STITES & HARBISON PLLC
ATTORNEYS

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AUG 22 2014
PUBLIC SERVICE
COMMISSION

421 West Main Street
Frankfort, KY 40601
[502] 223-3477
[502] 223-4124 Fax

August 22, 2014

Mark R. Overstreet
(502) 209-1219
(502) 223-4387 FAX
moverstreet@stites.com

HAND DELIVERED

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AUG 22 2014
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. 2014-00210

Dear Mr. Derouen:

Enclosed please find and accept for filing the original and ten copies of Kentucky Power Company's response to the Attorney General's August 15, 2014 data request.

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

Very truly yours,

Mark R. Overstreet

MRO
Jennifer B. Hans

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AUG 22 2014

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

KENTUCKY PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF KENTUCKY POWER COMPANY	**)**
FOR AUTHORITY PURSUANT TO KRS 278.300 TO ISSUE	**)**
AND SELL PROMISSORY NOTES OF ONE OR MORE	**) CASE NO. 2014-00210**
SERIES, AND FOR OTHER AUTHORIZATIONS	**)**

KENTUCKY POWER COMPANY'S RESPONSE TO ATTORNEY GENERAL'S FIRST SET OF DATA REQUESTS

August 22, 2014

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that 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. 2014-00210
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 21st day of August 2014.

Judy K. Rosquist 481393

Notary Public

My Commission Expires: January 23, 2017

Kentucky Power Company

REQUEST

Reference Kentucky Power's Response to Commission Staff's ("PSC") 1-1, Attachment 1. Please confirm that the $312.5 million in projected capital spending for the projects listed constitutes Kentucky Power's allocated costs and sole responsibility, and does not include any allocation as to the Mitchell generating station that may be shared with any other AEP-affiliated company.

a. As an addendum to Attachment 1, please provide the total "all-in" costs for all of the capital projects for which an allocation or sharing mechanism is in place for Kentucky Power.

b. Please provide Attachment 1 in response to PSC 1-1 and the addendum requested in response to 1a. above in electronic format with data including formulae in all cells and rows intact and fully accessible.

RESPONSE

The $312.5 million of projected capital expenditures for the period 2014-2016 does not include any expenditures for AEP Generation Resources 50% share of the Mitchell generation asset.

a - b. Please see the enclosed CD for KPSC 1-1 Attachment 1 and the requested addendum, AG 1-1 Attachment 1, in electronic format.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Reference Kentucky Power's Response to PSC 1-1, Attachment 1, where under "Environmental Generation" a sub-category is identified as "Other Environmental Projects." Do any of the capital projects in 2014 through 2016 relate in any way to the costs identified, planned or otherwise expended relating to Kentucky Power's proposal in Case No. 2011-00401 to retrofit the Big Sandy Unit 2 with scrubbers and related environmental controls? Please provide any and all documentation to support your response.

RESPONSE

No.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Were any of the capital expenditures planned for the Mitchell generating station in calendar year 2014 factored into the net book value of $536 million for which Kentucky Power paid a fifty percent (50%) interest in the facility?

a. If yes, please identify in detail the planned 2014 expenditures that were considered in assessing the value of Mitchell.

RESPONSE

No. The net book value was determined upon the closing of the transaction at midnight 12/31/13. Therefore, any expenditures in 2014 and beyond would not be a part of that net book value calculation.

a. N/A.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Reference Kentucky Power's Response to PSC 1-1, Attachment 1, where under "Environmental Generation" three (3) sub-categories are "Mitchell New Landfill," "Mitchell U1&U2 Dry Fly Ash Conversion," and "Mitchell New Landfill Haul Road." As to these projects, please respond to the following:

a. Please confirm that the total capital spending for these three (3) projects total $26.2 million.

b. Please confirm that of this total, $20.8 million or approximately 80% of this capital spending is planned for calendar year 2014.

c. Please identify the environmental rulemaking or other requirement for which these specific projects are required for compliance.

d. When did Kentucky Power or any predecessor in interest to the Mitchell generating station plan or otherwise begin the process for this $26.2 million in capital spending relating to Mitchell? Please provide any and all documentation to support your response.

RESPONSE

a. The total projected expenditure of the"Mitchell New Landfill", "Mitchell U1 & U2 Dry Flay Ash Conversion", and "Mitchell new Landfill Haul Road"for the years 2014-2016 is $26.2 million.

b. The projected expenditure for the three projects during 2014 is $20.8 million or 79.3% of the total three-year projected spending on the projects.

c. The Mitchell Plant's Dry Fly Ash conversion, Dry Fly Ash Landfill and Landfill Haul Road construction is to meet requirements of the current National Pollutant Discharge Elimination System water discharge permit. These projects will also position the Mitchell Plant for future compliance with the CCR rulemaking.

d. Ohio Power Company began budgeting for the projects in August 2010 and completed planning in January 2011. The Improvement Requisition (IR) for each project was approved in March 2011 and construction began in March 2012. Please see Attachment 1 to this response for the approval from the Sub-Company Board meeting. Please see Attachment 2 for a copy of the IR's.

WITNESS: Ranie K Wohnhas

AMERICAN ELECTRIC POWER

Date: March 14, 2011

Subject: **Improvement Requisitions Presented To The Subsidiary Boards of Directors**

From: **L. L. Dieck** LLDieck

To: **M. G. Morris**

Below is a summary of all the improvement requisitions to be presented to the Boards of Directors of the AEP System Subsidiary Companies at the scheduled March 22, 2011 meeting.

Capital Requisitions	$ 87,994,000
Lease Requisitions	$ 24,559,000
Total	$ 112,553,000

The attached exhibits include summaries for each company and additional information summaries for all projects of $3 million or greater for Generation, Transmission and AEP Utilities, and all projects of $2 million or greater for Shared Services and Environment, Safety, Health and Facilities.

cc: N. K. Akins
C. L. English
D. M. Miller
D. E. Welch
R. P. Powers
B. D. Radous
B. X. Tierney
S. Tomasky
R.E. Munczinski
P. Chodak
V. McCellon-Allen
C. R. Patton
J. Hamrock
G. G. Pauley
A.W. Smith
J. S. Solomon
M.C. McCullough
A. Vogel

Monthly Report of Improvement Requisitions
Approved for
Ohio Power Company
March 2011

	Number	Date Approved	Approved By	Description		Previously Approved	Amount To Be Authorized	Total
PGM	DP10K0002	03/02/11	Pauley/Hamrock	Distribution: Highland, KY - Highland Station -- Transformer Upgrade - Revision	*	$0	$313,000	$313,000
CI	000019836	03/17/11	Morris	Generation: Mitchell Units 1 and 2 - Conversion to Dry Fly Ash Handling System	*	$0	$46,995,000	$46,995,000
CI	CD110AHOH	03/01/11	McCullough/Hamrock	Generation: Cardinal Unit 1 - Air Heater Baskets	*	$0	$3,176,000	$3,176,000
CI	KMLFALFCI	03/17/11	Morris	Generation: Kammer-Mitchell Plant - New Landfill	*	$0	$8,003,000	$8,003,000
CI	KMLFALFHR	03/17/11	Morris	Generation: Kammer-Mitchell Plant - New Landfill Haul Road		$0	$1,905,000	$1,905,000
CPP	TA2010125	03/01/11	Heyeck/Hamrock	Transmission: Allen County, OH - Line relocations for Ohio DOT I-75 Improvement Project		$0	$614,000	$614,000
CPP	TP2010036	03/01/11	Heyeck/Hamrock	Transmission: Freeport, OH - New 34.5KV Service to Vail Rosebud Mining		$0	$1,226,000	$1,226,000
PGM	CBMTR0811	03/07/11	Hamrock/Tomasky	Transmission: EHV Circuit Breaker/Metering Replacement Program - Revision - Phase 2	*	$3,005,000	$3,538,000	$6,543,000
				Total Ohio Power Company		$3,005,000	$65,770,000	$68,775,000

* See Additional Information

Note: Requested current year amounts are in the approved budget or offsets have been made from other projects. Future year funding will be provided within the Operating Company forecast. Page

AEP

Capital Improvement Approval Requisition

Company: Ohio Power Company

Project ID & Title: KMLFALFCI - Kammer / Mitchell New Long Term CCR Landfill — Version 1

Business Line: Generation

Location: Kammer Mitchell Plant

Business Reason: Environmental, Safety & Health

Brief Descripton: The purpose of this CI is to request funding to complete the Phase 1 engineering and design necessary for the submittal of new landfill PTI permit applications for both the Conner Run (Brownfield) and Gatts Ridge (Greenfield) landfill sites. The Gatts Ridge site is adjacent to the existing Conner Run Impoundment. Both sites are to be pursued simultaneously due to regulatory approval risks associated with the preferred Conner Run site. Regulatory determinations are expected in early 2012 which will determine which site to construct and certify.

Authorization Amount:

	Previously Approved Amount	This Submission	Total Amount to be Authorized
Total	$0	$8,003,030	$8,003,030

Cash Flow:

	Prior Years	2011	2012	Future Years	Total
Capital	$119,691	$5,803,643	$2,079,697	$0	$8,003,031
Removal	$0	$0	$0	$0	$0
Total to be Authorized	$119,691	$5,803,643	$2,079,697	$0	$8,003,031
Associated O&M	$0	$0	$0	$0	$0

Start Date: 2/14/2011 **Completion Date:** 12/31/2016 **In Service Date:** 12/31/2015

Regulatory Cost Recovery: Ohio Power Company - $8.00M (100%), In-service 12/31/15

- $7.44M (93%) OPCo is permitted to seek a return on incremental environmental expenses through 2011 under the 2009 Ohio ESP order. Pursuant to this provision of the ESP, cost incurred through 12/31/11 will be included in an Environmental Investment Carry Cost Rider (EICCR) filing in February 2012. Recovery of these costs will commence on 7/1/12 if approved by the PUCO. Recovery of costs post-2011will be requested through the EICCR extension sought in the 1/27/11 SSO filing with the PUCO, which includes recovery of annually forecasted costs with a true-up mechanism.
- $0.56M (7%) Allocated to WPCo and recovered in current demand charge effective 1/1/10

Approved By: **Approved On:**

Capital Improvement Approval Requisition

Company: Ohio Power Company

Project ID & Title: KMLFALFHR , Kammer / Mitchell New Landfill Haul Road **Version 1**

Business Line: Generation

Location: Kammer Mitchell Plant

Business Reason: Environmental, Safety & Health

Brief Descripton: The purpose of this CI is to request funding to complete the Phase 1 engineering, design, permitting and construction cost estimates for a new haul road to the Conner Run Impoundment and possibly to Gatts Ridge landfill. Plans are underway to convert the Mitchell Plant to a dry fly ash system and the plants CCR's will be transported by truck to the impoundment either for beneficial use by Consol or permanent disposal in the new Conner Run Landfill or Gatts Ridge Landfill. The current access road to the impoundment will not support continuous hauling on a permanent basis due to inadequate design and poor condition.

Authorization Amount:

	Previously Approved Amount	This Submission	Total Amount to be Authorized
Total	$0	$3,047,438	$3,047,438

Cash Flow:

	Prior Years	2011	2012	Future Years	Total
Capital	$0	$686,336	$1,218,356	$0	$1,904,692
Removal	$0	$0	$0	$0	$0
Total to be Authorized	$0	$686,336	$1,218,356	$0	$1,904,692
Associated O&M	$0	$0	$0	$0	$0

Start Date: 2/14/2011 **Completion Date:** 12/31/2015 **In Service Date:** 11/30/2013

Regulatory Cost Recovery: Ohio Power Company - $1.90M (100%), in-service 11/30/13

- $1.77M (93%) OPCo is permitted to seek a return on incremental environmental expenses through 2011 under the 2009 Ohio ESP order. Pursuant to this provision of the ESP, cost incurred through 12/31/11 will be included in an Environmental Investment Carry Cost Rider (EICCR) filing in February 2012. Recovery of these costs will commence on 7/1/12 if approved by the PUCO. Recovery of costs post-2011will be requested through the EICCR extension sought in the 1/27/11 SSO filing with the PUCO, which includes recovery of annually forecasted costs with a true-up mechanism.
- $0.13M (7%) Allocated to WPCo and recovered in current demand charge effective 1/1/10

Approved By: **Approved On:**

Capital Improvement Approval Requisition

Company: Ohio Power Company

Project ID & Title: 19836 - Mitchell Units 1 & 2 - Dry Fly Ash Conversion — Version 1

Business Line: Generation

Location: Mitchell Plant - Moundsville, WV

Business Reason: Environmental, Safety and Health

Brief Descripton: The approval of this requisition will complete Phase 1 (begin detailed engineering/design, permitting, site preparation, foundation installation, long lead procurement) to make improvements to convert Mitchell Unit's 1 & 2 ash handling systems from a wet slurry transport/disposal process to a dry ash handling system. This conversion is required to meet the new National Pollutant Discharge Elimination System (NPDES) selenium limits at the fly ash pond outfall and to assist in providing for long-term disposal needs for Mitchell's fly ash. The total anticipated direct cost of this conversion at completion of all phases is $83,945,000.

Authorization Amount:

	Previously Approved Amount	This Submission	Total Amount to be Authorized
Total	$0	$46,944,652	$46,944,652

Cash Flow:

	Prior Years	2011	2012	Future Years	Total
Capital	$173,066	$3,995,396	$23,870,131	$18,956,059	$46,994,652
Removal	$0	$0	$0	$0	$0
Total to be Authorized	$173,066	$3,995,396	$23,870,131	$18,956,059	$46,994,652
Associated O&M	$0	$0	$0	$0	$0

Start Date: 3/1/2011 **Completion Date:** 2/15/2014 **In Service Date:** 2/15/2014

Regulatory Cost Recovery: Ohio Power Company - $46.99M (100%), in-service 2/15/14
> $43.70M (93%) OPCo is permitted to seek a return on incremental environmental expenses through 2011 under the 2009 Ohio ESP order. Pursuant to this provision of the ESP, cost incurred through 12/31/11 will be included in an Environmental Investment Carry Cost Rider (EICCR) filing in February 2012. Recovery of these costs will commence on 7/1/12 if approved by the PUCO. Recovery of costs post-2011 will be sought through the EICCR extension proposed in the 1/27/11 SSO filing with the PUCO, which would request recovery of annually forecasted costs with a true-up mechanism.
> $3.29M (7%) Allocated to WPCo and recovered in current demand charge effective 1/1/10

Approved By: **Approved On:**

Kentucky Power Company

REQUEST

Reference Kentucky Power's Response to PSC 1-1(b), where it is stated: "The capital projects listed on Attachment 1 requiring a certificate of public convenience and necessity are: (a) the conversion of Big Sandy Unit 1 to natural gas-fired generating unit (Environmental Generation); and (b) the Bonnyman-Soft Shell Transmission line (Transmission Reliability) ... The Mitchell generating station-related projects listed above were approved and in process on December 31, 2013 when Kentucky Power acquired its fifty percent undivided interest in the station." Notwithstanding the Attorney General's pending appeal of the Commission's Order in Case No. 2012-00578, please respond to the following:

a. Please provide a specific citation by page, paragraph and quotation to the Commission's Final Order dated October 7, 2013, in Case No. 2012-00578, upon which Kentucky Power relies for the assertion quoted above.

b. Reconcile your response to 5a. with the Commission's Final Order dated October 7, 2013, in Case No. 2012-00578, at page 39-40, in which it states:

  "The Commission finds that Kentucky Power's request to assume an undivided 50 percent interest in the liabilities associated with the Mitchell acquisition is for lawful objects within the corporate purposes of Kentucky Power, is necessary and appropriate for and consistent with the proper performance by Kentucky Power of its service to the public, will not impair its ability to perform that service, is reasonable, necessary, and appropriate for such purposes, and should be approved. In arriving at this decision, the Commission relied upon the testimony of witnesses for Kentucky Power who indicated that no environmental liabilities are known at this time as a result of environmental retrofits to the Mitchell Station. Additionally, the Commission relied upon Kentucky Power's testimony that because of prior maintenance and upgrades to the Mitchell Station, there are no known liabilities or repairs needed at the current time, and with only normal maintenance the Commission can expect the Mitchell Station to be operational in 2040." (Emphasis supplied.)

c. As to your responses to 5a. and 5b., if Kentucky Power relies on data or information extraneous to the four corners of the Commission's October 7, 2014 Final Order in Case No. 2012-00578, and/or extraneous to those documents and video transcripts which comprise the official record of that case, to support any possible, anticipated, considered or assumed environmental controls for Mitchell that Kentucky Power considered "approved and in process," please state so, identify each such extraneous source, and provide copies of same.

d. As to your responses to 5c., if yes please provide specific citations to the record in Case No. 2012-00578 upon which Kentucky Power relies to base its assertion that the capital expenditures were "approved and in process," and therefore, no CPCN is required.

RESPONSE

a. The excerpt from the Company's response quoted in the data request refers to three distinct types of capital projects: the Bonnyman-Softshell transmission line; the conversion of Big Sandy Unit 1 to a natural gas-fired unit; and certain Mitchell generating station environmental projects. Each project or type of project is addressed separately below:

    (i) <u>Bonnyman-SoftShell 138 kV Line</u>.

The Commission's October 7, 2013 Order in Case No. 2012-00578 does not refer to the Bonnyman-SoftShell project. Nor was there any reason for it to do so because the transmission line was not the subject of the Company's application in Case No. 2012-00578. On January 26, 2012, nearly eleven months before the Company filed its application in Case No. 2012-00578, the Commission issued its order granting the certificate of public convenience and necessity for the Bonnyman-SoftShell line.

The Bonnyman-SoftShell project is a 20-mile 138 kV transmission line in Knott and Perry Counties, Kentucky.

Kentucky Power filed its application for a certificate of public convenience and necessity for the line on September 29, 2011. The proceeding was assigned Case No. 2011-00295.

(ii) Big Sandy Unit 1

Paragraph 13 of the July 2, 2013 Stipulation and Settlement Agreement required Kentucky Power to file an application for a certificate of public convenience and necessity to convert Big Sandy Unit 1 to a natural gas-fired unit. The Commission approved, with four modifications unrelated to the conversion of Big Sandy Unit 1, the July 2, 2013 Stipulation and Settlement Agreement at page 43, paragraph 2 of its October 7, 2013 Order in Case No. 2012-00578. In accordance with its obligations under paragraph 13 of the July 2, 2013 Stipulation and Settlement Agreement, Kentucky Power on December 6, 2013 filed an application for a certificate of public convenience and necessity to convert Big Sandy Unit 1 to a natural gas-fired unit. The application was assigned Case No. 2013-00430. On August 1, 2014, the Commission issued an Order approving the application and granting the certificate of public convenience and necessity.

(iii) Mitchell Generating Station.

Paragraph 1 of the Commission's October 7, 2013 Order in Case No. 2012-00578 approved the transfer of a fifty percent undivided interest in the Mitchell generating station to Kentucky Power Company. The transfer of the fifty percent undivided interest in the Mitchell generating station to Kentucky Power occurred on December 31, 2013. Prior to the transfer, the Mitchell generating station was owned by Ohio Power Company, which is subject to the jurisdiction of the Public Utilities Commission of Ohio. At the time of the December 31, 2013 transfer, each of the Mitchell generating station-related projects identified by the Company in its response to Staff 1-1 was in progress and had received all necessary approvals, if any, under Ohio law. By the express terms of KRS 278.020(1) a certificate of public convenience and necessity from the Public Service Commission of Kentucky is required to "***begin*** the construction of any plant, equipment, property, or facility for furnishing to the public any of the services enumerated under KRS 278.010, except retail electric suppliers for service connections to electric-consuming facilities located within its certified territory and ordinary extensions of existing systems in the usual course of business ...." (emphasis supplied).

None of the identified projects otherwise requiring approval pursuant to KRS 278.020(1) were begun following December 31, 2013. In addition, many of the identified Mitchell generating station projects were not of sufficient magnitude or type so as to require approval under KRS 278.020(1) even if Kentucky Power had owned an interest in the Mitchell generating station at the time the projects were undertaken.

Kentucky Power acknowledges that following the December 31, 2013 transfer to the Company of the undivided interest in the Mitchell generating station the generating station is subject to the jurisdiction of the Public Service Commission of Kentucky and the requirements of KRS 278.020(1) with respect to projects commenced by or on behalf of the Company.

b. "The Commission finds that Kentucky Power's request to assume an undivided 50 percent interest in the liabilities associated with the Mitchell acquisition is for lawful objects within the corporate purposes of Kentucky Power, is necessary and appropriate for and consistent with the proper performance by Kentucky Power of its service to the public, will not impair its ability to perform that service, is reasonable, necessary, and appropriate for such purposes, and should be approved. ***In arriving at this decision, the Commission relied upon the testimony of witnesses for Kentucky Power who indicated that no environmental liabilities are known at this time*** as a result of environmental retrofits to the Mitchell Station. Additionally, the Commission relied upon Kentucky Power's testimony that because of prior maintenance and upgrades to the Mitchell Station, there are no known liabilities or repairs needed at the current time, and with only normal maintenance the Commission can expect the Mitchell Station to be operational in 2040." (Emphasis supplied.)

The Company's response to KPSC 1-1 is fully consistent with the quoted excerpt from the Commission's October 7, 2013 Order in Case No. 2012-00578, as well as the order in its entirety. It appears the data request may be premised upon a misconception regarding the meaning of the term "liability." The excerpt quoted in part (b) of this data request refers to that portion of the Company's application in Case No. 2012-00578 seeking approval pursuant to KRS 278.300 to assume the "Assumed Liabilities" associated with the transfer to Kentucky Power of the fifty percent undivided interest in the Mitchell generating station. The term "Assumed Liabilities" was a defined term in the Company's application and was defined as follows at page 7, paragraph 14 of the application:

"the liabilities described in Section 2.03 of the Asset Contribution Agreement between AEP Generation Resources Inc. and NEWCO Kentucky .... Excluded from Assumed Liabilities are those liabilities described in Section 2.04 of the Asset Contribution Agreement".

The requirement that the Company maintain, replace or upgrade its existing environmental equipment, or otherwise undertake projects to comply with existing or future environmental laws and requirements is not an "Assumed Liability," but instead is an ongoing cost of doing business. Moreover, the Company fully disclosed to the Commission, as well as the Attorney General and other parties to Case No. 2012-00578, the known and projected environmental-related construction and projects at the Mitchell generating station. *See* the Company's response to subpart (c) below.

c. The Company's application, testimony, responses to data requests, and hearing testimony fully disclosed to the Commission and the parties to Case No. 2012-00578, including the Attorney General, that the Mitchell generating station, like every other coal-fired generating station in the United States, was subject to existing and future environmental requirements mandating the installation, operation, maintenance, and replacement of environmental equipment and facilities. Without limitation, the following portions of the Commission record in Case No. 2012-00578 addressed such equipment and facilities:

(a) Response to KPSC 1-1;

(b) Response to KPSC 1-43;

(c) Response to KIUC 1-6;

(d) Response to KIUC 1-7;

(e) Response to KIUC 1-8;

(f) Response to KIUC 1-9;

(g) Response to KIUC 1-10;

(h) Response to KIUC 1-11;

(i) Response to KIUC 1-12;

(j) Response to KIUC 1-13

(k) Testimony of Scott C. Weaver at 23-24; Exhibit SCW-4;

(l) Testimony of John M. McManus at 11;

(m) Testimony of Jeffrey D. LaFleur at 5;

(n) Rebuttal Testimony of Jeffrey D. LaFleur at 4-5;

(o) Transcript of Hearing at 461-462 (Testimony of John M. McManus);

(p) Transcript of Hearing at 473 (Testimony of John M. McManus);

(q) Transcript of Hearing at 476-478 (Testimony of John M. McManus);

(r) Transcript of Hearing at 570 (Testimony of Jeffrey D. LaFleur);

(s) Transcript of Hearing at 593-594 (Testimony of Jeffrey D. LaFleur); and

(t) Transcript of Hearing at 600-601 (Testimony of Jeffrey D. LaFleur).

Please see Attachment 1 and the enclosed CD for the requested documents.

d. Please see the Company's response to subparts (a)-(c).

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to paragraph 1 of Kentucky Power's verified application ("Application"), where it states, "[A]t this crossroad, and as promised earlier this year when Kentucky Power withdrew its application to retrofit Big Sandy Unit 2, the Company has conducted in-depth analysis of reasonable portfolio alternatives to determine the best path to ensure adequate and reliable capacity for its customers." Provide in electronic format, with formulas intact and unprotected, along with the date the analysis was performed, copies of all in-depth analyses performed to determine the best path to ensure adequate and reliable capacity for Kentucky Power's customers.

RESPONSE

Please see KPSC 1-1.zip on the enclosed CD for the response.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to the McManus Testimony, page 11, lines 17 through 19.

a. Provide details of any modifications that have been implemented or are planned be implemented to bring the Mitchell Plant Units 1 and 2 into compliance with the pending EPA Clean Water Act 316b cooling water intake regulations.

b. Provide cost estimates for any modifications to enable the Mitchell Units to comply with pending EPA Clean Water Act 316b cooling water intake regulations.

c. Provide the expected schedule required to implement pending EPA Clean Water Act 316b cooling water intake regulations for the Mitchell Plant units.

RESPONSE

a. EPA is expected to promulgate the final 316(b) rule on or before June 27, 2013. The Mitchell units are currently equipped with closed-cycle cooling systems. As such the requirements in the proposed rule were not expected to have a significant impact. It is anticipated that an upgrade to the cooling water intake screens at the Mitchell plant may be required; however, the specifics of any upgrade will depend on the final rule.

b. Please refer to Company witness Weaver's Exhibit SCW-4 for an estimate of the costs necessary to comply with the proposed 316(b) Rule for the Mitchell Units 1 and 2.

c. The schedule to implement the proposed EPA Clean Water Act 316b regulations is expected in the finalized rule on or before June 27, 2013. In the proposed rule, EPA indicated that implementation would be "as soon as possible but within 8 years at the latest."
(http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/qa_proposed.pdf)

WITNESS: John M McManus

Kentucky Power Company

REQUEST

For continued operation on coal at BS2 (Option 1), please provide year by year estimates of environmental upgrade capital costs, environmental upgrade O&M costs, and other capital addition requirements. Provide the revenue requirement model with data assumptions including the capital environmental upgrade investment and capital additions for each capital cost, and O&M expenses through the planning period. This information should be provided electronically with all formulas intact and no pasted in values.

RESPONSE

The year by year estimates of environmental upgrade capital costs can be found in the response to KIUC 1-12. The response to KIUC 1-31, electronic file named BS2DFGD STRAT INPUT DATA.XLS, includes the environmental upgrade O&M costs and other capital addition requirements.

The Company utilized Strategist to determine the long term costs for Option 1. See response to AG 1-12 for the Strategist modeling assumptions for Option 1.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please state whether the list in Exhibit SCW-4 reflects all anticipated environmental upgrades required at Mitchell. Please state where these costs may be found in the Company's workpapers/economic analyses of the Mitchell acquisition option.

RESPONSE

Exhibit SCW-4 reflects the cost of all anticipated environmental upgrades at the time of this response.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Does the Company anticipate that the EPA will address the issues with the CSAPR regulations, and will eventually implement a modified CSAPR rule?

a. If so, when does the Company believe the modified CSAPR rule will be implemented? If not why not?

b. Has the Company incorporated estimates for these costs for BS1 and Mitchell in its economic evaluations? If not, why not, and if so, where in the Company's workpapers can these costs be found?

c. If not, please explain what the Company anticipates will happen to the CSAPR rule. For example does the Company assume that CAIR will continue and if so, where in the Company's workpapers can these costs be found.

d. Assume that CSAPR had passed as the EPA had intended. Please explain what modifications and annual costs would have been necessary at Mitchell, and BS1 to comply with CSAPR.

RESPONSE

It is unknown whether EPA will appeal the decision that vacated CSAPR to the Supreme Court or develop a replacement rule.

a. Because of the uncertainty regarding the strategy EPA will take in responding to the decision to vacate CSAPR, it is unknown when or if a modified CSAPR will be implemented.

b. No. Any analysis of potential impacts cannot be performed until EPA develops a CSAPR replacement and the requirements of such a rule are known.

c. As a result of the D.C. Circuit Court of Appeals decision to vacate CSAPR, the requirements of the CAIR remain effective until either the decision is reversed by the Supreme Court, or until EPA finalizes a CSAPR replacement rule.

d. The existing emission controls at the Mitchell Plant were expected to meet CSAPR requirements and, therefore, no modifications or additional costs for controls would have been required. The SO2 and NOx emissions market was expected to minimize, if not eliminate the need to install and/or modify emission control systems at Big Sandy Unit 1. The annual costs for Big Sandy Unit 1 would have been dependent on the market for SO2 and NOx emissions credits.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

With regard to both the 20% and 50% acquisitions of Mitchell, provide the revenue requirement model with data assumptions including the yearly capital environmental upgrade investment and capital additions for each capital cost through the planning period. This should include all revenue requirements (capital, O&M, environmental, etc.) that were included in the economic evaluations. This information should be provided electronically with all formulas intact and no pasted in values.

RESPONSE

The Company utilized Strategist to determine the long-term costs for Option 1 which can be found in the Company's response to KPSC 1-1. See the Company's response to AG 1-12 for the Strategist modeling assumptions for Option 1.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Concerning the BS1 retirement and replacement with a new CC unit, conversion to a repowered CC unit, and conversion to a gas fired steam turbine unit, provide the revenue requirement model with data assumptions including the yearly capital environmental upgrade investment and capital additions for each capital cost through the planning period. This should include all revenue requirements (capital, O&M, environmental, etc.) that were included in the economic evaluations. This information should be provided electronically with all formulas intact and no pasted in values.

RESPONSE

The thrust of the Company's filing in 2012-00578 centers on unit disposition alternatives --many of which are identified in this request-- associated with the 800-MW Big Sandy Unit 2, not the 278-MW Big Sandy Unit 1 (BS1). Each of those alternatives, including the 50% (780-MW) Mitchell Asset Transfer, approximates the replacement capacity and energy requirements for Unit 2. BS1 evaluation disposition options included: a 20% (312-MW) Mitchell Asset Transfer (Options #1A, #2A, #3A), a coal-to-gas conversion or re-fuel (Options #5A and #5A), as well as a PJM-market purchase replacement option (Options #1B, #2B, #3B, #4A, #4B and #6). The Company's ultimate recommended disposition for BS1 focused on the issuance of a 250-MW Request for Proposal for purpose of assessing the economic viability of both the bi-lateral capacity and energy market as well as the Big Sandy re-fuel option.

Please see the responses to PSC 1-1 as well as AG 1-12 for the detailed assumptions and evaluation results associated with the unique options highlighted.

WITNESS: Scott C. Weaver/Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please supply all workpapers and analyses that were developed to create the table found in Exhibit SCW-4 and supply the table itself. Please provide this information electronically, with all formulas intact, and no pasted in values.

RESPONSE

See KIUC 1-11 Attachment 1 on the enclosed CD.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Please supply all workpapers and analyses that were developed to create the Table 3 found in Mr. Weaver's testimony at page 22, and supply the table itself. Please provide this information electronically, with all formulas intact, and no pasted in values.

RESPONSE

See KIUC 1-12 Attachment 1 on the enclosed CD.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

On page 12 of Mr. Weaver's testimony, in referring to Mitchell he states that "it is not at all certain that additional retrofit requirements would be required in any event." Has the Company performed any analysis to explore what additional environmental regulations and what additional retrofits could realistically be required within the next 5 - 10 years? If so, please provide any analyses performed. Please supply this information electronically with all formulas intact.

RESPONSE

The Company has identified the expected environmental regulations and associated potential environmental projects as found in Company Weaver's Exhibit SCW-4.

WITNESS: John M McManus

Q. PLEASE DESCRIBE THE COSTS NOTED IN TABLE 3 AS "ADDITIONAL NON-RECURRING ENVIRONMENTAL COSTS INCLUDED IN MODELING (THRU 2021)", AND HOW SUCH COSTS WERE ALSO FACTORED INTO THIS UNIT DISPOSITION EVALUATION PROCESS.

A. These costs represent additional identifiable major capital spends that are expected to be incurred in the future for certain of the options modeled that are over-and-above the initial project costs. For instance, for the Option #1 Big Sandy 2 DFGD Retrofit, it was recognized that additional costs pertaining to emerging EPA regulation summarized earlier in this testimony—namely CCR and 316(b) rulemaking—could become a factor. Recognizing this, and considering the holistic nature of this evaluation process, it was necessary to consider those additional major, non-recurring capital costs that would be expected to be incurred at Big Sandy 2 beyond just the cost of the scrubber retrofit. To do otherwise would not be fair to the comparative long-term modeling exercise.

Likewise, note also in TABLE 3 that such additional, non-recurring future environmental capital costs have also been recognized for the Mitchell generating assets. Recall the transfer cost to KPCo represents the estimated AEP Generation Resources, Inc. balance sheet costs for these units as of the assumed asset ownership transfer date to be effective January 1, 2014. These additional costs reflect anticipated capital spends associated with future environmental-related requirements expected to be incurred at the Mitchell plant *beyond* that date. Such costs were then incorporated into the Strategist® modeling of the options that included such Mitchell ownership transfers.

SCW- Exhibit 4 offers project-specific detail of these major non-recurring environmental capital costs captured in the respective Big Sandy (retrofit) and Mitchell (asset transfer) resource option modeling.

Q. **WHAT WAS THE SOURCE OF THE MITCHELL ASSET TRANSFER COST DATA ALSO FOUND ON TABLE 3?**

A. KPCo's estimated Mitchell Unit Asset Transfer costs are based on estimates provided to me by Company Witness Wohnhas.

Q. **TABLE 3 DOES NOT SUMMARIZE OPTION #4 IN WHICH KPCO WOULD INITIALLY RELY ON AN ASSUMED MARKET REPLACEMENT OF <u>BOTH</u> BIG SANDY 1 AND 2 CAPACITY AND ENERGY. COULD YOU OFFER AN OVERVIEW OF THE MODELING APPROACH FOR THIS OPTION?**

A. The Strategist® modeling to proxy, specifically, Options #4A and 4B that was summarized on TABLE 1 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) retirement by June 2015 due to MATS rule requirements, would be fully-met via market sourcing for some interim period prior to the eventual addition of CC and/or simple-cycle CT capacity resources.

To perform that analysis, the modeling utilized projections of such market values for Unforced Capacity ("UCAP") applicable to the PJM Reliability Pricing

Estimated Non-Recurring Major Environmental Capital Expenditures
Associated with Emerging and Proposed U.S. EPA Rulemaking

- o Mercury and Air Toxics Standards (MATs) Rule
- o Coal Combustion Residuals (CCR) Rule
- o Clean Water Act "316(b)" Rule
- o Steam Electric Effluent Limitations Guidelines (ELG)
- o NPDES Permit Limits (Mitchell only)

Included in Strategist® KPCo-Resource Modeling for either Big Sandy or Mitchell Plants 'Options'

All Costs Exclude AFUDC ($000)

Option #1 Sandy 2 Retrofit	2012 Est.*	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
(Excluding DFGD & Assoc. Projects)	0	0	0	781	9,621	17,336	6,934	0	0	0	34,672
BS U2 Ash Waste Water Treatment System	0	0	0	17	35	178	1,157	0	0	0	1,387
BS U2 316(b)	0	0	0	0	883	4,089	4,213	0	0	0	9,185
BS U2 Bottom Ash Pond Reline											
TOTAL	0	0	0	798	10,539	21,603	12,304	0	0	0	45,244

Option #5 (Big Sandy 1 Convert to Gas)	2012 Est.*	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
BS U1 316(b)		0	71	160	200	356	2,312	0	0	0	3,099

Options #1A, 2A, 3A, 5A & 6 (Mitchell Asset Transfer) *100% of Est. Unit Costs*	2012 Est.* (A)	2013 (A)	2014	2015	2016	2017	2018	2019	2020	2021	Subtotal (2014-2021)	Total (A)
ML U1&2 Dry Fly Ash Conversion	29,219	54,798	20,780	0	0	0	0	0	0	0	20,780	104,796
ML U1&2 Bottom Ash Pond Reline	0	0	0	0	1,442	6,417	6,785	0	0	0	14,644	14,644
ML U1 Ash Waste Water Treatment System	566	1,529	4,346	3,336	0	0	0	0	0	0	7,681	9,776
ML U1 Electro-static Precipitator Upgrades (Ph 1)	1,224	4,527	0	0	0	0	0	0	0	0	0	5,751
ML U1 316(b)	0	0	40	72	88	27	42	1,143	0	0	1,412	1,412
ML U1 ELG Waste Water Treatment System	0	0	0	1,631	4,128	6,753	7,613	0	0	0	20,125	20,125
ML U1 Electro-static Precipitator Upgrades (Ph 2)	0	0	0	0	0	0	5,697	19,173	0	0	24,870	24,870
ML U2 Ash Waste Water Treatment System	566	1,529	4,346	3,336	0	0	0	0	0	0	7,681	9,776
ML U2 Electro-static Precipitator Upgrades (Ph 1)	0	0	881	4,190	0	0	0	0	0	0	5,071	5,071
ML U2 316(b)	0	0	40	72	89	27	42	1,143	0	0	1,413	1,413
ML U2 ELG Waste Water Treatment System	0	0	0	1,631	4,128	6,753	7,613	0	0	0	20,125	20,125
ML U2 Electro-static Precipitator Upgrades (Ph 2)	0	0	0	0	0	12,361	10,041	0	0	0	22,402	22,402
ML U0 New Haul Road and Landfill Expansion	10,108	11,673	13,734	0	805	3,884	5,755	4,194	4,446	4,241	37,059	58,840
TOTAL	41,683	74,056	44,166	14,268	10,680	36,222	43,588	25,653	4,446	4,241	183,264	299,003
20% of TOTAL Mitchell (KPCo Options: #1A, 2A & 3A)	8,337	14,811	8,833	2,854	2,136	7,244	8,718	5,131	889	848	36,653	59,801
50% of TOTAL Mitchell (KPCo Options: #5A & 6)	20,842	37,028	22,083	7,134	5,340	18,111	21,794	12,827	2,223	2,120	91,632	149,501

* *Note: 2012 represents a full-year forecast estimate*

(A) Estimated Costs incurred prior to 1/1/2014 were incorporated into the overall "Asset Transfer" Cost

Exhibit SCW-4

MATS RULE?

A. Yes. The emission control systems currently in place are expected to be sufficient for the Mitchell Plant to meet the requirements of the MATS Rule.

Q. **WILL ADDITIONAL MAJOR ENVIRONMENTAL CONTROLS BE REQUIRED AT THE MITCHELL PLANT TO MEET PROPOSED AND EMERGING REGULATORY COMPLIANCE NEEDS?**

A. Currently, the following environmental projects are underway for the purpose of meeting more stringent limits in the facilities' National Pollutant Discharge Elimination System ("NPDES") permit:

- Mitchell Units 1&2 Dry Fly Ash Conversion
- Mitchell Haul Road and New Landfill

Consideration is also being given to the installation of wastewater treatment technology as a component of these projects. These projects are also expected to satisfy the anticipated requirements of the CCR Rule, although there may be a need to re-line the bottom ash pond for compliance with the CCR Rule as well.

Finally, additional waste water treatment technology may be needed at Mitchell Units 1 and 2 for compliance with the emerging ELG Rule. The Company also anticipates a need to upgrade the cooling water intake system to comply with a revised 316(b) Rule.

The expected costs associated with these projects are used in the economic modeling addressed by Company Witness Weaver.

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

A. Yes.

Q. **ARE OTHER MAJOR ENVIRONMENTAL CAPITAL INVESTMENTS IN PROGRESS AT THE MITCHELL PLANT?**

A. Yes. Capital projects are currently in progress to build a new landfill and an associated haul road. The landfill will allow for the disposal of dry fly ash resulting from a dry fly-ash conversion project currently in progress at the Plant. As discussed by Company Witness McManus, it is anticipated that these projects will satisfy anticipated coal combustion residual regulations. It is also anticipated that future capital investments will be made to comply with other proposed environmental regulations. These anticipated future investments are discussed by Company Witnesses McManus and Weaver.

Q. **PLEASE DESCRIBE OTHER SIMILAR 800 MW COAL-FIRED UNITS IN AEP'S EASTERN FLEET.**

A. KPCo's Big Sandy Unit 2 and APCo's Amos Units 1 and 2 are of similar design and nominal generating capacity (800 MW) as Mitchell Units 1 and 2. Big Sandy Unit 2 was placed in service in 1969, and Amos Units 1 and 2 were placed in-service in 1971 and 1972, respectively. However, unlike the Mitchell and Amos units, Big Sandy Unit 2 is not retrofitted with a FGD system.

Mitchell Units 1 and 2 were the first of the 800 MW units in AEP's eastern fleet to have FGD and SCR systems installed. Since the installation of these systems at the Mitchell units, plant personnel have been able to proactively optimize the performance of its equipment and manage fuel costs in an effort to provide customers with reliable and cost-effective electricity. The Mitchell units have demonstrated their value through their generating performance.

for the simple reason that the Mitchell units already have been retrofitted with SO_2 emission controls while Big Sandy Unit 2 has not.

Q. **WHAT IS THE ENVIRONMENTAL RISK ASSOCIATED WITH THE THIRD PARTY-OWNED UNITS IDENTIFIED BY THE INTERVENORS?**

A. The plants involved in the third-party acquisitions that the intervenors allege are comparable have a higher overall environmental risk than Kentucky Power will have with the Mitchell units. As shown in the data gathered by Company Witness Fransen and summarized in Table 1 of his rebuttal testimony, these plants are not fully retrofitted with major environmental controls such as flue-gas desulfurization ("FGD") and selective-catalytic reduction ("SCR") systems. Of the three asset portfolios (Ameren, Dominion Resources, and Exelon) cited by KIUC Witness Mr. Kollen and Sierra Club Witness Mr. Woolf, only 33%, 38%, and 61% of the capacity of the units are equipped with FGD and SCR systems, respectively. Mitchell Plant is already fully equipped with both of these technologies.

In addition, from the cursory information presented by Mr. Kollen and Mr. Woolf, it is unclear whether costs of compliance with future environmental regulations were assessed as part of these transactions. Clearly, the cost to bring such units to environmental compliance comparable to the Mitchell units would lead to significant higher costs beyond the purchase price.

Q. **DO YOU FEEL THAT RISKS AT THE MITCHELL PLANT HAVE BEEN IDENTIFIED BY THE COMPANY?**

A. Yes. As discussed in my Direct Testimony, the Company is very familiar with the assets that it would receive at the Mitchell Plant. The Plant's current operating company, Ohio Power Company ("OPCo"), completed construction and placed the Mitchell Units in service in 1971, and has been the owner and operator of the Plant since then. OPCo also retrofitted the units with FGD and SCR emission control systems along with associated projects. In addition, AEP initiated planning efforts to identify future environmental project needs and associated costs at the Mitchell Plant due to recently finalized and proposed environmental regulations as discussed by Company Witness McManus.

Based upon the Company's knowledge of Mitchell Plant's history, I am comfortable that the Company understands what it is getting with the transfer of the Mitchell assets. By contrast, it is not possible to have such a detailed understanding with the acquisition of a third-party plant. As part of the AEP system, Kentucky Power knows that the OPCo units at Mitchell Plant have been provided with access to the same engineering, maintenance, and other resources as the 800 MW units at Big Sandy Plant and Amos Plant, which have the same basic design. Through sharing of best practices applicable to all units, a high level of availability and performance has been achieved. However, it is important to recognize that regardless of any company's attempt to assess the impacts of future environmental rules, until a rule is finalized and is not further challenged, any assessment contains an element of uncertainty.

Q Okay. Did -- did you provide any cost data to Mr. Weaver for any sort of retrofits that might be required, any sort of environmental retrofits that might be required on Mitchell units?

A Yeah. I did not provide the cost information. The process that -- that we go through is through -- to try and anticipate what new environmental requirements might go into effect and what they might require, and so that the organization I'm in provides input on that as we look at, you know, if EPA proposes a new regulation, to evaluate what that might require.

We'd then work with our engineering organization and our projects organization to evaluate what technologies might be available to meet new limits and what the cost of those technologies would be, and it's that information that ultimately is -- is provided to Mr. Weaver.

Q Okay. Well, let me be specific then. With respect to the model that Mr. Weaver used, my understanding from what you just said is you didn't provide the cost data for him for potential retrofits. Is that a fair statement? You were --

A That's correct.

Q Okay. So -- but my understanding is you would have told him what potential areas or retrofits might be needed on the Mitchell units; is that correct? Or you would have told the next group, the engineering group, to develop numbers with respect to that; is that --

A Right. So -- so the -- it's sort of a collaborative process. First my group would identify what the new requirement is. Does it require, you know, water treatment technology? Does it require you to -- to eliminate an ash pond?

Q Okay. Let me -- let me stop you there.

A Okay.

Q So what -- what -- in that process, because you know they're going to be modeling the costs of Mitchell, so what -- what environmental retrofits did you communicate they should model or that -- that the next step should get costs for -- for this -- for the models that he used for this case?

A The -- and -- and -- and this is done for -- across the fleet. It's not just at Mitchell plant as we evaluate the impact of, you know, rule by rule on any of our coal units and then develop cost information. So the cost information that Mr. Weaver has for Mitchell comes from a broader effort that looks at -- at the whole fleet.

If we thought we needed more time for technology installation, we could discuss with West Virginia an extension of the April 2015 compliance deadline.

Q But you haven't talked to them to get an ex -- extra year at this point?

A Not for Mitchell, 'cause we don't believe that -- that we need it.

Q Okay. The -- do you expect to incur the cost for the emission monitors in this calendar year?

A I'm not sure on that. Mr. Walton may have a better sense of -- of the schedule for that, but we may start to see some of that cost this year.

Q Okay. Do you know what the cost is?

A I do not.

Q Who would know that?

A It's -- we might have to check that, but Mr. LaFleur and Mr. Walton might have a better sense than I do or we may need to check that for you.

Q Okay. Let me go to another rule. Current -- and this is the transport rule, basically. CAIR, CSAPR.

A Uh-huh.

Q Currently, CAIR is in effect; is that right?

Q Let me --

A -- where people are.

Q Let me ask you. As a result of -- if that is implemented or finally implemented, would there be any additional controls that AEP would need at Mitchell?

A We don't think so, because it has a very high efficient -- high-removal efficiency scrubber already installed. Its SO2 emissions are very low.

Q Okay. Let me ask about the NAAQS PM2.5. Does Mitchell need anything for that?

A We don't think so for that as well. As EPA has been implementing that air quality standard, it's really the CAIR rule and the CSAPR rule that was a mechanism to address PM2.5, from an interstate transport basis, that sulfur dioxide and nitrogen oxides in the atmosphere to convert to particulates, and it gets measured in PM2.5.

So, again, with the level of SO2 and NOx control we have at Mitchell plant, we believe it's well-positioned for that standard as well.

Q Okay. Were -- with respect to -- and I know you mentioned 316 B before. Were those costs modeled? Potential additional costs of 316 B modeled.

A Yes, there were. The -- the Mitchell

units have what's called closed-cycle cooling. They have cooling towers already.

The 316 B proposal that EPA issued has requirements related to two aspects of -- of a cooling water system, and it requires what we believe may be an update -- an upgrade to the intake screens of that cooling water system. We included an estimate of the cost of updating the intake screens in the modeling.

Q And do you know what that cost was?

A I don't know the dollar specific.

Q Okay.

A I believe it may be in an exhibit in Mr. Weaver's testimony.

Q Okay. Likewise, I think you talked about the effluent limitations guidelines, which were those costs modeled as well?

A We took our best guess at what that -- that new rule might require in terms of additional wastewater treatment technology at our plants, and we incorporated an estimate for that in the modeling as well.

Q Okay. What about coal combustion residuals? Were there any additional costs modeled for that?

A We -- we have evaluated that rule for

all of our units. At Mitchell -- and I think there was mention already to some ongoing project at -- projects at Mitchell to convert the units to dry fly ash handling, to install a landfill.

Those are driven by the current water permit that the plant has, the MPDS permit, but those actions are the -- the very same actions that we anticipated we might have to do with the coal combustion residual rule.

So we're actually, in a lot of respects, ahead on the coal combustion residual with Mitchell because of work that's ongoing now at the plant.

Q What -- are there going to be more costs because there's a wet FGD rather than a dry?

A No. At Mitchell --

Q Not with res --

A -- the byproduct --

Q Not with respect to coal combustion residuals?

A No.

Q Okay.

A I don't believe so. Yeah.

Q Okay. There -- there's another rule proposed dealing with startup and shutdown issues. Are you familiar with the com -- the -- that issue?

Q Here you discuss additional major capital environmental investments, specifically plans to build a new landfill and an associated haul row -- road which are in progress at the Mitchell plant; is that correct?

A That's correct.

Q For how long have these projects been going on?

A To get -- now, realize that Mitchell is not under -- under my purview right now.

Q Yes, sir.

A Probably Mr. Walton could give you when it started. I think most these projects are going to complete by first of 2015, but I'm not real sure when they were started, and I think it's been a year or two.

Q Do you know the approximate cost of when they -- what the approximate cost will be when they are complete?

A I don't know the exact number, but I do know that we provided a data request with those numbers.

Q And if you could stay on line 5 with me, but go to -- I'm sorry. Page 5 with me, but go to lines 19 through 23.

budget. The total O&M budget.

Q Is -- does in the range of 45 million sound high or --

A That sounds high.

Q Okay.

A But it -- and it depends on -- I mean, you got -- when you're talking about O&M budget, we need to be very specific if we're talking about limestone included in that or not.

Q Okay. Let me -- let me ask this: Other than the -- upgrading the electrostatic precipitator -- and by the way, what is the approximate cost of doing that?

A I don't think I have that with me.

Q Is that in -- do you know what the budget --

A It's -- it's in our -- it's in our project.

Q Okay. And, likewise, do you know what the landfill costs would be? The landfill costs.

A The dry fly ash, I think, is the largest. It's a couple hundred million. We -- we -- those large capital projects, the landfill, the haul road, and the drive fly ash, we provided that in a request, information request.

Q Okay. And those projects are under way right now?

A They're under way, and, you know, they're part of the compliance.

Q Sure. And approximately when would they be completed?

A I think all of that is complete by the first of '15. Mr. Walton would probably be able to verify that.

Q Okay. Are -- are you aware of any other environmental budgeted items in the Mitchell capital plan other than the -- the electrostatic precipitators and the -- the landfill-related matters?

A Well, the land -- even the precipita -- the landfill is, order of magnitude, larger than anything we've got. Every year there's small capital.

Q But are you aware any of big ones?

A We have -- like Mr. McManus testified, we have capital in there to addressed, you know, estimates around some of the other environmental rules.

Q Do you know -- how much does it cost to put in a continuous emission monitor for mercury?

A The mercury ones? I think they're around a million each.

an operating agreement, but we have to get certificates of need and convenience from Virginia as well as West Virginia.

Any -- anything that we do at Amos, Amos 3, two-thirds of Amos 3 is owned by Ohio Power, a third is owned by APCo. We have an operating agreement.

Sporn plant, the four small units of Sporn plant, two units are opened by Ohio Power, two units are owned by APCo. APCo operates them. AP -- APCo operates Amos as well. So, yeah, we're very familiar with working with these operating agreements.

Q And in your experience in working with operating agreements, have you found them to be difficult?

A I've never had an issue. We've never had an issue with an operating agreement. You know, we're regula -- all the units operate in regulated units. We understand the jurisdictions that we operate in and the requirements, and we meet the -- we -- we haven't had an issue. We meet those requirements.

Q And in the response to your questions -- the questions from Vice-Chairman Gardner earlier, you mentioned that the product -- you know, budgets could change if commodity prices were impacted by inflation. That -- that is unrelated to the age of any unit; is that correct?

A That's correct.

Q And you also were asked questions about the -- the budgeted costs of environmental projects in -- in -- are anticipated in the near future for Mitchell.

MR. GISH: May I approach the witness to -- to show him an exhibit?

CHAIRMAN ARMSTRONG: Sure.

Q Are you familiar with this exhibit, Mr. LaFleur?

A I am.

Q Okay. Is that Exhibit SCW 4?

A I'm looking for the top. Yes.

Q And -- and so that -- that exhibit shows the --

A Environmental capital.

Q Okay. And those -- that's part of whose testimony? Is -- is SCW Scott C. Weaver?

A It is.

Q And --

A Got to look all over it.

Q And earlier today, Miss Cole asked you

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT A 138 KV TRANSMISSION LINE AND ASSOCIATED FACILITIES IN BREATHITT, KNOTT AND PERRY COUNTIES, KENTUCKY (BONNYMAN-SOFT SHELL LINE)	)	CASE NO. 2011-00295

O R D E R

On September 29, 2011, Kentucky Power Company ("Kentucky Power") tendered for filing, pursuant to KRS 278.020(2), 807 KAR 5:001, Section 8, 807 KAR 5:001, Section 9, and 807 KAR 5:120, an application for a Certificate of Public Convenience and Necessity ("CPCN") to construct a 138 kV transmission line in Knott and Perry counties approximately 20 miles in length, and for approval for the proposed expansion of the existing Bonnyman Station[1] in Perry County, Kentucky, along with the construction of associated facilities at Kentucky Power's existing Beckham Station and Soft Shell Station in Knott County, Kentucky, and the Haddix Station in Breathitt County.

PROCEDURAL HISTORY

On August 31, 2011, prior to filing its application, Kentucky Power filed a Motion for an Informal Conference for the purpose of addressing a procedural schedule in the case. On September 7, 2011, the Commission issued an Order finding that an informal

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[1] Kentucky Power's application identifies the Bonnyman Station, the Beckham Station, the Soft Shell Station, and the Haddix Station. These locations are not generating units. The terms "station" and "substation" are utilized interchangeably in reference to these locations.

conference would be more beneficial if it were scheduled after Kentucky Power's application had been filed. The Order directed Commission staff to issue a notice of informal conference after Kentucky Power's application had been received and accepted as filed. Kentucky Power's application was accepted as filed on September 29, 2011.

Pursuant to KRS 278.020(8), the Commission issued an Order on October 28, 2011 that extended the period of review of Kentucky Power's application to 120 days, up to and including January 27, 2012, and that established a procedural schedule.[2] The procedural schedule set a November 10, 2011 deadline for requests for intervention and allowed requests to be filed by November 15, 2011 for a public hearing in the county in which the transmission line is proposed to be constructed. No requests for intervention were filed and no requests for a public hearing in the county in which the transmission line is proposed to be constructed were made. One written comment was received on October 25, 2011.[3]

On December 7, 2011, an Order was issued setting this matter for hearing on January 4, 2012. On December 14, 2011, Kentucky Power filed a Motion to cancel the hearing, stating that there were no intervenors in the case and that no person had

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[2] The procedural schedule was issued without conducting an informal conference; as such, the purpose of convening an informal conference for the purpose of addressing a procedural schedule was rendered moot.

[3] On the morning of January 4, 2012, Mr. Dwight Jett, a property owner whose land will be impacted by the transmission line, appeared at the Commission offices in anticipation of a hearing. Staff contacted counsel for Kentucky Power and, later in the morning, representatives of Kentucky Power appeared at the Commission offices. An informal conference was conducted. On January 20, 2012, Kentucky Power filed a Status Report with regard to the January 4, 2012 meeting with Mr. Jett and indicated that Kentucky Power would respond to Mr. Jett's demand for the right-of-way purchase.

requested an evidentiary hearing and that the matter should be submitted for decision on the written record. On December 21, 2011, the Commission issued an Order cancelling the January 4, 2012 hearing and directing Kentucky Power to publish notice that the hearing was cancelled in those newspapers in which Kentucky Power had published notice of hearing pursuant to 807 KAR 5:011, Section 8(5).

Pursuant to its authority at KRS 278.020(8), the Commission utilized the services of an independent consulting firm, Accion Group,[4] to assist in its evaluation of Kentucky Power's application. On November 7, 2011, Accion Group's Final Report to the Commission, "Focused Review of Documentation Filed by Kentucky Power Company for a Proposed 138kV Transmission Line from Soft Shell Substation to Bonnyman Substation Case No. 2011-00295," was filed in the record. Accion performed an independent evaluation including an evaluation of:

1) Kentucky Power's analyses and conclusions in support of the reasonableness of the need for the proposed transmission line;

2) Kentucky Power's analyses and conclusions in support of its position that the proposed transmission line is the best overall alternative including wheeling of power through neighboring systems; and

3) The reasonableness of the routing proposed by Kentucky Power in that proper social, environmental, and economic factors were fairly and reasonably considered.

THE PROPOSED TRANSMISSION LINE

The proposed transmission line is to be constructed with two construction

[4] Accion Group, Inc., of Concord, New Hampshire was utilized by the Commission in this case.

configurations. Approximately 19 miles of the proposed 20-mile transmission line is proposed to be of single circuit configuration and in a new 100-foot right-of-way. The line is proposed to be in the center of this new right-of-way and will be supported by steel pole H-frame and three-pole structures. These structures will support three conductors and two overhead groundwires. The conductors will consist of 1,590 kcm Aluminum Conductor Steel Reinforced ("ACSR") conductors. The overhead groundwires will consist of one 7#8 Alumoweld wire and one fiber optic overhead groundwire, which will be used for relaying communications between stations. The average height of the structures is proposed to be approximately 85 feet.

Approximately one mile of the proposed 20-mile transmission line is proposed to be constructed within the existing Hazard-Bonnyman 69 kV line right-of-way. The existing Hazard-Bonnyman 69 kV structures are proposed to be replaced with steel lattice tower structures to support the new double circuit configuration. The average height of the existing structures is approximately 65 feet. The new steel lattice towers are proposed to be approximately 100 feet in height.

The proposed improvements to the Bonnyman Substation include: a) installation of a 138 kV/69kV, 130 MVA or similar MVA-rated transformer; b) installation of a 138 kV circuit breaker pointing toward Soft Shell Substation; c) installation of devices for line protection and control; d) installation of a sub-transmission transformer relay package on the new transformer; e) installation of a 69 kV breaker with relay control on the low side of the 138 kV/69kV transformer; f) replacement of relays on circuit breakers A & C with standard sub-transmission line relaying package; g) replacement of the 69 kV bus differential with relaying devices; and h) installation of a 24' W x 32' L x 10' H building for housing control equipment.

PROPOSED IMPROVEMENTS TO THE HADDIX SUBSTATION

The proposed minor improvements to the Haddix Substation will include the installation of a 5.4 MVAr, 69 kV capacitor bank.

PROPOSED IMPROVEMENTS TO THE BECKHAM SUBSTATION

The proposed minor improvements to the Beckham Substation include the installation of a 43.2 MVAr, 138 kV capacitor bank, and installation of a 24' W x 32' L x 10' H building for housing control equipment.

PROPOSED IMPROVEMENTS TO THE SOFT SHELL SUBSTATION

The proposed improvements to the Soft Shell Substation will allow for a new 138 kV line connection to the Bonnyman Substation.

PROJECTED COSTS

Kentucky Power's application states that the projected cost of this project is approximately $62.5 million. It further states that the proposed construction does not involve sufficient capital outlay to materially affect the financial condition of Kentucky Power,[5] and that construction will be financed through Kentucky Power's internally generated funds. It states that, after the proposed facilities are completed, their estimated annual cost of operation, excluding additional ad valorem taxes, will be approximately $50,000 per year for general maintenance and inspection. Finally, the application states that the projected annual additional ad valorem taxes resulting from the project are expected to total approximately $780,000.

PROPERTY ACQUISITION

The application states that the proposed transmission line will traverse approximately 84 parcels (excluding highway crossings) involving 65 landowners. To

[5] Application, paragraph 10, p. 4.

ensure flexibility necessary to address last-minute or unanticipated issues regarding construction of the transmission line, Kentucky Power has requested authority to move the approved centerline 250 feet in either direction (within a 500-foot corridor) as long as: 1) the property owner onto whose property the line is moved was notified of this proceeding in accordance with 807 KAR 5:120, Section 2(3) [sic];[6] and 2) the property owner onto whose property the line is moved agrees in writing to the requested move.

The application states that Kentucky Power is negotiating with affected property owners for acquisition of the necessary rights-of-way and that it has contacted all property owners over whose property the line is expected to cross in connection with obtaining permission to survey their property. The application also states that, "[t]o date, only four property owners have expressed objections to the line."[7] The application indicates that Kentucky Power will provide the Commission with periodic property acquisition status updates and that, after construction is completed, it will file with the Commission an "as-built" survey of the final location of the line.

<u>OTHER ALTERNATIVES CONSIDERED IN LIEU OF THE PROPOSED PROJECT</u>

The application states that Kentucky Power considered other alternatives in lieu of its current proposed project including 1) creating a second 161 kV interconnection with Kentucky Utilities Company at the Hyden Station and connecting Kentucky Power's Bonnyman Station; 2) re-conductoring the Hazard 69 kV sub-transmission loop; and 3) constructing a transmission line to Kentucky Power's Hazard Station from the TVA system.

[6] 807 KAR 5:120, Section 2(3).

[7] Application, paragraph 12, p. 5.

Kentucky Power states that these alternatives were rejected because they were not feasible or because they could not provide the same benefits at or below the cost of the proposed project.

ALTERNATIVE ROUTES AND SITES CONSIDERED

The application states that Kentucky Power retained the services of GAI Consultants, Inc. ("GAI") of Homestead, Pennsylvania to develop a route that 1) avoids or minimizes present and future land use conflicts; 2) reasonably minimizes adverse impact on environmental resources; and 3) is consistent with the Company's siting criteria. The *Transmission Land Siting Study* performed by GAI is included in Kentucky Power's application.

Kentucky Power indicates that stakeholder input was collected through public workshops conducted on December 7, 2010 in Hindman, Kentucky, and on December 8, 2010 in Hazard, Kentucky. The company further states that it established a public website to receive comments. It states that it met with large land holders (coal companies) to avoid or minimize future land use conflicts and potential relocation risks; and had over 100 landowner contacts by company land agents.

Kentucky Power explains that five transmission right-of-way line alternatives were considered, each of which begins at the Bonnyman Station and ends at the Soft Shell Station. "The GAI Report indicates that Alternative 3 will have the least impact on residences and existing and future mineral extraction. Alternative route 3 is 20 miles in length, generally parallels Route 80, and traverses a landscape dominated by past mineral extraction."[8]

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[8] Application, paragraph 25, p. 10.

Based on GAI's recommendation, Kentucky Power indicated that it selected the route identified as "Alternative 3"[9] in the application. Kentucky Power identified a number of reasons in the GAI report for the selection of Alternative 3, including:

1. As of the filing of the application, only four persons contacted had registered opposition. The other alternatives registered greater, albeit moderate, opposition during stakeholder input.

2. Alternative 3 has significantly less potential risk for future relocations (less than 10 percent) compared to the other alternatives due to its proximity to Route 80, which limits future mining.

3. Coal companies whose property would be crossed by the alternatives favored Alternative 3.

4. The cost to construct Alternative 3 is estimated to be approximately 10 percent less than the other alternatives.

5. The route, which was developed iteratively and in coordination with stakeholders, is strongly endorsed by local government officials and major landowners.

6. Due to the proximity to Route 80, there are numerous existing access roads which can be utilized for construction and maintenance of Alternative 3. In general, other alternatives deflect away from Route 80 and have fewer existing access roads.

7. Alternative 3 has the least impact on residences.

8. Alternative 3 will require a moderate amount of forest clearing (173 acres). Minimizing forest clearing to the extent practicable was recommended by the U.S. Fish

[9] Id.

and Wildlife Service to reduce potential impacts on federally-protected bats.

FINDINGS

Having reviewed the evidence in the record and being otherwise sufficiently advised, the Commission finds that the proposed 138 kV transmission line is necessary, its construction is reasonable and will not result in the wasteful duplication of facilities, and that approval thereof should be granted.

The Commission also understands the need, in limited circumstances, to permit a utility the flexibility to address unanticipated construction issues. The Commission therefore finds that Kentucky Power should have the ability to move the approved centerline of the right-of-way 250 feet in either direction (i.e., within a 500-foot corridor) as long as: (1) the property owner onto whose property the line is moved was notified of this proceeding in accordance with 807 KAR 5:120, Section 2(3); and (2) the property owner onto whose property the line is moved agrees in writing to the requested move. Kentucky Power should file with the Commission a survey of the final location of the line after all moves are completed and before construction begins.

Any changes greater than the distance identified in the paragraph above or involving landowners not identified in Kentucky Power's application will require Kentucky Power to file another application with the Commission. If another agency requires an alteration of the line that does not meet all of the conditions listed above, Kentucky Power must apply for a CPCN for the modified route.

Kentucky Power should file with the Commission an "as-built" survey of the final location of the line.

Kentucky Power should provide the Commission with periodic property-acquisition updates.

Kentucky Power should provide copies of any permits acquired in connection with this project, including but not limited to the Kentucky Pollutant Discharge Elimination System permit.

Kentucky Power's application for a CPCN for the construction of the proposed Bonnyman-Soft Shell 138 kV transmission line and related facilities should be approved.

IT IS THEREFORE ORDERED that:

1. Kentucky Power is granted a CPCN to construct the proposed Bonnyman-Soft Shell 138 kV transmission line and related facilities as set forth in its application.

2. In the event Kentucky Power moves the centerline of the right-of-way in either direction, Kentucky Power shall provide evidence to the Commission that the affected property owner, or owners, onto whose property the line is moved, was notified of this proceeding in accordance with 807 KAR 5:120, Section 2(3). In addition, Kentucky Power shall obtain the written permission of the property owner, or owners onto whose property the line is moved, and shall provide the Commission a copy of any such documentation within 30 days after such documentation becomes available.

3. In the event Kentucky Power desires any changes in the transmission line route greater than the distance identified in the findings paragraph above, or involving landowners not identified in Kentucky Power's application, Kentucky Power shall file a new application with the Commission.

4. In the event another agency requires an alteration of the line that does not meet all of the conditions identified in the findings paragraphs, Kentucky Power shall apply for a CPCN for the modified route.

5. Kentucky Power shall file with the Commission any permits acquired in connection with this project within 30 days of issuance.

6. Before construction begins on the transmission line, Kentucky Power shall file a survey of the final location of the transmission line, including a map with aerial photography, parcel lines and labels, the centerline and right of way, and pole locations, along with a table of parcels and easement status demonstrating that Kentucky Power has obtained all of the necessary easements to construct the transmission line. If Kentucky Power has not obtained all of the easements necessary to construct the transmission line, Kentucky Power shall file a report demonstrating that it has undertaken condemnation proceedings pursuant to KRS Chapter 416 in order to obtain the necessary rights-of-way.

7. Kentucky Power shall file with the Commission "as-built" drawings or maps within 60 days of completion of the construction authorized by this Order.

8. Any documents filed in the future pursuant to ordering paragraphs 2, 5, 6, or 7 herein shall reference this case number and shall be retained in the utility's general correspondence files.

9. This case is hereby closed and removed from the Commission's docket.

By the Commission

ENTERED

JAN 26 2012

KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

Executive Director

Honorable Mark R Overstreet
Attorney at Law
Stites & Harbison
421 West Main Street
P. O. Box 634
Frankfort, KENTUCKY 40602-0634

Ranie Wohnhas
Managing Director, Reg & Finance
American Electric Power
101 A Enterprise Drive
P. O. Box 5190
Frankfort, KY 40602

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE COMPANY TO CONVERT BIG SANDY UNIT 1 TO A NATURAL GAS-FIRED UNIT AND FOR ALL OTHER REQUIRED APPROVALS AND RELIEF	)))))))	CASE NO. 2013-00430

<u>ORDER</u>

On December 6, 2013, Kentucky Power Company ("Kentucky Power") filed an application, pursuant to KRS 278.020(1), seeking approval for a certificate of public convenience and necessity ("CPCN") to convert its Big Sandy Unit 1 ("BS1") from a coal-fired facility to a natural gas-fired unit.[1] Kentucky Power states that the proposed conversion of BS1 reflects a least-cost alternative for addressing the applicable environmental standards affecting that unit's continued operation.[2] The capital cost of the proposed BS1 conversion, excluding allowance for funds used during construction and the cost of constructing a gas transport lateral, is approximately $50 million.[3] The annual operation and maintenance cost associated with the proposed conversion of

[1] Application, p. 1.

[2] Application, p. 2.

[3] Direct Testimony of Robert L. Walton ("Walton Testimony"), p. 16.

BS1 is approximately $4.692 million.[4] The net present value of the costs of the lateral pipeline is estimated to be $49.35 million over the 15-year term of that contract.[5]

On January 14, 2014, the Commission issued an Order establishing a procedural schedule for the processing of this case. The procedural schedule provided for a deadline to request intervention, two rounds of discovery on Kentucky Power's application, an opportunity for the filing of intervenor testimony, discovery on intervenor testimony, and an opportunity for Kentucky Power to file rebuttal testimony. The only intervenor in this matter is Kentucky Industrial Utility Customers, Inc. ("KIUC").[6] On June 4, 2014, a formal hearing was held at the Commission's offices. Kentucky Power filed responses to post-hearing data requests and a post-hearing brief on June 12, 2014, and June 16, 2014, respectively. The matter now stands submitted for a decision.

BACKGROUND

Kentucky Power, a direct and wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"), is an electric utility which generates, transmits, distributes, and sells electricity to approximately 173,000 retail customers in all or portions of 20 eastern Kentucky counties.[7] Kentucky Power is a member of the PJM Interconnection, LLC ("PJM"), a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia and operates an energy market and a capacity market.

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[4] Kentucky Power's Response to Commission Staff's Initial Request for Information, Item 2.

[5] Supplemental Testimony of Ranie K. Wohnhas ("Wohnhas Supplemental"), p. 3.

[6] KIUC did not file any testimony in this case.

[7] Application, pp. 2-3.

Currently, Kentucky Power owns and operates the 1,078 megawatt ("MW") coal-fired Big Sandy Generating Station, consisting of the 800-MW Big Sandy Unit 2 ("BS2") and the 278-MW BS1[8] at Louisa, Kentucky. BS2 will be retired effective June 1, 2015.[9] Kentucky Power also has a unit power agreement with AEP Generating Company, an affiliate, to purchase 393 MW of capacity from the Rockport Plant, located in southern Indiana, through December 7, 2022.[10] Kentucky Power also owns an undivided 50 percent interest in the 1,560-MW Mitchell Generating Station ("Mitchell Station") located in Moundsville, West Virginia.[11] Lastly, Kentucky Power has a renewable energy purchase agreement with ecoPower Generation-Hazard LLC for the future purchase of 58.5 MW of capacity from a biomass facility to be located in Perry County, Kentucky.[12]

Kentucky Power asserts that the proposed refueling of BS1 is required to comply with the Mercury and Air Toxics Standard ("MATS") rule,[13] which was promulgated by the United States Environmental Protection Agency ("EPA") and became effective on

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[8] Application, p. 1

[9] Direct Testimony of Scott C. Weaver ("Weaver Testimony"), p.12.

[10] Weaver Testimony, p. 9.

[11] Case No. 2012-00578, Application of Kentucky Power Company for (1) a Certificate of Public Convenience and Necessity Authorizing the Transfer to the Company of an Undivided Fifty Percent Interest in the Mitchell Generating Station and Associated Assets; (2) Approval of the Assumption by Kentucky Power Company of Certain Liabilities in Connection with the Transfer of the Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral of Costs Incurred in Connection with the Company's Efforts to Meet Federal Clean Air Act and Related Requirements; and (5) All Other Required Approvals and Relief (Ky. PSC Oct. 7, 2013) (Hereinafter referred to as the "Mitchell Transfer Case").

[12] Case No. 2013-00144, Application of Kentucky Power Company for Approval of the Terms and Conditions of the Renewable Energy Purchase Agreement for Biomass Energy Resources Between the Company and ecoPower Generation-Hazard LLC; Authorization to Enter Into the Agreement; Grant of Certain Declaratory Relief; and Grant of all Other Required Approvals and Relief (Ky. PSC Oct. 10, 2013). The biomass facility is currently under development and it is anticipated that it will begin commercial operation in early 2017.

[13] 40 C.F.R. pts. 60 and 63.

April 16, 2012. The MATS rule sets forth standards for reducing the emissions of heavy metals (mercury, arsenic, chromium, and nickel) and acid gases (hydrochloric acid and hydrofluoric acid) and applies to new and existing coal- and oil-fired electric utility steam-generating units larger than 25 MW that produce electricity for consumption by the public. Existing units, such as BS1, will have until April 16, 2015, to be in compliance with the MATS rule.[14] A state's permitting agency has the authority to grant a one-year extension to install the control devices. Kentucky Power states that BS1 has, in fact, been granted such an extension until April 16, 2016, to achieve MATS compliance.[15]

In order for BS1 to comply with the MATS requirements, Kentucky Power maintains that it must install additional costly emission-control equipment,[16] switch fuels, or retire the unit. Due to the age of BS1, which was commissioned in 1963, and its relatively small size, Kentucky Power noted that the "relative economies of a large environmental investment"[17] option to retrofit BS1 with pollution-control equipment "lacked sufficient scale to merit consideration."[18] Kentucky Power ultimately determined that converting BS1 from a coal-fired to a natural gas unit is the least-cost alternative to comply with the MATS rule.

[14] Application, p. 4.

[15] Wohnhas Supplemental, p. 6.

[16] The pollution control technologies that would be needed to comply with MATS are flue gas desulfurization and selective catalytic reduction. *See* Application, p. 3.

[17] Weaver Testimony, p. 6

[18] *Id.*

KENTUCKY POWER'S ECONOMIC ANALYSIS

As part of its evaluation in determining the least-cost, reasonable solution to replacing the generation loss associated with the retirement of BS1, Kentucky Power issued a Request for Proposals ("RFP") on March 28, 2013, for up to 250 MW of capacity, energy, and potential ancillary services from designated "PJM Generation Capacity Resources."[19] The RFP sought proposals for a bundled product through a power-purchase agreement, tolling agreement, asset-purchase agreement, or other proposals as defined in the RFP.[20] The potential resource must have been capable of being online by June 1, 2015.[21] The RFP also sought proposals for demand-side management and cost-effective, energy-efficiency resources.[22]

In addition to the proposals solicited pursuant to the RFP, Kentucky Power also considered converting BS1 to a natural gas-fired generation unit.[23] The cost of the conversion project and the operating characteristics of the proposed conversion were developed by AEP Service Corporation's ("AEPSC") Projects, Controls, and Construction Group ("Projects Group").[24]

[19] Application, Exhibit 2, pp. 3-4. A "PJM Generation Capacity Resource" is defined in the RFP as a generation unit, or the right to capacity from a specified generating unit, that meets certain requirements under the PJM Reliability Assurance Agreement.

[20] *Id.*

[21] *Id.*

[22] *Id.*

[23] Direct Testimony of Joseph A. Karrasch ("Karrasch Testimony"), p. 3.

[24] *Id.*

The design, development, and management of the RFP process was directed by AEPSC's Development Group.[25] The evaluation of the proposals received in response to the RFP, including the BS1 conversion project, was performed by AEPSC's Evaluation Group.[26] In order to protect the integrity of the RFP process, the Development and Evaluation Groups were separated from the Projects Group and any affiliate of Kentucky Power that may have wished to participate in the RFP.[27] The purpose of the RFP was to allow Kentucky Power to utilize the results of the proposals to assess the least-cost, reasonable solution for replacing the BS1 generation as a coal-fired generating unit.[28]

In evaluating the best alternative for Kentucky Power to meet necessary capacity and energy requirements for its customers, Kentucky Power compared the long-term relative cumulative present worth ("CPW") of the BS1 natural gas conversion against two alternatives:

- Option 2A – Retire BS1 in June 2015 and replace the unit with purchases of capacity and energy from the PJM market for ten years, and then construct a new natural gas combustion turbine or combined-cycle units.
- Option 2B – Retire BS1 in June 2015 and replace the unit with bilaterally purchased capacity and energy from the "lowest cost" conforming offer received in response to the BS1 RFP.[29]

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[25] *Id.*

[26] *Id.*

[27] *Id.*

[28] Application, Exhibit 2, p. 3.

[29] Weaver Testimony, p. 4.

Kentucky Power utilized a long-term resource-optimization tool known as Strategist to identify the least-cost alternative.[30] Kentucky Power asserts that Strategist is a highly sophisticated and industry-wide-accepted economic-modeling software application and that it has utilized Strategist in determining the unit disposition proposals presented in Case No. 2011-00401[31] and Case No. 2012-00578.[32] [33] Kentucky Power notes that "the results from Strategist® offer a view of these relative, option-specific economics over the. . .[28]-year analysis study period . . . ."[34] In particular, the economic modeling evaluated each option on a systemwide basis by "being individually and mutually-exclusively substituted into Kentucky Power's resource portfolio *as an alternative to the continued operation of Big Sandy Unit 1 as a coal unit* effective June 1, 2015."[35]

The Strategist economic modeling runs utilized long-term forecasts of Kentucky Power's energy sales and peak demand ("load forecast"), as well as of the price of energy, capacity, coal, natural gas, and emissions allowances ("commodity forecast"), including the assumption of a carbon tax beginning in 2022.[36] The load forecast was developed internally by the AEP Economic Forecasting Group for Kentucky Power, and

[30] Weaver Testimony, p. 7.

[31] Case No. 2011-00401, Application of Kentucky Power Company for Approval of its 2011 Environmental Compliance Plan, for Approval of its Amended Environmental Cost Recovery Surcharge, and for the Grant of a Certificate of Public Convenience and Necessity for the Construction and Acquisition of Related Facilities (Ky. PSC May 31, 2012).

[32] Case No. 2012-00578, Kentucky Power Company (Ky. PSC Oct. 7, 2013).

[33] Weaver Testimony, p. 7.

[34] *Id.*

[35] Weaver Testimony, p. 12. (Emphasis in original).

[36] Weaver Testimony, p. 13.

the commodity forecast having been developed by the AEP Fundamental Analyst Group with the load forecast having been completed in June 2013 and the commodity pricing forecast having been completed in August 2013.[37]

Kentucky Power also utilized the pricing and performance data from the conforming responses to the BS1 RFP as benchmarks for the BS1 economic modeling process.[38] Regarding the performance assumptions in connection with the BS1 conversion proposal, Kentucky Power utilized a relatively higher heat rate, a lower capacity factor, and a relatively lower carbon dioxide emissions rate.[39] Regarding the estimated cost of the proposed conversion project, Kentucky Power indicated that the $50 million capital cost reflects sufficient risk contingency to ensure that the final job cost should not exceed the estimate.[40] According to Kentucky Power, the Strategist results offer an objective comparison of the CPW, or net present value, of costs over the 28-year study period for each of the options evaluated.[41]

When the actual cost of the pipeline lateral was subsequently utilized by Kentucky Power in its economic modeling rather than the preliminary indicative cost estimates, the updated economic analysis revealed that the proposed BS1 conversion had a lower CPW as compared to Option 2A, the market alternative, by approximately $148 million.[42] Although the economic modeling determined that Option 2B's CPW was

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[37] *Id. See Also*, Post Hearing Brief of Kentucky Power Company, pp. 9-10.

[38] Weaver Testimony, pp. 11-12.

[39] Walton Testimony, p. 6.

[40] Walton Testimony, p. 17.

[41] Weaver Testimony, p. 12.

[42] Kentucky Power's Response to Post-Hearing Data Requests, Item No.1, Attachment 1.

approximately $2.5 million lower than the CPW associated with the proposed refueling of BS1, Kentucky Power contends that such a difference is not material and well within the economic modeling's margin of error.[43] Kentucky Power contends that the benefits associated with the conversion of BS1 and the risks attendant with Option 2B tilt in favor of the proposed BS1 refueling as the "better least cost alternative."[44] Kentucky Power notes that Option 2B has risks such as counterparty risk, unit condition risk, and the fact that any power purchase agreement or tolling contract would be primarily under federal jurisdiction, rather than under the Commission's on-going jurisdiction.[45] In contrast, Kentucky Power asserts that the proposed BS1 conversion would eliminate all of the risks associated with the market alternative, but also would provide benefits such as allowing the company to diversify its fuel source mix in its generation portfolio (an increase to 18 percent natural gas generation post-conversion);[46] providing a physical hedge against potential higher-than-forecasted natural gas and attendant PJM energy prices;[47] and permitting Kentucky Power to retain a portion of its workforce and continue to pay taxes to the state and Lawrence County.

[43] Post Hearing Brief of Kentucky Power Company, p. 22.

[44] Post Hearing Brief of Kentucky Power Company, p. 23.

[45] Karrasch Testimony, pp. 10-12.

[46] Direct Testimony of Ranie K. Wohnhas, p. 7.

[47] Weaver Testimony, p. 17.

DISCUSSION

Legal Standard

No utility may construct or acquire any facility to be used in providing utility service to the public until it has obtained a CPCN from this Commission.[48] To obtain a CPCN, the utility must demonstrate a need for such facilities and an absence of wasteful duplication.[49]

"Need" requires:

> [A] showing of a substantial inadequacy of existing service, involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed or operated.
>
> [T]he inadequacy must be due either to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service.[50]

"Wasteful duplication" is defined as "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties."[51] To demonstrate that a proposed facility does not result in wasteful duplication, we have held that the applicant must demonstrate that a

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[48] KRS 278.020(1).

[49] *Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 252 S.W.2d 885 (Ky. 1952).

[50] *Id.* at 890.

[51] *Id.*

thorough review of all reasonable alternatives has been performed.[52] Selection of a proposal that ultimately costs more than an alternative does not necessarily result in wasteful duplication.[53] All relevant factors must be balanced.[54] The statutory touchstone for ratemaking in Kentucky is the requirement that rates set by the Commission must be fair, just and reasonable.[55]

Analysis of Need

Having reviewed the record and being otherwise sufficiently advised, the Commission finds that Kentucky Power has established a need for the proposed conversion of BS1. As Kentucky Power points out, BS1 as it is currently configured will be unable to comply with the MATS rule by April 16, 2016, without having either to make significant capital investments to add emissions control equipment or to convert the unit to burn natural gas instead of coal. Kentucky Power's decision to convert BS1 was the result of extensive analyses to determine the most reasonable least-cost alternative to comply with the MATS rule. Kentucky Power has sufficiently demonstrated that the power generated by BS1 is needed to meet the company's capacity and energy needs. The evidence of record indicates that, in the absence of BS1, Kentucky Power would be approximately 5 MW to 111 MW short of meeting its

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[52] Case No. 2005-00142, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky (Ky. PSC Sept. 8, 2005).

[53] *See Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 390 S.W.2d 168, 175 (Ky. 1965). *See also* Case No. 2005-00089, Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for the Construction of a 138 kV Electric Transmission Line in Rowan County, Kentucky (Ky. PSC Aug. 19, 2005).

[54] Case No. 2005-00089, East Kentucky Power (Ky. PSC Aug. 19, 2005), Order, p. 6.

[55] KRS 278.190(3).

PJM summer Unforced Capacity ("UCAP")[56] obligations from 2015 through 2019, if it is assumed that Kentucky Power would add new capacity or reduced load totaling 116 MW through biomass, wind, solar, demand-side management and energy-efficiency resources.[57] Because Kentucky Power is a winter-peaking system and its winter peak is approximately 300 MW higher than its summer peak, Kentucky Power's capacity-deficit position would be even more pronounced in the winter. The evidence showed that, without the BS1 capacity and again assuming 116 MW of additional new capacity or reduced load, Kentucky Power would be between approximately 157 MW and 254 MW short of the capacity needed to meet its projected winter peak loads for the planning years 2015 through 2028.[58]

Likewise, the evidence demonstrated that Kentucky Power would be energy short in the absence of BS1. For the planning year 2025, Kentucky Power would be energy short for approximately 1,026 hours, or 11.7 percent of the time for 2025.[59]

Analysis of Wasteful Duplication of Facilities

The Commission also finds that the proposed refueling of BS1 would not result in wasteful duplication of facilities. Kentucky Power maintains that the proposed refueling of BS1 is the optimal least-cost option compared to other available alternatives presented to deal with known environmental requirements. The analysis undertaken by

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[56] UCAP represents the amount of installed capacity that is available at any given time after discounting for time that an electric generating unit is unavailable due to outages.

[57] Kentucky Power Hearing Exhibit 1, p.1.

[58] *Id.*

[59] *Id.* at 2.

Kentucky Power demonstrates the proposed project's economic viability when evaluated in conjunction with other alternative scenarios.

In considering the decision currently before the Commission, we note that Kentucky Power's decision to convert BS1 was not made in isolation but was arrived at within the context of the company's decision to retire BS2 and to acquire an undivided 50 percent interest in the Mitchell Station and, to a lesser extent, the company's decision to enter into the renewable energy purchase agreement with a biomass merchant facility.[60] The Commission is also cognizant of the new reality within which Kentucky Power must operate with the termination on January 1, 2014, of the AEP Interconnection Agreement ("Pool Agreement"). Under the Pool Agreement, Kentucky Power, along with several other AEP affiliates, jointly operated their systems, which allowed Kentucky Power access to low-cost capacity and energy. Kentucky Power must now operate as a stand-alone utility and will be required to conduct resource planning to meet its load requirements. Kentucky Power's decision is constrained further by the potential additional costs imposed by more stringent environmental regulations, such as the recently issued EPA Clean Power Plan to regulate carbon emissions on existing power units.

The complexity of our review of Kentucky Power's proposal is heightened by the fact that its economic analysis utilizes forecasted assumptions, which we find overall to be reasonable, but any change in the assumptions utilized could have an impact on the outputs. An example might be the early Strategist modeling prior to or during the Mitchell Transfer Case in which it projected a 25 percent capacity factor for BS1 if it

[60] Case No. 2013-00144, Kentucky Power Company (Ky. PSC Oct. 10, 2013).

were to be kept in service as a gas-fired generating unit. Later in the process, as it reviewed the fuel requirements necessary for the lateral pipeline, Kentucky Power's Commercial Operations Organization utilized another modeling tool, Plexos, which predicted a reduced capacity factor between 9 to 16 percent for the refueled BS1.[61] Variances like these illustrate that the capacity process is not an exact science, yet one with multiple fluctuating components which the Commission is left to analyze when determining the best decision given the best information at the time.

The Commission finds that the proposed conversion of BS1 from a 278-MW coal-fired to a 268-MW natural gas-fired facility would bring that unit into MATS compliance. The change would utilize the majority of BS1's existing infrastructure, including such items as the steam turbine and electrical generator, electrical distribution system, condensate and feedwater systems, wastewater processing equipment, and the plant infrastructure and buildings. There will, however, be necessary changes to the steam-producing boiler, the control systems which monitor the natural gas system, and modifications to the associated balance of plant systems.[62] The conversion is expected to be completed by mid-May 2016.[63]

Kentucky Power provided information to the Commission concerning the BS1 conversion as far back as December 2011, when it filed with the Commission an application, later withdrawn, to retrofit BS2. In its subsequent filing, it proposed retiring

[61] Weaver, video transcript at 14:03.

[62] Walton testimony, pp. 4-5.

[63] *Id.* at 7.

BS2 and purchasing 50 percent of the Mitchell Station.[64] While Kentucky Power's application to acquire the Mitchell Station was pending before the Commission, Kentucky Power issued an RFP in March 2013. This RFP solicited least-cost, reasonable offers to supply up to 250 MWs to Kentucky Power as an alternative to keeping BS1 operating. The RFP was limited to projects within the PJM footprint that could be delivered by June 2015. Kentucky Power received qualifying proposals and evaluated them within the context of the Mitchell Transfer Case. The RFP analysis showed that the conversion of BS1 to natural gas was a lowest-cost proposal.[65] Based on this analysis, Kentucky Power notified the bidders that it opted to withdraw its RFP.[66]

The economic modeling for the BS1 conversion was first initiated prior to Kentucky Power's filing of its case to retrofit BS2 with a flue-gas desulfurization system. Kentucky Power withdrew the BS2 retrofit case and thereafter filed with the Commission the Mitchell Transfer Case, supported by an analysis that showed the combination of acquiring 50 percent of Mitchell with the BS1 refueling as the best least-cost alternative to meet current environmental regulations.[67] In the Mitchell Transfer Case, AEPSC utilized Strategist to analyze the viability of rational alternatives for replacing BS1 and BS2 over a 30-year period.

In the instant case, Strategist analyzed a number of reasonable economic alternatives over a 28-year projection for Kentucky Power to consider before

[64] Kentucky Power evaluated 11 different scenarios in Case No. 2012-00578, including the refueling of BS1 in combination with the acquisition of 50 percent of the Mitchell plants.

[65] Weaver Testimony, p. 18.

[66] By the time of the RFP withdrawal, the bids had already expired.

[67] Case No. 2012-00578, Kentucky Power Company (Ky. PSC Oct. 7, 2013), Order, p. 16.

determining that refueling was a least-cost alternative. In an effort to verify this position, Kentucky Power modeled the "worst case" reasonably anticipated cost-overrun scenario.[68] It further updated and used the most recent June 2013 load forecast projection developed by the AEP Economic Forecasting Group. Upon receiving estimates from utility consultants and natural gas transporters, it ran these estimates through the "worst case reasonably anticipated" cost-overrun scenario of the model.[69] To further ensure a robust cost analysis, Kentucky Power used a budget estimator with a 99.9 percent probability of correctness to ensure that all possibilities in the refueling process were included and evaluated such that the resulting estimate was sufficiently robust. With these current and substantial inputs in place, Strategist preferred the refueling option of choice, thereby assuring it as a least-cost option.

At the time Kentucky Power filed this case with the Commission, it had firm projections concerning the cost to convert BS1; however it had not released its January 2014 RFP to obtain firm costs for the lateral pipeline. Although it did not have a firm cost for the gas lateral, for modeling purposes in this case, Kentucky Power utilized cost estimates acquired from FERC-regulated pipeline companies for similar pipeline construction.[70] In this case, the lateral pipeline will be owned and operated by the winning bidder, who is responsible for acquiring all necessary permits and regulatory approvals. All costs associated with the construction of the lateral pipeline will be borne by the winning bidder, and recovered from Kentucky Power over a 15-year term. In May 2014, Kentucky Power received nine pipeline bids from seven bidders, then

[68] Weaver video transcript at 11:25.

[69] This setting ensures with 70 percent probability that the projected cost will be a maximum cost.

[70] Walton testimony, p. 9

reviewed the conforming bids received for the lowest-cost proposal and notified the winner bidder.

Kentucky Power selected Columbia Gas Transmission, LLC ("Columbia Gas") to construct and operate the $49.35 million (present value) lateral pipeline. The Columbia Gas lateral pipeline will be constructed exclusively for use by Kentucky Power at the Big Sandy station, will be in service by June 1, 2016, and includes guaranteed firm transmission rights on the Columbia Gas Interstate transmission line. To further support the refueling position as the best least-cost alternative, the lateral pipeline proposal came in $14 million dollars lower than the modeled cost.

Kentucky Power contends that purchasing natural gas on the spot market is appropriate for BS1. The plant will operate as a load-following unit, will be dispatched by PJM, and will remain on line in much the same fashion as a base-load unit. As a load follower, the plant will present difficulties in predicting when it will clear the market and how long it will remain in service. Given that a converted BS1 will operate as a load-following unit, the Commission finds that Kentucky Power makes a compelling argument that having the opportunity to purchase gas when it is needed is more flexible than being tied to a long-term gas purchase contract.[71]

The Commission further finds that the conversion preserves a viable generating plant operating within the Commonwealth, thus retaining some of the current employees and supporting the local tax base. A converted BS1 also permits Kentucky Power to evolve from a utility whose generation has been significantly reliant on coal to one which

[71] Kentucky Power's Response to Commission Staff's Initial Request for Information, Item 3.

is diversifying its fuel supply. This modification should further allow Kentucky Power to adapt to regulatory or economic changes targeted at a single fuel source.

As noted above, before the Commission authorizes a CPCN, it must find that there is a need and an absence of wasteful duplication. Further, the proposal must be feasible in terms of its impact on rates. The Commission has examined the complex facts and circumstances of this matter, including, but not limited to, existing and proposed EPA regulations; the termination of the AEP Pool Agreement; the multiple economic modeling and commodity pricing assumptions therein; the projected PJM energy pricing and the inherent risks and price volatility of market purchases; and the inclusion of this proposal as an element of Kentucky Power's resource mix as presented in the Mitchell Transfer Case and in Kentucky Power's recently filed IRP.[72] Accordingly, based on the facts of this case, the Commission finds the proposal satisfies the statutory requirements that there is a need, and an absence of wasteful duplication. Here, as in the Mitchell Transfer Case, Kentucky Power's proposal is the most reasonable lowest-cost available option and, therefore, the proposal is feasible in terms of its impact on rates.

IT IS THEREFORE ORDERED that:

1. Kentucky Power's request for a Certificate of Public Convenience and Necessity pursuant to KRS 278.020(1) and 807 KAR 5;001, Section 15, to convert Big Sandy Unit 1 from a coal-fired generating unit to a natural gas-fired generating unit is approved.

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[72] Case No. 2013-00475, Integrated Resource Planning Report of Kentucky Power Company to the Kentucky Public Service Commission (Application filed Dec. 20, 2013).

2. Within 30 days of the completion of the conversion of BS1, Kentucky Power shall file with the Commission the actual cost of the construction.

3. Any documents filed in the future pursuant to ordering paragraph 2 herein shall reference this case number and shall be retained in utility's general correspondence file.

By the Commission

ENTERED
AUG 01 2014
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

Kenneth J Gish, Jr.
Stites & Harbison
250 West Main Street, Suite 2300
Lexington, KENTUCKY 40507

Honorable Michael L Kurtz
Attorney at Law
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

Honorable Mark R Overstreet
Attorney at Law
Stites & Harbison
421 West Main Street
P. O. Box 634
Frankfort, KENTUCKY 40602-0634

Ranie Wohnhas
Managing Director
Kentucky Power Company
101 A Enterprise Drive
P. O. Box 5190
Frankfort, KY 40602

Kentucky Power Company

REQUEST

Reference Kentucky Power's Response to PSC 1-1(b), Attachment 1. Under the heading "Transmission," KPCo indicates it plans capital spending in excess of $25 million during the 2014-2016 period for what it terms "reliability." Provide a detailed list of each project which falls under the "reliability" category, together with a reason for each project.

RESPONSE

Please see Attachment 1 to this response.

WITNESS: Ranie K Wohnhas

Kentucky Power Transmi[illegible]pital Detail
dollars in millions

Project Type	Project ID	Project Name	Reason	2014	2015	2016
Reliability	P11028013 TAPROWLine work at Elkhorn	Bluefield System Improvement Project	Project to solve voltage criteria and excessive outage concerns in Bluefield - Pikeville Area	0.1	0.0	0.0
	P13039016 D/KP/Prestonsburg Land Purchas	Prestonsburg Area Conversion	Replace nonstandard 46 kV network with 69/138 kV	0.0	0.1	0.0
	P12001003 TKPBEAVER CREEK - Remote End	Cedar Creek Station Improvements	Project to solve voltage criteria on Cedar Creek area 69 kV subtransmission due to loss of Beaver Creek - Johns Creek 138kV line.	0.0	0.1	0.1
	P11028010 TKPLine work at Elkhorn City	Bluefield System Improvement Project	Project to solve voltage criteria and excessive outage concerns in Bluefield - Pikeville Area	0.0	0.1	0.1
	P11028008 TKPLine work at Elkhorn City	Bluefield System Improvement Project	Project to solve voltage criteria and excessive outage concerns in Bluefield - Pikeville Area	0.0	0.1	0.1
	P11028009 TKPLine work at Elkhorn City	Bluefield System Improvement Project	Project to solve voltage criteria and excessive outage concerns in Bluefield - Pikeville Area	0.0	0.1	0.1
	P12104006 T/KP/Bellefonte 138kV Remote R	Portsmouth Area SCADA Installations - Phase 2	Improve SCADA penetration	0.0	0.2	0.0
	000015466 T/KyP/KY-BELLEFONTE 138/69 kV	Bellefonte 138 kV: 138/69 kV Upgrades	Project addresses thermal criteria by replacing Bellefonte 138/69kV transformer	0.3	0.0	0.0
	000010377 Forestry KY T NERC	Forestry T NERC - KP	Provide resources to complete capital vegetation management clearing, including ROW widening and trimming for all KP Transmission jurisdictions	0.1	0.1	0.1
	TP0921003 T/KyPCO/Trans two 69kV Structu	Hazard Area Improvements	Project to address thermal/voltage criteria in Hazard area	0.3	0.0	0.0
	P10115003 TKPStone Tap - Retire	Johns Creek, Stone, and Inez Station Improvement	Improve 138 kV sectionalizing capabilities and reduce outage times	0.2	0.2	0.0
	P11028016 TKPBreaks 69kV Extension - C	Bluefield System Improvement Project	Project to solve voltage criteria and excessive outage concerns in Bluefield - Pikeville Area	0.0	0.3	0.0
	TP0921007 TKPHazard-Jackson 69kV Line	Hazard Area Improvements	Project to address thermal/voltage criteria in Hazard area	0.2	0.0	0.0
	TP1015202 T/KY/Baker 765/345 kV Trf Addi	Baker Transformer	Project to address PJM identified thermal criteria by adding second transformer at Baker.	0.1	0.3	0.1
	P13039007 T/KP/Kenwood Station: Replace	Looped Service to Kenwood Station	Project to address operational/safety concerns at Kenwood and Van Lear S.S. Will also eliminate radial feed to Kenwood, improving reliability	0.0	0.6	0.0
	P12122001 T/KP/Raceland Station SCADA Up	KPCO Ashland Area SCADA Improvements	Improve Kentucky SCADA penetration	0.1	0.1	0.4
	P12122003 T/KP/Belhaven Station SCADA Up	KPCO Ashland Area SCADA Improvements	Improve Kentucky SCADA penetration	0.1	0.1	0.4
	P12122004 T/KP/Howard Collins Station SC	KPCO Ashland Area SCADA Improvements	Improva Kentucky SCADA penetration	0.1	0.1	0.4
	P12122006 T/KP/Siloam Station Station SC	KPCO Ashland Area SCADA Improvements	Improve Kentucky SCADA penetration	0.1	0.1	0.4
	P12057001 T/KP/BECKHAM-Install two 138kV	Beckham Station Circuit Breaker Installation	Project to address AEP Momentary Permanent Outage Index (MPOI) planning criteria by eliminating too many MOABs in series.	0.0	0.0	0.6
	P12026001 TKYDorton-RetireRemove Equi	Dorton 138kV Circuit Breaker Installation	Project will alleviate thermal issues identified in PJM 2015 Gen. Retirement studies. Will address MPOI criteria on Beaver Creek - Clinch River 138kV circuit.	0.3	1.0	0.0
	P10115002 TKPStone-RetRem Switches	Johns Creek, Stone, and Inez Station Improvement	Improve 138 kV sectionalizing capabilities and reduce outage times	0.3	1.4	0.0
	P10115001 TKPJohns Creek-RetRem MOABs	Johns Creek, Stone, and Inez Station Improvement	Improve 138 kV sectionalizing capabilities and reduce outage times	0.9	0.8	0.0
	000012898 Forestry KP T non-NERC	Forestry T non-NERC - KP	Provide resources to complete capital vegetation management clearing, including ROW widening and trimming for all KP Transmission jurisdictions	0.6	0.6	0.6
	P12001001 TKPCedar Creek-RetireRemove	Cedar Creek Station Improvements	Project to solve voltage criteria on Cedar Creek area 69 kV subtransmission due to loss of Beaver Creek - Johns Creek 138kV line.	0.0	1.7	1.2
	P11028004 Elkorn City Station Rebuild	Bluefield System Improvement Project	Project to solve voltage criteria and excessive outage concerns in Bluefield - Pikeville Area	0.0	7.9	1.4
Reliability	Sum:			3.7	16.0	6.2

Kentucky Power Company

REQUEST

Reference Kentucky Power's Response to PSC 1-1(b), Attachment 1. Under the heading "Transmission," KPCo indicates it plans $4.5 million in capital spending for "customer service." Explain why KPCo's retail customers should have to pay for transmission-level customer service.

RESPONSE

First and foremost, the Company has an obligation to provide service to customers, whether at transmission voltages, primary voltages or secondary voltages. Further, since the transmission system is needed to move power from generators to the local distribution system, all retail customers pay for both generation and transmission service. Most customers receive service at distribution voltages and also pay for distribution service, while all customers pay for metering, billing, customer accounting and customer service related costs.

Transmission-level customer service expenditures generally relate to improvements to the transmission system to accommodate the provision of service to large commercial and industrial customers. Any customer specific expenditures may also be subject to the extension of service requirements of the Commission's regulations and Company's terms and conditions of service. In all events the costs of providing service are allocated to customer classes based upon cost-causation principles as part of the Company's class cost of service study in a rate application.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Reference Kentucky Power's Response to PSC 1-1(b), Attachment 1. Under the heading "Reliability/Asset Program," KPCo indicates it plans capital spending in excess of $26 million over the 2014-2016 time period. Provide a detailed list of each project which falls under this category, together with a reason for each project under the "Reliability/Asset Program."

RESPONSE

Please see Attachment 1 to this response.

WITNESS: Ranie K Wohnhas

Kentucky Power Distribution Capital Detail
dollars in millions

Project Type	Project ID	Project Name	Reason	2014	2015	2016
Reliability/Asset Program	A13212009 D/KP/Coalton - Telecom Legacy	Coalton - Telecom Legacy Circuit Upgrades	Upgrade of Telephone Co services to mitigate price increase	0.1	-	-
	A13212010 D/KP/Coleman - Telecom Legacy	Coleman - Telecom Legacy Circuit Upgrades	Upgrade of Telephone Co services to mitigate price increase	0.1	-	-
	A13212011 D/KP/Salisbury (KP) - Telecom	Salisbury (KP) - Telecom Legacy Circuit Upgrades	Upgrade of Telephone Co services to mitigate price increase	0.1	-	-
	A13212014 D/KP/Topmost - Telecom Legacy	Topmost - Telecom Legacy Circuit Upgrades	Upgrade of Telephone Co services to mitigate price increase	0.1	-	-
	A13212015 D/KP/Whitesburg - Telecom Lega	Whitesburg - Telecom Legacy Circuit Upgrades	Upgrade of Telephone Co services to mitigate price increase	0.1	-	-
	A13212012 D/KP/Soft Shell - Telecom Lega	Soft Shell - Telecom Legacy Circuit Upgrades	Upgrade of Telephone Co services to mitigate price increase	0.1	-	-
	A13212016 D/KP/Stinnett - Telecom Legacy	Stinnett - Telecom Legacy Circuit Upgrades	Upgrade of Telephone Co services to mitigate price increase	0.1	-	-
	P12057002 D/KP/HAZARD-Remote End Relay U	Beckham Station Circuit Breaker Installation	Component - Hazard Remote End Relay Upgrades	-	-	0.2
	P13037002 D/KP/Beaver Creek Station - Re	Fremont Station Improvement Project	Component - Remote end relay changes on Beaver Creek - Freemont 138 kV line	-	-	0.2
	TP0921001 DS/KYPCO/Beckham 138kV Cntl Ho	Beckham 138 kV Control House at Station	Component of the transmission voltage support for area	0.3	-	-
	000008184 KP Asset Programs Eng Support	Asset Programs Engineering Support	Engineering Support for overhead Work Orders for Assest Programs	0.2	0.2	0.2
	P12124003 DKPLOVELY Station SCADA Upgr	Area SCADA Improvements	SCADA Upgrade	0.5	-	-
	TP1010502 DSKPCOBusseyville 138kV upgr	Busseyville Station 138 kV Upgrades	Replace 138 kV bus and risers	0.5	-	-
	000016528 KYCutout-Arrester	Kentucky Cutout and Arrester Program	Replacing cutouts and arresters	0.5	0.5	0.5
	EDN014680 Ds-Kp-AI Pole Replacement	Asset Improvement Program Pole Replacement	Replacing of poles found from circuit inspection or ground line treatment program	0.5	0.6	0.6
	EDN014720 Ds-Kp-AI Recloser Replacement	Asset Improvement Program Recloser Replacement	Replacing of reclosers to perform cyclical maintenance	0.6	0.6	0.6
	P12057003 D/KP/BEAVER CREEK-Remote End R	Beckham Station Circuit Breaker Installation	Component - Remote end relay changes on Beaver Creek - Hazard 138 kV line	-	0.3	2.0
	000008169 KP Asset Imp Eng Support	Asset Improvement Engineering Support	Engineering Support for overhead Work Orders for Assest Improvements	0.8	0.8	0.8
	000007599 KP-Failed Equip No Outage	Failed Equipment No Outage	Replacing tagged defective equipment where no outage occurred	1.1	1.2	1.2
	000007818 KP/Small Local Asset Improv	Small Local Asset Improvements	Small projects where asset improvements are made	1.5	1.6	1.6
	000001745 KP Reliability Improvements	Reliability Improvements	General (non specific projects) with focus on improving reliability circuit indices	4.9	0.8	0.4
Reliability/Asset Program	Sum:			12.0	6.5	8.4

Kentucky Power Company

REQUEST

Reference Kentucky Power's Response to PSC 1-1(b), Attachment 1. Under the heading "Customer Service," KPCo indicates it plans in excess of $36 million in capital spending during the 2014-2016 time period. Provide a detailed list of each project which falls under this category, together with a reason for each project.

RESPONSE

The $37.3 million distribution customer service capital expenditures projected during 2014-2016 is an estimate based upon historical expenditures for customer service work and is not established on a project by project basis. Thus, the Company cannot provide the requested information. Examples of such capital expenditures include new service installs and service upgrades.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

For each item of proposed capital spending identified in KPCo's response to PSC 1-1(b), Attachment 1, state whether KPCo in any prior proceeding sought Commission approval for any such project, or any project similar to it, but in which approval for such spending was denied. In each such case, provide a citation to the specific case number.

RESPONSE

None of the capital projects identified in the Company's response to KPSC 1-1(b) was the subject of, or similar to, the subject of any Commission certificate of public convenience and necessity proceeding in which approval was denied.

WITNESS: Ranie K Wohnhas