE ESTIMATED COSTS ASSOCIATED WITH THE CHOSEN BIG SANDY UNIT 2 "FGD RETROFIT" TECHONOLGY ALTERNATIVE (OPTION #1), AS WELL AS THE "REPLACEMENT NEW-BUILD GAS COMBINED CYCLE" ALTERNATIVE (OPTION #2), AND THE "BIG SANDY 1 REPOWERED GAS COMBINED CYCLE" ALTERNATIVE (OPTION #3) PREVIOUSLY DESCRIBED, THAT WERE UTILIZED IN YOUR DETAILED ECONOMIC EVALUATIONS?

A. The following **TABLE 2** offers a summary of the installed costs of these alternatives:

TABLE 2

Estimated "Alternative" Capital Expenditures

Utilized in Strategist Modeling

(TOTAL Project Costs, Excluding AFUDC)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
(1)			EPC Cost		Add'l Owner's Cost/OH Alloc	TOTAL COST *(Excluding AFUDC)*	
(2)		*Unit Capacity*	Millions	$/kW Installed	Millions	Millions	$/kW Installed
(3)	Option #1: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(4)	RETROFIT Option						
(5)	**Dry (NID™) FGD**		$769	869	$70	$839	948
(6)	*Plus: Add'l Costs included in Modeling*						
(7)	*CCR-Related (thru 2017)*		*$44*	*30*	*$4*	*$48*	*32*
(8)	*TOTAL All Projects*	*800*	*$813*	*899*	*$74*	*$887*	*980*
(9)		*Unit Capacity*					
(10)		*(w/Duct-Firing)*	Millions	$/kW Installed	Millions	Millions	$/kW Installed
(11)	Option #2: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(12)	REPLACEMENT Option						
(13)	**New-Build CC** *(@ BS site)*	*904*	$1,066	1,092	$75	$1,141	1,169
(14)		*Unit Capacity*					
(15)		*(w/Duct-Firing)*	Millions	$/kW Installed	Millions	Millions	$/kW Installed
(16)	Option #3: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(17)	REPLACEMENT Option						
(18)	**BS1 CC Repowering**	*780*	$994	1,180	$70	$1,063	1,262

Note that the TABLE 2 "E(ngineering) P(rocurement) C(onstruction) Cost" of $769 million for Option #1 (Big Sandy Unit 2 NID™ DFGD Retrofit), as well as the "Total Cost (excluding AFUDC)" of $839 million, were provided to me by Company witness Walton and were a function of the EP&FS/FEL FGD technology screening process previously discussed. The EPC costs for Option #2 (New-Build CC Replacement) and Option #3 (Big Sandy Unit 1 CC Repowering) identified above of $1,066 million, and $994 million, respectively, are based on the estimates provided to me by the AEP EP&FS organization.

Note also that these costs are exclusive of AFUDC. As it pertains to the Option #1 estimate, for instance, the <u>total</u> NID™ DFGD project cost *inclusive* of AFUDC would be approximately $940 million. This model-calculated total project AFUDC proxy of $101 million was utilized for comparative modeling purposes.[5]

Q. FINALLY, COULD YOU OFFER AN OVERVIEW OF THE "(FULL) REPLACEMENT CAPCITY PURCHASE" ALTERNATIVE AVAILABLE TO KPCO—IN LIEU OF INSTALLING AN FGD RETROFIT ON BIG SANDY UNIT 2 *OR* REPLACING IT CONTEMPORANEOUSLY WITH A CC—AS YOU HAVE IDENTIFIED AS "<u>OPTION #4</u>"?

A. The Strategist® modeling to proxy this option was based on the assumption that any and all incremental capacity and energy requirements to meet KPCo native load and demand requirements, in recognition of a Big Sandy Unit 2 (and Big Sandy Unit 1) retirements by January 1, 2015, would be met via "market" sourcing for some interim period prior to the eventual addition of CC capacity resources.

[5] $940 million total project cost with AFUDC - $839 million TABLE 2 "Total Cost (Excluding AFUDC)".

To perform that valuation, the modeling assumed the AEP Pool would no longer exist. Rather, it utilized an assumption based on the estimates for such market values for Unforced Capacity ("UCAP") from the PJM Reliability Pricing Model ("RPM"), as provided by the AEP Fundamental Analysis group. This option assumes, however, that a "stand-alone" KPCo would first elect to participate in the RPM capacity auction construct described in the Exhibit SCW-1 information appendix.

Likewise, the attendant very significant KPCo *energy* requirements that would emerge under this Option #4 alternative were based on Fundamental Analysis' estimates of PJM on-peak and off-peak pricing proxied at the AEP Generating hub. Exhibit SCW-2 offers a summary of these respective capacity and energy forecasted values.

For purposes of the modeling exercise for this Option #4, two specific "sub-options" were evaluated. Option "#4A" assumed that KPCo would fully rely on PJM market capacity and energy—in lieu of the Big Sandy units or a replacement CC-build—for a period of up to 5 years (or, until 2020) before such time that replacement CC capacity would be added by KPCo. Option "#4B" assumed that KPCo would rely on the same market capacity and energy for a longer interim period, up to 10 years (or, until 2025). It is the Company's belief that the "shorter-term" market exposure profile (Option #4A) would be the more likely option that would be considered—*if at all*—as I will discuss later in this testimony. However, in the interest of transparency, and to offer some reasonable alternative "banding", a longer-term alternative was also chosen for modeling (Option #4B).

Q. YOU HAVE INDICATED NATURAL GAS PRICING AS BEING ONE OF THE KEY DRIVERS FOR THIS ANALYTICAL PROCESS. COULD YOU PLEASE ELABORATE ON WHY THAT IS SO?

A. In the electric utility industry, the natural gas-fired units often serve as the marginal cost, or "price-setting" units based on their relative higher position in a typical regional "dispatch stack" (relative to 'first-run', lower variable cost hydro, nuclear and coal-fired units). For example, as part of either a Day-Ahead or Real-Time dispatch/market, the lowest-cost generating sources offered into PJM during any given time interval would be called upon as the initial generation segments. Higher-cost generation/dispatch segments offered would then be picked up until the load obligations are met. In other words, the dispatch is "stacked" based on contemporaneous loading needs *and* the relative variable (dispatch) cost of the market-offered units. Therefore, in PJM, with its abundance of lower-variable cost baseload capacity (hydro, nuclear and coal), even efficient gas-fired CC units may not be economically-merited to be dispatched during, particularly, "off-peak" hours.[6] As a result, the price of natural gas will not only determine where gas-fueled units may be placed in any regional dispatch stack, it will then, naturally, largely determine the Locational Marginal Price (LMP) that may "clear" for energy in any market-based system during any given hour.

Typically, the higher the gas price, the higher gas-fired units—such as even thermally-efficient combined cycle units—would "settle" in the dispatch stack that operates in PJM. Then, depending upon those contemporaneous load requirements,

[6] Although the definition varies, typically, 'on-peak' hours represent a 16-hour per-day period M-F, 6AM-10PM, excluding holidays, with 'off-peak' then representing the balance of all hours.

the higher the resulting market-based energy price/LMP might be. Based on that, margins or "spreads" available to more efficient *coal-fired* units could simultaneously be improved.

Contrastingly, the lower the gas price, the lower that such a CC unit may settle in the PJM market-based dispatch/supply stack, thereby setting a lower clearing price for, potentially, a greater number of hours/sub-hours. Under this latter outcome, coal units could potentially be called upon to generate less energy at a lower available spread.

Q. WOULD YOU PLEASE OFFER AN OVERVIEW OF THE FORECASTED FUNDAMENTAL COMMODITY PRICING, INCLUDING NATURAL GAS, THAT WERE USED IN THESE MODELING ANALYSES?

A. As shown in **TABLE 3** below, an array of <u>five (5) unique, long-term commodity pricing views</u> were utilized in the UD Analyses, consisting of a "base" view and four additional "scenario" views:

TABLE 3

('BASE') "Fleet Transition-CSAPR" … *reflecting:*

- Fairly significant *long-term* fundamental reductions in natural gas pricing due largely to: a) the recognition of emerging EPA initiatives including CSAPR and EGU MACT; and b) the advent of significant incremental domestic shale gas supply at relatively low extraction costs resulting in natural gas pricing remaining in approximately the mid-to-high $5 per MMBtu range well into the next decade (real, 2010 dollars) per Exhibit SCW-2; and
- a 2022 timeframe for the implementation of CO_2/carbon legislation and attendant pricing (*i.e.*, effectively a carbon "tax" on fossil generation).

TABLE 3 *(con't)*

Commodity Price "Banding" Scenarios…

2. "Fleet Transition-CSAPR: HIGHER Band"… *same as the 'BASE' case except:*

- Reflective of lower levels of shale gas supply impacting fundamental pricing, with natural gas pricing approaching the $7 per MMBtu level by next decade (real, 2010 dollars).

3. "Fleet Transition-CSAPR: LOWER Band" … *same as the 'BASE' case except:*

- Reflective of an even more-aggressive proliferation of lower-cost shale gas supply resulting in a sustained natural gas pricing near the $5 per MMBtu level into the next decade (real, 2010 dollars).

"Carbon/CO_2" Pricing Scenarios…

4. "Fleet Transition-CSAPR: No Carbon"… *same as the 'BASE' case above except:*

- No carbon tax assumed throughout the long-term period modeled.

5. "Fleet Transition-CSAPR: Early Carbon" … *same as 'BASE' case except:*

- An accelerated—versus 'Base' view—2017 timeframe for the implementation of CO_2/carbon legislation and attendant pricing.

This 'Base' or "Fleet Transition-CSAPR" view reflects a very recent (September, 2011) long-term view of commodity prices—inclusive of natural gas prices—performed by the AEP Fundamental Analysis group. Selected commodity pricing from that forecast that were utilized in this economic modeling are shown in Exhibit SCW-2. These Fleet Transition-CSAPR views focused significantly on emerging natural gas pricing dynamics and considered evolving information that would support natural gas supply increases tied to the projected emergence of additional, significant levels of domestic shale gas at very competitive extraction costs.

Each of these pricing forecasts also assume a "Carbon/CO_2" impact as a result of the implementation of any prospective carbon-reduction legislation; however, that perspective is reflected assuming three unique sets of implementation timing. The 'Base' view assumed such legislation would be effective by 2022, while the two "Carbon/CO_2 Pricing Scenarios" identified under TABLE 3 assume such legislation would be effective as early as the year 2017, or at some point beyond the economic study period offered in this Strategist® modeling. The relative timing for the 'Base' view (2022) is largely in recognition of the potential continued aversion in the U.S. Congress to passing comprehensive CO_2 legislation that would establish either a carbon-based cap-and-trade mechanism or, as an alternative, a "carbon tax" on emissions. So, under the notion that it potentially could be five years before such action is taken by Congress, plus the assumption based on prior proposed CO_2 legislation—such as Waxman-Markey and Kerry-Lieberman—that *another* 5 years would be afforded for the ultimate implementation of any such legislation, an effective date for such CO_2/carbon pricing impacts of 2022 was deemed by Company management as a plausible outcome. Using that same implementation logic, the advanced carbon/CO2 pricing scenario of 2017 would then represent the *earliest* that such legislation could be implemented <u>even if</u> enacted within the current, 112th Congress.

VII. <u>EVALATION OF MODELING RESULTS</u>

Q. BASED ON THESE INPUT PARAMETERS, WHAT WERE THE RESULTS OF THE UNIT DISPOSITION ALTERNATIVE ANALYSES FOR BIG SANDY UNIT 2 PERFORMED IN STRATEGIST®?

A. Exhibit SCW-4 offers a tabular summarization and comparison of the modeling results for the four primary disposition options for Big Sandy Unit 2, while Exhibits SCW-4A through 4E offer a broader view of the results for *each* of the five individual commodity pricing scenarios previously defined in TABLE 3.

As also previously described in this testimony these modeling results represent <u>relative</u> cost analyses, meaning each are compared to one another for determining the "least-cost" alternative outcome. Given that, Exhibit SCW-4 reflects the costs of the two nearer-term alternative-build options—as well as market options—identified earlier in this testimony (Options #2, #3, #4A and #4B) as compared to a "Base" or reference alternative. For purpose of these economic assessments, that Base alternative was established as Option #1 from TABLE 1...

> *"Retrofit Big Sandy Unit 2 with DFGD technology by approximately June 1, 2016..."*

Q. WHY WAS OPTION #1 (RETROFIT BIG SANDY UNIT 2) SELECTED AS THE "BASE" ALTERNATIVE?

A. The selection of a "Base" alternative is largely semantics as the relative economics would be the same regardless as to which option is identified as that base. That being said, the prospect of retaining Big Sandy Unit 2 by way of retrofitting it with FGD technology is a reasonable going-in assumption. The Company has no known operational issues at that facility, and the indicative design and engineering offered by Company witness Walton would suggest that the retrofit itself is readily feasible. Moreover, KPCo's most recent (2009) Integrated Resource Plan—which preceded the U.S. EPA's final CSAPR and proposed EGU MACT and CCR rulemaking—had likewise reflected that the unit would be retrofitted with an FGD by roughly the same timeframe.[7]

Q. EXHIBIT SCW-4 INDICATES THAT THE OPTION THAT WOULD CALL FOR THE RETIREMENT AND REPLACEMENT OF BIG SANDY UNIT 2

[7] Kentucky Power Company Case No. 2009-00339, pages 4-39 and 4-40.

WITH A NEW-BUILD COMBINED CYCLE FACILITY (OPTION #2), HAS A HIGHER CPW OF COSTS ("G" REVENUES REQUIREMENTS) OVER THE PERIOD ANALYZED UNDER ALL OF THE PRICING SCENARIOS PREVIOUSLY DESCRIBED. PLEASE ELABORATE ON THIS.

A. First, Exhibit SCW-4 offers a multi-dimensional view of the modeling results. It is first segregated into the <u>five</u> sets of future commodity pricing scenarios—displayed vertically—that were identified in TABLE 3. It is *also* segregated into two unique views surrounding the period of time afforded incremental cost recovery associated with the Big Sandy Unit 2 DFGD retrofit investment… 15 years versus 20 years.

<u>BASE Pricing Results</u>:

Focusing first on the relative disposition results under the "Base" ("Fleet Transition-CSAPR") pricing, it suggests that the "Retire and Replace Big Sandy Unit 2 with a New-Build CC" (Option #2) would be more costly than the "Retrofit Big Sandy Unit 2 with DFGD" (Option #1) over the study period in amounts ranging from +$236 million -to- +$274 million, depending on the recovery period assumed for the DFGD.

<u>"Commodity Price Banding" Results</u>:

Moving down Exhibit SCW-4 to assess the additional "banding" pricing scenarios, when modeled at pricing represented under the Fleet Transition-CSAPR: LOWER Band scenario—a view that would relatively favor a gas resource solution versus a coal solution—it would indicate that, again, the "Retire and Replace with a New-Build CC" option is more costly versus Option #1 with results ranging from

+$177 million -to- +$214 million. Finally, under a Fleet Transition CSAPR: HIGHER Band pricing scenario, not surprisingly, the "Retire and Replace with New-Build CC" alternative would become even more costly versus Option #1 with results ranging from +$437 million -to- $+474 million.

<u>"Carbon/CO_2 Pricing Scenario" Results</u>:

Moving further down Exhibit SCW-4 to assess pricing scenarios around the timing of a Carbon/CO_2 "tax", when modeling at pricing represented under the Fleet Transition-CSAPR: Early Carbon (2017) scenario—another view that would relatively favor a gas solution versus a coal solution given the relative higher uncontrolled CO_2 emission from a coal-fired source—it indicates that the Option #2 New-Build CC option remains more costly versus Option #1 over the study period by amounts ranging from +$180 million -to- $218 million. Focusing finally on the scenarios pricing for Fleet Transition-CSAPR: No Carbon, again not surprisingly, the Option #2 CC-build solution would become even more costly versus Option #1 in amounts now ranging from +$315 million -to- +$352 million, depending on the recovery period assumed for the DFGD retrofit option.

Q. FURTHER, EXHIBIT SCW-4 INDICATES THAT THE OPTION THAT WOULD CALL FOR THE RETIREMENT AND REPLACEMENT OF BIG SANDY UNIT 2 WITH THE "REPOWERING" OF BIG SANDY UNIT 1 AS A COMBINED CYCLE FACILITY (OPTION #3) ALSO HAS A HIGHER CPW OF COSTS ("G" REVENUES REQUIREMENTS) OVER THE PERIOD ANALYSED UNDER *ALL* OF THE PRICING SCENARIOS PREVIOUSLY DESCRIBED. PLEASE ALSO ELABORATE ON THIS.

A. <u>BASE Pricing Results</u>:

Focusing first on the relative disposition results under the "Base", or Fleet Transition-CSAPR pricing scenario, it indicates that the "Retire and Replace with a CC-Repowered Big Sandy 1" alternative (Option #3) would be more costly versus Option #1 (Retrofit Big Sandy 2 with DFGD) in amounts ranging from +$252 million -to- +$290 million.

"Commodity Price Banding" Results:

Moving down Exhibit SCW-4 to assess the "banding" of such pricing scenarios (Fleet Transition-CSAPR "LOWER" and "HIGHER" Bands, respectively), it continues to indicate higher relative costs under the "Retire and Replace with a CC-Repowered Big Sandy 1" Option #3, with results ranging from +$183 million -to- +$220 million under the "LOWER Band" pricing; and from +$458 million -to- +$495 million under the "HIGHER Band" pricing scenario when compared to Option #1.

"Carbon/CO2 Pricing Scenario" Results:

When comparing study period economics of Option #3 versus Option #1 under "Fleet Transition-CSAPR: Early Carbon", the CC-Repowered Big Sandy 1 option continued to be more costly in amounts ranging from +$190 million -to- $228 million. Finally, comparing these options under "Fleet Transition-CSAPR: No Carbon" pricing, the incremental cost of Option #3 would, as expected, increase to a range of +$334 million -to- +$371 million.

Q. YOU HAVE INDICATED THE ECONOMICS ARE BASED ON A 30-YEAR STUDY PERIOD. WHAT IS THE ULTIMATE IMPLICATION OF THESE COMPARATIVE ECONOMICS TO KPCO'S CUSTOMERS?

A. To provide some context for these relative CPW results, for every $100 million "CPW" difference between any two options, there is a +$1.90 per Mwh levelized annual impact on KPCo's "G" revenue requirement over the subsequent economic life cycle analyzed—expressed in 2011 dollars. For instance, when comparing Option #1 versus Option #2 results under the Base, or "Fleet Transition-CSAPR" pricing scenario (15-year Retrofit recovery period), the resulting +$236 million CPW variance would equate to a levelized annual impact on G-revenue requirements of +$4.49 per Mwh (or 0.449 cents/kWh), in 2011 dollars.[8] Therefore assuming, for ease of demonstration, that this <u>relative</u> revenue requirement impact were applied equally to all tariffs, a typical KPCo Residential customer utilizing 1,000 kWh of energy per month would experience a relative (*not* absolute) G-rate impact of +$4.49 per month over the *entire* affected (*i.e.*, beginning in 2016) future study period by accepting a natural gas CC solution in lieu of continuing the operation of an environmentally-retrofitted Big Sandy Unit 2.

Q. PLEASE DISCUSS IN FURTHER DETAIL THE SENSITIVITIES REFLECTED ON EXHIBIT SCW-4 THAT VARIES THE "RETROFIT RECOVERY PERIOD".

A. The Strategist® modeling was performed to recognize the recovery of fixed investment costs associated with the Big Sandy 2 DFGD retrofit option (Option #1)

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[8] 236 / 100 x 1.90 = 4.49

encompassing a 15-year period. Recognizing also an assumed expectation of future service life for the unit that could exceed 60 years, this recovery timeframe was then utilized to reasonably align such a service life if the unit were to be retrofitted in 2016.[9] However, to offer some sensitivity around this recovery period, these analyses also employed a view that assumed such DFGD investment recovery could occur over a longer—20 year—timeframe, under the notion that the unit's service could exceed 65 years.

As reflected on Exhibit SCW-4, however, assuming a 15-year *versus* a 20-year recovery period for the NID™ DFGD environmental investment associated with Big Sandy Unit 2 in Option #1 did not significantly impact the relative disposition analytics in any event. The overall impact on each of the relative life-cycle CPW differentials was approximately +$37 million. In other words, such advanced recovery (from 20 years to 15 years) of these environmental investments would neither add significant costs to the Base/"Option #1" Big Sandy 2 retrofit economics in absolute terms nor—as previously reviewed—would it cause the *relative* economics with either of the replacement-build alternatives (Options #2 or #3) to be significantly influenced.

Q. WHAT ADDITIONAL OBSERVATIONS AND CONCLUSIONS CAN YOU DRAW FROM THE ECONOMIC COMPARISONS IN EXHIBIT SCW-4?

A. Based even on the modeling results that were predicated on a more "gas-friendly" *earlier* Carbon/CO_2 (Fleet Transition-CSAPR: Early Carbon) and *lower* natural gas and attendant energy pricing (Fleet Transition-CSAPR: LOWER Band) scenarios, it

[9] 2016 (DFGD in-service date) + 15 (years) = 2030 *less* 1969 (original BS2 in-service date) = ~60 years.

would continue to strongly support the Big Sandy Unit 2 DFGD alternative. In general terms, assessing the full suite of modeled CPW differences between "Option #1", "Option #2" and "Option #3" in Exhibit SCW-4, that are inclusive of these hugely impactful discrete risk elements, it would indicate that a specific "metal-in-the-ground" (*i.e.*, non-market) solution that would call for the retrofit of Big Sandy Unit 2 would represent the best option for KPCo and its customers.

Q. FOCUSING NOW ON THE "MARKET-PURCHASE" REPLACEMENT ALTERNATIVE (OPTION #4), WHAT CONCLUSIONS CAN BE DRAWN?

A. The indicative Strategist® results also summarized in Exhibit SCW-4, indicates that Option #4A ("Retire and Replace Big Sandy Unit 2 with [100%] purchased capacity and energy from a [PJM] market for up to 5 years [through 2020] then replace with a CC"), would continue to reflect comparative study period economics favoring Option #1 (Big Sandy 2 DFGD Retrofit). Under 'Base' or Fleet Transition-CSAPR pricing this market solution was more costly than the Option #1 by amounts ranging from +$79 million -to- +$116 million, depending on the DFGD recovery period assumed. To reinforce this result, when comparing this Option #4A study period cost versus those of Option #1 across the *full suite* of pricing "scenarios" set forth in TABLE 3, the relative CPW cost of an Option #4A solution would range from as low as +$20 million ("Fleet Transition-CSAPR: Early Carbon" pricing) to as high as +303 million ("Fleet Transition-CSAPR: HIGHER Band" pricing).

However, results for Option #4B—which would extend the market purchase period to 10 years (through 2025)—suggests somewhat less-conclusive results, with that Option #4B appearing to offer a relative "wash" versus the study period costs under 'Base' or Fleet Transition-CSAPR pricing for Option #1 ranging from <$47 million> -to- <$10 million> (*i.e.*, a slight Option #4B savings). In fact, when comparing this Option #4B study period costs versus Option #1 across the full set of pricing scenarios, it would indicate a relative CPW cost range of between +$229 million (assuming the "Fleet Transition-CSAPR: HIGHER Band" pricing scenario) to <$119 million> (under a Fleet Transition-CSAPR: LOWER Band" pricing scenario).

Q. IN SPITE OF THOSE RELATIVE MODELING RESULTS FOR "OPTION 4B", WHAT CONCERNS WOULD EXIST IF KPCO WERE TO EXERCISE AN OPTION THAT WOULD FOREGO A "BUILD" SOLUTION WITH ONE DEPENDENT ON PROJECTED (PJM –BASED) MARKET PRICING?

A. While plausible, it also potentially subjects KPCo and its customers to additional pricing and performance risks. As summarized in my Exhibit SCW-1 information appendix, AEP has continued to elect to "opt-out" of the PJM-RPM construct under the notion that its customers "…are economically advantaged in that they are subject to lesser levels of (capacity) pricing uncertainty by its participation within the FRR to fulfill its capacity reserve obligations."[10] This statement implies that AEP and KPCo view its obligation to reliably serve its customers as paramount. The Company has no assurances that any future capacity required by PJM will be built as a result of the PJM-RPM construct. In fact, according to PJM's own "2013/2014 RPM Base Residuals Auction Results" report document, since the RPM's inception for the 2007/08 planning period, and through the 2013/14 period, only 5,762 MW of <u>new</u>

[10] See page 5 of Exhibit SCW-1.

thermal installed capacity (ICAP) has been offered into all of those Base Residual Auctions—or, on average, a little above 800 MW per auction year.[11]

Q. GIVEN THESE CONCERNS REGARDING THE FUTURE AVAILABILITY OF CAPACITY IN THE PJM-RPM CONSTRUCT, WHAT IS YOUR CONCLUSION REGARDING OPTION #4 (RETIRE AND REPLACE BIG SANDY UNIT 2 WITH [PJM] MARKET PURCHASES)?

A. Based on the above observations, I believe that while the value of PJM-RTO[12] capacity established by the AEP Fundamental Analysis group is, in most forecast years, below the cost of a new CC-build—as well as PJM's established Net Cost of New Entry ("CONE") value[13]--any potential economic benefit of Option #4 could be quickly muted and eliminated. Specifically, any perceived benefits of Option #4 could be diminished upon recognizing:

a) The price of capacity under the PJM-RPM construct currently clears on a *single* incremental planning year basis, with <u>no</u> assurances—for sellers or buyers—as to the *sustainability* of those prices from year-to-year;

b) from a buyer's perspective the price of capacity under the PJM-RPM construct could begin to ultimately mirror, or exceed, Net CONE on a consistent basis[14]; and/or

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[11] http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-base-residual-auction-report.ashx

[12] The projection of RPM capacity value offered by the AEP Fundamentals group reflects PJM's western or "RTO" region.

[13] CONE is an RPM market proxy for a base/"1.0 multiple" capacity value based on the fixed cost associated with the construction and operation of a simple-cycle combustion turbine (CT), *net* of some (small) market credits that would be subscribed to that CT via the sale of energy and other ancillary products.

[14] The current Net CONE value for UCAP for the most recent (2014-15) PJM planning year was established by PJM at $342 per MW-day

c) the price of the attendant PJM market *energy* could likewise exceed projected pricing levels.

Further, the relatively modest Strategist®-modeled CPW cost "benefits" associated with, specifically, Option #4B ("Retire and Replace Big Sandy Unit 2 with [PJM] Capacity purchases for up to 10 years [through 2025]") previously described, suggests that there is no significant set of economic outcomes that would alter the Company's belief that—when coupled with the fact that PJM-RPM capacity market construct remains relatively immature—the inherent *year-to-year* pricing uncertainty and economic risks around being a capacity market "price-taker" are not in the best interest of KPCo's customers.

Q. COULD KPCO EXERCISE YET OTHER "MARKET" OPTIONS IN LIEU OF A PJM (RPM MARKET) OPTION?

A. Yes. Depending upon the ultimate disposition of the current AEP Pool, other options could be available to KPCo outside of the Pool construct. For instance, assuming that KPCo would effectively become a stand-alone entity—in addition to "build" replacement options—an option could be to enter into a market-based competitive solicitation for *all* capacity—and attendant energy—being displaced by the potential retirement of Big Sandy Unit 2 (and Big Sandy Unit 1).

Q. WHY WAS THAT OPTION NOT EVALUATED?

A. It essentially was. In fact, Option #2 ("Retire and Replace Big Sandy 2 with a New Build CC" option) offers such a proxy. Based on discussions with AEP commercial experts, it is very reasonable to assume that any *long-term* (minimum, 10-20 year term) competitive purchase power agreement (PPA) solicitation—for not only replacement capacity but for the largely "baseload" energy also being replaced—would be effectively offered/priced at the cost of a new-build combined cycle in response to such a solicitation.

Q. COULD OTHER, PREVIOUSLY-BUILT COMBINED CYCLE CAPACITY RESIDING WITHIN THE PJM FOOTPRINT BE OFFERED AS PART OF ANY SUCH LONG-TERM COMPETITIVE SOLICITATION UNDERTAKING BY KPCO?

A. While that is possible, KPCo and AEP believe such existing asset markets are extremely limited, particularly for higher-utilization combined cycle assets. For instance, the Company is aware of no active solicitations or informal inquiries for the sale of such combined cycle generating assets. A further complication would be that any pre-existing CC asset residing within PJM that did not already have long-term, bi-lateral off-takes for its capacity and energy are likely currently being offered into—and clearing in—the RPM construct, meaning such assets would not be available to KPCo as part of any such bi-lateral arrangement in any event. Given also the fact that since essentially all of any potential "merchant" CC assets residing in PJM were built early last-decade (or earlier), there is an emerging concern that these facilities will soon be facing significant, time-based turbine inspections and expensive re-builds as well as other steam-cycle and balance-of-plant maintenance issues, thereby lessening their relative economic contribution values. Finally, given this (bi-lateral) market uncertainty surrounding existing CC generating assets, it further suggests that even if one were to assume that such generating capacity and energy were available, those prices—via an asset purchase, or PPA—would, again, likely ultimately proxy the cost of new-build replacement CC capacity and energy as modeled under *Option #2*, discounted for known and measurable required maintenance.

VIII. VALIDATION OF RESULTS / ADDITIONAL RISK ASSESSMENT

Q. YOU TESTIFIED THAT THE "UD ANALYSES" CONSIDERED VARIATIONS IN THE RELATIVE TIMING OF A CARBON PRICE/TAX AND, PARTICULARLY, NATURAL GAS PRICING. WHAT ADDITIONAL KEY RISK FACTORS REQUIRE CONSIDERATION?

A. In addition to commodity price risk, the other major variable in such disposition analyses would be construction cost and performance risk surrounding the available resource alternatives.

Q. WHAT STEPS HAS THE COMPANY TAKEN TO ADDRESS THE COST TO CONSTRUCT ANY OF THE ALTERNATIVES THAT WERE ASSESSED AS PART OF YOUR ECONOMIC MODELING?

A. As addressed in more detail in the direct testimony of Company witness Walton, prudent steps have been taken to ensure a reasonable level of construction cost certainty that would be acceptable to this Commission. That testimony indicates that significant effort has been performed to-date, or is in the process of being performed, in terms of preliminary engineering and design (E&D) around the chosen alternative tied to the DFGD Retrofitting of Big Sandy Unit 2 (Option #1). Further, AEP EP&FS set forth specific construction cost estimates associated with two alternatives that would replace the Big Sandy 2 with either a "New-build CC generating facility" (Option #2) and a "CC-Repowered Big Sandy Unit 1" (Option #3) solution.

Q. **DESPITE THE DILIGENCE THAT WAS UNDERTAKEN BY KPCO TO ESTABLISH REASONABLE CERTAINTY AROUND CONSTRUCTION COSTS, HAVE ADDITIONAL DISCRETE ANALYSES BEEN PERFORMED TO ASSESS THIS CONSTRUCTION (COST) RISK?**

A. Yes. "Break-even" installed cost calculations were made that determined the relative economic point of indifference (*i.e.*, a subsequently changed installed cost level that would result in the relative CPW differentials identified on Exhibit SCW-4 between Option #1 and Option #2—as well as CPW differentials between Option #1 and Option #3—being "zero" dollars.) These sensitivity analyses were performed from the perspective of the cost of the Big Sandy Unit 2 Retrofit option (TABLE 2; Option #1), *and* from the perspective of the estimated capital spend associated with both the New-build CC unit (TABLE 2; Option #2) and the CC-Repowered Big Sandy Unit 1 (TABLE 2; Option #3) replacement alternatives. As summarized on TABLE 2, those Big Sandy Unit 2 Retrofit installed costs, with overheads but excluding AFUDC, total $948 per kW, while the respective Replacement New-build CC unit's installed cost and Replacement CC-Repowered Big Sandy Unit 1 costs are $1,169 per kW and $1,262 per kW, with overheads but excluding AFUDC; and each represented in current (2011) dollars.

Q. **PLEASE DESCRIBE THE RESULTS OF THESE DISCRETE CONSTRUCTION COST SENSITIVITY ANALYSES WHEN ASSESSING**

THE POSSIBILITY OF INSTALLING REPLACEMENT CC CAPACITY (OPTIONS #2 AND #3).

A. Based on the results represented on Exhibit SCW-4, it was determined that under the "Base", or Fleet Transition-CSAPR long-term commodity pricing scenario, the cost of the Big Sandy Unit 2 DFGD Retrofit would have to increase from the current project cost estimates reflected on TABLE 2 by a magnitude of +23.8 percent, or by +200 million as-spent dollars (from $839 million -to- $1,039 million, excluding AFUDC) before the relative Strategist®-determined *CPW* cost differential to a Replacement CC-Build alternative (Option #2) would decline from the currently projected +$236 million figure (15 year retrofit recovery), to zero. Likewise, when assessing the relative +$252 million CPW cost differential to a CC-Repowered Big Sandy Unit 1 (Option #3), the cost of that DFGD Retrofit would have to increase by +25.4 percent, or by +213 million as-spent dollars (from $839 million -to- $1,052 million, excluding AFUDC) to achieve the same point of indifference.

Viewed from the perspective of the "Replacement Build" options, it would suggest that the installed cost of the Option #2 CC alternative would have to be <u>reduced</u> from the current cost estimate by < 20.7 percent>, or by <236 million> as-spent dollars (from $1,141 million -to- $905 million, excluding AFUDC), before that Strategist®-determined relative CPW economic results would achieve that same point of indifference. Similarly, the cost of the Option #3 build alternative would have to be reduced from the current cost estimate by <23.7 percent>, or by <252 million> as-spent dollars (from $1,063 million -to- $811 million, excluding AFUDC).

Naturally, these respective "break-even" values would vary based on the attendant long-term pricing scenario utilized (per TABLE 3). From the perspective of the installed cost of the DFGD Retrofit (Option #1), this range would be as low as +17.8 percent (under Fleet Transition-CSAPR: LOWER Band pricing) to as high as +46.1 percent (under Fleet Transition-CSAPR: HIGHER Band pricing). From the perspective of the installed cost of the "New-Build Replacement CC" (Option #2), this range would be from as low as <15.5 percent> (under Fleet Transition-CSAPR: LOWER Band pricing) to as high as <38.3 percent> (under Fleet Transition-CSAPR: HIGHER Band pricing).

Q. BASED ON THESE INSTALLED-COST SENSITIVITY ANALYSES, WHAT FURTHER CONCLUSIONS CAN YOU DRAW?

A. These respective "break-even" results surrounding the necessary decision-altering shifts in installed cost estimates that would be forced to manifest represent significant differences. Considering also that these analyses were performed independently, meaning the costs of the "other" alternative (be it the "Big Sandy 2 Retrofit"… or, the "New-Build CC"/"CC Repowering" options) were assumed to be held constant, those differences are even more pronounced. In fact, if upward (or downward) costs pressures were to be experienced that would influence underlying materials, metals and alloys, certain equipment and components, or even craft labor, such cost migrations would likely impact ***both***—not just one—of those construction alternatives to some degree (*i.e.*, such alternative installed cost estimates would more likely move more in unison with each other).

In summary, it could be concluded that the pursuit of a Big Sandy Unit 2 NID™ DFGD retrofit option has significant economic advantages, particularly after considering the relative impacts associated with three of the more critical "driving" economic risk parameters; the future cost of natural gas and the attendant energy pricing it directly influences, the potential timing of CO_2/carbon pricing, and the future costs to construct either of the available options.

Q. WHAT ADDITIONAL RISK ASSESSMENTS WERE PERFORMED?

A. As presented in detail in Section III of Exhibit SCW-1, an attempt to further quantify the potential risks inherent in the recommended KPCo capacity resource profile that would potentially include a DFGD-retrofitted Big Sandy Unit 2, an additional set of holistic economic risk analyses were executed. Using another AEP proprietary tool known as Aurora$^{xmp®}$, this stochastic, or "Monte Carlo" modeling technique was performed to assess the relative impacts of varying "driving" risk factors over *multiple* forecast simulations.

Q. WOULD YOU PLEASE SUMMARIZE THE RESULTS OF THAT ADDITIONAL MONTE CARLO RISK MODELLING DESCRIBED IN EXHIBIT SCW-1?

A. Exhibit SCW-5 offers both an optical and tabular summary of those results. It indicates that the relative CPW cost of Option #1 (Retrofit) was ranked first among the four options analyzed by virtue of it offering the lowest relative Revenue Requirement at Risk (RRaR) profile. As further described in Exhibit SCW-1, RRaR represents the difference between the calculated "G"-cost CPW 50th percentile (median) and 95th percentile outcome across the 100 simulations modeled. The 95th

percentile representing a level of required revenue sufficiently high that it will be exceeded, assuming that the given plan were adopted, with an estimated probability of just 5.0 percent. Therefore, RRaR represents a measure of customer risk or uncertainty inherent in each portfolio. The *larger* the RRaR, the *greater* the level of risk that KPCo's customers could be subjected to a <u>higher</u> generation cost-of-service/revenue requirement.

As specifically shown on the Exhibit SCW-5 Monte Carlo modeling result table, the RRaR for the Big Sandy 2 DFGD Retrofit (Option #1) was $815 million. These means that within a 95 percent confidence level that the overall study period costs of this option would not exceed that level of incremental cost. The RRaR for the CC-Build Replacement (Option #2) was higher, at $1,173 million. So when compared with Option #1, it indicates that Option #2 was determined to be "more risky" (*i.e.*, had greater cost uncertainty between the 50th and 95th percentile simulated results) by an order-of-magnitude of nearly 44 percent.[15]

When comparing the attendant risk profile of Option #1 versus that of the alternative that would Replace Big Sandy 2 with "Market" Capacity and Energy for 10 years (Option #4B), that relative risk increases. The RRaR for Option #4B was determined to be similar to Option #2, at $1,179 million; or a level higher than the Option #1 RRaR level by *44.6 percent*. That is, although the "discrete" risk modeling results—shown on Exhibit SCW-4—from the Strategist®-based modeling point to this Option #4B as being a near "wash" with a Big Sandy Unit 2 DFGD retrofit solution, this additional Monte Carlo-based risk modeling indicates KPCo's

[15] 1,173 / 815 – 1 = 0.439

customers would be potentially exposed to *significantly* greater cost-of-service/revenue requirement uncertainty in the future under that "market" alternative.

Therefore, this additional risk modeling confirms the results and recommendations established by the Strategist® modeling process that determined that the Option #1 (Big Sandy 2 DFGD Retrofit) was the least-cost alternative as set forth in Exhibit SCW-4, *as well as* empirically-confirms the previous notion identified within this testimony that described the attendant "price taker" risk associated with a market solution (Option #4) would not be in the best interest of KPCo's customers.

IX. OTHER FACTORS

Q. DO THESE MODELED BIG SANDY UNIT 2 DISPOSITION ANALYSES REFLECT OTHER—DIRECT AND INDIRECT—IMPACTS OVER-AND-ABOVE THOSE THAT WOULD INCREMENTALLY AFFECT KPCO'S "G" COST-OF-SERVICE?

A. No. The analyses offered in this testimony do not incorporate other such costs. For instance, these costs do not include any and all relative local or regional socio-economic impacts tied to any disposition alternative surrounding Big Sandy Unit 2. Company witness Wohnhas does address these points in his testimony.

Likewise, as indicated previously in this testimony, these disposition alternative economics focused on incremental investment only, in that: "(a)ny on-going 'return-on' *and* 'return-of' (depreciation/amortization) capital associated with pre-existing generation plant-in-service are ignored, as such costs/revenue requirements would be assumed to be consistent across all alternatives analyzed."[16] This means, for instance, that an alternative that would call for the retirement of Big Sandy Unit 2 (Options #2, #3 and #4) were each not further incrementally-burdened with any presumed asset write-off costs under the notion that KPCo would receive full cost recovery (*i.e.*, return "of") for all previous investment in that unit irrespective of the ultimate disposition outcome.

Q. IF ASSESSING THE NEED FOR CAPACITY FROM AN "AEP (POOL)" PERSPECTIVE, AS OPPOSED TO A POTENTIAL KPCO "STAND-ALONE" PERSPECTIVE, WOULD THE NEED FOR KPCO TO PROVIDE SUCH REPLACEMENT CAPACITY—IN LIEU OF RETROFITTING AND RETRAINING BIG SANDY UNIT 2—BE VIEWED ANY DIFFERENTLY?

A. No. Clearly *even if*: a) the AEP Pool were to continue in its current form; and b) KPCo ultimately were to take action that would result in the removal/retirement—without replacement—of the Company's 800-MW Big Sandy Unit 2, KPCo would become an even more significant "deficit" Member Company within the AEP Pool. As such it could then be obligated, in any event, to provide the "next" incremental tranche of capacity under the AEP Pool construct. If such capacity were not built by KPCo and it elected to rely on the AEP Pool, the resulting incremental annualized capacity settlement impact (cost) to KPCo beginning in approximately 2016 associated with the incremental loss of that 800 MW of Member Primary Capacity could be up to approximately $134 million in that year[17], or an amount potentially above the cost of Option #1. Moreover, unlike the capacity settlement impacts which

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[16] Page 17 description of Strategist® modeling cost/output parameters

[17] 800 MW x (1 – 0.067 [KPCo annualized MLR-2016]) x ~$15/kW-month (est. Pool capacity equalization rate , 2016) x 12 months = ~$134 million (2016)

would be anticipated to continue to increase over time for its "deficit" Member Companies as the capacity equalization rates of its "surplus" Member Companies escalate over time, the cost-of-service associated with any KPCo-*owned* capacity resource investment would be expected to <u>decline</u> over time as the investment/rate base is depreciated.

Q. COULD THIS NEED FOR, NOT ONLY SIGNIFICANT LEVELS OF CAPACITY, BUT INCREMENTAL *ENERGY* BE MET VIA THE (PJM) MARKET, IN LIEU OF ADDITIONAL KPCO (OR AEP-EAST) RESOURCES, SUCH THAT KPCO CUSTOMERS WOULD NOT BE HARMED?

A. That is uncertain. While the PJM energy market would be available to AEP-East, KPCo as well as the other Load Serving Entities (LSE) within the RTO, an obvious question would be the ultimate availability—and with that, the attendant cost—of such energy sources from PJM over time. Under the same context in which AEP has "opted-out" of the PJM-RPM capacity auction in favor a self-planning construct within the FRR, that same uncertainty surrounding power supply (and cost) would suggest that it would be reasonable to attempt to meet the ultimate *energy* needs of its customers via the best self-planning "fit" that would address those anticipated all-hours requirements. To do otherwise, as suggested earlier in this testimony, would entail with it the willingness to take on risk from the perspective of being a (market) price-taker. Moreover, it would essentially needlessly abdicate the Company's obligation to serve its customers with proven/known capacity and energy resources.

Q. THIS TESTIMONY HAS FOCUSED ON A "RETROFIT" OPTION ASSOCIATED ONLY WITH THE COMPANY'S LARGER (800 MW) OWNED UNIT—BIG SANDY UNIT 2. WAS THAT OPTION CONSIDERED FOR THE 278 MW BIG SANDY UNIT 1?

A. Yes. However, the evaluation favored the retirement and replacement of that unit. This is not surprising when one considers several factors. First, is the prospect that any such FGD retrofitting of a smaller unit would typically be at a higher "unit" cost per kW. Second, is the fact that the Unit 1 is six years older and is a "subcritical" (versus the supercritical Unit 2) boiler design, thus it operates at a slightly poorer relative thermal efficiency (*i.e.*, higher heat rate). This, in turn, means that a Unit 1 retrofit option would be forced to spread such fixed retrofit costs over less relative generated energy than Unit 2. Third, is the fact that while Big Sandy Unit 2 is already retrofitted with SCR technology—for NOx emission control—Big Sandy Unit 1 is <u>not</u> currently retrofitted with SCR. Given that, minimally, FGD plus SCR technology will be required to be installed in order to be compliant with proposed EGU MACT rulemaking, *both* technology retrofits would then be required for Big Sandy Unit 1.

Therefore, for purposes of this planning process, KPCo has determined that it would not be in the best interests of its customers if Big Sandy Unit 1 were not considered for environmental retrofitting; but either retired as of the implementation of the proposed EGU MACT rule (effective: January 1, 2015), or "Repowered" as a 740-MW natural gas CC (Option #3) by January 1, 2016 as discussed in this testimony.

Q. RECOGNIZING THAT THE TOTAL INSTALLED GENERATING CAPABILITY OF BOTH BIG SANDY UNITS 1 AND 2 COMBINED IS 1,078-MW, IT WOULD APPEAR THAT NONE OF THE FIRST THREE "BUILD" OPTIONS ANALYZED (OPTIONS #1, #2 AND #3) WOULD SERVE TO REPLACE THIS CAPACITY IN ITS ENTIRETY. PLEASE ELABORATE ON THAT.

A. Option #1 through #3 would serve to "preserve or replace" generating capacity equal to 800-MW, 904-MW, and 780-MW, respectively.[18] This outcome is largely a consideration of the potential relative financial and regulatory impacts associated with the Company's: a) construction funding capability and, ultimately, b) achievement of cost recovery for the replacement of yet an <u>additional</u> ~170 -to- 310 MW of, ostensibly, new-build natural gas CC capacity and energy.

Q. DOES THIS THEN INDICATE THAT, BEYOND 2015, THIS "ADDITIONAL" KPCO-REQUIRED CAPACITY AND ENERGY WOULD BE PROVIDED BY AVAILABLE MARKETS—BE IT AN AEP POOL OR PJM-BASED MARKET?

A. Yes. This Big Sandy unit disposition plan would result in the need for "3rd-party" (affiliate or non-affiliate) capacity and energy purchases for some period beyond 2015. At this time it is not known how long this period would extend. The Company will continue to evaluate future prospects for such capacity and energy additions into the future.

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[18] Option #2 (904-MW) and Option #3 (780-MW) assume duct-firing capability for maximum generating output; however, given the negative incremental impacts that duct-firing would present on unit heat rate, such impacts on annual *energy* contribution for those options would be more aligned with capacity levels excluding duct-firing: 762-MW and 740-MW, respectively.

Under the assumption that there would be *no* AEP Pool impacting KPCo's future capacity and energy requirements, and recognizing also the previously-discussed uncertainty surrounding the PJM-RPM construct going forward, future KPCo resource planning cycles could fill up to ~300 MW of capacity and energy needs with:

- (Short -to- long-term) unsolicited bilateral purchases;
- (short -to- long-term) solicitations for capacity and energy;
- RPM market participation; and/or
- company capacity-builds

Therefore, due to the fact that KPCo could bear some level of market exposure under this planned approach as represented in the additional Monte Carlo risk modeling performed, this represents yet another reason why a "full" Big Sandy Unit 2 (and Unit 1) market replacement alternative (Option #4) should be dismissed, and that only the "metal-in-the-ground" solutions (Options #1 through #3) should be given ultimate consideration.

X. CONCLUSIONS AND RECOMMENDATIONS BASED ON THESE ANALYSES

Q. PLEASE SUMMARIZE YOUR TESTIMONY FROM THE PERSPECTIVE OF THE "UNIT DISPOSITION ANALYSES" PERFORMED.

A. Several final summarizations and conclusions can be drawn from the information offered within this testimony.

(1) KPCo, AEP and other utilities will likely be subject to significant cost and (implementation) timing challenges going-forward in achieving emerging U.S. EPA rulemaking that could impinge coal-based generation.

(2) KPCo has set forth alternative capacity resource options that offer a reasonable array of unit disposition alternatives, including introduction of alternative natural gas-fired capacity-build solutions in lieu of retrofitting Big Sandy Unit 2.

(3) KPCo has performed robust economic analyses around these alternatives that would point to the retrofit of Big Sandy Unit 2 with an OEM proprietary ("NID™") DFGD technology (Option #1) as being the least-cost solution over the long-term economic study period when compared to either the replacement of Big Sandy Unit 2 with a New-Build CC (Option #2), or the replacement of Big Sandy 2 with a CC-Repowered Big Sandy Unit 1 (Option #3).

(4) KPCo has corroborated via additional risk modeling, that a full replacement of Big Sandy Unit 2 (and Big Sandy Unit 1) capacity and energy by way of a "market" solution alone would disadvantage its customers due to it being fraught with potential market price and performance uncertainty—including the existing PJM-RPM construct—that could expose these customers to ultimate reliability and, possibly, year-to-year volatility in the form "price-taker" risk.

(5) KPCo further believes that fulfilling such capacity needs as part of its own, "native" resource portfolio would be both desired—and necessary—*irrespective* of whether or not the current AEP Pool construct continues in its current form.

(6) KPCo confirms and submits that based on the alternative least-cost and discrete price risk scenarios profiling—including the prospect for carbon/CO_2—performed in its Strategist® modeling, as well as construction cost sensitivity and, finally, Monte Carlo risk modeling, that it is in the long-term best interest of its customers to leverage its thermally-efficient and

previously SCR-retrofitted Big Sandy Unit 2 by recommending it now be retrofitted with DFGD technology by approximately June 1, 2016, so as to be compliant with known and anticipated EPA rulemaking.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

The undersigned, Scott C. Weaver being duly sworn, deposes and says he is the Managing Director Resource Planning and Operation Analysis for American Electric Power that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

SCOTT C. WEAVER

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Scott C. Weaver, this the 28th day of November, 2011.

Notary Public

NOTARIAL SEAL STATE OF OHIO

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2016

My Commission Expires: October 1, 2016

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

I. BACKGROUND AND GOVERNANCE

A. Overview of the interrelationship between KPCo and AEP for purposes of capacity resource planning

The total AEP System includes eleven utility operating companies, operating in eleven states, with generation and transmission assets in, primarily, two different Regional Transmission Organization (RTO) planning and operational regions. Those RTOs are the PJM Interconnection, L.L.C. ("PJM"), in AEP's eastern zone, and the Southwest Power Pool (SPP) in its western zone. KPCo is a wholly-owned subsidiary of AEP—serving retail customers in eastern Kentucky—and is located in its eastern or PJM zone. In addition to KPCo, the AEP Operating Companies comprising this eastern zone (collectively, "AEP-East") consist of:

- Appalachian Power Company (APCo), serving large portion of West Virginia, and western Virginia;
- Columbus Southern Power Company (CSP), serving portions of central and southern Ohio;
- Indiana Michigan Power Company (I&M), serving portions of northern and eastern Indiana and southwestern Michigan; and
- Ohio Power Company (OPCo), serving portions of Ohio.[1]

In addition, two additional Operating Companies residing in this eastern zone, Kingsport Power Company (KgP) and Wheeling Power Company (WPCo) represent non-generating affiliates.

AEP-East collectively serves about 3.6 million customers in an approximate 90,000 square-mile area of Virginia, West Virginia, Ohio, Indiana, Michigan, Kentucky and Tennessee.

B. AEP Pool: planning responsibilities and obligations

The projected capacity resource needs for KPCo are currently established in concert with that of AEP-East under the auspices of the previously mentioned AEP Interconnection Agreement ("AEP Pool"), which was established "(f)or the purposes of obtaining the most

[1] CSP and OPCo have filed with the Public Utility Commission of Ohio to seek to legally merge the two companies effective January 1, 2012. A decision on that proposed merger has yet to be rendered.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

efficient coordinated expansion and operation of their electric power supply facilities…"[2]. This includes the coordinated and integrated determination of load and (peak) demand obligations for KPCo and each of the other Member Companies defined in that agreement (APCo, CSP, I&M, and OPCo). Further, under Article 5.7.1 of the AEP Pool, KPCo and the other Member Companies are obligated to "…rectify or alleviate" any relative (Member Primary) capacity deficits of an extended nature so as to maintain an "equalization" over time.

As such, the going-forward capacity obligations of KPCo have been to, minimally, maintain its resource contribution to meet both the needs of its own native customers, as well as its share of the AEP-East requirements.

1. **Historical fulfillment of KPCo's capacity obligation within the AEP Pool**

   As summarized above, under the AEP Pool the collective resources of each of the AEP Member Companies have historically been considered when determining such capacity positions. As a contributor to that process, KPCo has typically operated in a deficit capacity position vis-à-vis the other AEP Member Companies. Therefore, it has incurred "capacity settlement" payments to those Member Companies that are surplus. As also indicated, this "backstop" arrangement has been utilized over the decades to attempt to ensure reasonable economies for the collective resource needs of the AEP System.

2. **Discussion of potential change to this AEP Pool**

   KPCo and its affiliate AEP Pool Member Companies served notice to each other and the Pool's Agent, AEPSC, on December 17, 2010, of the collective intent to terminate the AEP Pool effective January 1, 2014. This is a revocable notice of termination and that resolution discussions among stakeholders will be forthcoming. At this time, however, the ultimate outcome of that process is not known. Of course not knowing that ultimate outcome, from a planning perspective it further emphasizes the criticality of any future decisions surrounding the make-up of KPCo's "native" resource profile.

[2] Article 4.1 of the AEP Interconnection Agreement.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

II. RESOURCE NEED

A. Description of KPCo's customer base

KPCo's customer base consists of both retail and sales-for-resale customers located in eastern Kentucky. Approximately 173,000 residential, commercial, industrial and other retail, end-use customers are served by the Company. These KPCo retail customers represent nearly 99 percent of I&M's energy sales in 2010, with the balance coming from sales to the Cities of Vanceburg and Olive Hill, for which KPCo provides wholesale service for ultimate distribution and resale to their end-use customers.

B. Overview of KPCo's peak demand requirements

To ensure the continuation of reliable service, the peak demand of its customer base represents one of the primary underpinnings of any capacity resource plan. The peak load requirement of all KPCo retail and sales for resale wholesale customers is seasonal in nature, with distinctive peaks occurring in both the summer and the winter seasons. Historically, KPCo's peak demand has been recorded in the winter season, with the all-time winter peak being 1,808 MW, which occurred on February 6, 2007. Contrastingly, the highest recorded summer peak was 1,388 MW, which occurred on August 2, 2006.

The following **Table 1-1** offers the latest AEP Economic Forecasting projection of KPCo and AEP-East (summer) peak demand and internal load. Over the next 10 year period (through 2020) KPCo's summer demand is anticipated to increase by a compound annual growth rate of 0.59 percent, or by a total of 66 MW; relative results which are slightly lower than those of AEP-East for the same period.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

Table 1-1

Projected (Summer) Peak Demand and Internal Load
KPCo and AEP-East
(Sep-2011 Fcst)

	Peak Demand (MW)			Internal Load (GWh)	
Year	KPCo	AEP-East*	Year	KPCo	AEP-East*
2011	1,221	20,698	2011	7,667	125,470
2012	1,238	21,075	2012	7,729	127,318
2013	1,239	21,351	2013	7,727	128,689
2014	1,243	21,515	2014	7,752	129,445
2015	1,247	21,644	2015	7,772	129,976
2016	1,252	21,711	2016	7,806	130,552
2017	1,256	21,853	2017	7,842	131,173
2018	1,271	22,006	2018	7,883	131,944
2019	1,281	22,163	2019	7,926	132,798
2020	1,287	22,273	2020	7,967	133,593
2021	1,299	22,500	2021	8,013	134,489
2022	1,309	22,672	2022	8,062	135,372
2023	1,313	22,815	2023	8,113	136,258
2024	1,320	22,944	2024	8,168	137,223
2025	1,333	23,186	2025	8,216	138,146
2026	1,344	23,374	2026	8,267	139,105
2027	1,354	23,569	2027	8,319	140,108
2028	1,362	23,721	2028	8,373	141,157
2029	1,369	23,933	2029	8,419	142,128
2030	1,379	24,135	2030	8,470	143,160

	KPCo	AEP-East*		KPCo	AEP-East*
10-Year (2011-2020):			10-Year (2011-2020):		
Total Growth	66	1,575	Total Growth	301	8,123
Compound Annual Growth Rate	0.59%	0.82%	Compound Annual Growth Rate	0.43%	0.70%
20-Year (2011-2030):			2011-2030:		
Total Growth	157	3,437	Total Growth	803	17,690
Compound Annual Growth Rate	0.64%	0.81%	Compound Annual Growth Rate	0.53%	0.70%

* AEP-East includes Ohio-Wires customers

C. PJM Reserve Margin Criteria

It is assumed that the underlying minimum reserve margin criteria to be utilized in the determination of AEP-East and, ultimately, KPCo capacity needs assessment is the current PJM board-approved Installed Reserve Margin (IRM) level of 15.3 percent.[3]

[3] As established by PJM for the 2014/15 Reliability Pricing Model (RPM) Base Residual Auction as well as for "non-auction" Fixed Resource Requirement (FRR) entities such as AEP. For purpose of the modeling exercise to be discussed throughout this testimony, it is assumed this 15.3% IRM level would remain constant going-forward.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

D. KPCo and AEP obligation to provide reserve margin in PJM

On October 1, 2004, AEP transferred functional control of its transmission facilities as well as its generation dispatch, including the transmission and generation facilities owned by its operating companies, including KPCo, to PJM. With that, the PJM Reliability Assurance Agreement (RAA) defines the requirements surrounding various reliability criteria, including measuring and ensuring capacity adequacy. In that regard, each Load Serving Entity (LSE) in PJM is required to provide an amount of capacity resources determined by PJM based on several factors, including PJM's IRM requirement. This requirement is itself based on the amount of resources needed to maintain, among other things, a loss-of-load expectation of one day in ten years. Additionally, load diversity among the LSEs and PJM, and generating asset-assumed equivalent forced outage rates (EFOR) represent other factors impacting such required minimum reserve levels.

Further, beginning in 2007—for the initial 2010/11 "Planning Year"—through today—for the most recent 2014/15 Planning Year—AEPSC, as agent for its AEP-East LSEs, including KPCo, has given annual notice of its intent to elect to opt-out of the PJM Reliability Pricing Model (RPM) three-year forward capacity auction and, instead, meet its capacity resource obligation through participation in the optional, FERC-authorized Fixed Resource Requirement (FRR) construct. FRR requires AEP and KPCo to set forth its future capacity resource profile and position under, essentially, a "self-planning" format that is predicated upon ensuring the stand-alone achievement of its future customer peak demand *plus* IRM requirements.

It continues to be AEP's position that the interests of its LSEs and, ultimately, those operating company customers are better preserved under that FRR framework. While AEPSC reserves the future option of electing to participate in the RPM forward auction process, it believes that the AEP LSE's customers, including KPCo's, are economically advantaged in that they are subject to lesser levels of (capacity) pricing uncertainty by its participation within the FRR to fulfill its capacity reserve obligations.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

E. KPCo's current available capacity resources

To meet the most recent projected peak demand and annual energy requirements of its customers, as part of its FRR obligations in PJM for the current, 2010/2011 Planning Year, KPCo is relying on 1,470 MW of owned—or for which it currently has a long-term purchase entitlement—generating capability. The make-up of KPCo's PJM-recognized installed capability (ICAP) includes a portfolio of coal facilities identified in the following table:

COAL:

- ✓ Big Sandy Unit 1 (278-MW) located in Louisa, KY. In-service 1963
- ✓ Big Sandy Unit 2 (800-MW) located in Louisa, KY. In-service 1969
- ✓ Rockport Unit 1 (197-MW) located in Spencer County, IN [4] In-service 1984
- ✓ Rockport Unit 2 (195-MW) located in Spencer County, IN [5] In-service 1989

TOTAL (2011/2012 PJM Planning Year) **1,470** MW

F. KPCo's current available "demand" resource (DSM)

Demand-Side Management (DSM) in the form of both "active" and "passive" Demand Response (DR) initiatives have been incorporated into the Company's resource planning. Active DSM, in the form of peak-modifying DR activity have been projected as well as passive DSM in the form of Energy Efficiency (EE) programs, which KPCo and this Commission has supported for some time. The following **Table 1-2** identifies the level of KPCo (total) demand reduction initially anticipated over the forecasted time horizon based, in part, on the requirements for DSM as set forth in Case No. 2010-00095, approved in August, 2010. While not at all trivial, it is evident, however, that such DR resource contributions from such estimated DSM activity by or around the mid-part of this decade of approximately 30-40 MW are clearly well below the

[4] This reflects KPCo's 30% purchase entitlement from the (50%), AEP Generating Company (AEG) ownership share of the (total) 1315-MW unit.
[5] This reflects KPCo's 30% purchase entitlement from the (50%), AEG share of the 1300-MW unit that is currently under lease to non-affiliate Lessors.

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

significant capacity needs that would be at issue when considering the disposition of units on the scale of Big Sandy Unit 2.

Table 1-2

AEP-Projected Demand Response (DR) and Energy Efficiency (EE)
KPCo and AEP-East

	(CURRENT) PJM-APPROVED INTERRUPTIBLE DEMAND RESPONSE Peak Reduction (MW)		+ (PROJECTED) "ACTIVE" DEMAND RESPONSE Peak Reduction (MW)		+ (PROJECTED) "PASSIVE" DEMAND RESPONSE Peak Reduction (MW)		= TOTAL DEMAND RESPONSE Peak Reduction (MW)	
Year	KPCo	AEP-East	KPCo	AEP-East	KPCo	AEP-East	KPCo	AEP-East
2011	0	445	2	47	2	76	4	568
2012	0	445	4	50	4	149	8	644
2013	0	445	4	50	7	252	10	747
2014	0	445	11	180	9	390	19	1,015
2015	0	445	18	300	10	523	28	1,268
2016	0	445	26	450	15	650	41	1,545
2017	0	445	35	600	18	765	53	1,811
2018	0	445	36	612	20	866	56	1,923
2019	0	445	36	624	21	993	58	2,063
2020	0	445	37	637	23	1,128	60	2,210
2021	0	445	38	649	23	1,221	61	2,315
2022	0	445	39	662	24	1,293	62	2,401
2023	0	445	39	676	23	1,350	63	2,471
2024	0	445	40	689	23	1,391	64	2,525
2025	0	445	41	703	23	1,427	64	2,575
2026	0	445	41	703	23	1,439	64	2,587
2027	0	445	41	703	23	1,439	64	2,587
2028	0	445	41	703	24	1,437	65	2,585
2029	0	445	41	703	23	1,439	64	2,587
2030	0	445	41	703	23	1,439	64	2,587

	(PROJECTED) CUMULATIVE ENERGY EFFICIENCY (GWh)	
Year	KPCo	AEP-East
2011	13	611
2012	31	988
2013	47	1,467
2014	60	2,232
2015	70	2,968
2016	95	3,699
2017	113	4,351
2018	122	4,927
2019	130	5,651
2020	136	6,419
2021	137	6,920
2022	138	7,325
2023	138	7,651
2024	137	7,904
2025	136	8,095
2026	135	8,162
2027	135	8,162
2028	135	8,162
2029	135	8,162
2030	135	8,162

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

G. SUMMARY: KPCo's current PJM "capacity position"

Assuming that the KPCo LSE were viewed individually as part of a PJM-planning perspective, the following **Table 1-3** offers an overview of such a KPCo "stand-alone" capacity position within PJM. This view effectively assumes that the Company would continue to elect to participate in the PJM RPM as an FRR (*i.e.*, self-planning) entity as opposed to participating in PJM's capacity auction construct. Further it assumes, as a "going-in" or base assumption that Big Sandy Unit 2 would continue to contribute ICAP into PJM; whereas Big Sandy Unit 1 would continue to contribute ICAP up to, minimally, the 2014/15 PJM Planning Year and then be retired.

As reflected in the column identified as "Net Position w/ New Capacity" (col. 20), KPCo would ultimately become "short" capacity by 279 MW beginning with that 2014/15 Planning Year timeframe. This demonstrates and confirms that while KPCo may initially be able to maintain a *manageable* capacity position in PJM assuming Big Sandy Unit 1 was retired while Big Sandy Unit 2 was environmentally-retrofitted and continued operation, the Company would clearly become <u>significantly</u> capacity-deficient—with an attendant market pricing exposure—if the 800-MW Big Sandy Unit 2 were *also* to be retired with no contemporaneous replacement of its capacity and energy.

Appendix

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

Table 1-3

KENTUCKY POWER COMPANY

Projected Resource Capacity, Load/Peak Demands, and PJM UCAP Reserve Margins ("CLR")--PJM FRR Planning Perspective

Based on September 2011 Load Forecast

(2011/2012 - 2030/2031 PJM Planning Years)

"Going-In" Capacity Position (No New Thermal Resource Additions or Purchases)

(Assuming U.S. EPA [Proposed] EGU MACT Rulemaking "ACCELERATED" Unit Retirements re: BS1)

	Obligation to PJM										Resources								I&M Position (MW)		PJM Reserve Margin			
Planning Year	(1) Internal Demand (a)	(2) DSM (b)	(3) Projected DSM Impact (c)	(4) Net Internal Demand	(5) Interruptible Demand Response (d)	(6) Demand Response Factor	(7) Forecast Pool Req't (e)	(8) UCAP Obligation	(9) Net UCAP Market Obligation (f)	(10) Total UCAP Obligation	(11) Existing Capacity & Planned Changes (g)	(12) Net Capacity Sales (h)	(13) Planned Capacity Additions: Units	(14) Planned Capacity Additions: MW (i)	(15) Annual Purchases	(16) Net ICAP	(17) AEP EFORd (j)	(18) Available UCAP	(19) Net Position w/o New Capacity	(20) Net Position w/ New Capacity	(21) Total UCAP Obligation Less IDR and IRM	(22) Installed Reserve Margin (IRM)	(23) I&M Reserve Margin Above PJM IRM	(24) Total I&M Reserve Margin
				=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)						=(11)-(12) + Sum(14) +(15)		=(16)*(1-(17))	=((11)-(12) +(15)) *(1-(17)) -(10)	=(18)-(10)	=((10)+((5)*(6)*(7)))/(1+(22))		=(20)/(21)	=(22)+(23)
2011 /12 (k)	1,218	(2)	(1)	1,217	2	0.955	1.083	1,317	0	1,317	1,470	104				1,366	6.26%	1,280	(37)	(37)	1,142	15.50%	-3.24%	12.26%
2012 /13 (k)	1,253	(4)	(1)	1,252	4	0.950	1.080	1,348	0	1,348	1,470	58				1,412	7.15%	1,311	(37)	(37)	1,171	15.40%	-3.16%	12.24%
2013 /14 (k)	1,283	(7)	(1)	1,282	4	0.957	1.080	1,382	0	1,382	1,470	(6)				1,476	7.38%	1,367	(15)	(15)	1,202	15.30%	-1.25%	14.05%
2014 /15 (k)	1,300	(9)	(2)	1,298	11	0.956	1.081	1,392	0	1,392	1,192	(6)				1,198	7.09%	1,113	(279)	(279)	1,217	15.30%	-22.93%	-7.63% (l)
2015 /16	1,247	(10)	(4)	1,243	18	0.956	1.081	1,326	0	1,326	1,180	(5)				1,185	7.09%	1,101	(225)	(225)	1,166	15.30%	-19.30%	-4.00%
2016 /17	1,252	(15)	(7)	1,246	26	0.956	1.081	1,319	0	1,319	1,187	(7)				1,194	7.09%	1,109	(210)	(210)	1,167	15.30%	-17.99%	-2.69%
2017 /18	1,256	(18)	(9)	1,247	35	0.956	1.081	1,312	0	1,312	1,187	(8)				1,195	7.09%	1,110	(202)	(202)	1,169	15.30%	-17.28%	-1.98%
2018 /19	1,271	(20)	(10)	1,260	36	0.956	1.081	1,325	0	1,325	1,187	(8)				1,195	7.09%	1,110	(215)	(215)	1,181	15.30%	-18.20%	-2.90%
2019 /20	1,281	(21)	(15)	1,266	36	0.956	1.081	1,331	0	1,331	1,193	(5)				1,198	7.08%	1,113	(218)	(218)	1,187	15.30%	-18.37%	-3.07%
2020 /21	1,287	(23)	(18)	1,269	37	0.956	1.081	1,333	0	1,333	1,198	(4)				1,202	7.08%	1,117	(216)	(216)	1,189	15.30%	-18.16%	-2.86%
2021 /22	1,299	(23)	(20)	1,279	38	0.956	1.081	1,344	0	1,344	1,198	(3)				1,201	7.08%	1,116	(228)	(228)	1,200	15.30%	-19.01%	-3.71%
2022 /23	1,309	(24)	(21)	1,287	39	0.956	1.081	1,352	0	1,352	1,198	(2)				1,200	7.08%	1,115	(237)	(237)	1,207	15.30%	-19.63%	-4.33%
2023 /24	1,313	(23)	(23)	1,290	39	0.956	1.081	1,354	0	1,354	1,198	(1)				1,199	7.08%	1,114	(240)	(240)	1,210	15.30%	-19.84%	-4.54%
2024 /25	1,320	(23)	(23)	1,296	40	0.956	1.081	1,360	0	1,360	1,198	0				1,198	7.08%	1,113	(247)	(247)	1,216	15.30%	-20.32%	-5.02%
2025 /26	1,333	(23)	(24)	1,310	41	0.956	1.081	1,373	0	1,373	1,198	0				1,198	7.08%	1,113	(260)	(260)	1,228	15.30%	-21.18%	-5.88%
2026 /27	1,344	(23)	(23)	1,320	41	0.956	1.081	1,385	0	1,385	1,198	0				1,198	7.08%	1,113	(272)	(272)	1,238	15.30%	-21.97%	-6.67%
2027 /28	1,354	(23)	(23)	1,331	41	0.956	1.081	1,397	0	1,397	1,198	0				1,198	7.08%	1,113	(284)	(284)	1,248	15.30%	-22.75%	-7.45%
2028 /29	1,362	(24)	(23)	1,338	41	0.956	1.081	1,404	0	1,404	1,198	0				1,198	7.08%	1,113	(291)	(291)	1,254	15.30%	-23.20%	-7.90%
2029 /30	1,369	(23)	(23)	1,346	41	0.956	1.081	1,412	0	1,412	1,198	0				1,198	7.08%	1,113	(299)	(299)	1,261	15.30%	-23.70%	-8.40%
2030 /31	1,379	(23)	(23)	1,356	41	0.956	1.081	1,423	0	1,423	1,198	0				1,198	7.08%	1,113	(310)	(310)	1,271	15.30%	-24.39%	-9.09%

Notes: (a) Based on (September 2011) Load Forecast (with implied PJM diversity factor)

(b) Existing plus approved and projected "Passive" EE, and IVV
(note: these values & timing are for reference only and are not reflected in position determination)

(c) For PJM planning purposes, the impact of new DSM is 'delayed' three years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process

(d) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR

(e) Installed Reserve Margin (IRM) = 15.5%(2011), 15.4%(2012), 15.3%(2013-2030)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes company MLR share of:
FRR view of obligations only

(g) EFFICIENCY IMPROVEMENTS:
2015/16: Rockport 1: 36 MW (turbine upgrade) (offset to DFGD derate)
2019/20: Rockport 2: 36 MW (turbine upgrade)
2020/21: Rockport 2: 35 MW (valve upgrade)

(g) continued
DFGD DERATES:
1/2016: Rockport 1: 35 MW
1/2016: Big Sandy 2: 12 MW
RETIREMENTS (Under "BASE [EGU MACT-ACCELERATED]" view):
1/2015: Big Sandy 1

(h) Includes (MLR Share, pre-2014) of:
<Purchase> (from Constellation) of 315 MW in 2011/12
Commitment (for FRR purposes) of 22 MW from Tanners Ck 4 in 2011/12 and 30 MW in 2012/13
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA 2011/12-2012/13 (387 MW; 160 MW)
RPM Auction Sales 2011/12 - 2013/14 (1414, 696, 761) (MW ICAP)
3.6 MW capacity <credit> from SEPA's Philpot Dam via Blue Ridge contract
Plus:
Estimated I&M nominations for PJM EE ('passive' DR program) levels --reflected as a UCAP '<resource>'--
as part of PJM's emerging auction products (eff: 2014/15)

(i) Any new wind and solar capacity value is assumed to be 13% and 38% of nameplate

(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCapacity
as of twelve months ended 9/30 of the previous year... Forecast represents latest Generation estimates

(k) PJM latest forecast of AEP Zonal coincident peak demand (allocated to Operating Co. LSEs, incl. I&M)
which are ultimately utilized to established capacity position

(l) Through the PJM 2014/15 Planning Year, I&M capacity position has been established from an overall AEP (Eastern Zone) perspective, under the Fixed Resource Requirement (FRR) planning options... Subsequent years are to-be-determined.

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III. ADDITIONAL RISK ANALYSIS

Once the discretely-modeled Strategist® resource alternative plan portfolios identified in Exhibits SCW-4 as well as Exhibits SCW- 4A though 4E were established, they were subjected to risk "stress-testing" to ensure that none of the plans had outcomes that were economically-exposed—versus the other plans—under an array of input variables.

A. The Aurora^{XMP} Model

The proprietary Aurora$^{XMP®}$ model was developed by EPIS, Inc. in the mid 1990's and has been licensed for use by AEP since 2002. Aurora^{XMP} is primarily a production costing model using a fundamentals-based, multi-area, transmission-constrained dispatch logic in order to simulate real market conditions. At AEP it is used by the AEP Fundamental Analysis group primarily as a long-term optimization tool to forecast mid- and long-term power prices and other industry commodity pricing for all regions within the Eastern Interconnect and ERCOT.

One of the features of the Aurora$^{XMP®}$ model is its endogenous risk analysis capabilities for stochastic or random-variable ("Monte Carlo") simulations. For the purposes of this study, a commonly accepted sampling method (the Latin-Hypercube) is employed by the tool in order to generate a plausible distribution of risk factors with a relatively small number of samples or risk iterations.

This study focused solely on the KPCo portfolio of generating units. One hundred (100) risk iteration runs were simulated with six risk factors being sampled. The results take the form of a distribution of possible "G(eneration)" cost-of-service/revenue requirement outcomes for each plan portfolio. The input variables, or "key risk factors" considered by Aurora$^{XMP®}$ within this analysis were:

- Coal prices ($/MMBtu);
- natural gas prices ($/MMBtu);
- power prices (on-peak & off-peak) ($/Mwh);
- CO_2 emission (allowance) price/tax ($/tonne);
- full requirements KPCo load (Gwh); and
- construction costs (annual carrying costs) ($/kW-year)

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Where appropriate, these key variables were correlated based largely on historical data as represented below in **Table 1-4**:

Table 1-4: ***Assumed Variable Correlations***

Monthly Correlation Targets	Natural Gas Prices	Coal Prices	CO_2 Emission Price/Tax	Power Prices	Load
Natural Gas Prices	1	0.09	-0.22	0.87	*seasonal*
Coal Prices		1	0.69	0.19	0.74
CO_2 Emission Price/Tax			1	-0.14	0.05
Power Prices (All Hrs)				1	0.75
Demand					1

	European Futures
	European Futures / US Data validated
	US Data
	Hypothesized

Source: AEP Fundamental Analysis

B. Modeling Process and Results

For each portfolio, the modeled *difference* between the calculated "G"-cost CPW 50th (median) and 95th percentile outcome across the 100 simulations was identified as "Revenue Requirement at Risk" (RRaR). The 95th percentile represents a level of required revenue sufficiently high that it will be exceeded, assuming that the given plan were adopted, with an estimated probability of only 5.0 percent. The RRaR represents a measure of customer risk or uncertainty inherent in each portfolio. The *larger* the RRaR, the *greater* the level of risk that KPCo's customers could be subjected to a higher generation cost-of-service/revenue requirement.

The following **Table 1-5** illustrates for the Option #1 (Big Sandy Unit 2 Retrofit) plan portfolio, the average levels of these key risk factors—both overall (*i.e.*, all outcomes), and in the simulated outcomes in which CPW of G-revenue requirement exceeds the 95th percentile; or the upper-bound of Revenue Requirement at Risk (*i.e.*, the cumulative distribution "tail"). While this figure is specific to the "Retrofit" plan, the numbers would be similar under the other plans.

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Table 1-5: ***Key Risk Factors – Means***

Simulated Outcomes -- Big Sandy 2 Retrofit (Option #1)					
Key Risk Factor	All Outcomes	RRaR-Exceeding Outcomes (>95%)			Year
	Mean	Mean	Difference	%Diff	
Coal prices (nominal $/MMBtu)	2.59	3.03	0.43	16.7%	2020
Natural Gas Prices (nominal $/MMBtu)	8.62	10.22	1.59	18.5%	2025
Pow er Prices (nominal $/Mw h - All Hrs)	54.06	67.38	13.32	24.6%	2020
CO2 Emission Price/Tax ($/Tonne)	13.97	17.23	3.26	23.3%	2022
Load (Gw h)	9,208	11,284	2,076	22.5%	2020
FOM, Constr Costs / MW	4.99	5.44	0.45	9.0%	2025

Source: AEP Fundamental Analysis

The price of Power (energy) and CO_2 Emission Price/Tax are greater among the RRaR-Exceeding Outcomes, suggesting that they are critical sources of risk to revenue requirements. The relative difference between the average "tail" and overall average outcomes for those respective variables is 24.6% and 23.3%, which is marginally greater than the relative difference of other key risk factors.

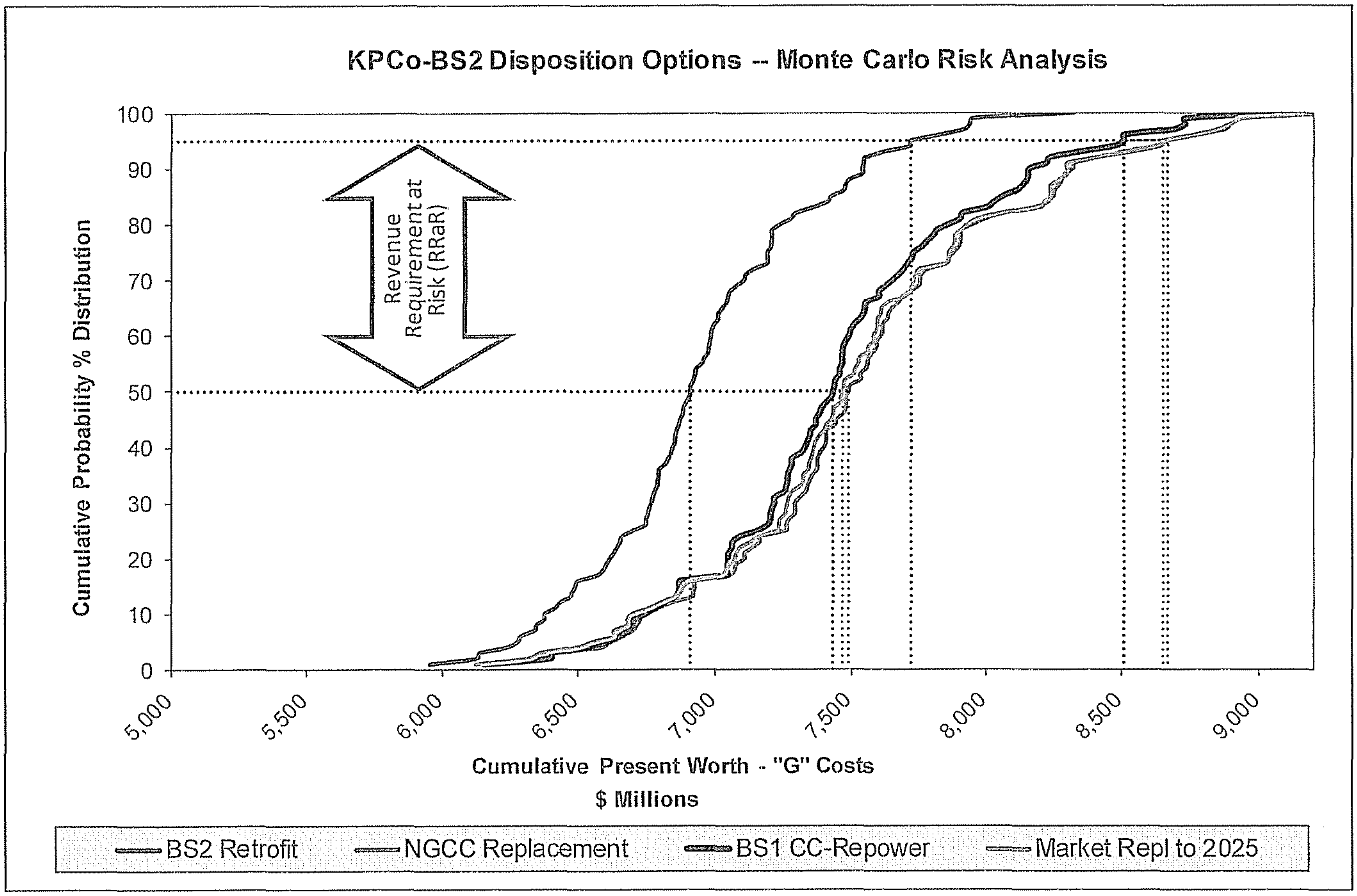
It might be assumed that the very worst possible futures for the Big Sandy Retrofit (Option #1) would be characterized by high fuel and (CO_2) emission prices, but low power prices. But according to the analysis of the historical values of risk factors that underlies this study, such futures have essentially no chance of occurring. Any possible future with higher fuel prices would essentially always have higher power prices. Additionally, the risk factor analysis also implies a slightly inverse correlation between CO_2 emission price/tax and some of the other risk factors that determine the tail cases, including power prices. So, in these tail cases, the average CO_2 allowance price could actually be *less* than the average across all possible futures when power prices are randomly selected to be high.

Figure 1-1 below shows the distribution of outcomes for each of the four plans that were evaluated (Option #1, #2, #3 and #4B). Note that these CPW results are largely consistent with the CPW values calculated using the Strategist® tool, with the Option #1 (Big Sandy 2 DFGD Retrofit) case being the lowest cost plan. The importance of this evaluation, though, is not in matching the discrete Strategist® results, but in examining the relative risk among the portfolios. As Figure 1-1—including the supporting table—indicates, the RRaR (difference between the 50th and

Supplemental Information to Support the KPCo Planning Process and Issues Represented in this CPCN Application

95th probability percentile simulated result) is also far superior (lower) for Option #1. This reinforces the conclusions from the Strategist® optimization analysis that, again, Option #1 is the optimal alternative based on the relative reduced price/cost risk exposure to KPCo's customers over the long-term study period.

Figure 1-1: KPCo-BS2 Disposition – Simulation Risk Distribution



		Option #1	*Option #2*	*Option #3*	*Option #4B*			
CPW ($000)	*Cumul. Distribution Percentile*	BS2 Retrofit	NGCC Replacement	BS1 CC-Repower	Market Repl to 2025	*Delta* Retrofit - NGCC	*Delta* Retrofit - Repower	*Delta* Retrofit - Mkt to 2025
	50	6,907,015	7,492,590	7,433,656	7,469,125	(585,575) *-8.5%*	(526,641) *-7.6%*	(562,110) *-8.1%*
	95	7,722,158	8,666,036	8,508,691	8,647,851	(943,877) *-12.2%*	(786,532) *-10.2%*	(925,693) *-12.0%*
Relative Rank:	*CPW*	1	4	2	3			
RRaR ($000)								
	95th vs. 50th	815,143	1,173,446	1,075,034	1,178,726	(358,303) *-44.0%*	(259,891) *-31.9%*	(363,583) *-44.6%*
Relative Rank:	*RRaR*	1	3	2	4			

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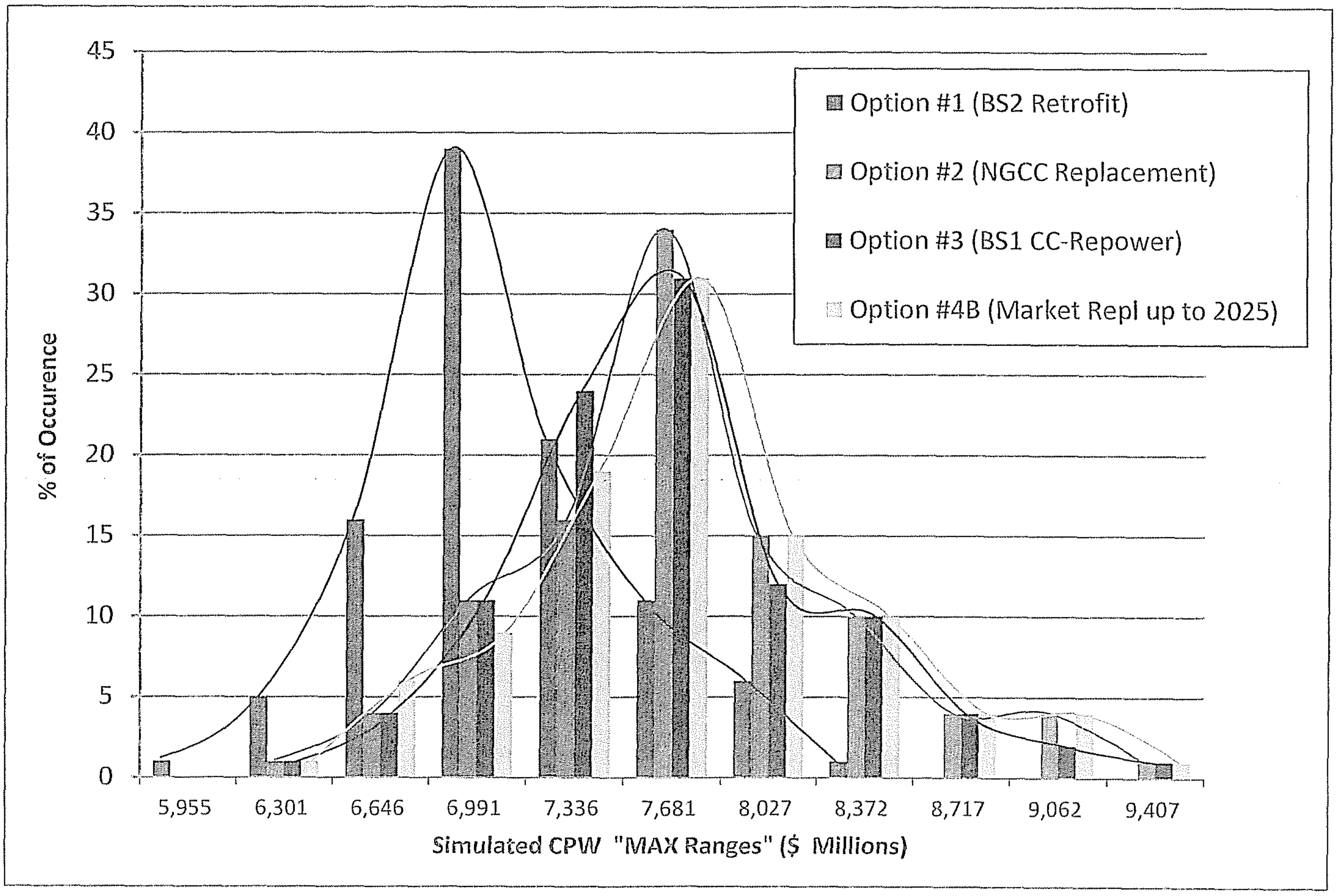
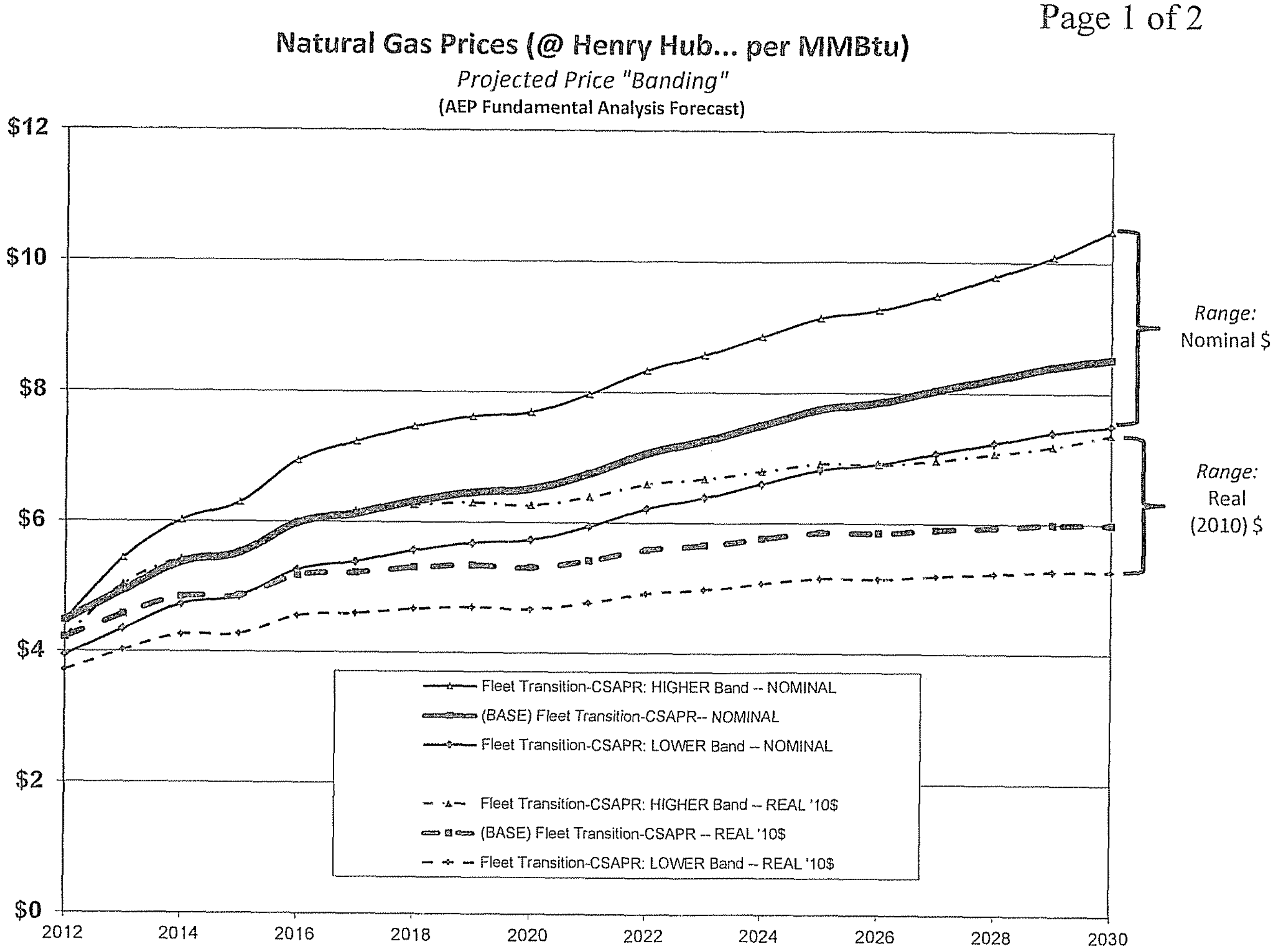
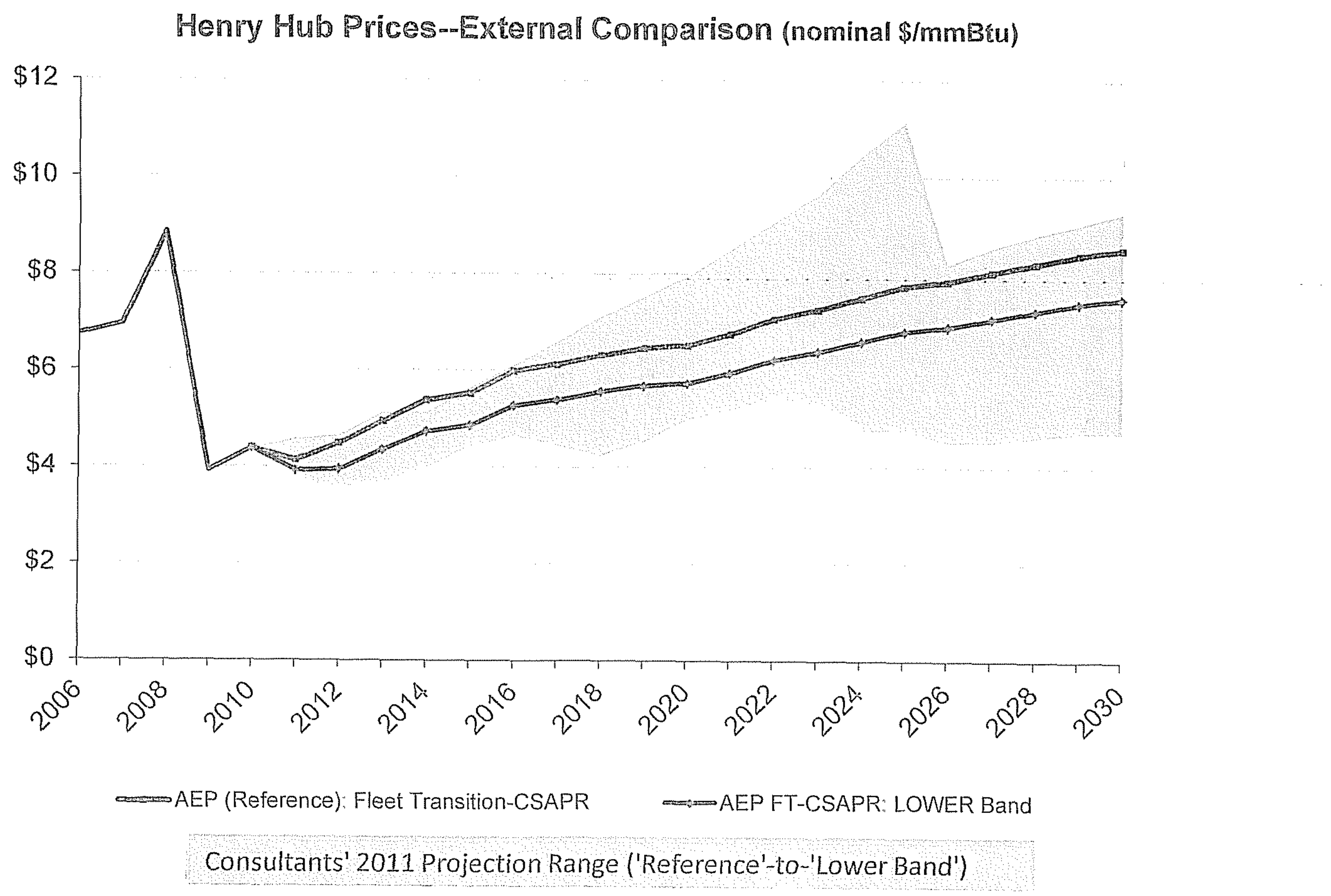
Finally, ***Figure 1-2*** offers a histogram—"bell curve" plotting—of these same Monte Carlo-simulated results. This view of the Aurora$^{XMP®}$ modeled results indicates that the 100 simulated CPW outcomes for Option #1 are more "symmetrical". This means there is approximately an equal probability that any randomly-simulated outcome would be above or below the highest occurring range of outcomes. However the simulated outcomes for Options #2, #3 and #4B are slightly less symmetrical, with those portfolio profiles indicating a greater percentage of outcomes <u>above</u> the highest-occurring range of results (i.e., approaching that "tail" outcome). This would offer another optic highlighting the greater RRaR associated with those options. Likewise, it would point to Option #4B as perhaps having the greatest level of cost uncertainty/risk.

Figure 1-2: KPC-BS2 Disposition-Simulation Histogram




Natural Gas Prices (@ Henry Hub... per MMBtu)
Projected Price "Banding"
(AEP Fundamental Analysis Forecast)
$12
$10
$8
$6
$4
$2
$0
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
Range:
Nominal $
Range:
Real
(2010) $
Fleet Transition-CSAPR: HIGHER Band -- NOMINAL
(BASE) Fleet Transition-CSAPR-- NOMINAL
Fleet Transition-CSAPR: LOWER Band -- NOMINAL
Fleet Transition-CSAPR: HIGHER Band -- REAL '10$
(BASE) Fleet Transition-CSAPR -- REAL '10$
Fleet Transition-CSAPR: LOWER Band -- REAL '10$


Henry Hub Prices--External Comparison (nominal $/mmBtu)
$12
$10
$8
$6
$4
$2
$0
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
AEP (Reference): Fleet Transition-CSAPR
AEP FT-CSAPR: LOWER Band
Consultants' 2011 Projection Range ('Reference'-to-'Lower Band')

Summary of Long-Term Commodity Price Forecast Scenarios

(Source: AEP Fundamental Analysis)

Annual Average (Nominal Dollars)

NATURAL GAS (Henry Hub) ($/MMBtu)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2012	4.48	4.48	3.94	4.48	4.48
2013	4.94	5.43	4.35	4.94	4.94
2014	5.38	6.02	4.73	5.38	5.38
2015	5.52	6.29	4.86	5.52	5.52
2016	5.99	6.94	5.27	5.99	5.99
2017	6.13	7.23	5.39	6.42	6.13
2018	6.32	7.46	5.56	6.60	6.32
2019	6.46	7.62	5.68	6.73	6.46
2020	6.52	7.69	5.73	6.78	6.52
2021	6.75	7.97	5.94	7.06	6.60
2022	7.07	8.34	6.22	7.22	6.68
2023	7.26	8.57	6.39	7.35	6.86
2024	7.51	8.86	6.61	7.51	7.10
2025	7.75	9.14	6.82	7.75	7.32
2026	7.85	9.26	6.91	7.85	7.42
2027	8.04	9.49	7.08	8.04	7.60
2028	8.22	9.78	7.23	8.22	7.77
2029	8.41	10.08	7.40	8.41	7.94
2030	8.52	10.48	7.50	8.52	8.05

CO2 ($/Metric Tonne)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2012	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	15.08	0.00
2018	0.00	0.00	0.00	15.28	0.00
2019	0.00	0.00	0.00	15.47	0.00
2020	0.00	0.00	0.00	15.68	0.00
2021	0.00	0.00	0.00	15.88	0.00
2022	15.08	15.48	15.48	16.08	0.00
2023	15.28	15.67	15.67	16.29	0.00
2024	15.48	15.88	15.88	16.50	0.00
2025	15.67	16.08	16.08	16.72	0.00
2026	15.88	16.29	16.29	16.94	0.00
2027	16.08	16.50	16.50	17.16	0.00
2028	16.29	16.72	16.72	17.38	0.00
2029	16.50	16.94	16.94	17.60	0.00
2030	16.72	17.12	17.16	17.84	0.00

NAPP (6.0#) ($/Ton-FOB Mine)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2012	56.75	64.13	53.91	56.75	56.75
2013	58.00	66.70	53.36	58.00	58.00
2014	60.00	69.00	53.40	60.00	60.00
2015	62.36	72.34	55.50	62.36	62.36
2016	64.72	75.08	57.60	64.72	64.72
2017	65.92	76.47	58.67	64.00	65.92
2018	67.18	77.93	59.79	65.22	67.18
2019	68.45	79.40	60.92	66.46	68.45
2020	69.71	80.87	62.05	67.68	69.71
2021	71.18	82.57	63.35	69.10	71.18
2022	70.90	82.24	63.10	70.55	72.67
2023	72.37	83.95	64.41	72.02	74.18
2024	73.87	85.69	65.74	73.51	75.71
2025	75.38	87.44	67.09	75.01	77.26
2026	76.91	89.22	68.45	76.54	78.84
2027	78.46	91.02	69.83	78.08	80.43
2028	80.04	92.85	71.24	79.65	82.04
2029	81.65	94.71	72.66	81.25	83.69
2030	83.27	96.60	74.11	82.87	85.36

CAPP (1.6#) ($/Ton-FOB Mine)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2012	79.97	91.46	75.97	79.97	79.97
2013	83.46	97.95	75.11	83.46	83.46
2014	84.83	101.44	74.65	84.83	84.83
2015	85.21	102.25	74.98	85.21	85.21
2016	85.52	102.62	75.26	85.52	85.52
2017	85.31	102.37	75.07	82.83	85.31
2018	86.94	104.33	76.51	84.41	86.94
2019	88.58	106.30	77.95	86.00	88.58
2020	90.22	108.26	79.39	87.59	90.22
2021	92.07	110.48	81.02	89.38	92.07
2022	91.66	109.99	80.66	91.21	93.95
2023	93.52	112.22	82.30	93.07	95.86
2024	95.41	114.49	83.96	94.94	97.79
2025	97.31	116.77	85.63	96.84	99.74
2026	99.24	119.09	87.33	98.76	101.72
2027	101.19	121.43	89.05	100.70	103.72
2028	103.18	123.81	90.80	102.68	105.76
2029	105.19	126.23	92.57	104.68	107.82
2030	107.24	128.69	94.37	106.72	109.92

ON-Peak Energy (PJM-AEP Gen Hub) ($/Mwh)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2012	50.57	55.16	47.59	49.73	50.30
2013	50.14	55.48	44.98	48.59	47.85
2014	54.24	62.03	49.26	54.28	54.45
2015	56.71	65.49	53.60	56.42	56.79
2016	63.56	71.80	58.75	62.42	63.74
2017	63.48	71.72	59.20	71.84	64.41
2018	64.18	73.15	60.06	72.73	65.25
2019	65.44	74.08	60.90	73.21	66.31
2020	66.33	75.16	60.86	73.82	66.55
2021	67.64	77.00	62.38	75.75	67.28
2022	76.79	85.88	72.64	77.34	68.31
2023	78.33	87.97	74.25	78.43	70.32
2024	80.34	89.78	74.99	79.55	71.04
2025	82.18	92.27	76.25	81.48	73.07
2026	83.23	93.67	77.71	82.70	73.94
2027	84.57	95.54	79.22	84.24	75.28
2028	86.25	98.14	80.55	86.25	76.51
2029	87.64	100.30	81.53	87.32	77.70
2030	89.34	103.70	82.78	88.75	78.95

OFF-Peak Energy (PJM-AEP Gen Hub) ($/Mwh)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2012	30.92	33.66	29.07	30.33	30.27
2013	30.55	35.01	28.55	30.15	29.97
2014	33.26	38.84	31.15	32.95	33.34
2015	33.89	40.47	32.16	33.73	34.34
2016	39.57	45.94	36.16	38.65	40.12
2017	41.57	48.09	38.59	51.00	41.67
2018	42.57	49.48	39.25	52.03	42.70
2019	43.60	50.18	40.01	52.82	43.47
2020	44.18	51.40	40.52	53.54	44.35
2021	45.76	53.01	41.76	55.14	45.22
2022	55.93	63.44	52.41	56.56	46.22
2023	56.84	65.25	53.42	57.35	47.67
2024	58.85	66.65	54.17	58.69	48.94
2025	60.37	68.79	55.93	60.38	50.72
2026	61.06	70.11	56.67	61.28	51.59
2027	62.64	72.07	58.15	62.85	53.19
2028	64.05	74.08	59.05	64.56	54.40
2029	65.66	76.20	60.20	65.80	55.78
2030	67.49	78.87	61.12	66.82	56.65

Capacity Value (PJM-RTO RPM) ($/MW-Day)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon	
2012	16.46	16.46	16.46	16.46	16.46	*
2013	27.73	27.73	27.73	27.73	27.73	*
2014	126.00	126.00	126.00	126.00	126.00	*
2015	215.25	215.25	215.25	215.25	215.25	
2016	281.92	281.92	281.92	281.92	281.92	
2017	235.98	199.63	230.85	210.98	240.98	
2018	200.39	166.43	179.76	180.39	205.39	
2019	224.57	211.40	186.64	214.57	230.57	
2020	253.47	253.86	212.57	243.47	261.47	
2021	280.05	293.65	238.70	265.05	295.05	
2022	304.18	330.64	264.71	289.18	322.18	
2023	325.73	364.68	288.14	310.73	345.73	
2024	344.58	391.96	308.40	329.58	364.58	
2025	360.58	405.21	325.58	345.58	380.58	
2026	373.61	411.28	340.04	358.61	394.61	
2027	383.50	417.45	350.60	363.50	405.50	
2028	390.13	423.72	358.23	370.13	413.13	
2029	392.94	430.07	362.96	372.94	416.94	
2030	392.16	436.27	361.29	372.16	418.16	

* Represents PJM-RTO (i.e. "western" or "rest-of-market" PJM) Base Residual Auction UCAP clearing prices for those respective XXXX/(XXXX+1) forward PJM Planning Years

Summary: Big Sandy Unit 2 FGD Technology & Fuel Screening
Relative Economic (<COST> / SAVINGS) vs. Lowest Cost Case
Ranked in order of "Relative 10-Yr IRR" (as well as other objective risk factors)

#	CASE#	DESCRIPTION	Relative 10yr NPV ($000s)	Relative 10yr IRR	Relative 20yr NPV ($000s)	Relative 20yr IRR	Relative Payback (Yrs.)
1	Case 23	BS2 FGD Case 23 NID EST-3B [4.5 lb/Mmbtu]	-	-	-	-	-
2	Case 21	BS2 FGD Case 21 NID Base EST-1B [3.0 lb/Mmbtu]	($1,661)	**-0.7%**	($8,255)	-0.2%	0.2
3	Case 7	BS2 FGD Case 7 Dry Base EST-1B [3.0 lb/Mmbtu]	($54,330)	**-1.4%**	($52,307)	-0.7%	0.5
4	Case 19	BS2 FGD Case 19 NID EST-3A [4.5 lb/Mmbtu]	($48,371)	**-3.7%**	($44,669)	-0.7%	0.5
5	Case 1	BS2 FGD Case 1 Wet Base EST-1A [4.5 lb/Mmbtu]	($218,049)	**-4.0%**	($182,078)	-1.8%	5.3
6	Case 17	BS2 FGD Case 17 NID Base EST-1A [3.0 lb/Mmbtu]	($49,352)	**-4.3%**	($51,397)	-0.9%	0.7
7	Case 3	BS2 FGD Case 3 Wet EST-3A [3.0 lb/Mmbtu]	($213,530)	**-4.5%**	($183,767)	-1.9%	5.8
8	Case 5	BS2 FGD Case 5 Dry Base EST-1A [3.0 lb/Mmbtu]	($105,270)	**-5.4%**	($102,801)	-1.5%	3.6
9	Case 8	BS2 FGD Case 8 Dry Est-2B [1.7 lb/Mmbtu]	$38,234	**-7.4%**	($5,199)	-1.0%	0.8
10	Case 22	BS2 FGD Case 22 NID EST-2B [1.7 lb/Mmbtu]	$85,581	**-7.6%**	$31,016	-0.6%	0.4
11	Case 2	BS2 FGD Case 2 Wet EST-2A [1.7 lb/Mmbtu]	($137,733)	**-10.8%**	($151,536)	-2.5%	5.8
12	Case 6	BS2 FGD Case 6 Dry EST-2A [1.7 lb/Mmbtu]	($10,791)	**-11.7%**	($49,772)	-1.7%	5.3
13	Case 18	BS2 FGD Case 18 NID EST-2A [1.7 lb/Mmbtu]	$39,289	**-11.7%**	($8,001)	-1.3%	2.4
14	*Case 28*	*BS2 FGD Case 28 Dry CDS w/FF [4.5 lb/Mmbtu]*	*not initially screened **				

* Added Case 28 (Dry CDS+FF @ 4.5#) to address an additional option due to SO2 removal limitations of Dry (SDA) w/FF technology alternative for coals greater than 3.0# sulfur
This option was evaluated as part of the subsequent Strategist-based "best in (technology) type" screening analysis

NOTE: Although not the optimal relative Net Present Value (NPV) result, "Case 23" was screened as the optimum Dry-NID FGD technology/coal option based on 10-Year relative IRR ... AND given AEP-FEL concern over 1.7# coal availability & price

Kentucky Power Company
Big Sandy 2 Technology/Fuel Screening Analysis
Strategist-Based Screening of "Best of Technology-Types"

	CASE 23 "BEST" Dry NID Tech w/ 4.5#	CASE 5 "BEST" Dry SDA-FF Tech w/ 3.0#	Case 28 "BEST" Dry CDS-FF Tech w/ 4.5#	CASE 1 "BEST" Wet Tech w/ 4.5#	BS1 FGD (1)
2014					
2015					
2016	BS2 FGD (23)	BS2 FGD (5)	BS2 FGD (1)	BS2 FGD (1)	BS1 FGD BS2 FGD
2017					
2018					
2019	BS1 Retirement 1- 407 MW CC,	BS1 Retirement 1- 407 MW CC,	BS1 Retirement 1- 407 MW CC,	BS1 Retirement 1- 407 MW CC,	
2020					
~					
2025	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	
2026					
2027					1- 407 MW CC,
~					
2040					

Cumulative Present Worth (CPW) of Costs ($000):

(2011-2040)	CASE 23	CASE 5	Case 28	CASE 1	BS1 FGD
CPW	$7,478,031	$7,589,736	$7,576,725	$7,632,485	$7,545,951
Less: ICAP Revenue	$103,499	$102,794	$100,679	$95,742	$141,015
Total	$7,374,532	$7,486,942	$7,476,046	$7,536,743	$7,404,936

Savings/(Cost) vs. Case 23 ($000)					
CPW		($111,705)	($98,693)	($154,454)	($67,920)
Less: ICAP Revenue		($705)	($2,821)	($7,757)	$37,515
Total		($112,410)	($101,514)	($162,211)	($30,404)

Note:
(1) "Big Sandy 1 FGD" does NOT include estimates for required SCR as well as CCR-related costs

Kentu ver Co.
Big Sandy Unit 2 Disposition Analysis
Life-Cycle Study Period (30-Year, 2011-2040) Economics

<u>COMPARATIVE</u> Cumulative Present Worth (CPW) of Relative KPCo "G" Revenue Requirements (2011 $) (COST / <SAVINGS>)

$ Millions

	Assuming: 15-Year RETROFIT Recovery Period				*Assuming*: 20-Year RETROFIT Recovery Period			
	Option #2 RETIRE & REPLACE Big Sandy Unit 2 with "NEW-BUILD" (@ BS site) NG-Combined Cycle Capacity & Energy (1/2016)	Option #3 RETIRE & REPLACE Big Sandy Unit 2 with "REPOWERED" Big Sandy U1 Combined Cycle Capacity & Energy (1/2016)	Option #4 RETIRE & REPLACE Big Sandy Unit 2 with PURCHASED (PJM-RPM) Capacity & Energy (1/2016): Option #4A For up to 5 Yrs (thru 2020)	Option #4 RETIRE & REPLACE Big Sandy Unit 2 with PURCHASED (PJM-RPM) Capacity & Energy (1/2016): Option #4B For up to 10 Yrs (thru 2025)	Option #2 RETIRE & REPLACE Big Sandy Unit 2 with "NEW-BUILD" (@ BS site) NG-Combined Cycle Capacity & Energy (1/2016)	Option #3 RETIRE & REPLACE Big Sandy Unit 2 with "REPOWERED" Big Sandy U1 Combined Cycle Capacity & Energy (1/2016)	Option #4 RETIRE & REPLACE Big Sandy Unit 2 with PURCHASED (PJM-RPM) Capacity & Energy (1/2016): Option #4A For up to 5 Yrs (thru 2020)	Option #4 RETIRE & REPLACE Big Sandy Unit 2 with PURCHASED (PJM-RPM) Capacity & Energy (1/2016): Option #4B For up to 10 Yrs (thru 2025)
	versus... 'BASE'/Option #1: RETROFIT Big Sandy Unit 2 with Dry FGD Technology (6/2016)				*versus...* 'BASE'/Option #1: RETROFIT Big Sandy Unit 2 with Dry FGD Technology (6/2016)			
L/T Commodity Pricing Scenarios								
BASE: "Fleet Transition-CSAPR"	236	252	79	(47)	274	290	116	(10)
'Commodity Price Banding' Scenarios...								
2. "Fleet Transition-CSAPR: HIGHER Band"	437	458	266	192	474	495	303	229
3. "Fleet Transition-CSAPR: LOWER Band"	177	183	21	(119)	214	220	58	(82)
'Carbon/CO_2 Pricing' Scenarios...								
4. "Fleet Transition-CSAPR: No Carbon"	315	334	166	47	352	371	203	84
5. "Fleet Transition-CSAPR: Early Carbon (2017)"	180	190	20	(115)	218	228	57	(78)

Note:
-- A "POSITIVE" value above would favor the RETROFIT (Option #1)... a "<NEGATIVE>" value would favor the alternative option
-- Every $100 Million change in CPW is equivalent to a <u>$1.90 per Mwh</u> (0.190 cents/kWh) impact on <u>levelized annual</u> KPCo G-revenue requirements (2011$) over the affected 2016-2040 period

Additional Notes:
o 'BASE' ("Fleet Transition-CSAPR") pricing scenario --as well as "HIGHER Band" and "LOWER Band" pricing scenarios-- assumes carbon/CO2 pricing is effective in 2022
o Options #2 and #3 (RETIRE & REPLACE BS2 w "New-Build CC" and "CC-Repowered BS1", respectively) assumes a 30-year recovery period for the CC in all analyses
o Options #1, #2 and #4 assume Big Sandy Unit 1 is retired 1/2015 (Option #3 assumes that unit is repowered as a CC unit)
o All analyses includes KPCo's 30% purchase entitlement share of AEG's 50% (~650-MW) portion of Rockport Units 1 and 2 (or, ~393-MW of capacity and energy)
(i.e. resulting in effectively no relative impact on any of these Big Sandy 2 disposition analyses)
o Big Sandy 2 "Retirement" Options #2, #3 and #4 also conservatively <u>exclude</u> costs associated w/ socio-economic impacts to the region
(i.e. resulting in effectively no relative impact on any of these BS2 disposition analyses)
o "G" Revenue Requirements established on a KPCo "stand-alone" basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)... Such costs inclusive of:
1) <u>All</u> KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM; and
3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits on coal unit and/or new-build/repowered NG-CC capacity)

Exhibit SCW-4

Big Sandy Unit 2 under BASE: "Fleet Transition-CSAPR" Commodity Pricing

Kentucky CPCN Filing Economic Analysis

Capacity Resource Optimization

Resource Plan Summary

Resource Plan Year	'BASE' Option #1 BS2 DFGD Retrofit 6/2016	Option #2 (1) RK Retires 1/2016 with (Brownfield) CC Replacement	Option #3 (1) RK Retires 1/2016 with BS2 CC Repwrng Replacement	Option #4A (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2020	Option #4B (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2025	BS2 "Timing" Sensitivity Option #1A BS2 DFGD Retrofit Delayed until 1/2017 (~1-Yr EGU MACT Delay)
2011-2013						
2014				45 MW- ICAP	45 MW- ICAP	
2015	Big Sandy 1 Retire	Big Sandy 1&2 Retire	Big Sandy 2 Retire	225 MW- ICAP	225 MW- ICAP	Big Sandy 1 Retire
2016	Big Sandy 2 Retrofit	1 -904 MW NGCC	Big Sandy 1 1 -780 MW Repower,	938 MW- ICAP	938 MW- ICAP	Big Sandy 2 Mothball (1-yr)
2017				922 MW- ICAP	922 MW- ICAP	Big Sandy 2 Retrofit
2018				930 MW- ICAP	930 MW- ICAP	
2019				934 MW- ICAP	934 MW- ICAP	
2020				1 -904 MW NGCC	938 MW- ICAP	
2021					939 MW- ICAP	
2022					951 MW- ICAP	
2023					957 MW- ICAP	
2024					967 MW- ICAP	
2025	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1 -904 MW NGCC, 1-407 MW CC	
2026						
~						
2040						
Life-Cycle Analysis Period (2011-2040)						
($000)						
CPW of Revenue Requirements	6,724,489	7,152,559	7,079,239	6,811,507	6,487,042	6,721,898
Less: ICAP Revenue	(114,391)	77,262	(11,944)	(106,260)	(304,545)	(114,503)
CPW of Revenue Requirements, Net	6,838,879	7,075,297	7,091,182	6,917,767	6,791,587	6,836,401
A. Cost/(Savings) Over 'BASE' Case						
CPW of Revenue Requirements		428,070	354,750	87,018	(237,447)	(2,591)
Less: ICAP / Pool Revenue		191,652	102,447	8,130	(190,154)	(112)
CPW of Revenue Requirements, Net		236,418	252,303	78,888	(47,293)	(2,478)
B. Cost/(Savings) Over 'BASE' Case						
Impact of 20-Year (vs. 15-Year) RETROFIT Cost Recovery		37,200	37,200	37,200	37,200	37,200
CPW of Revenue Requirements, Net		273,618	289,503	116,088	(10,093)	34,722

Note:

- o The 'BASE' / Option 1 (Big Sandy 2 RETROFIT) analysis results assumes a **15-year recovery period** for the incremental DFGD retrofit investment
- o Option #2 (Big Sandy 2 RETIRED & REPLACED w/ a [BS-site 'Brownfield'] CC) assumes a 30-year recovery period for the new-build CCs in all analyses
- o Option #3 (Big Sandy 2 RETIRED & REPLACED w/ a CC-Repowered Big Sandy U1) assumes a 20-year recovery period in all analyses
- o All cases (except Option #3) assume that Big Sandy 1 retired 1/2015
- o In all cases, effectively assumes replacement capacity & energy for BS1 would be 'delayed' until ~2025 in recognition of a) the (incremental) financing/cost burden to KPCo and its customers; and b) assumed limited (PJM) market availability of reasonably-priced replacement capacity & energy during the interim (~150-300 MW)
- o Evalution economics (all cases) reflect KPCo's 30% share (~195-MW) Purchase Entitlement from affiliate AEG Generating Cos.' 50% Ownership Share of both Rockport Units 1&2
- o "Retirement" options EXCLUDE costs associated w/ socio-economic impacts to the plant staff, supply vendors, or to the overall easten-Kentucky region
- o "G" Revenue Requirements established on a KPCo "stand-alone" (basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)...

  Inclusive of:

  1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM; and

  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

Exhibit SCW-4A

Big Sandy Unit 2 under: "Fleet Transition-HIGHER Band" Commodity Pricing

Kentucky CPCN Filing Economic Analysis

Capacity Resource Optimization

Resource Plan Summary

Resource Plan Year	'BASE' Option #1 BS2 DFGD Retrofit 6/2016	Option #2 (1) RK Retires 1/2016 with (Brownfield) CC Replacement	Option #3 (1) RK Retires 1/2016 with BS2 CC Repwrng Replacement	Option #4A (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2020	Option #4B (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2025
2011-2013				45 MW- ICAP	45 MW- ICAP
2014				225 MW- ICAP	225 MW- ICAP
2015	Big Sandy 1 Retire	Big Sandy 1&2 Retire	Big Sandy 2 Retire	938 MW- ICAP	938 MW- ICAP
2016	Big Sandy 2 Retrofit	1 -904 MW NGCC	Big Sandy 1 1 -780 MW Repower,		
				922 MW- ICAP	922 MW- ICAP
2017				930 MW- ICAP	930 MW- ICAP
2018				934 MW- ICAP	934 MW- ICAP
2019				1 -904 MW NGCC	938 MW- ICAP
2020					939 MW- ICAP
2021					951 MW- ICAP
2022					957 MW- ICAP
2023					967 MW- ICAP
2024					1 -904 MW NGCC,
2025	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1-407 MW CC
2026					
~					
2040					
Life-Cycle Analysis Period (2011-2040)					
($000)					
CPW of Revenue Requirements	7,178,617	7,816,447	7,741,800	7,477,588	7,189,328
Less: ICAP Revenue	(111,382)	89,299	(6,332)	(78,460)	(292,309)
CPW of Revenue Requirements, Net	7,290,000	7,727,148	7,748,132	7,556,049	7,481,637
A. Cost/(Savings) Over 'BASE' Case					
CPW of Revenue Requirements		637,830	563,183	298,971	10,711
Less: ICAP / Pool Revenue		200,682	105,050	32,922	(180,927)
CPW of Revenue Requirements, Net		437,149	458,132	266,049	191,638
B. Cost/(Savings) Over 'BASE' Case					
Impact of 20-Year (vs. 15-Year)					
RETROFIT Cost Recovery		37,200	37,200	37,200	37,200
CPW of Revenue Requirements, Net		474,349	495,332	303,249	228,838

Note:

- o The 'BASE' / Option 1 (Big Sandy 2 RETROFIT) analysis results assumes a **15-year recovery period** for the incremental DFGD retrofit investment
- o Option #2 (Big Sandy 2 RETIRED & REPLACED w/ a [BS-site 'Brownfield'] CC) assumes a 30-year recovery period for the new-build CCs in all analyses
- o Option #3 (Big Sandy 2 RETIRED & REPLACED w/ a CC-Repowered Big Sandy U1) assumes a 20-year recovery period in all analyses
- o All cases (except Option #3) assume that Big Sandy 1 retired 1/2015
- o In all cases, effectively assumes replacement capacity & energy for BS1 would be 'delayed' until ~2025 in recognition of a) the (incremental) financing/cost burden to KPCo and its customers; and b) assumed <u>limited</u> (PJM) market availability of reasonably-priced replacement capacity & energy during the interim (~150-300 MW)
- o Evalution economics (all cases) reflect KPCo's 30% share (~195-MW) Purchase Entitlement from affiliate AEG Generating Cos.' 50% Ownership Share of both Rockport Units 1&2
- o "Retirement" options EXCLUDE costs associated w/ socio-economic impacts to the plant staff, supply vendors, or to the overall easten-Kentucky region
- o "G" Revenue Requirements established on a KPCo "stand-alone" (basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)...

  Inclusive of:

  1) <u>All</u> KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO_2); 2) on-going plant FOM; and

  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

Exhibit SCW-4B

Big Sandy Unit 2 under: "Fleet Transition-LOWER Band" Commodity Pricing

Kentucky CPCN Filing Economic Analysis
Capacity Resource Optimization
Resource Plan Summary

Resource Plan Year	'BASE' Option #1 BS2 DFGD Retrofit 6/2016	Option #2 (1) RK Retires 1/2016 with (Brownfield) CC Replacement	Option #3 (1) RK Retires 1/2016 with BS2 CC Repwrng Replacement	Option #4A (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2020	Option #4B (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2025
2011-2013				45 MW- ICAP	45 MW- ICAP
2014				225 MW- ICAP	225 MW- ICAP
2015	Big Sandy 1 Retire	Big Sandy 1&2 Retire	Big Sandy 2 Retire	938 MW- ICAP	938 MW- ICAP
2016	Big Sandy 2 Retrofit	1 -904 MW NGCC	Big Sandy 1 1 -780 MW Repower,	922 MW- ICAP	922 MW- ICAP
2017				930 MW- ICAP	930 MW- ICAP
2018				934 MW- ICAP	934 MW- ICAP
2019				1 -904 MW NGCC	938 MW- ICAP
2020					939 MW- ICAP
2021					951 MW- ICAP
2022					957 MW- ICAP
2023					967 MW- ICAP
2024					1 -904 MW NGCC,
2025	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1-407 MW CC
2026					
~					
2040					
Life-Cycle Analysis Period (2011-2040)					
($000)					
CPW of Revenue Requirements	6,466,223	6,822,787	6,748,205	6,494,581	6,182,746
Less: ICAP Revenue	(108,542)	71,203	(9,322)	(101,059)	(273,169)
CPW of Revenue Requirements, Net	6,574,765	6,751,584	6,757,528	6,595,640	6,455,915
A. Cost/(Savings) Over 'BASE' Case					
CPW of Revenue Requirements		356,564	281,982	28,358	(283,477)
Less: ICAP / Pool Revenue		179,746	99,220	7,483	(164,626)
CPW of Revenue Requirements, Net		176,819	182,762	20,875	(118,850)
B. Cost/(Savings) Over 'BASE' Case					
Impact of 20-Year (vs. 15-Year)					
RETROFIT Cost Recovery		37,200	37,200	37,200	37,200
CPW of Revenue Requirements, Net		214,019	219,962	58,075	(81,650)

Note:
- o The 'BASE' / Option 1 (Big Sandy 2 RETROFIT) analysis results assumes a **15-year recovery period** for the incremental DFGD retrofit investment
- o Option #2 (Big Sandy 2 RETIRED & REPLACED w/ a [BS-site 'Brownfield'] CC) assumes a 30-year recovery period for the new-build CCs in all analyses
- o Option #3 (Big Sandy 2 RETIRED & REPLACED w/ a CC-Repowered Big Sandy U1) assumes a 20-year recovery period in all analyses
- o All cases (except Option #3) assume that Big Sandy 1 retired 1/2015
- o In all cases, effectively assumes replacement capacity & energy for BS1 would be 'delayed' until ~2025 in recognition of a) the (incremental) financing/cost burden to KPCo and its customers; and b) assumed limited (PJM) market availability of reasonably-priced replacement capacity & energy during the interim (~150-300 MW)
- o Evalution economics (all cases) reflect KPCo's 30% share (~195-MW) Purchase Entitlement from affiliate AEG Generating Cos.' 50% Ownership Share of both Rockport Units 1&2
- o "Retirement" options EXCLUDE costs associated w/ socio-economic impacts to the plant staff, supply vendors, or to the overall easten-Kentucky region
- o "G" Revenue Requirements established on a KPCo "stand-alone" (basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)...

  Inclusive of:
  1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM; and
  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

Exhibit SCW-4C

Big Sandy Unit 2 under: "Fleet Transition-No Carbon" Commodity Pricing

Kentucky CPCN Filing Economic Analysis

Capacity Resource Optimization

Resource Plan Summary

Resource Plan Year	'BASE' Option #1 BS2 DFGD Retrofit 6/2016	Option #2 (1) RK Retires 1/2016 with (Brownfield) CC Replacement	Option #3 (1) RK Retires 1/2016 with BS2 CC Repwrng Replacement	Option #4A (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2020	Option #4B (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2025
2011-2013				45 MW- ICAP	45 MW- ICAP
2014				225 MW- ICAP	225 MW- ICAP
2015	Big Sandy 1 Retire	Big Sandy 1&2 Retire	Big Sandy 2 Retire	938 MW- ICAP	938 MW- ICAP
2016	Big Sandy 2 Retrofit	1 -904 MW NGCC	Big Sandy 1 1 -780 MW Repower,	922 MW- ICAP	922 MW- ICAP
2017				930 MW- ICAP	930 MW- ICAP
2018				934 MW- ICAP	934 MW- ICAP
2019				1 -904 MW NGCC	938 MW- ICAP
2020					939 MW- ICAP
2021					951 MW- ICAP
2022					957 MW- ICAP
2023					967 MW- ICAP
2024					1 -904 MW NGCC, 1- 407 MW CC
2025	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	
2026					
~					
2040					
Life-Cycle Analysis Period (2011-2040)					
($000)					
CPW of Revenue Requirements	6,296,457	6,809,054	6,734,818	6,473,342	6,146,215
Less: ICAP Revenue	(115,572)	82,264	(11,440)	(104,198)	(312,943)
CPW of Revenue Requirements, Net	6,412,030	6,726,790	6,746,259	6,577,540	6,459,157
A. Cost/(Savings) Over 'BASE' Case					
CPW of Revenue Requirements		512,597	438,361	176,885	(150,242)
Less: ICAP / Pool Revenue		197,837	104,132	11,375	(197,370)
CPW of Revenue Requirements, Net		314,760	334,229	165,510	47,128
B. Cost/(Savings) Over 'BASE' Case					
Impact of 20-Year (vs. 15-Year)					
RETROFIT Cost Recovery		37,200	37,200	37,200	37,200
CPW of Revenue Requirements, Net		351,960	371,429	202,710	84,328

Note:

- o The 'BASE' / Option 1 (Big Sandy 2 RETROFIT) analysis results assumes a **15-year recovery period** for the incremental DFGD retrofit investment
- o Option #2 (Big Sandy 2 RETIRED & REPLACED w/ a [BS-site 'Brownfield'] CC) assumes a 30-year recovery period for the new-build CCs in all analyses
- o Option #3 (Big Sandy 2 RETIRED & REPLACED w/ a CC-Repowered Big Sandy U1) assumes a 20-year recovery period in all analyses
- o All cases (except Option #3) assume that Big Sandy 1 retired 1/2015
- o In all cases, effectively assumes replacement capacity & energy for BS1 would be 'delayed' until ~2025 in recognition of a) the (incremental) financing/cost burden to KPCo and its customers; and b) assumed limited (PJM) market availability of reasonably-priced replacement capacity & energy during the interim (~150-300 MW)
- o Evalution economics (all cases) reflect KPCo's 30% share (~195-MW) Purchase Entitlement from affiliate AEG Generating Cos.' 50% Ownership Share of both Rockport Units 1&2
- o "Retirement" options EXCLUDE costs associated w/ socio-economic impacts to the plant staff, supply vendors, or to the overall easten-Kentucky region
- o "G" Revenue Requirements established on a KPCo "stand-alone" (basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)...

  Inclusive of:

  1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO_2); 2) on-going plant FOM; and

  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

Exhibit SCW-4D

Big Sandy Unit 2 under: "Fleet Transition-Early Carbon" Commodity Pricing

Kentucky CPCN Filing Economic Analysis

Capacity Resource Optimization

Resource Plan Summary

Resource Plan Year	'BASE' Option #1 BS2 DFGD Retrofit 6/2016	Option #2 (1) RK Retires 1/2016 with (Brownfield) CC Replacement	Option #3 (1) RK Retires 1/2016 with BS2 CC Repwrng Replacement	Option #4A (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2020	Option #4B (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2025
2011-2013				45 MW- ICAP	45 MW- ICAP
2014				225 MW- ICAP	225 MW- ICAP
2015	Big Sandy 1 Retire	Big Sandy 1&2 Retire	Big Sandy 2 Retire	938 MW- ICAP	938 MW- ICAP
2016	Big Sandy 2 Retrofit	1 -904 MW NGCC	Big Sandy 1 1 -780 MW Repower,		
2017				922 MW- ICAP	922 MW- ICAP
2018				930 MW- ICAP	930 MW- ICAP
2019				934 MW- ICAP	934 MW- ICAP
2020				1 -904 MW NGCC	938 MW- ICAP
2021					939 MW- ICAP
2022					951 MW- ICAP
2023					957 MW- ICAP
2024					967 MW- ICAP
2025	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1 -904 MW NGCC, 1- 407 MW CC
2026					
~					
2040					
Life-Cycle Analysis Period (2011-2040) ($000)					
CPW of Revenue Requirements	7,096,011	7,461,072	7,386,922	7,127,793	6,803,200
Less: ICAP Revenue	(111,660)	72,971	(11,072)	(100,168)	(289,247)
CPW of Revenue Requirements, Net	7,207,670	7,388,101	7,397,994	7,227,961	7,092,447
A. Cost/(Savings) Over 'BASE' Case					
CPW of Revenue Requirements		365,062	290,912	31,782	(292,810)
Less: ICAP / Pool Revenue		184,631	100,588	11,491	(177,587)
CPW of Revenue Requirements, Net		180,431	190,324	20,291	(115,223)
B. Cost/(Savings) Over 'BASE' Case					
Impact of 20-Year (vs. 15-Year) RETROFIT Cost Recovery		37,200	37,200	37,200	37,200
CPW of Revenue Requirements, Net		217,631	227,524	57,491	(78,023)

Note:
- o The 'BASE' / Option 1 (Big Sandy 2 RETROFIT) analysis results assumes a **15-year recovery period** for the incremental DFGD retrofit investment
- o Option #2 (Big Sandy 2 RETIRED & REPLACED w/ a [BS-site 'Brownfield'] CC) assumes a 30-year recovery period for the new-build CCs in all analyses
- o Option #3 (Big Sandy 2 RETIRED & REPLACED w/ a CC-Repowered Big Sandy U1) assumes a 20-year recovery period in all analyses
- o All cases (except Option #3) assume that Big Sandy 1 retired 1/2015
- o In all cases, effectively assumes replacement capacity & energy for BS1 would be 'delayed' until ~2025 in recognition of a) the (incremental) financing/cost burden to KPCo and its customers; and b) assumed limited (PJM) market availability of reasonably-priced replacement capacity & energy during the interim (~150-300 MW)
- o Evalution economics (all cases) reflect KPCo's 30% share (~195-MW) Purchase Entitlement from affiliate AEG Generating Cos.' 50% Ownership Share of both Rockport Units 1&2
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- o "G" Revenue Requirements established on a KPCo "stand-alone" (basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)...

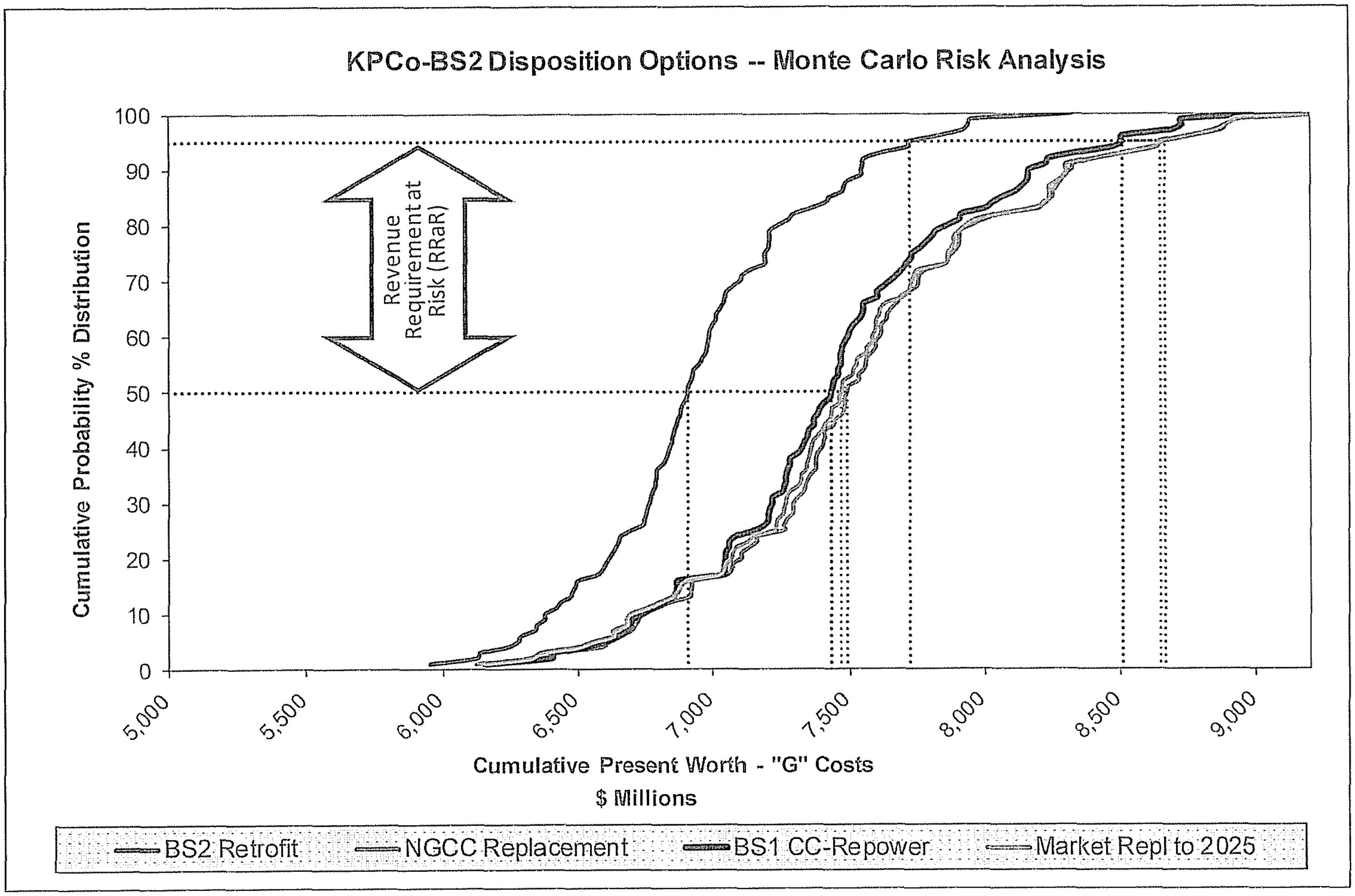
  Inclusive of:

  1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM; and

  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

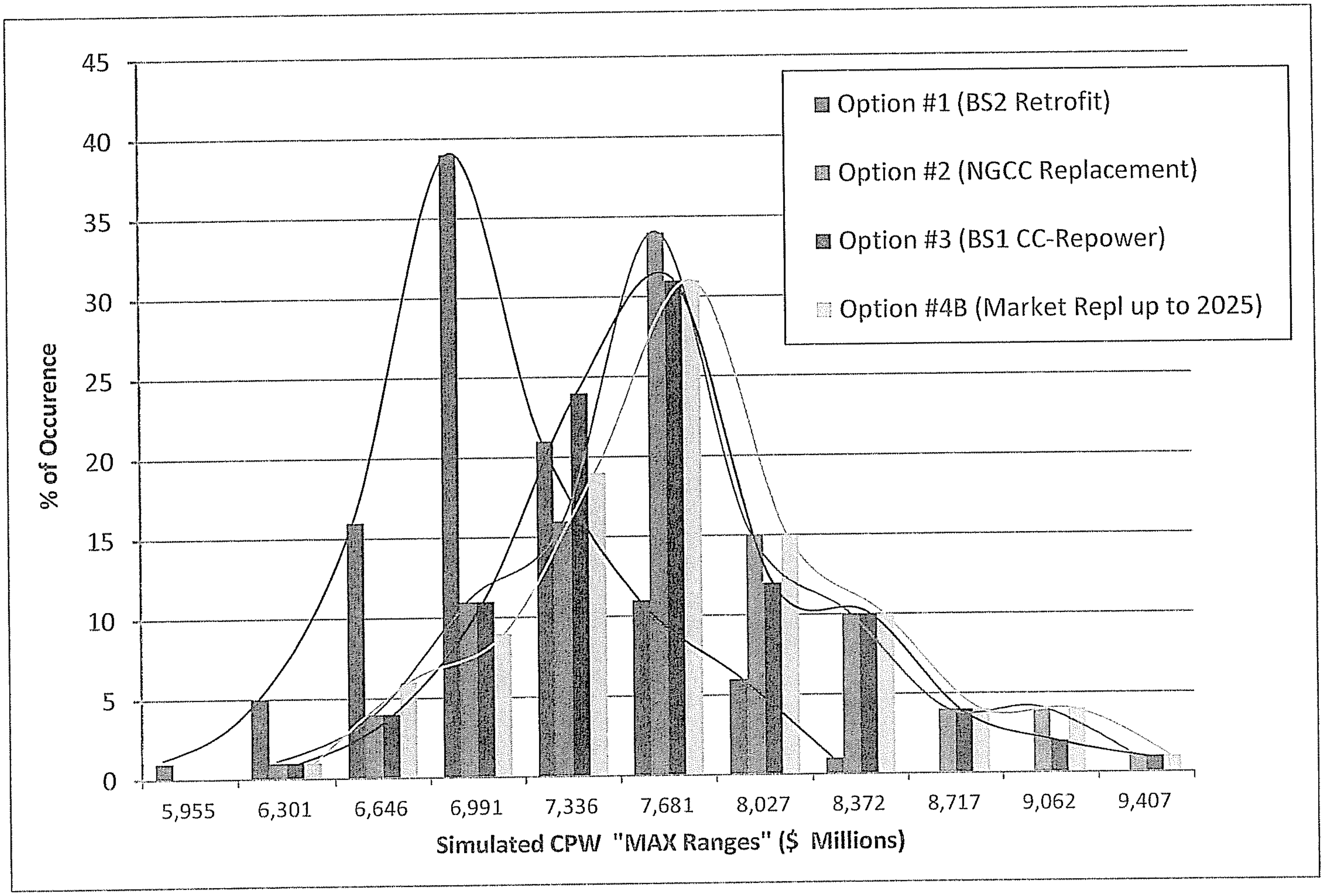
Exhibit SCW-4E

Figure 5-1



		Option #1	*Option #2*	*Option #3*	*Option #4B*			
CPW ($000)	*Cumul. Distribution Percentile*	BS2 Retrofit	NGCC Replacement	BS1 CC-Repower	Market Repl to 2025	*Delta* Retrofit - NGCC	*Delta* Retrofit - Repower	*Delta* Retrofit - Mkt to 2025
	50	6,907,015	7,492,590	7,433,656	7,469,125	(585,575) *-8.5%*	(526,641) *-7.6%*	(562,110) *-8.1%*
	95	7,722,158	8,666,036	8,508,691	8,647,851	(943,877) *-12.2%*	(786,532) *-10.2%*	(925,693) *-12.0%*
Relative Rank:	*CPW*	1	4	2	3			
RRaR ($000)								
	95th vs. 50th	815,143	1,173,446	1,075,034	1,178,726	(358,303) *-44.0%*	(259,891) *-31.9%*	(363,583) *-44.6%*
Relative Rank:	*RRaR*	1	3	2	4			

Figure 5-2


Option #1 (BS2 Retrofit)
Option #2 (NGCC Replacement)
Option #3 (BS1 CC-Repower)
Option #4B (Market Repl up to 2025)
% of Occurence
45
40
35
30
25
20
15
10
5
0
5,955
6,301
6,646
6,991
7,336
7,681
8,027
8,372
8,717
9,062
9,407
Simulated CPW "MAX Ranges" ($ Millions)

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY	)	
FOR APPROVAL OF ITS 2011 ENVIRONMENTAL	)	
COMPLIANCE PLAN, FOR APPROVAL OF ITS	)	
AMENDED ENVIRONMENTAL COST RECOVERY	)	Case No. 2011-00401
SURCHARGE TARIFF, AND FOR THE GRANT OF A	)	
CERTIFICATE OF PUBLIC CONVENIENCE AND	)	
NECESSITY FOR THE CONSTRUCTION AND	)	
ACQUISITION OF RELATED FACILITIES	)	

DIRECT TESTIMONY

OF

RANIE K. WOHNHAS

DIRECT TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2011-00401

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**DIRECT TESTIMONY OF
RANIE K. WOHNHAS, 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 Ranie K. Wohnhas. My position is Managing Director, Regulatory and Finance, Kentucky Power Company (Kentucky Power, KPCo or Company). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

II. BACKGROUND

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A: I earned a Bachelor of Science degree with a major in accounting from Franklin University, Columbus, Ohio in December 1981. I began work with Columbus Southern Power in 1978 working in various customer services and accounting positions. In 1983, I transferred to Kentucky Power Company working in accounting, rates and customer services. I became the Billing and Collections Manager in 1995 overseeing all billing and collection activity for the Company. In 1998, I transferred to Appalachian Power Company working in rates. In 2001, I transferred to the AEP Service Corporation (AEPSC) working as a Senior Rate Consultant. In July 2004, I assumed the position of Manager, Business Operations Support with KPCo and was promoted to Director in April 2006. I was promoted to my current position as Managing Director, Regulatory and Finance effective September 1, 2010.

Q: **WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR, REGULATORY AND FINANCE?**

A: I am primarily responsible for managing the regulatory and financial strategy for KPCo. This includes planning and executing rate filings for both federal and state regulatory agencies and certificate of public convenience and necessity filings before this Commission. I am also responsible for managing the Company's financial operating plans including various capital and O&M operational budgets which interface with all other AEP organizations impacting KPCo performance. As part of the financial strategy, I work with various AEPSC departments to ensure that adequate resources such as debt, equity and cash are available to build, operate and maintain the KPCo electric system assets providing service to our retail and wholesale customers.

Q: **HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

A: Yes. I have testified before this Commission in various fuel proceedings and the last two base rate case filings (Case Nos. 2005-00341 and 2009-00459). I am also testifying in our current filing for public utility status for Kentucky Transco (Case No. 2011-00042), and in support of the Company's application for a certificate of public convenience and necessity to construct the proposed Bonnyman-Soft Shell 138 kV transmission line and related facilities (Case No. 2011-00295).

III. PURPOSE OF TESTIMONY

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: The purpose of my testimony is to provide an overview of KPCo's request for a certificate of public convenience and necessity (CPCN) to install the necessary environmental control equipment on Big Sandy Unit 2 ("the Plant") as required by final and proposed environmental regulations, and its inclusion as part of the Company's 2011 Environmental Compliance Plan and Environmental Cost Recovery mechanism. Also, I will be addressing the recovery of approximately $15.2 million of costs incurred and currently recorded in account 183 for a Phase I feasibility analyses for a flue-gas desulfurization (FGD) system on Big Sandy Unit 2 as part of the Company's on-going efforts to meet Federal Clean Air Act and related requirements. That feasibility analysis began in the third Quarter of 2004 and was suspended in the second Quarter of 2006. Lastly, I will address the accounting treatment of a fifteen year depreciation life recovery for the FGD and treatment of emission allowances.

Q: PLEASE IDENTIFY THE OTHER WITNESSES TESTIFYING IN SUPPORT OF KPCO'S APPLICATION IN THIS PROCEEDING?

A: The other witnesses testifying on behalf of KPCo are:

Witness	Title	Testimony Support
John M. McManus	Vice President – Environmental Services	Environmental Laws and Regulations
Scott C. Weaver	Managing Director – Resource Planning & Operational Analysis	Economic Evaluation of Resource Alternatives
Robert L. Walton	Managing Director – Projects & Controls	FGD Technology and Project Cost Estimates

Lila P. Munsey	Manager, Regulatory Services	Environmental Cost Recovery

IV. ADDITIONAL ENVIRONMENTAL CONTROLS TO BE INCLUDED IN THE 2011 ENVIRONMENTAL COMPLIANCE PLAN

Q: WHAT SPECIFIC ENVIRONMENTAL CONTROL FACILITIES IS KPCO SEEKING AUTHORITY TO INSTALL AT KPCO'S BIG SANDY UNIT 2?

A: The Company is requesting permission to install a dry flue gas desulfurization (DFGD) system that includes an ash haul road and landfill. These are described in more detail in the testimony of Witness Robert L. Walton.

Q: ARE THERE OTHER ENVIRONMENTAL PROJECTS THAT KPCO IS REQUESTING TO ADD TO ITS EXISTING ENVIRONMENTAL COMPLIANCE PLAN SO AS TO RECOVER THE COSTS ASSOCIATED WITH THROUGH ITS ENVIRONMENTAL SURCHARGE?

A: Yes. We are requesting approval to include four projects from Ohio Power's Amos plants and one project each from Indiana & Michigan's Rockport and Tanners Creek plants in KPCo's 2011 Environmental Compliance Plan. The need for these projects is explained in the testimony of Witness John M. McManus. The recovery of their associated costs is discussed in the testimony and exhibits of Witness Lila P. Munsey.

V. FLUE GAS DESULFURIZATION UNIT (FGD) AND OTHER MODIFICATIONS TO BIG SANDY UNIT 2

1. BIG SANDY UNIT 2 FGD

Q: WHY DOES BIG SANDY UNIT 2 REQUIRE A FGD UNIT?

A: Witness McManus details in his testimony the final and proposed environmental requirements affecting the continued operation of KPCo's Big Sandy Unit 2. The need to address these environmental issues and time frames for their implementation led the Company to analyze multiple alternatives as discussed by Witness Scott C. Weaver. After reviewing these alternatives, the Company selected the DFGD as the most cost-effective means of complying with the Federal Clean Air Act as amended and those federal, state, and local environmental requirements which apply to coal combustion wastes and by-products in connection with its operation of Big Sandy Unit 2, particularly in light of the short compliance time.

Q: WHAT TECHNOLOGY WAS CHOSEN FOR THE FGD AT BIG SANDY UNIT 2?

A: As discussed in Witness Walton's testimony, the Company chose a DFGD technology that provides the ability to burn coal that has a sulfur content of up to 4.5 lbs SO_2/MMBtu.

Q: WERE OTHER ALTERNATIVES TO THE FGD UNIT CONSIDERED?

A: Yes. The Company evaluated two different combined cycle gas alternatives and a "market-purchase" alternative. Witness Weaver explains these alternatives in detail in his direct testimony.

Q: **WHY WERE THESE ALTERNATIVES NOT CHOSEN?**

A: As explained in detail by Witness Weaver, the DFGD was the least cost compared to the two combined cycle gas alternatives and the "market-purchase" alternatives.

Q: **WHAT OTHER FACTORS WERE CONSIDERED BY THE COMPANY IN DECIDING TO INSTALL A FGD UNIT AT BIG SANDY UNIT 2?**

A: Although not outcome determinative, the Company believes socio-economic factors also favor its choice. In addition, KPCo also considered the General Assembly's policy of fostering and encouraging the use of Kentucky coal by electric utilities serving the Commonwealth in weighing the gas and market purchase options.

Q: **WHAT WERE THOSE SOCIO-ECONOMIC FACTORS?**

A: Retiring Big Sandy Unit 2 and replacing it with a gas unit would have cost approximately 86 jobs and $6.0 million in annual compensation. Of course, the market purchase option would have had an even greater deleterious effect. In addition, the Company calculated that the gas option would have reduced payroll and property taxes respectively by $3.2 million and $461,000 annually. With market prices at $75 per ton, coal sales to Big Sandy Plant inject approximately $165 million per year into the local economy which would be eliminated along with the indirect impact on mining and transportation (500 jobs, $8 million in severance taxes, and $25 million in wages per year) of the gas options.

Q: **WAS THE COMPANY'S FINAL DECISION BASED UPON THESE SOCIO-ECONOMIC ITEMS?**

A: No. The DFGD alternative was the clear economic low cost winner with the least risk. But the socio-economic effects informed and reinforced that decision.

Q: PLEASE RECONCILE THE COMPANY'S CURRENT PROPOSAL TO RETROFIT BIG SANDY UNIT 2 WITH A FGD UNIT WITH ITS JUNE 9, 2011 ANNOUNCEMENT THAT IT INTENDED TO RETIRE BIG SANDY UNITS 1 AND 2 AND REPOWER BIG SANDY UNIT 1 AS A COMBINED CYCLE GAS UNIT.

A: Those plans were based upon a preliminary analysis that indicated repowering of Big Sandy Unit 1 would be the least cost alternative. Subsequently, and as explained by Witness Walton, a more robust and detailed analysis was performed on the four alternatives. That completed analysis revealed that contrary to the preliminary review, the low cost alternative is installation of a DFGD on Big Sandy Unit 2.

2. ***BIG SANDY UNIT 2 BOILER MODIFICATIONS***

Q: ARE THERE OTHER MODIFICATIONS PLANNED FOR BIG SANDY UNIT 2 IN CONNECTION WITH THE INSTALLATION OF THE DFGD UNIT?

A: Yes. KPCo plans to modify the Big Sandy Unit 2 boiler to permit the burning of coal with sulfur content of up to 4.5 pounds per MM/Btu.

Q: WHY DOES THE COMPANY SEEK TO BURN COAL WITH A SULFUR CONTENT OF UP TO 4.5 LBS SO_2/MMBTU?

A: The addition of FGD equipment and subsequent boiler modifications to permit the consumption of coal having a sulfur content of up to 4.5 lbs SO_2/MMBtu will allow for greater flexibility by blending the various fuel that can be consumed at the Plant. The current environmental permits, as well as other physical limitations of the boiler, limit the Plant's possible fuel options to consuming only Central Appalachian (CAPP) low sulfur coal. With the installation of the proposed FGD equipment and the corresponding boiler modifications, the Plant will be able to consume coal containing higher amounts of sulfur, thereby allowing the Plant to broaden its sources of coal. More specifically, the proposed facilities will allow the Plant both to continue to consume coal from the CAPP region, and will expand its fuel options to include other potentially lower cost coals.

Q: **DID THE COMPANY CONSIDER OTHER BOILER MODIFICATION OPTIONS?**

A: Yes. Two possible FGD installations and corresponding boiler modifications were considered, one permitting coals having a sulfur dioxide content of up to 3.0 lbs. SO_2/MMBtu and the other permitting coals having a sulfur dioxide content of up to 4.5 lbs. SO_2/MMBtu. While the 3.0 lbs. SO_2/MMBtu option provides some additional fuel purchase flexibility, the blend of either Northern Appalachian (NAPP) or Illinois Basin (ILB) coal would most likely be limited to no greater than 30% with the remainder of the coal being from the CAPP region. The 4.5 lbs. SO_2/MMBtu FGD and boiler modification being proposed would easily allow a 50/50 blend of either NAPP or ILB coals to be blended with CAPP coals, thus providing a lower overall cost of fuel. Such blending has the potential to save approximately eight percent on the cost of fuel annually. Without the proposed

FGD and boiler modifications the KPCO's customers would be subject to price fluctuations of the highly stressed CAPP market.

Q: **WHAT WOULD BE THE CONSEQUENCES OF NOT MODIFYING THE BOILER?**

A: Not modifying the boiler would limit the plant's fuel flexibility. To capture the full potential of the FGD the proposed boiler modifications to permit the burning of 4.5 lbs. SO_2/MMBtu FGD are necessary.

3. TIMING OF THIS APPLICATION

Q: **ALTHOUGH CERTAIN OF THE ENVIRONMENTAL REQUIREMENTS DRIVING THIS APPLICATION HAVE ONLY RECENTLY BECOME FINAL, OR EVEN BEEN PROPOSED, KENTUCKY POWER HAS BEEN AWARE OF EVOLVING ENVIRONMENTAL STANDARDS FOR A NUMBER OF YEARS. WHY DID THE COMPANY NOT TAKE ACTION EARLIER?**

A: It did. As highlighted below and discussed in greater detail by Witness Walton, KPCo began its preliminary investigation into installing a FGD unit at Big Sandy 2 as early as 2004. That work was suspended in 2006 because of increases in the estimated cost of the wet FGD system then being investigated, and a decrease in the price spread between low and higher sulfur coal. The Company restarted conceptual and analytical work in support of a CPCN filing in the first quarter of 2010 in light of the changing environmental requirements and the purported abundance of shale gas and new DFGD technology.

Q: HOW DOES THE COMPANY PROPOSE TO RECOVER THE COSTS OF THE FGD?

A: The Company is requesting as part of this application recovery of the FGD costs through our environmental cost recovery mechanism as supported by the testimony of Witness Munsey.

VI. NOTICE OF TERMINATION OF THE POOL AGREEMENT

Q. DO CERTAIN OF THE COSTS ASSOCIATED WITH THE NON-BIG SANDY 2 PROJECTS THAT ARE BEING ADDED TO KENTUCKY POWER'S ENVIRONMENTAL FLOW TO KENTUCKY POWER THROUGH THE AEP INTERCONNECTION (POOL) AGREEMENT?

A. Yes. All of the costs associated with Amos Plant and Tanner Creek Plant projects flow to Kentucky Power through the Pool Agreement. In addition, a portion of the costs associated with the Rockport Plant flow to Kentucky Power through the Pool Agreement. The remainder of the Rockport costs flow through the Rockport Unit Power Agreement.

Q: DID PARTIES TO THE AEP POOL AGREEMENT SERVE NOTICE TO EACH OTHER OF THEIR INTENT TO TERMINATE THIS AGREEMENT EFFECTIVE NO LATER THAN JANUARY 1, 2014?

A: Yes, but it is not known now what sort of agreement, if any, may replace it.

Q: IF THE POOL AGREEMENT IS BEING TERMINATED, WHY SHOULD THIS COMMISSION APPROVE COST RECOVERY OF ANY

ENVIRONMENTAL PROJECT ON GENERATING UNITS FROM SURPLUS COMPANIES?

A: The Pool Agreement will be in effect at the time of the Commission's order in this proceeding. All costs that flow through the Pool Agreement should continue to be recoverable. The Company recognizes its obligation to amend its Environmental Plan and associated tariff to reflect any changes to the Pool Agreement.

VII. PRELIMINARY INVESTIGATION COSTS

Q: **ARE THERE OTHER COSTS BESIDES THE CURRENT FGD AND OTHER ENVIRIONMENTAL PROJECTS THAT THE COMPANY IS SEEKING TO RECOVER?**

A: Yes. During the period April 2004 through April 2006 the Company accumulated $15.2M in account 1070001 in connection with a preliminary investigation of a Big Sandy Unit 2 FGD and landfill. When this work was suspended, these costs were transferred from Account 1070001 (Construction Work in Progress) to Account 1830000 (Preliminary Survey and Investigation). With the project being restarted, the Company plans to transfer the funds back into account 1070001.

Q: **WHY SHOULD THE COMMISSION ALLOW RECOVERY OF THESE COSTS WHEN THE CURRENT PLANS ARE FOR A DIFFERENT TYPE FGD TECHNOLOGY?**

A: The costs incurred in 2004-2006, like the costs incurred to date, were reasonable and prudent efforts to address the then existing environmental requirements in connection with the continued operation of Big Sandy Unit 2. The suspension of the original project and subsequent events allowed for new, even more effective technology to be developed, while allowing KPCo to install a system that will meet the heightened requirements of the recent environmental rule-making. The Company acted reasonably and prudently in beginning and suspending the 2004-2006 analysis and as such these cost should be recoverable as part of the total cost for the installation of the DFGD at Big Sandy Unit 2.

VIII. DEPRECIATION

Q: IS THERE ANY OTHER ACCOUNTING ISSUES BEING PROPOSED WITH THIS FILING?

A: Yes. The Company proposes to depreciate the cost of the FGD over a 15-year period.

Q: PLEASE EXPLAIN THE COMPANY'S ACCOUNTING FOR DEPRECIATION EXPENSE FOR THE FGD AT BIG SANDY UNIT 2.

A: Depreciation expense will be recorded by charging Account 403, Depreciation Expense, and crediting Account 108, Accumulated Provision for Depreciation of Electric Plant. This specific asset will be assigned a project which will permit the depreciation to be tracked directly to the FGD asset.

Q: WHY IS THE COMPANY SEEKING TO DEPRECIATE THE FGD AT BIG SANDY UNIT 2 OVER 15 YEARS?

A: Though the installation of a FGD at Big Sandy Unit 2 will allow it to operate under currently promulgated and proposed EPA rules, the effect of future environmental regulations, particularly carbon legislation, is uncertain. Because of this uncertainty, the Company believes that reducing the period over which the investment will be depreciated will reduce risk of stranded investment should future increased EPA standards cause operation of this unit not to be economically feasible in the future.

IX. EMISSION ALLOWANCES

Q. HOW ARE THE EMISSION ALLOWANCES ACCOUNTED FOR BY KPCO?

A. Emission allowances are accounted for differently for compliance and accounting purposes. For compliance purposes, allowances are held and the allowances are surrendered to match consumption. From an accounting perspective, emission allowances are kept on the company's books at an average inventory cost of the allowances held. For instance, when Cross-State Air Pollution Rule (CSAPR) emission allowances are allocated by the EPA, they are done so at zero cost. As such, using these allowances for consumption would result in zero dollars in emission expense. However, if KPCo purchases allowances to meet its emission obligation, then (subsequent to purchase) each allowance held will be valued at the average cost of all allowances held in inventory including those allocated and purchased.

Q. DOES KPCO PLAN TO ACCOUNT FOR CSAPR ALLOWANCES DIFFERENTLY THAN THOSE ALLOWANCES ASSOCIATED WITH PRIOR ENVIRONMENTAL REGULATIONS?

A. No. KPCo has been accounting for, and recovering costs associated with, Title IV SO_2 allowances under the Clean Air Act (CAA) as well as SO_2 and NO_x allowances under the Clean Air Interstate Rule (CAIR), over the lives of those rules. While CSAPR emission allowances will be held in different sub-accounts to differentiate between them and the allowances created under other regulations in accordance with FERC Uniform System of Accounts, the allowances themselves will be subject to the same accounting procedures regarding value, gains and losses, and surrender, as the allowances under the other regulations. KPCo also is proposing to recover the CSAPR emission allowances costs in the same manner as other environmental regulations, which is through the Environmental Surcharge.

Q. **IS IT REASONABLE FOR KPCO TO RECOVER ITS PRUDENTLY INCURRED COSTS ASSOCIATED WITH CSAPR EMISSIONS ALLOWANCES?**

A. Yes. The CSAPR is, in part, a replacement for the CAIR, and KPCo is proposing to recover the cost of emission allowances under the CSAPR just as it has previously done under Title IV of the CAA and the CAIR. Other than the fact that the allowances were created under a different rulemaking, there is no difference in the rationale for recovery of the costs associated with emission allowances.

Q. **WHAT IS THE MAGNITUDE OF THE COSTS THAT KPCO IS EXPECTING TO INCUR FOR EMISSION ALLOWANCES UNDER THE CSAPR?**

A. For 2012, the Company has forecasted it will consume $6.2 million in CSAPR emission allowances. Aside from the forecasted expense, KPCo is also currently forecasting to have a gain of $650,000 in 2012 associated with the sale of annual NO_x allowances under the CSAPR.

Q. WHAT DETERMINES THE PRICE OF ALLOWANCES UNDER CSAPR IF THEY ARE ALLOCATED AT ZERO COST?

A. The price of an allowance under the CSAPR is determined by the market that develops for the allowances. The market price is determined by the cost at which companies are willing to sell their excess allowances, versus the cost that companies are willing to pay to earn the right to increase emissions.

Q. IS THERE A GUARANTEE THAT THERE WILL BE A ROBUST MARKET FOR CSAPR ALLOWANCES?

A. No. While the intent of the USEPA, as highlighted through technical updates made to the CSAPR in October 2011, is to have a developed and fluid market where allowances are readily available, it is possible that the market will not develop in such a fashion.

X. RETURN ON EQUITY

Q. WHAT RETURN ON EQUITY IS KENTUCKY POWER PROPOSING FOR USE IN CONNECTION WITH THE COMPANY'S ENVIRONMENTAL FACILITIES?

A. The Company proposes to use a 10.5% return on equity.

Q. WHAT IS THE BASIS FOR THAT RECOMMENDATION?

A. In the "Unanimous Settlement Agreement" that was approved by the Commission by its Order dated June 28, 2010 in Case No. 2009-00459, the parties agreed that "[f]or purposes of the Tariff E.S., and for accounting for allowance for funds used during construction (AFUDC), Kentucky Power shall be entitled to use a 10.5% rate of return on equity." The parties to the "Unanimous Settlement Agreement" further specified a return on equity of 10.5% for purposes of the rate increase approved by the Commission by the same. In addition, a 10.5% return on equity is reasonable, and that rates resulting from the use of that return on equity in connection with Tariff E.S. are fair, just and reasonable.

XI. 2011 ENVIRONMENTAL COMPLIANCE PLAN AND RELATED MATTERS

Q. HAS THE COMPANY PREPARED A 2011 ENVIRONMENTAL COMPLIANCE PLAN FOR USE IN RECOVERING ITS COSTS ASSOCIATED COMPLYING WITH APPLICABLE ENVIRONMENTAL REQUIREMENTS?

A. Yes. It is attached as Exhibit 3 to the Application. Witness McManus explains the environmental requirements associated with each project.

Q. IN HER TESTIMONY, MS. MUNSEY INDICATES THAT THE IMPACT ON KPCO'S ELECTRIC CUSTOMERS IS ESTIMATED TO BE A 0.20% INCREASE IN 2012 WITH A MAXIMUM INCREASE OF 31.41% IN 2016. IS THE COMPANY WILLING TO DISCUSS A MORE GRADUAL PHASE-IN OF THE INCREASE OVER THE SAME PERIOD?

A. Yes.

XII. CONCLUSION

Q: PLEASE SUMMARIZE YOUR TESTIMONY.

A: The Company has prudently examined all options to comply with the various proposed and promulgated environmental rules that affect the Company's Big Sandy Unit 2. The detailed modeling conducted to evaluate the alternatives indicates the DFGD technology is the least cost/ least risk solution. Finally, the costs identified for Kentucky Power's 2011 Environmental Compliance Plan are reasonable and cost-effective for complying the environmental requirements specified in KRS 278.183.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

VERIFICATION

The undersigned, Ranie K. Wohnhas being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Ranie K. Wohnhas

RANIE K. WOHNHAS

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by, Ranie K. Wohnhas, this the 30th day of November, 2011.

Judy K. Rosquist

Notary Public

My Commission Expires: January 23, 2013

CASE NO: 2011-00401

CONTAINS

LARGE OR OVERSIZED

MAP(S)

RECEIVED ON: December 5, 2011