EXHIBIT RCS-16

Kentucky Power Company

REQUEST

With regard to the proposed Kentucky Economic Development Surcharge, please confirm
that all funds collected will go solely toward economic development, and exclusively within the KPCo service territory. If not, why not?

RESPONSE

Kentucky Power confirms the statement. All funds collected through the K.E.D.S. tariff will be directed to economic development in the Company's service territory.

WITNESS: John A Rogness

American Electric Power Company, Inc.
2013 Gain Sharing Plan

Introduction

AEP is searching for sustainable cost savings in connection with its current business plan. The objectives of the 2013 Gain Sharing Plan (the Plan) are to:

- Align and create an avenue for all employees to contribute to the sustainable savings target;
- Create an environment that is not just about cutting Operations and Maintenance (O&M) costs, but focused on new ideas and on working differently in the future that will lead to savings; and
- Create a line of sight for each employee to contribute to the generation of innovative or money saving ideas that result in a direct benefit for AEP in 2013.

Overview

The current AEP budget assumes that the Company will achieve $200 million of sustainable savings for 2013 (the "2013 Target"). Under this Plan, AEP would share with the eligible Participants 50% of meaningful sustainable savings and additional revenues that result in AEP exceeding the 2013 Target. The payout cap generally will be $1,000 per eligible Participant.

Terms & Conditions

Gain Sharing

Employees are encouraged to submit cost-saving and revenue-enhancing ideas. AEP Management reserves full discretion to decide whether, when and how any of the submitted ideas will be implemented. To the extent AEP generates meaningful sustainable savings and additional revenues that result in AEP exceeding the 2013 Target, there will be a payout to the eligible Participants.

A Committee has been formed to administer this Plan. The Committee will have full discretionary authority to make all determinations under this Plan, including but not limited to,

- Whether and to what extent AEP achieves savings and additional revenues for 2013 that both (a) exceed the 2013 Target and (b) are sustainable into future years. That sustainable excess is referred to in this Plan as the "Gain;"
- The number and identity of the Participants who will be considered eligible for the payment of an award under this Plan;
- The amount payable under this Plan to eligible Participants, which shall not exceed Fifty Percent (50%) of the Gain (the "Gain Sharing Pool");
- The Gain Sharing Pool generally shall be allocated among the eligible Participants, using the following guidelines:
    - The share for each eligible Participant shall be prorated based upon the number of whole or partial months during calendar year 2013 that such Participant was on the payroll of a Participating AEP System Company;

  - The share for each eligible Participant classified by AEP as a part time employee shall be further reduced by applying a percentage equal to the percentage of full-time status that such Participant's estimated regular work schedule approximately represents.
  - The non-prorated full share for any eligible Participant shall not exceed $1,000 of regular bonus pay (the "Payout Cap");
  - The Committee shall take into account the impact of applicable law, including wage and hour laws, on the amount payable to eligible Participants who are entitled to overtime pay during 2013;
  - The Committee may further enhance the share of eligible Participants who receive overtime pay during 2013 in a manner similar to that implemented for compliance with applicable law; and
- Whether the Gain is meaningful, provided that the Gain shall not be considered meaningful if it would result in a Gain Sharing Pool that would provide a payout of less than $50 to any eligible Participant who is classified by the Committee as a full time employee for the entire 2013 calendar year.

All determinations by the Committee shall be final and binding on all interested persons.

All payments shall be subject to such taxes, deductions and withholdings determined by the Committee to be required by law or otherwise appropriate.

Committee

The Committee consists of American Electric Power Service Corporation's Chief Executive Officer & President, Chief Operating Officer, Chief Financial Officer, Chief Administrative Officer, General Counsel and top Human Resources officer. The CEO of American Electric Power Company, Inc. may change the composition and number of members of the Committee at any time for any reason. The Committee may delegate day-to-day authority to administer the Plan, as they deem appropriate. In lieu of an official meeting, the Committee may act by written or electronic consent of a majority of its members.

The Committee's interpretations of the Plan provisions are conclusive and binding on all Participants.

The Committee has sole authority to amend or terminate the Plan and may do so at any time, for any reason, either with or without notice. The Committee may adopt, delete, modify or adjust the manner in which Gain is to be measured at any time, including after the conclusion of 2013, should the Committee determine that changes in AEP structure or other significant business situations would result in a Gain for the year that is not reflective of the actual performance of the business. The Committee may also modify the eligibility criteria for the Plan and add or delete individual participants or groups of participants.

Participation

All AEP employees classified as full-time or regular part-time on the payroll of a Participating AEP System Company at the time a gain sharing award payment is made under this Plan will be "Participants" in the Plan for 2013 except:

1. Any employee who is an Executive Officer (that is, those employees identified by AEP as subject to the disclosure requirements set forth in Section 16 of the Securities Exchange Act of 1934, as amended) at any time between January 1, 2013 and the date the payment of any award under this Plan,
2. Any employee represented by unions that have not accepted the opportunity to participate in the Plan prior to December 31, 2013,
3. Individuals classified by AEP as temporary employees, co-ops, interns, contract workers and any other non-employee status as of December 31, 2013
4. Employees who have received no Qualifying Pay during calendar year 2013; and
5. Employees hired (or last rehired) by AEP on or after December 1, 2013.

Each direct or indirect wholly owned subsidiary of American Electric Power Company, Inc., which has employees on its payroll shall be considered a Participating AEP System Company, except that Bluestar Energy S.A.C. shall not be considered a Participating AEP System Company for purposes of this Plan.

For purposes of this Plan, "Qualifying Pay" shall include only: (1) Regular Earnings – Straight Rate; (2) Paid Vacation; (3) Paid Holidays; (4) Paid Personal Days Off; (5) Sick Pay (Non-occupational & Occupational); (6) Paid Jury Duty; (7) Paid Death in Family; (8) Paid Rest Period; (9) Inclement Weather Pay; (10) Lump Sum Merit Increase; (11) Lump Sum General Increase; (12) Grievance Settlement for Wages; (13) Overtime – Nonexempt and Exempt; (14) Shift Premium; (15) Sunday Premium; (16) Military Pay; and (17) Trip Pay (River). Earnings not classified as one of the above types in the AEP payroll system are not considered "Qualifying Pay" for purposes of determining eligibility for an award.

Participation in this Plan shall not confer any right to continued employment or to continued participation in any replacement or successor program.

Plan Participants are expected to comply with all applicable Company policies and directives as well as all applicable laws and regulations. Failure to do so may have many serious consequences, including but not limited to forfeiture of Plan eligibility in the current and future years.

Participants must be employed on the payroll of a Participating AEP System Company at the time of payment of a gain sharing award to be eligible to receive a gain sharing award for 2013, except as otherwise noted below. Individuals will not be eligible for an award if not on the payroll of a Participating AEP System Company at the time of payment, regardless of the reason they are not on such a payroll (e.g., if the Participant would die, retire, sever, resign or otherwise terminate their employment).

If a Participant transfers on or before December 31, 2013 to a position that is ineligible to participate in the Plan, then such Participant will be ineligible to receive an award from the Plan for 2013.

Satisfaction of eligibility criteria does not guarantee the payment of any award.

Award Payment

Award payment will be made within 2-1/2 months after the end 2013 or as soon as practical thereafter if it is impractical, either administratively or economically, to make payments within this time period.

EXHIBIT RCS-17

Kentucky Power Company

REQUEST

Provide all schedules, workpapers, and computations in electronic spreadsheet format with all formulas intact. For all input values, provide the source documents and/or calculations, including all electronic spreadsheets with all formulas intact.

RESPONSE

In addition to Sections IV and V, which were filed on December 23, 2015 as excel spreadsheets, the requested documents are attached as follows:

Attachment numbers	Witness
1 through 31	Davis
32	McCoy
33 through 36	Stegall
37 through 55	Vaughan
56 through 57	Reitter
58 through 72	Yoder
73 through 78	Wohnhas
79 through 83	LaFleur
84 through 151	Avera/McKenzie *Please note, the yellow highlighting in KIUC_1_17_Attachment 91 was for internal purposes only and does not indicate confidentiality.
152 through 167	Rogness
168 through 198	Elliott

WITNESS: Ranie K Wohnhas

AEV WP 2

Kentucky Power Company

Adjustment to PJM Charges and Credits to Reflect the AEP East Pool Termination, Removal of Big Sandy 1 & 2 PJM Charges and Annualization of Stand Alone PJM Charges
Test Year Twelve Months Ended 9/30/2014

LINE NO.	DESCRIPTION	KPCO TOTAL COMPANY ADJUSTMENT	ALLOCATION FACTOR	KENTUCKY PSC RETAIL JURISDICTION ADJUSTMENT	
	Operating Expenses				
1	Energy Related	$ 1,593,344	Energy	$ 1,571,037	
2	Demand Related	$ 6,007,677	PDAF/Specific	$ 6,013,265	
3	Total	$ 7,601,021		$ 7,584,302	**Increase Operating Expense**

PJM Adjustment Calculations AEV WP 2
KPCo 12 Months Ended September 30, 2014
Positive amounts are charges (expense) negative amounts are credits (revenue)

	FERC Account	Account Name	Test Year Per Books	Remove Pool (Q4 2013)	Remove Big Sandy1	Remove Big Sandy2	Reclass MWh from OSS to Serve LSE	Add Incremental LSE Congestion Costs	January - September 2014 Sub Total	Anualization Adj	Going Level LSE PJM Charges and Credits	Total of Adjustments	Kentucky PSC Jurisdiction Allocation Factor		Kentucky PSC Jurisdiction Total Adjustment
PJM	4470093	PJM Implicit Congestion-LSE	20,004,934	(1,250,735)	(4,562,334)	(14,017,902)	11,822,355	2,783,354	14,779,673	4,926,558	19,706,230	(298,704)	Energy	0.986	$ (294,522)
PJM	4470101	PJM FTR Revenue-LSE	(9,650,962)	826,791					(8,824,172)	(2,941,391)	(11,765,562)	(2,114,600)	Energy	0.986	$ (2,084,996)
PJM	4470116	PJM Meter Corrections-LSE	(53,563)	29,886					(23,677)	(7,892)	(31,569)	21,994	Energy	0.986	$ 21,686
PJM	4470202	PJM OpRes-LSE-Credit	(1,937,677)	1,280,467	115,255	137,461			(404,494)	(134,831)	(539,325)	1,398,352	Energy	0.986	$ 1,378,776
PJM	4470203	PJM OpRes-LSE-Charge	5,537,329	(748,077)					4,789,252	1,596,417	6,385,669	848,340	Energy	0.986	$ 836,463
PJM	5550040	PJM Inadvertent Mtr Res-LSE	(42,077)	16,223					(25,854)	(8,618)	(34,472)	7,605	Energy	0.986	$ 7,499
PJM	5550041	PJM Ancillary Serv.-Sync	5,611	50					5,661	1,887	7,548	1,937	Energy	0.986	$ 1,910
PJM	5550074	PJM Reactive-Charge	(10,125)	(1,702)					(11,826)	(3,942)	(15,769)	(5,644)	PDAF	0.986	$ (5,565)
PJM	5550075	PJM Reactive-Credit	28,427	(28,426)					1	0	1	(28,425)	PDAF	0.986	$ (28,027)
PJM	5550076	PJM Black Start-Charge	2,003,256	(776,903)					1,226,353	408,784	1,635,138	(368,118)	PDAF	0.986	$ (362,965)
PJM	5550077	PJM Black Start-Credit	(3,073)	3,073					(0)	(0)	(0)	3,073	PDAF	0.986	$ 3,030
PJM	5550078	PJM Regulation-Charge	1,914,421	(225,120)					1,689,301	563,100	2,252,401	337,980	Energy	0.986	$ 333,248
PJM	5550079	PJM Regulation-Credit	(434,775)	21,186	121,628	481,229			189,267	63,089	252,357	687,132	Energy	0.986	$ 677,512
PJM	5550083	PJM Spinning Reserve-Charge	1,381,828	(33,999)					1,347,829	449,276	1,797,106	415,278	Energy	0.986	$ 409,464
PJM	5550084	PJM Spinning Reserve-Credit	(340,677)	17,297	44,365	85,007			(194,008)	(64,669)	(258,678)	81,999	Energy	0.986	$ 80,851
PJM	5550090	PJM 30m Suppl Rserv Charge LSE	382,926	3,731					386,657	128,886	515,543	132,617	Energy	0.986	$ 130,760
PJM	5550093	Peak Hour Avail charge - LSE	(67,133)	-					(67,133)	-	(67,133)	-	PDAF	0.986	$ -
PJM	5614001	PJM Admin-SSC&DS-Internal	626,172	(134,296)	(19,025)	(58,624)	77,649		491,877	163,959	655,835	29,663	Energy	0.986	$ 29,248
PJM	5618001	PJM Admin-RP&SDS- Internal	149,196	(32,322)					116,874	38,958	155,832	6,636	Energy	0.986	$ 6,543
PJM	5757001	PJM Admin-MAM&SC- Internal	688,223	(144,220)					544,003	181,334	725,337	37,114	Energy	0.986	$ 36,594
PJM Subtotal			20,182,261	(1,177,095)	(4,300,110)	(13,372,829)	11,900,004	2,783,354	16,015,584	5,360,906	21,376,490	1,194,229			$ 1,177,510
OATT	4561035	Network Integrated Transmission S	37,238,858						37,238,858	4,353,853	41,592,711	4,353,853	Direct to KY Retail		$ 4,353,853
OATT	5650016	Network Integrated Transmission S	5,140,478						5,140,478	601,009	5,741,487	601,009	Direct to KY Retail		$ 601,009
OATT	4561005	Firm and Non-Firm Point to Point Tr	(680,082)						(680,082)		(680,082)	-	Direct to KY Retail		$ -
OATT	4561036	Schedule 1a Charges	614,746						614,746		614,746	-	Direct to KY Retail		$ -
OATT	5650015	Schedule 1a Charges	41,137						41,137		41,137	-	Direct to KY Retail		$ -
OATT	4561060	Transmission Enhancement Charge:	459,418						459,418	147,476	606,894	147,476	Direct to KY Retail		$ 147,476
OATT	5650012	Transmission Enhancement Charge:	3,976,612						3,976,612	1,276,511	5,253,123	1,276,511	Direct to KY Retail		$ 1,276,511
OATT	5650019	Transmission Enhancement Charge:	355,174						355,174	114,013	469,187	114,013	Direct to KY Retail		$ 114,013
OATT	4561002	RTO Formation Costs	140,253						140,253		140,253	-	Direct to KY Retail		$ -
OATT	4561003	Expansion Cost Recovery Charge	86,070						86,070	(86,070)	-	(86,070)	Direct to KY Retail		$ (86,070)
OATT Subtotal			47,372,664	-	-	-	-	-	47,372,664	6,406,792	53,779,456	6,406,792			$ 6,406,792
Total of Net PJM Tracker Accounts											75,155,946	7,601,021			
											$ 54,675,810	$ 6,007,677	Total Demand Adj		$ 6,013,265
											$ 20,480,136	$ 1,593,344	Total Energy Adj		$ 1,571,037
											$ 75,155,946	$ 7,601,021	Total O&M Adj		$ 7,584,302

AEV WP 2

SUBACCOUNT AEPKPD

OP_MONTH (Multiple Items)

Row Labels	Sum of DA_OP_RES	Sum of BAL_LOST_OP_CR	Sum of REG_RMCCP	Sum of REG_RMPCP	Sum of REG_LOST_OPPORTUNITY_COST	Sum of SYNCH_RESERVE_TIER1	Sum of SYNCH_SRMCP	Sum of SYNCH_RES_LOST_OPPORTUNITY
AEP BIG SANDY 1		152,658	65,341	4,886	51,401	24,094	16,523	3,748
AEP BIG SANDY 2		182,070	145,524	11,019	324,686	54,932	18,904	11,171
Grand Total		334,728	210,865	15,905	376,087	79,026	35,427	14,919
		LRS	Net	Net	Net	Net	Net	Net

SUBACCOUNT AEPKPD

Regulation LOC credits from test year

Sum of BAL_LOST_(	Column Labels								
Row Labels	AEP BIG SA	AEP BIG SANDY 2	Grand Total	KPD	OSS Ratio	LSE Ratio	BS 1 LSE LOC Credit	BS 2 LSE LOC Credit
Jan-14	152,658	182,070	334,728	1/1/2014	0.24501	0.75499	115,255.26	137,461.03
Feb-14		-	-	2/1/2014	0.23695	0.76305		
Mar-14		-	-	3/1/2014	0.24064	0.75936		
Apr-14		-	-	4/1/2014	0.32194	0.67806		
May-14		-	-	5/1/2014	0.1836	0.8164		
Jun-14		-	-	6/1/2014	0.36622	0.63378		
Jul-14		-	-	7/1/2014	0.32581	0.67419		
Aug-14		-	-	8/1/2014	0.37329	0.62671		
Sep-14		-	-					
Grand Total	152,658	182,070	334,728					

KPSC Case No. 2014-00396 General Rate Adjustment
KIUC First Set of Data Requests
Dated January 29, 2015
Item No. 90
Page 1 of 1

Kentucky Power Company

REQUEST

Please provide detailed workpapers, electronically with all formulas intact, showing how PJM charges were derived that were added back in that the Company assumed it would incur to serve internal load without having BS2. Also, explain why administrative fees for both BS1 and BS2 were added back in, when Mr. Vaughan at line 7 of page 25 states that administrative fees for just BS2 had to be added back in.

RESPONSE

See the Company's response to KIUC 1-17, specifically see KIUC_1_17_Attachments 40 and 41 for the requested workpapers regarding the amounts in columns E and F of Exhibit AEV 5 page 2 of 5.

Only the $58,624 of PJM administrative fees related to the internal load served by Big Sandy 2 should have been added back. The $19,025 of PJM administrative fees related to Big Sandy 1 should not have been added back in because the $19,025 is included in the Company's proposed BS1OR revenue requirement.

WITNESS: Alex E Vaughan

Kentucky Power Company

REQUEST

Refer to the testimony of Mr. Vaughan concerning the BS1OR.

a. When will Big Sandy be converted to a natural gas fired generating plant?

b. For each year, 2009 through 2014, identify the total amounts, by account, of each type of cost that KPCo is proposing be recovered in the BS1OR Rider.

RESPONSE

a. The Big Sandy Gas Conversion project is scheduled to be in-service in June 2016.

b. Please see AG_1_338_Attachment1.xls for this response.

WITNESS: Alex E Vaughan

Big Sandy Unit 1 Actual Expenses			Calendar Years					
Account by Cal Yr	**O&M Account**		**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Allowances	5090000	Allow Consum Title IV SO2	$442,883	$1,945,381	$3,195,691	$2,269,435	$1,346,394	$1,628,061
	5090001	Allowance Consumption - NOx						$5,951
	5090005	An. NOx Cons. Exp	$127,129	$80,437	$266,931	$19,953	$2,982	$25,702
Allowances Total			**$570,013**	**$2,025,818**	**$3,462,623**	**$2,289,387**	**$1,349,375**	**$1,659,714**
Ash Sales	5010012	Ash Sales Proceeds				($57,201)	($3,320)	($14,295)
Ash Sales Total						**($57,201)**	**($3,320)**	**($14,295)**
Consumables	5020001	Lime Expense	($0)					
	5020002	Urea Expense						$590
	5020003	Trona Expense	$0			$5		
	5020004	Limestone Expense	($0)					$0
	5020007	Lime Hydrate Expense						$5
	5020008	Activated Carbon		$0	$5	($2)	$0	
Consumables Total			**($0)**	**$0**	**$5**	**$2**	**$0**	**$596**
Fuel Handling	5010000	Fuel	$136,026	$80,820	$197,353	$69,558	$110,895	$108,076
	5010003	Fuel - Procure Unload & Handle	$518,113	$461,863	$909,585	$540,641	$1,050,795	$1,396,450
Fuel Handling Total			**$654,139**	**$542,683**	**$1,106,938**	**$610,198**	**$1,161,691**	**$1,504,526**
Gypsum Opns	5010027	Gypsum handling/disposal costs	$0					
	5010028	Gypsum Sales Proceeds						$0
	5010029	Gypsum handling/displ-Affiliat						$0
Gypsum Opns Total			**$0**					**$0**
Steam Maint	5100000	Maint Supv & Engineering	$100,843	$100,171	$582,274	$572,540	$603,953	$599,323
	5110000	Maintenance of Structures	$284,095	$218,348	$360,874	$224,501	$215,058	$395,971
	5120000	Maintenance of Boiler Plant	$2,686,941	$2,991,305	$1,742,595	$1,402,747	$2,451,854	$2,093,541
	5130000	Maintenance of Electric Plant	$1,003,484	$3,910,196	$319,365	$359,919	$252,295	$442,802
	5140000	Maintenance of Misc Steam Plt	$157,007	$237,997	$298,031	$178,966	$136,374	$438,118
	5140025	Maint MiscStmPlt Environmental				$1	($1)	
Steam Maint Total			**$4,232,370**	**$7,458,017**	**$3,303,139**	**$2,738,674**	**$3,659,534**	**$3,969,754**
Steam Opns	5000000	Oper Supervision & Engineering	$1,233,419	$1,357,503	$1,155,440	$519,521	$455,605	$502,489
	5000001	Oper Super & Eng-RATA-Affil	$4,954	$13,399	$7,803	$6,321	$7,224	$9,790
	5020000	Steam Expenses	$321,863	$136,637	$367,847	$257,863	$318,629	$193,070
	5020025	Steam Exp Environmental	$5	$9	($24)	$1	($3)	
	5050000	Electric Expenses	$23,761	$11,801	$121,497	$76,131	$102,968	$127,425
	5060000	Misc Steam Power Expenses	$779,139	$2,437,681	$1,338,337	$1,437,754	$1,111,503	$1,273,072
	5060001	Dresden Misc Steam Pwer Exp						$0
	5060002	Misc Steam Power Exp-Assoc	$1,826	$8,965	$10,202	$8,677	$5,984	$6,032
	5060003	Removal Cost Expense - Steam						$0
	5060004	NSR Settlement Expense						$0
	5060025	Misc Stm Pwr Exp Environmental	$1	($1)			$4	($2)
	9230002	Outside Svcs Empl - Assoc						$0
Steam Opns Total			**$2,364,967**	**$3,965,994**	**$3,001,102**	**$2,306,268**	**$2,001,915**	**$2,111,875**
A&G Opns	9200000	Administrative & Gen Salaries	$811,753	$857,319	$676,056	$816,924	$1,164,770	$741,159
	9210001	Off Supl & Exp - Nonassociated	$67,966	$56,859	$48,841	$45,602	$141,748	$40,913
	9210003	Office Supplies & Exp - Trnsf					$6	$1
	9210005	Cellular Phones and Pagers	$3	$1				$0
	9230001	Outside Svcs Empl - Nonassoc	$161,322	$120,012	$142,633	$198,454	$340,364	$196,428
	9230003	AEPSC Billed to Client Co	$428,116	$493,366	$419,296	$336,655	($64,012)	$42,745
	9240000	Property Insurance	$87,286	$93,645	$110,672	$98,120	$68,691	$39,741
	9250000	Injuries and Damages	$75,571	$74,893	$82,317	$76,217	$68,345	$68,861
	9250001	Safety Dinners and Awards	$20		$106	$105	$163	$284
	9250002	Emp Accdent Prvntion-Adm Exp	$445	$698	$374	$561	$366	$485
	9250004	Injuries to Employees	$105	$2,380	$7,468	$1,879	$544	$1,865
	9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	$16,261	$19,623	($86,434)	$38,882	$31,377	$21,419
	9250007	Prsnal Injries&Prop Dmage-Pub	$101,607	$71,243	$25,462	$575	$27,661	$18,700
	9250010	Frg Ben Loading - Workers Comp	($4,693)	($7,358)	($2,663)	($4,470)	($10,756)	($815)
	9260000	Employee Pensions & Benefits				$33	$38	
	9260001	Edit & Print Empl Pub-Salaries	$1,536	$1,453	$2,448	$2,004	$810	$2,191
	9260002	Pension & Group Ins Admin	$922	$1,089	$3,162	$3,405	$2,279	$6,280
	9260003	Pension Plan	$232,868	$305,825	$336,933	$372,809	$431,295	$494,844
	9260004	Group Life Insurance Premiums	$20,370	$18,482	$16,711	$16,788	$12,850	$12,654
	9260005	Group Medical Ins Premiums	$607,776	$511,505	$436,753	$431,332	$365,796	$394,913

Big Sandy Unit 1 Actual Expenses		Calendar Years					
Account by Cal Yr	**O&M Account**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
	9260006 Physical Examinations						
	9260007 Group L-T Disability Ins Prem	($343)	$20,895	$19,925	$1,332	$1,008	$855
	9260009 Group Dental Insurance Prem	$20,161	$27,724	$24,453	$24,362	$22,072	$12,355
	9260010 Training Administration Exp	$169	$284	$126	$94	$132	$74
	9260012 Employee Activities	$6	$207	$226	$207	$239	$165
	9260014 Educational Assistance Pmts	$982	$1,175	$43	$242		$162
	9260019 Employee Benefit Exp - COLI						$10,000
	9260021 Postretirement Benefits - OPEB	$436,664	$366,317	$277,597	$163,395	($166,980)	($372,243)
	9260026 Savings Plan Administration				$6		
	9260027 Savings Plan Contributions	$170,099	$171,198	$175,639	$160,445	$134,974	$177,883
	9260036 Deferred Compensation	$700	($235)				
	9260037 Supplemental Pension	$7	$1		$0		
	9260040 SFAS 112 Postemployment Benef						$160,313
	9260050 Frg Ben Loading - Pension	($27,762)	($52,436)	($57,924)	($78,969)	($92,724)	($79,027)
	9260051 Frg Ben Loading - Grp Ins	($94,734)	($98,429)	($93,040)	($108,629)	($97,797)	($95,606)
	9260052 Frg Ben Loading - Savings	($34,672)	($30,630)	($31,249)	($36,557)	($31,322)	($44,811)
	9260053 Frg Ben Loading - OPEB	($45,201)	($43,668)	($31,377)	($52,305)	$10,228	$11,212
	9260055 IntercoFringeOffset- Don't Use	($5,279)	($8,109)	($7,773)	($43,756)	($29,271)	($315,464)
	9260056 Fidelity Stock Option Admin			$27			
	9260057 Postret Ben Medicare Subsidy	($95,258)	($107,726)	($100,813)	$67,563	$45,395	$82,248
	9260058 Frg Ben Loading - Accrual	$13,017	($180)	($934)	$1,430	$557	($6,610)
	9260060 Amort-Post Retirement Benefit					$25,335	$22,975
	9280000 Regulatory Commission Exp	$1	($1)	$0	($0)	$5,466	$2,108
	9280001 Regulatory Commission Exp-Adm	$3	($2)	($3)	($1)	($0)	($0)
	9280002 Regulatory Commission Exp-Case	($104)	$9,303	$703	$10,063	$31,430	$61,321
	9301000 General Advertising Expenses			$588	$882	$484	$75
	9301001 Newspaper Advertising Space	$28,945	($22,853)	$1,822	$1,334	$2,137	$827
	9301002 Radio Station Advertising Time	$185	$33	$158	$297	$5	$380
	9301003 TV Station Advertising Time			$54		$253	
	9301006 Spec Corporate Comm Info Proj						
	9301008 Direct Mail and Handouts	$69					
	9301009 Fairs, Shows, and Exhibits	$61	$48				
	9301010 Publicity	$127	$89	$90	$137	$290	$252
	9301011 Dedications, Tours, & Openings	$4	$2		$0		
	9301012 Public Opinion Surveys		$1	($1)			
	9301014 Video Communications	$6	$3	$4	$1	$1	
	9301015 Other Corporate Comm Exp	$1,374	$1,403	$1,671	$2,585	$1,552	$659
	9302000 Misc General Expenses	$21,222	($66,800)	$33,255	$18,181	$18,056	$16,049
	9302003 Corporate & Fiscal Expenses	$1,850	$944	$1,407	$1,027	$974	$1,392
	9302006 Assoc Bus Dev - Materials Sold						
	9302007 Assoc Business Development Exp		$1	($1)	($0)	$6	$28
	9302458 AEPSC Non Affliated expenses				$12	$3	($0)
	9310002 Rents - Personal Property	$15,939	$7,154	$494	$386	$11,994	$16,548
A&G Opns Total		**$3,017,473**	**$2,796,748**	**$2,435,305**	**$2,569,639**	**$2,476,832**	**$1,746,789**
Taxes OTIT	4081002 FICA	$285,123	$373,062	$299,460	$284,242	$236,531	$394,070
	4081003 Federal Unemployment Tax	$1,749	$3,317	$3,741	$3,112	$4,256	$4,218
	408100506 Real & Personal Property Taxes	$0					
	408100507 Real & Personal Property Taxes	($62,008)					
	408100508 Real & Personal Property Taxes	$148,693	$22,272	$912	($50,153)		
	408100509 Real & Personal Property Taxes	$49	$768,249	($44,421)	($2,641)		
	408100510 Real Personal Property Taxes		$51	$222,078	($9,185)	$828	
	408100511 Real Personal Property Taxes			$51	$221,599	($11,946)	
	408100512 Real Personal Property Taxes					$221,235	$4,548
	408100513 Real Personal Property Taxes						$215,276
	4081007 State Unemployment Tax	$3,324	$5,042	$3,878	$3,206	$4,193	$9,136
	408100814 State Franchise Taxes						$1,435
	408101414 Federal Excise Taxes						$116
	408102014 State Business Occup Taxes						$160,589
	408102908 Real/Pers Prop Tax-Cap Leases	($859)					
	408102909 Real/Pers Prop Tax-Cap Leases	$694	$1	$0			
	408102910 Real-Pers Prop Tax-Cap Leases		$1,522		($978)		
	408102911 Real-Pers Prop Tax-Cap Leases			$1,357	($376)	($970)	

Big Sandy Unit 1 Actual Expenses		Calendar Years					
Account by Cal Yr	**O&M Account**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
	408102912 Real-Pers Prop Tax-Cap Leases				$1,011	($294)	
	408102913 Real-Pers Prop Tax-Cap Leases					$293	$509
	408102914 Real-Pers Prop Tax-Cap Leases						$503
	4081033 Fringe Benefit Loading - FICA	($40,901)	($39,491)	($40,840)	($46,209)	($41,178)	($57,605)
	4081034 Fringe Benefit Loading - FUT	($393)	($407)	($369)	($320)	($265)	($505)
	4081035 Fringe Benefit Loading - SUT	($393)	($543)	($576)	($534)	($483)	($1,797)
Taxes OTIT Total		**$335,078**	**$1,133,075**	**$445,270**	**$402,775**	**$412,199**	**$730,492**
Purchased Pwr	5560000 Sys Control & Load Dispatching	$103,805	$96,919	$82,599	$44,209	$34,606	$52,018
	5570000 Purchased Pwr Expenses	$667,642	$630,208	$577,347	$369,256	$321,309	$172,566
Purchased Pwr Total		**$771,447**	**$727,127**	**$659,946**	**$413,465**	**$355,915**	**$224,585**
A&G Maint	9350000 Maintenance of General Plant				$2		
	9350001 Maint of Structures - Owned	$5	($4)	($12)	$0	$755	$896
	9350002 Maint of Structures - Leased	$2	$3			($0)	$161
	9350003 Maint of Prprty Held Fture Use					$0	$68
	9350007 Maint of Radio Equip - Owned	$13,613		$18			
	9350012 Maint of Data Equipment						$0
	9350013 Maint of Cmmncation Eq-Unall	$68,212	$80,782	$62,638	$39,386	$12,985	$7,806
	9350015 Maint of Office Furniture & Eq	($13)	$15,200	$188	$12	$42,739	$46,778
	9350016 Maintenance of Video Equipment					$41	
	9350019 Maint of Gen Plant-SCADA Equ					$4	$0
	9350023 Site Communications Services				$15		
A&G Maint Total		**$81,818**	**$95,981**	**$62,833**	**$39,415**	**$56,525**	**$55,710**
Grand Total		**$12,027,304**	**$18,745,443**	**$14,477,159**	**$11,312,623**	**$11,470,666**	**$11,989,745**

KPSC Case No. 2014-00396 General Rate Adjustment
Attorney General's Second Set of Data Requests
Dated February 24, 2015
Item No. 114
Page 1 of 1

Kentucky Power Company

REQUEST

Big Sandy Unit Operation Rider (BS1OR). Refer to the response to AG 1-338 and Company Exhibit AEV-4. Please reconcile the amounts shown on AG_1_338_Attachment1 to the proposed BS1OR revenue requirement of $18,245,412. Identify, quantify and explain each reconciling item and show detailed calculations.

RESPONSE

The amounts included in the Company's response to AG 1-338 are calendar year totals of non-fuel clause Big Sandy Unit 1 O&M. These are comparable to items a and b on Company Exhibit AEV-4 page 1 of 3, however items a and b are test year amounts. The historic test year in this case is the 12 months ending September 30, 2014.

Item d from Company Exhibit AEV-4 page 1 of 3 was not included in the Company's response to AG 1-338 because the requested analysis has not been performed for 2009 - 2014, only for the historic test year in this proceeding.

Also, the Company's response to AG 1-338 was not grossed up by item f of Company Exhibit AEV-4 page 1 of 3.

WITNESS: Alex E Vaughan

EXHIBIT RCS-18

Kentucky Power Company

REQUEST

Refer to the response to Staff's First Request, Item 33. For the test year, provide the following information at it relates to lobbying activities:

a. The names of each of the Company's Kentucky registered lobbyists.

b. For each of the registered lobbyists, the dollar amount and percentage of the lobbyist's salary, fringe benefits, any incentive pay, and expense reports recorded below the line and any lobbying activities costs reflected in the Company's proposed cost of service.

c. The dollar amount of any lobbying activity allocated to KentuckyPower from AEP or any of its subsidiaries, along with a statement in which these costs are recorded and account numbers where these costs are recorded (above or below the line).

RESPONSE

a. Gregory Pauley, James Keeton, and Brad Hall.

b. During the test year period, 100% of Mr. Pauley's $220,420 salary was directly charged to Account 920.0 (Administrative & General Salaries), while $1,951 in expenses were charged to Account 426.4 (Civic & Political Activities) based upon the nature and purpose of the work performed. Please see the response to KPSC 1-33 for information on James Keeton and Brad Hall.

Kentucky Power found that .95% ($2,095) of Mr. Pauley's salary should have been charged to Account 426.4, instead of Account 920.0. In addition, Kentucky Power found that 12.6% ($18,063) of Mr. Hall's salary should have been charged to Account 426.4 instead of Account 920.0.

c.. Please see response to KPSC 1-33.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

List each athletic and employee association to which the Company contributes and the associated amounts for the test year and preceding year. State how the Company has treated these expens-es for ratemaking purposes in the test year.

RESPONSE

The Company contributed to the University of Kentucky Football association in the amount of $2,400 for the test year and $1,200 for the preceding year. The $2,400 was included in test year O&M expenses.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

For the base year list all payments made for employee gifts, employee awards, employee luncheons and dinners, employee picnics and all other similar type items. For each, list the dollar amount paid, the payee, the account charged and state the purpose. Provide copies of invoices which exceed $5,000.

RESPONSE

As recorded in account 9260012, the amount of Kentucky Power Company directly charged employee related expenses for the period October 1, 2013 through September 30, 2014 was a total of $5,815. See AG_1_267_Attachment1.pdf.

WITNESS: Jason M. Yoder

AG Data Request #267 - Payments Made for Employee Gifts, Awards, Activities
October 1, 2013 through September 30, 2014

Acctg Date	Name	Account	Amount
2013-10-03	JP MORGAN CHASE CORPORATE CARD ACTIVITY	9260012	762.00
2013-10-03	JP MORGAN CHASE CORPORATE CARD ACTIVITY	9260012	1,496.72
2013-10-21	JP MORGAN CHASE CORPORATE CARD ACTIVITY	9260012	125.00
2013-11-11	JP MORGAN CHASE CORPORATE CARD ACTIVITY	9260012	225.00
2013-11-11	JP MORGAN CHASE CORPORATE CARD ACTIVITY	9260012	550.00
2014-05-06	JP MORGAN CHASE CORPORATE CARD ACTIVITY	9260012	200.00
2014-09-19	JP MORGAN CHASE CORPORATE CARD ACTIVITY	9260012	1,338.94
2014-09-19	JP MORGAN CHASE CORPORATE CARD ACTIVITY	9260012	1,117.60
Total			5,815.26

KPSC 2014-00396 General Rate Adjustment
Attorney General's Initial Set of Data Requests
Dated January 29, 2015
Item No. 268
Page 1 of 1

Kentucky Power Company

REQUEST

Identify all expenses incurred during the test year for athletic events, tickets, sky boxes and all sporting activities.

a. Specifically identify the activity and dollar amount.
b. Provide copies of paid vouchers and invoices supporting these expenditures.

RESPONSE

a.

UK Football Tickets	$2,226.00
PGA Championship	$29,256.00
Total	$31,482.00

b. Please see AG_1_268_Attachment1.pdf.

WITNESS: Ranie K Wohnhas

Belinda A Stacy

From:	Belinda A Stacy
Sent:	Tuesday, February 10, 2015 9:24 AM
To:	Belinda A Stacy
Subject:	Sent from Snipping Tool

2014 Football Renewal — US $4626.00

Invoice Number 698265

Renewal Item

Item name	Seat	Qty	Price	Amount Paid
2014 Football Processing Fee	GA [S] 1 7187	1 Adult	US $10.00	US $10.00
2014 Football Season Tickets	Section 217 Row 7 27-28	2 Adult	US $277.00	US $554.00
2014 Football Season Tickets	Section 217 Row 6 31-32	2 Adult	US $277.00	US $554.00
2014 Football Season Tickets	Section 214 Row 7 4-7	4 Adult	US $277.00	US $1108.00

Donation

Donation Name	Total
2014 Football Donation (FY14)	US $2400.00

Invoice Total: US $4626.00

https://oss.ticketmaster.com/html/invoicing_history.html?l=EN&CNTX=54da1423b6b9c6-39022076

PGA

Ship To:
VALHALLA GOLF CLUB
15503 Shelbyville Rd
LOUISVILLE. KENTUCKY 40245

Bill To: RANIE WOHNHAS
KENTUCKY POWER COMPANY
101A Enterprise Dr PO BOX 5190
FRANKFORT. KENTUCKY 40601

Remit To:
PGA Tournament Corp
FEIN: 65-0394725
P.O. BOX 31089
PALM BEACH GARDENS. FLORIDA 33420

Please include the invoice number on all remittances.
For questions regarding this invoice, please contact our A/R department at (561) 624-7623

Invoice Number
215521

Billing Date	**Shipping Date**
6/19/14	
Purchase Order Number	
Shipping Reference	Ship Via
Customer Account Number	Customer Site
17809	LOUISVILLE 2, KY

Terms	**Due Date**	**Customer Contact**	**Contact Phone**	**Contact Fax**
IMMEDIATE	6/27/14	RANIE WOHNHAS	696-7004	696-7006

Item Num	Description	Quantity Shipped	Tax	Unit Price	Extended Amount
1	2014 PGA CHAMPIONSHIP - THURSDAY, FRIDAY, SATURDAY - 10 PERSON CHAMPIONS CLUB TABLE, CLUB RENTAL & AMENITIES	3	Yes	8,500.00	25,500.00
2	2014 PGA CHAMPIONSHIP - CHAMPIONS CLUB THURSDAY TICKET	2	Yes	350.00	700.00
3	2014 PGA CHAMPIONSHIP - CHAMPIONS CLUB FRIDAY TICKET	2	Yes	350.00	700.00
4	2014 PGA CHAMPIONSHIP - CHAMPIONS CLUB SATURDAY TICKET	2	Yes	350.00	700.00

Tax Summary

Tax Name	Tax Rate(%)	Tax Precedence	Tax Extended Amount
CITY	0		0.00
COUNTY	0		0.00
STATE	6		1,656.00

Line	27,600.00
Tax	1,656.00
Shipping	0.00
Total	29,256.00
Payments and Credits	0.00
Outstanding balance as of 6/20/14 in USD	29,256.00

WIRE TRANSFER INSTRUCTIONS:

Bank of America
Commercial Banking Division
Address: One, Financial Plaza, 9th Floor
P.O. Box 407090, FT. Lauderdale, Florida 33394

ABA Number For ACH 063100277
ABA Number For Wire 026009593
Credit Account: PGA OF AMERICA
Account Number: 3602758540
Swift Address: BOFAUS3N

Voucher Accounting Entries

*Business Unit: 110 Voucher ID: 00243217 Invoice Number: 215521

*Accounting Line View Option: Standard ☐ Show Foreign Currency Search Reset

Invoice Date: 06/20/2014 Vendor ID: 0000206056 Vendor Name: PGA TOURNAMENT CORP INC

Accounting Information Find | View All First 1 of 2 Last

Posting Process: AP Accrual GL Dist Status: Distributed

Customize | Find | View All | First 1-2 of 2 Last

Main Information | Chartfields | Journal

Description	Description	Description	Monetary Amount	Currency Code	Ledger	GL Unit
Expense Distribution	Expense Distribution	Expense Distribution	29,256.00	USD	ACTUALS	110
Accounts Payable	Accounts Payable	Accounts Payable	-29,256.00	USD	ACTUALS	110

Display Docs

Kentucky Power Company

REQUEST

Refer to the response to AG 1-103.

a. Please provide a breakout of the membership dues by organization and include an explanation of how each such organizations benefits ratepayers.

b. Please explain fully and in detail whether the amount of lobbying expense is embedded in the amounts discussed in the response to Staff 1-33. If not, state the accounts in which these test year lobbying costs were recorded.

c. Please provide a breakout of the test year charitable contributions by organization and specify the account(s) in which these amounts were recorded.

d. Please provide a breakout by amount and account of the public relations expense and include an explanation of how each such public relations expense benefits ratepayers.

RESPONSE

a. Please see AG_2_64_Attachment1.xls for the response. Membership into these organizations allows Company personnel to build relationships, gather and share information, and stay abreast of pertinent national, state and local issues that affect the Company. In addition, memberships allow Company personnel to work collaboratively to address issues or projects that may affect both the Company and the service territory. Having well informed Company personnel active in these organizations benefits all Kentucky Powerr customers.

b. Please see response to KPSC 2-111.

c. Please see AG_2_64_Attachment1.xls for the answer to this response.

d. Please see AG_2_64_Attachment1.xls for the answer to this response. The use of public relations benefits all of Kentucky Power's customers by keeping the public informed on matters that can affect the service the Company provides.

WITNESS: Gregory G Pauley

Totals	Total	Non COS	Cost of Service
Memberships	59,157.16	11,225.00	47,932.00
Charitable Contributions	323,109.67	310,235.00	12,875.00
Public Relations Expenses	1,427,458.59	1,179,301.00	248,158.00
Total	1,809,725.42	1,500,761.00	308,965.00

Voucher	Acctg Date	Name	Account	Affiliate	Dept	Cost Comp	Project	Subcat	ABM Act	Amount
00107009	2013-10-18	BELLEFONTE COUNTRY CLUB	5000000		10218	954	WSBSBL004		320	1,734.73
00111849	2014-03-10	OHIO BOARD OF N I U L	5060000		10642	954	KMLMLPBCO		317	40.00
00115276	2014-05-08	AMERICAN LEGION EMBLEM	5060000		10642	954	KMLMLPBCO		294	190.55
00116022	2014-05-21	AMERICAN LEGION EMBLEM	5060000		10642	954	KMLKMPBCO		294	193.50
00111707	2014-03-06	NORTHERN OHIO RIVER INDUSTRIAL	5060000		10642	954	000001121		292	373.38
00109678	2014-01-27	THREE RIVERS POLLUTION RESPONSE COUNCIL	5060000		10642	954	000001121		292	250.00
00231340	2013-10-01	BELLEFONTE COUNTRY CLUB	5800000		12396	954	EDN103175		954	403.00
00232751	2013-10-30	BELLEFONTE COUNTRY CLUB	5800000		12396	954	EDN103175		954	403.00
00235097	2013-12-18	BELLEFONTE COUNTRY CLUB	5800000		12396	954	EDN103175		954	390.00
00235096	2013-12-18	BELLEFONTE COUNTRY CLUB	5800000		12396	954	EDN103175		954	390.00
00238696	2014-03-11	BELLEFONTE COUNTRY CLUB	5800000		12396	954	EDN103175		954	330.00
00243366	2014-06-25	BELLEFONTE COUNTRY CLUB	5800000		12396	954	EDN103175		954	330.00
00244864	2014-07-29	BELLEFONTE COUNTRY CLUB	5800000		12396	954	EDN103175		954	330.00
00245523	2014-08-12	BELLEFONTE COUNTRY CLUB	5800000		12396	954	EDN103175		954	330.00
00246768	2014-09-12	BELLEFONTE COUNTRY CLUB	5800000		12396	954	EDN103175		954	330.00
00236256	2014-01-16	BELLEFONTE COUNTRY CLUB	5880000		12396	954	EDN103175		322	390.00
00237343	2014-02-11	BELLEFONTE COUNTRY CLUB	5880000		12396	954	EDN103175		268	390.00
00240224	2014-04-11	BELLEFONTE COUNTRY CLUB	5880000		12396	954	EDN103175		268	330.00
00241833	2014-05-19	BELLEFONTE COUNTRY CLUB	5880000		12396	954	EDN103175		268	330.00
00234303	2013-12-04	INTL SOC ARBORICULTURE	5930000		12681	954	000009160		230	205.00
00236253	2014-01-16	INTL SOC ARBORICULTURE	5930000		12681	954	000009160		230	205.00
00241700	2014-05-15	INTL SOC ARBORICULTURE	5930000		12681	954	000009160		230	145.00
00241903	2014-05-20	INTL SOC ARBORICULTURE	5930000		12681	954	000009160		230	145.00
00235105	2013-12-18	SOUTHEAST KENTUCKY CHAMBER OF COMMERCE	9100000		11439	954	EDNANDA		293	10.00
00237847	2014-02-24	SOUTHEAST KENTUCKY CHAMBER OF COMMERCE	9100000		11439	954	EDNANDA		293	20.00
00245914	2014-08-22	FRANKFORT COUNTRY CLUB	9100000		11439	954	EDNANDA		263	350.00
00245914	2014-08-22	FRANKFORT COUNTRY CLUB	9100000		11439	954	EDNANDA		263	350.00
00232477	2013-10-23	NATIONAL ASSN REG UTIL COM	9210001		12392	954	EDNANDA		290	795.00
00237844	2014-02-24	NATIONAL ASSN REG UTIL COM	9210001		12392	954	EDNANDA		290	520.00
00244211	2014-07-15	FRANKFORT COUNTRY CLUB	9210001		12392	954	EDNANDA		294	350.00
00245894	2014-08-21	FRANKFORT COUNTRY CLUB	9210001		12392	954	EDNANDA		290	350.00
00245956	2014-08-25	WINUP	9301015		12393	954	EDN103175		292	350.00
00246327	2014-09-02	WINUP	9301015		12396	954	EDN103175		292	350.00
00235893	2014-01-08	ASHLAND ALLIANCE	9302000		12396	953	000001121		292	3,000.00
00232902	2013-11-04	ASSOCIATION OF ENERGY SERVICES	9302000		11834	953	000001121		292	2,000.00
00235127	2013-12-18	FLOYD COUNTY CHAMBER OF COMMERCE	9302000		11680	953	000001121		292	120.00
00239035	2014-03-18	INTERNATIONAL ECONOMIC DEV COUNCIL	9302000		11439	954	000001121		292	385.00
00236416	2014-01-22	KENTUCKY ASSOCIATION FOR	9302000		11439	953	000001121		292	150.00
00235810	2014-01-07	KENTUCKY ASSOCIATION OF	9302000		11439	953	000001121		292	3,000.00
00243822	2014-07-07	KENTUCKY ASSOCIATION OF	9302000		12390	953	EDNANDA		292	5,340.00
00238511	2014-03-06	KENTUCKY CHAMBER OF COMMERCE	9302000		11439	953	000001121		292	21,250.00
00235327	2013-12-20	PIKEVILLE ROTARY CLUB	9302000		11680	953	000001120		292	42.50
00235330	2013-12-20	PIKEVILLE ROTARY CLUB	9302000		11680	953	000001121		292	42.50
00119405	2014-07-24	SOUTHEAST KENTUCKY CHAMBER OF COMMERCE	9302000		10218	953	000001121		292	999.00
										47,932.16

Voucher	Name	Account	Amount
00110579	MARSHALL COUNTY CHAMBER OF COMMERCE	5060000	750.00
00237956	FOUNDATION FOR TRI-STATE COMMUNITY INC	9301000	1,000.00
00240578	KENTUCKY CHAMBER OF COMMERCE	9302000	7,500.00
00240662	KENTUCKY CHAMBER OF COMMERCE	9302000	3,625.00
			12,875.00

00237956	2014-02-25	APPALACHIAN NEWS EXPRESS	9090000	12394	960	EDNANDA	293	150.00
00240578	2014-04-21	APPALACHIAN NEWS EXPRESS	9090000	12394	960	EDNANDA	293	150.00
00240662	2014-04-23	APPALACHIAN NEWS EXPRESS	9090000	12394	960	EDNANDA	293	175.00
00110579	2014-02-12	APPALACHIAN NEWS EXPRESS	9301001	12394	960	EDNANDA	293	250.00
00232751	2013-10-30	APPALACHIAN NEWS EXPRESS	9301001	12394	960	EDNANDA	293	250.00
00235097	2013-12-18	ASHLAND BREAKFAST KIWANIS CLUB	9090000	12394	960	EDNANDA	293	50.00
00244864	2014-07-29	BIG SANDY AREA DEVELOPMENT DIS	9301015	12394	994	EDNANDA	294	5,000.00
00243019	2014-06-18	CAPITAL RESULTS	9090000	12394	960	EDNANDA	293	18,412.83
00243131	2014-06-20	CAPITAL RESULTS	9090000	12394	960	EDNANDA	293	28,868.10
00237842	2014-02-24	CAPITAL RESULTS	9090000	12394	960	EDNANDA	293	18,290.64
00239239	2014-03-24	CAPITAL RESULTS	9090000	12394	960	EDNANDA	293	678.59
00239240	2014-03-24	CAPITAL RESULTS	9301010	12394	260	EDNANDA	293	1,500.00
00239241	2014-03-24	CURRENT MEDIA INC	9090000	12394	960	EDNANDA	293	850.00
00241414	2014-05-07	DEUTSCHE BANK TRUST CO AMERICAS	9302003	11389	263	FANANDA	661	4,000.00
00243458	2014-06-27	EAST KENTUCKY BROADCASTING INC	9090000	12394	960	EDNANDA	293	7,800.00
00245096	2014-08-05	FLOYD COUNTY TIMES	9090000	12394	960	EDNANDA	293	152.20
00245096	2014-08-05	FORTY & EIGHTER HONOR SOCIETY	9301001	12394	960	EDNANDA	293	65.00
00246353	2014-09-03	FOUNDATION FOR TRI-STATE COMMUNITY INC	9301000	12393	955	000001120	294	1,000.00
00246356	2014-09-03	GRAYSON FAMILY COMMUNICATIONS INC	9090000	12394	960	EDNANDA	293	150.00
00247067	2014-09-19	GRAYSON FAMILY COMMUNICATIONS INC	9090000	12394	960	EDNANDA	293	150.00
00233520	2013-11-14	GRAYSON FAMILY COMMUNICATIONS INC	9090000	12394	960	EDNANDA	293	150.00
00233520	2013-11-14	GRAYSON FAMILY COMMUNICATIONS INC	9090000	12394	960	EDNANDA	293	150.00
00233520	2013-11-14	GRAYSON FAMILY COMMUNICATIONS INC	9090000	12394	960	EDNANDA	293	150.00
00233520	2013-11-14	GRAYSON FAMILY COMMUNICATIONS INC	9090000	12394	960	EDNANDA	293	150.00
00241434	2014-05-08	GRAYSON FAMILY COMMUNICATIONS INC	9090000	12394	960	EDNANDA	293	150.00
00245095	2014-08-05	GRAYSON FAMILY COMMUNICATIONS INC	9090000	12394	960	EDNANDA	293	150.00
00231728	2013-10-08	GRAYSON FAMILY COMMUNICATIONS INC	9090000	12394	960	EDNANDA	293	150.00
00231729	2013-10-08	GRAYSON FAMILY COMMUNICATIONS INC	9090000	12394	960	EDNANDA	293	150.00
00231730	2013-10-08	HAZARD HERALD	9301001	12394	960	EDNANDA	293	304.40
00231901	2013-10-10	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	32.48
00232705	2013-10-29	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	1.25
00233252	2013-11-11	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	184.80
00233471	2013-11-13	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	20.00
00233576	2013-11-15	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	35.00
00233658	2013-11-18	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	20.00
00234123	2013-11-27	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	184.80
00234311	2013-12-04	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	5.00
00234312	2013-12-04	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	198.80
00234392	2013-12-05	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	10.00
00234393	2013-12-05	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	15.00
00234494	2013-12-09	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	151.20
00234495	2013-12-09	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	184.80
00234955	2013-12-16	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	5.00
00235206	2013-12-19	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	20.00
00235940	2014-01-09	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	25.00
00235981	2014-01-10	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	35.00
00236611	2014-01-27	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	24.00
00237190	2014-02-06	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	10.00
00237252	2014-02-07	INDEPENDENT, THE	9090000	12394	960	EDNANDA	293	427.00
00237316	2014-02-10	INDEPENDENT, THE	9090000	12394	960	EDNANDA	293	849.00

00238466	2014-03-06	INDEPENDENT, THE	9090000	12394	960	EDNANDA	293	400.00
00238640	2014-03-10	INDEPENDENT, THE	9090000	12394	960	EDNANDA	293	400.00
00238641	2014-03-10	INDEPENDENT, THE	9090000	12394	960	EDNANDA	293	1,198.00
00238781	2014-03-13	INDEPENDENT, THE	9090000	12394	960	EDNANDA	293	820.00
00239788	2014-04-03	INDEPENDENT, THE	9090000	12394	960	EDNANDA	295	299.00
00239789	2014-04-03	INDEPENDENT, THE	9090000	12394	960	EDNANDA	293	509.00
00240211	2014-04-11	INDEPENDENT, THE	9301001	12394	960	EDNANDA	293	250.00
00241119	2014-05-01	INDEPENDENT, THE	9301001	12394	960	EDNANDA	293	400.00
00241277	2014-05-06	INDEPENDENT, THE	9301001	12394	960	EDNANDA	293	195.00
00241400	2014-05-07	INDEPENDENT, THE	9301001	12394	960	EDNANDA	293	180.00
00241431	2014-05-08	INDEPENDENT, THE	9301001	12394	960	EDNANDA	295	500.00
00241553	2014-05-12	INDEPENDENT, THE	9301015	12394	390	EDNANDA	294	90.00
00241553	2014-05-12	INDEPENDENT, THE	9301015	12394	393	EDNANDA	294	5.40
00241554	2014-05-15	EMPLOYEE EXPENSE	5800000	12396	396	EDN103175	294	54.43
00241554	2014-05-12	EMPLOYEE EXPENSE	5800000	12396	396	EDN103175	294	18.44
00241974	2014-05-23	EMPLOYEE EXPENSE	5870000	11266	510	EDN103175	294	63.74
00242523	2014-06-06	EMPLOYEE EXPENSE	5870000	11266	510	EDN103175	294	168.69
00243175	2014-06-23	EMPLOYEE EXPENSE	5880000	11680	290	EDN103175	293	49.99
00243796	2014-07-03	EMPLOYEE EXPENSE	5880000	11680	510	EDN103175	294	63.12
00244129	2014-07-14	EMPLOYEE EXPENSE	5880000	11680	396	EDN103175	294	12.93
00244130	2014-07-14	EMPLOYEE EXPENSE	5880000	11680	510	EDN103175	294	816.58
00244134	2014-07-14	EMPLOYEE EXPENSE	5880000	11683	520	EDN103175	293	37.41
00244135	2014-07-14	EMPLOYEE EXPENSE	5880000	10129	520	EDN103175	294	24.51
00245319	2014-08-07	EMPLOYEE EXPENSE	5880000	12389	510	EDN103175	294	22.00
00245591	2014-08-14	EMPLOYEE EXPENSE	5880000	12389	510	EDN103175	294	171.37
00246969	2014-09-17	EMPLOYEE EXPENSE	5880000	11680	510	EDN103175	294	215.39
00246970	2014-09-17	EMPLOYEE EXPENSE	5880000	10695	396	EDN103175	294	29.24
00246971	2014-09-17	EMPLOYEE EXPENSE	5880000	11680	520	EDN103175	294	24.60
00246972	2014-09-17	EMPLOYEE EXPENSE	9301015	12393	510	EDN103175	294	13.93
00247011	2014-09-18	EMPLOYEE EXPENSE	9301015	12393	510	EDN103175	294	199.00
00232478	2013-10-23	EMPLOYEE EXPENSE	9301015	12393	510	EDN103175	294	8.00
00232747	2013-10-30	EMPLOYEE EXPENSE	9301015	12393	510	EDN103175	294	12.78
00232748	2013-10-30	EMPLOYEE EXPENSE	9301015	10695	396	EDN103175	293	19.08
00232748	2013-10-30	EMPLOYEE EXPENSE	9301015	12393	396	EDN103175	294	26.85
00232748	2013-10-30	EMPLOYEE EXPENSE	9100000	11439	510	EDNANDA	293	10.00
00232752	2013-10-30	EMPLOYEE EXPENSE	9100000	12390	520	EDNANDA	718	76.42
00233577	2013-11-15	EMPLOYEE EXPENSE	9100000	12390	520	EDNANDA	718	7.09
00233583	2013-11-15	EMPLOYEE EXPENSE	9100000	12390	520	EDNANDA	718	66.45
00233688	2013-11-18	EMPLOYEE EXPENSE	9100000	11439	510	EDNANDA	293	126.65
00233688	2013-11-18	EMPLOYEE EXPENSE	9100000	11439	510	EDNANDA	293	745.00
00233688	2013-11-18	EMPLOYEE EXPENSE	9100000	11439	510	EDNANDA	293	150.00
00233688	2013-11-18	EMPLOYEE EXPENSE	9100000	11439	510	EDNANDA	293	250.00
00235105	2013-12-18	EMPLOYEE EXPENSE	9100000	11439	954	EDNANDA	293	10.00
00235579	2013-12-30	EMPLOYEE EXPENSE	9100000	12394	396	EDNANDA	293	233.25
00235580	2013-12-30	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	24.71
00235580	2013-12-30	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	4.08
00235580	2013-12-30	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	41.73
00235580	2013-12-30	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	8.94
00236956	2014-02-04	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	10.80
00236957	2014-02-04	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	149.00

00236957	2014-02-04	EMPLOYEE EXPENSE	9100000	11439	954	EDNANDA	293	20.00
00236957	2014-02-04	EMPLOYEE EXPENSE	9100000	12394	290	EDNANDA	293	81.22
00237847	2014-02-24	EMPLOYEE EXPENSE	9100000	11439	510	EDNANDA	293	1,535.00
00238342	2014-03-04	EMPLOYEE EXPENSE	9100000	12390	520	EDNANDA	718	76.24
00238712	2014-03-11	EMPLOYEE EXPENSE	9100000	12390	520	EDNANDA	718	24.95
00239019	2014-03-18	EMPLOYEE EXPENSE	9100000	12394	520	EDNANDA	294	12.18
00239019	2014-03-18	EMPLOYEE EXPENSE	9100000	11439	510	EDNANDA	293	52.00
00239955	2014-04-07	EMPLOYEE EXPENSE	9100000	11439	290	EDNANDA	293	30.00
00239956	2014-04-07	EMPLOYEE EXPENSE	9100000	11439	510	EDNANDA	293	356.00
00239957	2014-04-07	EMPLOYEE EXPENSE	9100000	12394	933	EDNANDA	293	7.35
00240179	2014-04-10	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	7.92
00240179	2014-04-10	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	6.42
00240935	2014-04-28	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	99.00
00242159	2014-05-29	EMPLOYEE EXPENSE	9100000	12394	520	EDNANDA	293	4.79
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12394	520	EDNANDA	293	33.00
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	24.65
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	31.81
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12394	520	EDNANDA	293	16.00
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	1.09
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	6.54
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	3.27
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	109.00
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	26.71
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	48.84
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12394	520	EDNANDA	293	7.64
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12390	520	EDNANDA	718	68.17
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12390	520	EDNANDA	718	55.11
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12390	510	EDNANDA	718	2.98
00242160	2014-05-29	EMPLOYEE EXPENSE	9100000	12390	510	EDNANDA	718	19.40
00242396	2014-06-05	EMPLOYEE EXPENSE	9100000	12390	510	EDNANDA	718	54.00
00242725	2014-06-11	EMPLOYEE EXPENSE	9100000	12390	510	EDNANDA	718	22.36
00242725	2014-06-11	EMPLOYEE EXPENSE	9100000	12390	510	EDNANDA	718	149.00
00242725	2014-06-11	EMPLOYEE EXPENSE	9100000	12390	510	EDNANDA	718	149.00
00242725	2014-06-11	EMPLOYEE EXPENSE	9100000	11439	510	EDNANDA	293	351.54
00242726	2014-06-11	EMPLOYEE EXPENSE	9100000	11439	510	EDNANDA	293	12.46
00242726	2014-06-11	EMPLOYEE EXPENSE	9100000	11439	510	EDNANDA	293	45.50
00242726	2014-06-11	EMPLOYEE EXPENSE	9100000	11439	510	EDNANDA	293	602.16
00242726	2014-06-11	EMPLOYEE EXPENSE	9100000	12390	510	EDNANDA	718	41.73
00242726	2014-06-11	EMPLOYEE EXPENSE	9100000	12390	290	EDNANDA	718	8.00
00242726	2014-06-11	EMPLOYEE EXPENSE	9100000	12390	510	EDNANDA	718	36.00
00242726	2014-06-11	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	8.83
00242726	2014-06-11	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	41.73
00242729	2014-06-11	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	30.90
00242729	2014-06-11	EMPLOYEE EXPENSE	9100000	11439	520	EDNANDA	294	8.60
00242729	2014-06-11	EMPLOYEE EXPENSE	9210001	12392	290	EDNANDA	294	6.00
00244443	2014-07-21	EMPLOYEE EXPENSE	9210001	11439	396	EDNANDA	294	207.60
00244862	2014-07-29	EMPLOYEE EXPENSE	9210001	11439	510	EDNANDA	294	13.03
00244863	2014-07-29	EMPLOYEE EXPENSE	9210001	11439	290	EDNANDA	294	61.74
00244863	2014-07-29	EMPLOYEE EXPENSE	9210001	11439	290	EDNANDA	293	1,000.00
00244863	2014-07-29	EMPLOYEE EXPENSE	9210001	11439	392	EDNANDA	294	29.94

00245478	2014-08-11	EMPLOYEE EXPENSE	9210001	11439	396	EDNANDA	294	18.05
00245478	2014-08-11	EMPLOYEE EXPENSE	9210001	11439	396	EDNANDA	294	63.94
00245478	2014-08-11	EMPLOYEE EXPENSE	9210001	11439	510	EDNANDA	294	26.37
00246332	2014-09-02	EMPLOYEE EXPENSE	9210001	11439	396	EDNANDA	294	38.75
00247068	2014-09-19	EMPLOYEE EXPENSE	9210001	11439	396	EDNANDA	294	58.25
00232477	2013-10-23	EMPLOYEE EXPENSE	9210001	11439	396	EDNANDA	294	11.60
00233265	2013-11-11	EMPLOYEE EXPENSE	9210001	11439	520	EDNANDA	294	28.52
00233265	2013-11-11	EMPLOYEE EXPENSE	9210001	11439	396	EDNANDA	294	53.00
00233281	2013-11-11	EMPLOYEE EXPENSE	9210001	11439	396	EDNANDA	294	53.32
00233281	2013-11-11	EMPLOYEE EXPENSE	9210001	11439	396	EDNANDA	294	-53.32
00233281	2013-11-11	EMPLOYEE EXPENSE	9210001	11439	510	EDNANDA	293	34.22
00233281	2013-11-11	EMPLOYEE EXPENSE	9210001	11439	290	EDNANDA	293	565.00
00235099	2013-12-18	EMPLOYEE EXPENSE	9210001	11439	396	EDNANDA	294	90.10
00235099	2013-12-18	EMPLOYEE EXPENSE	9210001	11439	396	EDNANDA	294	67.06
00235100	2013-12-18	EMPLOYEE EXPENSE	9210001	11439	520	EDNANDA	293	13.66
00235100	2013-12-18	EMPLOYEE EXPENSE	9210001	11439	520	EDNANDA	294	10.46
00235100	2013-12-18	EMPLOYEE EXPENSE	9210001	11439	396	EDNANDA	293	93.07
00235100	2013-12-18	EMPLOYEE EXPENSE	9210001	11439	290	EDNANDA	294	50.00
00235100	2013-12-18	EMPLOYEE EXPENSE	9210001	11439	396	EDNANDA	293	45.00
00235100	2013-12-18	EMPLOYEE EXPENSE	9210001	11439	290	EDNANDA	294	50.00
00235100	2013-12-18	EMPLOYEE EXPENSE	9210001	12392	510	EDNANDA	294	14.34
00235444	2013-12-26	EMPLOYEE EXPENSE	9210001	12392	510	EDNANDA	294	99.00
00235444	2013-12-26	EMPLOYEE EXPENSE	9210001	12392	520	EDNANDA	294	33.00
00237346	2014-02-11	EMPLOYEE EXPENSE	9210001	12392	290	EDNANDA	294	333.33
00237347	2014-02-11	EMPLOYEE EXPENSE	9301015	12394	396	EDNANDA	295	40.86
00237347	2014-02-11	EMPLOYEE EXPENSE	9301015	12394	396	EDNANDA	295	340.89
00238465	2014-03-06	EMPLOYEE EXPENSE	9301015	12394	396	EDNANDA	293	572.08
00238712	2014-03-11	EMPLOYEE EXPENSE	9301015	12394	396	EDNANDA	295	30.51
00239020	2014-03-18	EMPLOYEE EXPENSE	9301015	12394	393	EDNANDA	295	11.06
00239021	2014-03-18	EMPLOYEE EXPENSE	9301015	12394	396	EDNANDA	295	184.39
00240226	2014-04-11	EMPLOYEE EXPENSE	9302000	12394	396	EDNANDA	294	345.97
00240226	2014-04-11	EMPLOYEE EXPENSE	5060000	10642	510	KMLKMPBCO	294	61.69
00240226	2014-04-11	EMPLOYEE EXPENSE	5060000	10642	510	KMLKMPBCO	294	113.42
00240226	2014-04-11	EMPLOYEE EXPENSE	5060000	10642	954	KMLKMPBCO	294	193.50
00240226	2014-04-11	EMPLOYEE EXPENSE	5060000	10642	396	KMLMLPBCO	294	26.97
00242728	2014-06-11	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	34.56
00242728	2014-06-11	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	167.63
00242728	2014-06-11	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	19.37
00244211	2014-07-15	EMPLOYEE EXPENSE	5060000	10642	396	KMLMLPBCO	294	428.09
00245523	2014-08-12	EMPLOYEE EXPENSE	5060000	10642	396	KMLMLPBCO	294	759.81
00245523	2014-08-12	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	126.72
00245587	2014-08-14	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	160.10
00232928	2013-11-04	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	48.59
00232936	2013-11-04	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	156.10
00232937	2013-11-04	EMPLOYEE EXPENSE	5060000	10642	396	KMLMLPBCO	294	31.80
00233250	2013-11-11	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	97.05
00233655	2013-11-18	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	134.17
00233656	2013-11-18	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	155.10
00233657	2013-11-18	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	18.34
00234493	2013-12-09	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	2.39

00235207	2013-12-19	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	335.26
00237189	2014-02-06	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	21.41
00238412	2014-03-05	EMPLOYEE EXPENSE	5060000	10642	396	KMLMLPBCO	294	21.19
00239265	2014-03-24	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	33.50
00239345	2014-03-25	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	74.20
00240559	2014-04-21	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	251.17
00241069	2014-04-30	EMPLOYEE EXPENSE	5060000	10642	396	KMLMLPBCO	294	95.40
00241685	2014-05-15	EMPLOYEE EXPENSE	5060000	10642	396	KMLMLPBCO	294	95.40
00242523	2014-06-06	EMPLOYEE EXPENSE	5060000	10642	396	KMLMLPBCO	294	-95.40
00243171	2014-06-23	EMPLOYEE EXPENSE	5060000	10642	396	KMLMLPBCO	294	61.44
00243374	2014-06-25	EMPLOYEE EXPENSE	5060000	10642	954	KMLMLPBCO	294	190.55
00244134	2014-07-14	EMPLOYEE EXPENSE	5060000	10642	396	KMLMLPBCO	294	18.00
00244404	2014-07-18	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	18.96
00245318	2014-08-07	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	2.19
00245590	2014-08-14	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	159.66
00241275	2014-05-06	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	38.00
00241276	2014-05-06	EMPLOYEE EXPENSE	5060000	10642	396	KMLMLPBCO	294	149.55
00241972	2014-05-23	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	19.89
00242179	2014-05-30	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	63.58
00242521	2014-06-06	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	91.53
00242522	2014-06-06	EMPLOYEE EXPENSE	5060000	10642	396	KMLMLPBCO	294	409.54
00235600	2013-12-30	EMPLOYEE EXPENSE	5060000	10642	520	KMLMLPBCO	294	33.89
00234956	2013-12-16	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	13.77
00234957	2013-12-16	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	80.61
00234958	2013-12-16	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	19.08
00237315	2014-02-10	EMPLOYEE EXPENSE	5060000	10642	396	KMLMLPBCO	294	408.00
00237668	2014-02-19	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	167.63
00237673	2014-02-19	EMPLOYEE EXPENSE	5000000	10218	396	WSBSBL004	294	6.35
00240638	2014-04-23	EMPLOYEE EXPENSE	5000000	10218	510	WSBSBL004	294	32.83
00240639	2014-04-23	EMPLOYEE EXPENSE	5000000	10218	510	WSBSBL004	294	98.10
00240640	2014-04-23	EMPLOYEE EXPENSE	5000000	10218	396	WSBSBL004	294	53.64
00243172	2014-06-23	EMPLOYEE EXPENSE	9100000	12390	520	EDNANDA	718	6.41
00244128	2014-07-14	EMPLOYEE EXPENSE	9100000	12390	520	EDNANDA	718	6.53
00231342	2013-10-01	EMPLOYEE EXPENSE	9100000	12390	520	EDNANDA	718	6.87
00231342	2013-10-01	EMPLOYEE EXPENSE	9100000	12390	510	EDNANDA	718	10.00
00231342	2013-10-01	EMPLOYEE EXPENSE	9100000	12390	510	EDNANDA	718	14.00
00231342	2013-10-01	EMPLOYEE EXPENSE	9100000	12390	520	EDNANDA	718	6.53
00232753	2013-10-30	KENTUCKY ALLIANCE FOR RADIO & TELEVISION	9301002	12394	960	EDNANDA	293	822.00
00232753	2013-10-30	KENTUCKY CHAMBER OF COMMERCE	9302000	11439	955	000001120	294	7,500.00
00232835	2013-10-31	KENTUCKY CHAMBER OF COMMERCE	9302000	11439	955	000001120	294	3,625.00
00232835	2013-10-31	KENTUCKY CHAMBER OF COMMERCE	9100000	12390	510	EDNANDA	718	399.00
00233251	2013-11-11	KENTUCKY COLONEL	9090000	12394	960	EDNANDA	293	50.00
00233251	2013-11-11	KENTUCKY COLONEL	9301001	12394	960	EDNANDA	293	50.00
00234124	2013-11-27	KENTUCKY DIVISION OF FORESTRY	9301015	12394	390	EDNANDA	293	1,649.06
00238702	2014-03-11	KENTUCKY LEGIONNAIRE	9301001	12394	960	EDNANDA	293	50.00
00239675	2014-04-01	KENTUCKY PRESS SERVICE INC	9090000	12394	960	EDNANDA	293	9,972.42
00239675	2014-04-01	KENTUCKY PRESS SERVICE INC	9090000	12394	960	EDNANDA	293	14,319.90
00240181	2014-04-10	KENTUCKY PRESS SERVICE INC	9090000	12394	960	EDNANDA	293	-20.83
00240181	2014-04-10	KENTUCKY PRESS SERVICE INC	9090000	12394	960	EDNANDA	293	4,165.68
00243173	2014-06-23	KENTUCKY PRESS SERVICE INC	9301001	12394	960	EDNANDA	293	7,464.14

00243173	2014-06-23	KENTUCKY PRESS SERVICE INC	9301001	12394	960	EDNANDA	293	20.83
00243174	2014-06-23	KNOTT COUNTY SPORTSPLEX	9301001	12394	960	EDNANDA	293	1,000.00
00243174	2014-06-23	LADYFINGERS CATERING	9100000	12390	510	EDNANDA	718	2,136.41
00246641	2014-09-10	LOUISA ROTARY CLUB	5000000	10218	956	WSBSBL004	294	434.00
00246641	2014-09-10	MANUFACTURERS NEWS INC	9100000	12394	390	EDNANDA	294	174.00
00240935	2014-04-28	MARSHALL COUNTY CHAMBER OF COMMERCE	5060000	10642	955	000001121	294	750.00
00243217	2014-06-23	MARSHALL COUNTY CHAMBER OF COMMERCE	5060000	10642	999	KMLMLPBCO	294	14.00
00231785	2013-10-21	MARSHALL COUNTY CHAMBER OF COMMERCE	5060000	10642	999	KMLMLPBCO	294	21.00
00235795	2014-01-15	MARSHALL COUNTY CHAMBER OF COMMERCE	5060000	10642	999	KMLMLPBCO	294	28.00
00110992	2014-02-21	MARSHALL COUNTY CHAMBER OF COMMERCE	5060000	10642	999	KMLMLPBCO	294	28.00
00111072	2014-02-24	MARSHALL COUNTY CHAMBER OF COMMERCE	5060000	10642	999	KMLMLPBCO	294	14.00
00116022	2014-05-21	MARSHALL COUNTY CHAMBER OF COMMERCE	5060000	10642	999	KMLMLPBCO	294	35.00
00109285	2014-01-20	PAINTSVILLE HERALD	9090000	12394	960	EDNANDA	293	238.00
00109909	2014-01-31	PAINTSVILLE HERALD	9090000	12394	960	EDNANDA	293	399.00
00109909	2014-01-31	PAINTSVILLE HERALD	9090000	12394	960	EDNANDA	293	99.00
00110760	2014-02-18	PAINTSVILLE HERALD	9090000	12394	960	EDNANDA	293	99.00
00110760	2014-02-18	PAINTSVILLE HERALD	9090000	12394	960	EDNANDA	293	99.00
00110761	2014-02-18	PAINTSVILLE HERALD	9090000	12394	960	EDNANDA	293	224.00
00110761	2014-02-18	PAINTSVILLE HERALD	9090000	12394	960	EDNANDA	293	99.00
00111267	2014-02-26	PAINTSVILLE HERALD	9090000	12394	960	EDNANDA	293	311.38
00111572	2014-03-05	PAINTSVILLE HERALD	9090000	12394	960	EDNANDA	293	111.37
00112537	2014-03-21	PAINTSVILLE HERALD	9090000	12394	960	EDNANDA	293	99.00
00112537	2014-03-21	PAINTSVILLE HERALD	9090000	12394	960	EDNANDA	293	111.38
00112537	2014-03-21	PAINTSVILLE HERALD	9090000	12394	960	EDNANDA	293	111.37
00112537	2014-03-21	PAINTSVILLE HERALD	9301001	12394	960	EDNANDA	293	126.00
00112537	2014-03-21	PAINTSVILLE HERALD	9301001	12394	960	EDNANDA	293	50.00
00112538	2014-03-21	PAPA JOHNS	5060000	10218	520	WSBSBL004	294	87.02
00112538	2014-03-21	PGA TOURNAMENT CORP INC	9302000	11439	999	EDNANDA	294	29,256.00
00112538	2014-03-21	EMPLOYEE EXPENSE	5800000	12396	520	EDN103175	294	125.60
00112538	2014-03-21	EMPLOYEE EXPENSE	9210001	12396	520	EDNANDA	294	76.04
00113268	2014-04-02	EMPLOYEE EXPENSE	9210001	12396	510	EDNANDA	294	184.80
00113268	2014-04-02	EMPLOYEE EXPENSE	5060000	10642	510	KMLMLPBCO	294	207.20
00113268	2014-04-02	PR NEWSWIRE ASSOCIATION LLC	9301010	12394	260	EDNANDA	293	2.25
00113268	2014-04-02	PR NEWSWIRE ASSOCIATION LLC	9301010	12394	260	EDNANDA	293	22.50
00113268	2014-04-02	PR NEWSWIRE ASSOCIATION LLC	9301010	12394	260	EDNANDA	293	2.70
00113268	2014-04-02	PR NEWSWIRE ASSOCIATION LLC	9301010	12394	260	EDNANDA	293	1.95
00113268	2014-04-02	PR NEWSWIRE ASSOCIATION LLC	9301010	12394	260	EDNANDA	293	11.40
00113268	2014-04-02	PR NEWSWIRE ASSOCIATION LLC	9301010	12394	260	EDNANDA	293	10.80
00113268	2014-04-02	PR NEWSWIRE ASSOCIATION LLC	9301010	12394	260	EDNANDA	293	21.60
00113269	2014-04-02	PR NEWSWIRE ASSOCIATION LLC	9301010	12394	960	EDNANDA	293	1.95
00113269	2014-04-02	PR NEWSWIRE ASSOCIATION LLC	9301010	12394	260	EDNANDA	293	1.50
00113269	2014-04-02	PR NEWSWIRE ASSOCIATION LLC	9301010	12394	260	EDNANDA	293	1.95
00113269	2014-04-02	PREMIUMS & PROMOTIONS INC	9301002	12394	390	EDNANDA	293	1,024.68
00113269	2014-04-02	PREMIUMS & PROMOTIONS INC	9301015	12394	393	EDNANDA	294	67.83
00113269	2014-04-02	PREMIUMS & PROMOTIONS INC	9301015	12394	390	EDNANDA	294	935.58
00113269	2014-04-02	PREMIUMS & PROMOTIONS INC	9301015	12394	390	EDNANDA	295	1,157.60
00113269	2014-04-02	PREMIUMS & PROMOTIONS INC	9301015	12394	393	EDNANDA	295	83.93
00113269	2014-04-02	PREMIUMS & PROMOTIONS INC	9301015	12394	393	EDNANDA	293	21.20
00113606	2014-04-09	PREMIUMS & PROMOTIONS INC	9301015	12394	390	EDNANDA	293	282.68
00113606	2014-04-09	PREMIUMS & PROMOTIONS INC	9301015	12394	393	EDNANDA	293	41.63

00114234	2014-04-22	PREMIUMS & PROMOTIONS INC	9301015	12394	390	EDNANDA	293	555.00
00114556	2014-04-29	PREMIUMS & PROMOTIONS INC	9301015	12394	393	EDNANDA	293	63.66
00114666	2014-04-30	PREMIUMS & PROMOTIONS INC	9301015	12394	390	EDNANDA	293	848.83
00114666	2014-04-30	PREMIUMS & PROMOTIONS INC	9301015	12394	396	EDNANDA	294	271.57
00114666	2014-04-30	PREMIUMS & PROMOTIONS INC	9301015	12394	393	EDNANDA	294	16.29
00114666	2014-04-30	EMPLOYEE EXPENSE	9100000	12394	520	EDNANDA	293	4.44
00114666	2014-04-30	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	16.39
00114906	2014-05-02	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	294	27.44
00115276	2014-05-08	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	19.04
00116003	2014-05-21	EMPLOYEE EXPENSE	9100000	12394	510	EDNANDA	293	136.64
00116003	2014-05-21	EMPLOYEE EXPENSE	9210001	11439	510	EDNANDA	294	3.39
00116004	2014-05-21	EMPLOYEE EXPENSE	9210001	11439	510	EDNANDA	294	6.22
00116004	2014-05-21	EMPLOYEE EXPENSE	9210001	11439	510	EDNANDA	293	6.72
00116399	2014-05-29	EMPLOYEE EXPENSE	9210001	11439	510	EDNANDA	293	145.60
00116399	2014-05-29	UNITED WAY OF UPPER OHIO VALLEY	5060000	10642	290	KMLMLPBCO	294	600.00
00116575	2014-06-02	US BANK NATIONAL ASSOCIATION	9302003	11389	263	FANANDA	661	2,000.00
00116943	2014-06-06	US POSTAL SERVICE	9100000	12394	933	EDNANDA	293	125.00
00116944	2014-06-06	WDHR	9301001	12394	960	EDNANDA	293	270.00
00117844	2014-06-24	WDHR	9301002	12394	960	EDNANDA	293	960.00
00117844	2014-06-24	WDHR	9301002	12394	960	EDNANDA	293	560.00
00117925	2014-06-25	WIFX	9301001	12394	960	EDNANDA	293	100.00
00118076	2014-06-27	WLSI-AM	9301001	12394	960	EDNANDA	293	160.00
00118082	2014-06-27	EMPLOYEE EXPENSE	9210001	12392	954	EDNANDA	294	350.00
00119778	2014-07-30	WPKE RADIO	9301001	12394	960	EDNANDA	293	160.00
00121212	2014-08-27	WXCC FM	9301002	12394	960	EDNANDA	293	960.00
00121212	2014-08-27	WXCC FM	9301002	12394	960	EDNANDA	293	560.00
00121477	2014-09-03	WXKQ-FM/WTCW-AM	9090000	12394	960	EDNANDA	293	750.00
00121477	2014-09-03	WYMT-TV	9090000	12394	960	EDNANDA	293	7,250.00
00121745	2014-09-09	WYMT-TV	9090000	12394	960	EDNANDA	293	2,500.00
00122080	2014-09-15	WYMT-TV	9090000	12394	960	EDNANDA	293	250.00
00122713	2014-09-29	WYMT-TV	9090000	12394	960	EDNANDA	293	550.00
00122714	2014-09-29	WYMT-TV	9090000	12394	960	EDNANDA	293	6,000.00
00107681	2013-11-20	WYMT-TV	9090000	12394	960	EDNANDA	293	2,250.00
00108026	2013-12-09	WYMT-TV	9090000	12394	960	EDNANDA	293	5,000.00
00108026	2013-12-09	WYMT-TV	9301000	12394	960	EDNANDA	293	3,250.00
00108667	2014-01-07	WYMT-TV	9301000	12394	960	EDNANDA	293	1,500.00
00112053	2014-03-12	WYMT-TV	9301001	12394	960	EDNANDA	293	1,000.00
00117368	2014-06-13	WYMT-TV	9301003	12394	960	EDNANDA	293	2,600.00
								248157.76

EXHIBIT RCS-19

Kentucky Power Company

REQUEST

The AFUDC-related Deferred FIT calculation in footnote 1 of Section V, S-4, page 19 assumes that the cost related to A/R Financing in the capital structure is tax-deductible. In this regard, please provide the following information:

a. Confirm the above-stated fact. If you disagree, explain your disagreement.

b. If confirmed, explain why the Company has not made the same assumption (i.e., treat the A/R Financing cost component of the proposed overall rate of return as a tax-deductible item in the calculation of the interest synchronization adjustment on Section V, S-4, page 20.

RESPONSE

a. We agree.

b. The A/R Financing had not been a part of the capital structure in preceding base rate cases, and thus was inadvertently overlooked in calculation of the interest synchronization adjustment. Please refer to page 2 of this response for a revised interest synchronization adjustment.

WITNESS: Errol K Wagner

Kentucky Power Company
Interest Synchronization
Test Year Twelve Months Ended 6/30/2005

Section V
Workpaper S-4
Page 20
Revised

Ln No (1)	Description (2)	PSC Jurisdictional Amount (3)
1	LTD, per Capitalization (Sch 3, C 12, Ln 1)	$482,392,123
2	LTD Rate (WP S-2, P 1, C 5, Ln 1)	5.70%
3	Annualized LTD Interest	$27,496,351
4	STD, per Capitalization (Sch 3, C 12, Ln 2)	$3,340,763
5	STD Rate (WP S-2, P 1, C 5, Ln 2)	3.34%
6	Annualized STD Interest	$111,581
7	A/R Financing, per Capitalization (Sch 3, C 12, Ln 3)	$30,052,250
8	A/R Financing Rate (WP S-2, P 1, C 5, Ln 3)	2.99%
9	Annualized A/R Financing Interest	$898,562
10	Total Annualized Interest (Ln 3 + Ln 6 + Ln 9)	$28,506,495
11	Interest per Books Net of ABFUDC	$29,914,717
12	Percent Retail (GP-TOT)	0.990
13	Retail Interest (Ln 11 x Ln 12)	$29,615,570
14	Decrease Interest Expense (Ln 10 - Ln 13)	($1,109,075)
15	SIT Rate	7.20%
16	SIT Adjustment (Ln 14 x Ln 15)	$79,853
17	Net Change for FIT (Ln 14 x Ln 16)	($1,029,222)
18	FIT Rate	35.00%
19	FIT Adjustment	$360,228

Witness: R.K. Wohnhas

EXHIBIT RCS-20

Kentucky Power Company

REQUEST

Capitalization. Refer to (1) the Direct Testimony of Company witness Wohnhas, (2) Section V, Exhibit 1, Schedule 2 (page 1), and (3) Filing Requirement 807 KAR 5:001 Section 16 (4)(i) (pages 391-392).

a. Please explain fully and in detail why the Company's revenue requirement is calculated using the capitalization amount of $1,147,480,328 versus the Kentucky jurisdictional rate base amount of $1,158,186,514.

b. Please cite by date and docket number, the Commission Order which authorized KPCo to use a capitalization amount (of $1,147,480,328) in its revenue requirement calculation that is different from the rate base amount (of $1,158,186,514).

c. Referring to page 392 of Filing Requirement 807 KAR 5:001 Section 16 (4)(i), please explain fully and in detail the difference of $39,598,442 that is reflected on Line 19 of page 392.

d. Please provide a breakout of the components which comprise the unreconciled difference of $39,598,442.

RESPONSE

a. The Company has filed using capitalization in each base rate case filed since at least the early 1980's.

b. Case Nos. 8734, 9061, 91-066, 2005-00341, 2009-00459.

c-d. The Company is working to provide this reconciliation, but is not able to complete prior to the due date of these responses. The Company will supplement this response no later than February 16, 2015.

WITNESS: Ranie K Wohnhas

KPCO Capitalization to Rate Base Reconciliation Summary

	Section V Exhibit 1 Schedule 3 Capitalization	Section V Exhibit 1 Schedule 4 Rate Base	Difference in Capitalization & Rate Base	Included in Section II, Pg 392 Reconciliation	Not Included in Section II, Pg 392 Reconciliation
Totals from Balance Sheet Detail:	1,568,317,356	1,672,428,595	(104,111,239)	(50,304,628)	(53,806,611)
Adjustments					
Proforma Debt Adjustment	5,000,000		5,000,000		5,000,000
FRECO A/C 124 Property	(4,534,316)		(4,534,316)		(4,534,316)
CARRS Site	(6,778,355)	(6,778,355)	-		-
Non-Utility	(995,120)		(995,120)		(995,120)
Section V, Exhibit 1, Schedule 4, Column 3					
Electric Plant in Service - Net		(61,174,525)	61,174,525		61,174,525
Cash Working Capital		(30,953,848)	30,953,848		30,953,848
Construction Work in Progress		(21,313)	21,313		21,313
Subtotal	1,561,009,565	1,573,500,554	(12,490,989)	(50,304,628)	37,813,639
Jurisdictional Allocation Adjustment	(12,762,673)	(16,577,921)	3,815,248		3,815,248
Subtotal	1,548,246,892	1,556,922,633	(8,675,741)	(50,304,628)	41,628,887
Going-Level Adjustments					
Weather Normalization		(443,589)	443,589		443,589
Customer Annualization		(29,882)	29,882		29,882
Remove AEP Pool		(1,310,105)	1,310,105		1,310,105
System Sales Margin		7,590,356	(7,590,356)		(7,590,356)
O&M Expense Interest on Customer Deposit		(303)	303		303
Normalization Major Storms		(80,970)	80,970		80,970
Amortization Storm Cost Deferral		(279,684)	279,684		279,684
Rate Case Expense		32,255	(32,255)		(32,255)
Postage Rate Increase		1,527	(1,527)		(1,527)
Eliminate Advertising Expense		(3,826)	3,826		3,826
Annualization of Lease Costs		9,122	(9,122)		(9,122)
Reliability		1,331,988	(1,331,988)		(1,331,988)
Pension and OPEB Expense		(25,823)	25,823		25,823
Amortization of Deferred IGCC Costs		6,563	(6,563)		(6,563)
Amortization of Deferred CCS FEED Study Costs		4,303	(4,303)		(4,303)
Amortization of Deferred CARRS Site Costs		12,916	(12,916)		(12,916)
Amortization of Deferred Preliminary Big Sandy FGD Costs		138,162	(138,162)		(138,162)
Incentive Compensation Plan		(121,689)	121,689		121,689
KPCo T&D Annualization Employee Related Expense		3,697	(3,697)		(3,697)
Remove Big Sandy O&M		(5,339,667)	5,339,667		5,339,667
PJM Charges and Credits Adjustment to Reflect Pool Termination, Removal of Big Sandy		948,038	(948,038)		(948,038)
Adjustments to Include Test Year Mitchell Plant O&M		1,104,981	(1,104,981)		(1,104,981)
Mitchell Plant Maintenance Normalization		402,976	(402,976)		(402,976)
Eliminate Mitchell O&M FGD		(1,859,919)	1,859,919		1,859,919
Cost of Removal Adjustment 2014		(60,983)	60,983		60,983
FGD Movement from Base to Environmental (Mitchell)	(223,164,406)	(223,164,406)	-		-
Mitchell Coal Stock	664,080	664,080	-		-
Big Sandy Coal Stock	(18,709,274)	(18,709,274)	-		-
Removal of Coal Related Assets	(147,983,065)	(147,983,065)	-		-
Removal of Big Sandy M&S form Rate Base	(6,268,345)	(6,268,345)	-		-
Removal of Big Sandy CWIP form Rate Base	(5,305,554)	(5,305,554)	-		-
Adjustment Subtotals	(400,766,564)	(398,736,120)	(2,030,444)	-	(2,030,444)
Total	**1,147,480,328**	**1,158,186,513**	**(10,706,185)**	**(50,304,628)**	**39,598,443**

Values from Section II, Page 392

KPSC Jurisdiction Rate Base		1,158,186,514			
Subtotal of Reconciling Items				(91,775,197)	
Cash Working Capital				41,470,569	
Subtotal				(50,304,628)	
Difference					39,598,442
KPSC Jurisdiction Capitalization	1,147,480,328				

KPCO Balance Sheet Detail

ASSETS	Section IV Page 3 & 4 Per Books 9/30/2014	Section V Exhibit 1 Schedule 3 Capitalization	All Balance Sheet Items Funded by Capitalization	Section V Exhibit 1 Schedule 4 Rate Base	Difference in Capitalization & Rate Base	Included in Section II, Pg 392 Reconciliation	Not Included in Section II, Pg 392 Reconciliation
1010001 Plant in Service	2,731,720,184		2,731,720,184	2,731,720,184	0		0
1010002 Plant In Service-Transmission	0		0		0		0
1011001 Capital Leases	6,651,762		6,651,762	6,651,762	0		0
1050001 Held For Fut Use	7,405,959		7,405,959	7,405,959	0		0
1060001 Const Not Classifd	148,935,471		148,935,471	148,935,471	0		0
Plant In Service	2,894,713,376		2,894,713,376	2,894,713,376	0		0
1011004 Capital Leases - Gen & Misc	0		0		0		0
1011012 Accrued Capital Leases	0		0		0		0
General Plant	0		0	0	0		0
1070001 CWIP - Project	80,210,718		80,210,718	80,210,718	0		0
Construction Work-In-Progress	80,210,718		80,210,718	80,210,718	0		0
ELECTRIC UTILITY PLANT	**2,974,924,094**		**2,974,924,094**	**2,974,924,094**	**0**		**0**
1011006 Prov-Leased Assets	(2,145,480)		(2,145,480)	(2,145,480)	0		0
1080001 A/P for Deprec of Plt	(987,826,643)		(987,826,643)	(987,826,643)	0		0
1080005 RWIP - Project Detail	9,135,302		9,135,302	9,135,302	0		0
1080011 Cost of Removal Reserve	(21,769,449)		(21,769,449)	(21,769,449)	0		0
1080013 ARO Removal Deprec - Accretion	4,046,340		4,046,340	0	4,046,340		4,046,340
1110001 A/P for Amort of Plt	(21,951,155)		(21,951,155)	(21,951,155)	0		0
less Accum Provision - Depre, Depl, Amort.	(1,020,511,085)		(1,020,511,085)	(1,024,557,424)	4,046,340		4,046,340
NET ELECTRIC UTILITY PLANT	**1,954,413,009**		**1,954,413,009**	**1,950,366,669**	**4,046,340**		**4,046,340**
1210001 Nonutility Property - Owned	995,120		995,120		995,120	995,120	0
Gross NonUtility Property	995,120		995,120	0	995,120	995,120	0
1220001 Depr&Amrt of Nonutl Prop-Ownd	(219,958)		(219,958)		(219,958)	(219,958)	0
Less Depr & Amort NonUtility Property	(219,958)		(219,958)	0	(219,958)	(219,958)	0
1240026 Other Property - CCNC	0		0		0	0	0
1240027 Other Property - RWIP	3,795		3,795		3,795	3,795	0
1240029 Other Property - CPR	4,534,316		4,534,316		4,534,316	4,534,316	0
Other Property Investments	4,538,111		4,538,111	0	4,538,111	4,538,111	0
Net NonUtility Property	5,313,273		5,313,273	0	5,313,273	5,313,273	0
Investment in Consol Subsidiaries	0		0		0		0
Investment in NonConsol Subsidiaries	0		0		0		0
Investment in NonConsol Subs Cost Basis	0		0		0		0
Investment in Subsidiary & Associated	0		0	0	0		0
1240002 Oth Investments-Nonassociated	806		806		806	806	0
1240007 Deferred Compensation Benefits	81,979		81,979		81,979	81,979	0
1240092 Fbr Opt Lns-In Kind Sv-Invest	152,086		152,086		152,086	152,086	0
Other Investments	234,871		234,871	0	234,871	234,871	0
1290000 Pension Net Funded Position	4,788,574		4,788,574		4,788,574		4,788,574
1290001 Non-UMWA PRW Funded Position	10,385,901		10,385,901		10,385,901		10,385,901
1290002 SFAS 106 - Non-UMWA PRW	2,869,871		2,869,871		2,869,871		2,869,871
1290003 SFAS 87 - Pension	(1,969,737)		(1,969,737)		(1,969,737)		(1,969,737)
Other Special Funds	16,074,609		16,074,609	0	16,074,609		16,074,609
1581000 SO2 Allowance Inventory	0		0		0		0
Allowance - NonCurrent	0		0	0	0		0
1750002 Long-Term Unreal Gns - Non Aff	1,382,987		1,382,987		1,382,987	1,382,987	0
1750022 L/T Asset MTM Collateral	(46,735)		(46,735)		(46,735)	(46,735)	0
1760011 L/T Asset for Commodity Hedges	0		0		0	0	0
Long Term Energy Trading Contracts	1,336,252		1,336,252		1,336,252	1,336,252	0
OTHER PROPERTY AND INVESTMENTS	22,959,006		22,959,006	0	22,959,006	6,884,396	16,074,610
1310000 Cash	653,790		653,790		653,790	1,307,580	(653,790) *
Cash and Cash Equivalents	653,790		653,790	0	653,790	1,307,580	(653,790)
1340050 Spec Deposit Mizuho Securities	154,543		154,543		154,543	309,085	(154,543) *
1340051 Spec Depost RBC	941,429		941,429		941,429	1,882,859	(941,429) *
Special Deposits	1,095,972		1,095,972	0	1,095,972	2,191,944	(1,095,972)
Other Intercompany Adj Working Funds	0		0		0	0	0
Miscellaneous Working Funds	0		0		0	0	0
Auction Rate Securities	0		0		0	0	0
Special Deposits and Working Funds	1,095,972		1,095,972	0	1,095,972	2,191,944	(1,095,972)
Temporary Cash Investments	0		0		0	0	0
Cash and Cash Equivalents	1,749,762		1,749,762	0	1,749,762	3,499,524	(1,749,762)
1450000 Corp Borrow Prg (NR-Assoc)	9,577,118		9,577,118		9,577,118		9,577,118
Advances to Affiliates	9,577,118		9,577,118	0	9,577,118		9,577,118
1420001 Customer A/R - Electric	32,905,597		32,905,597		32,905,597	32,905,597	0
1420014 Customer A/R-System Sales	524,277		524,277		524,277	524,277	0
1420019 Transmission Sales Receivable	8,318		8,318		8,318	8,318	0
1420022 Cust A/R - Factored	(37,559,285)		(37,559,285)		(37,559,285)	0	(37,559,285)
1420023 Cust A/R-System Sales - MLR	953,600		953,600		953,600	953,600	0
1420024 Cust A/R-Options & Swaps - MLR	19,656		19,656		19,656	19,656	0
1420027 Low Inc Energy Asst Pr (LIEAP)	0		0		0	0	0
1420044 Customer A/R - Estimated	522,235		522,235		522,235	522,235	0
1420050 PJM AR Accrual	2,991,974		2,991,974		2,991,974	2,991,974	0
1420052 Gas Accruals	0		0		0	0	0
1420053 AR Coal Trading	0		0		0	0	0
1420054 Accrued Power Brokers	13,802		13,802		13,802	13,802	0
1420057 Customer A/R - REC activity	31		31		31	31	0

KPCO Balance Sheet Detail

ASSETS	Section IV Page 3 & 4 Per Books 9/30/2014	Section V Exhibit 1 Schedule 3 Capitalization	All Balance Sheet Items Funded by Capitalization	Section V Exhibit 1 Schedule 4 Rate Base	Difference in Capitalization & Rate Base	Included in Section II, Pg 392 Reconciliation	Not Included in Section II, Pg 392 Reconciliation
1420101 Other Accounts Rec - Cust	0		0		0	0	0
1420102 AR Peoplesoft Billing - Cust	957,364		957,364		957,364	957,364	0
Acct Rec - Customers	1,337,570		1,337,570	0	1,337,570	38,896,854	(37,559,285)
1430022 2001 Employee Biweekly Pay Cnv	94,583		94,583		94,583	94,583	0
1430023 A/R PeopleSoft Billing System	0		0		0	0	0
1430081 Damage Recovery - Third Party	43,963		43,963		43,963	43,963	0
1430083 Damage Recovery Offset Demand	(43,232)		(43,232)		(43,232)	(43,232)	0
1430089 A/R - Benefits Billing	0		0		0	0	0
1430101 Other Accounts Rec - Misc	0		0		0	0	0
1430102 AR Peoplesoft Billing - Misc	2,313		2,313		2,313	2,313	0
1710048 Interest Receivable -FIT -LT	0		0		0	0	0
1710248 Interest Receivable -FIT -ST	0		0		0	0	0
1710348 Interest Receivable -SIT -LT	0		0		0	0	0
1710448 Interest Receivable. -SIT -ST	12		12		12	12	0
1720000 Rents Receivable	2,182,210		2,182,210		2,182,210	2,182,210	0
Acct Rec - Miscellaneous	2,279,848		2,279,848	0	2,279,848	2,279,848	0
1440002 Uncoll Accts-Other Receivables	(23,817)		(23,817)		(23,817)	(23,817)	0
Acct Rec - AP for Uncollectible Accounts	(23,817)		(23,817)	0	(23,817)	(23,817)	0
1460001 A/R Assoc Co - InterUnit G/L	31,973,243		31,973,243		31,973,243	31,973,243	0
1460002 A/R Assoc Co - Allowances	0		0		0	0	0
1460006 A/R Assoc Co - Intercompany	853,542		853,542		853,542	853,542	0
1460009 A/R Assoc Co - InterUnit A/P	12,626		12,626		12,626	12,626	0
1460011 A/R Assoc Co - Multi Pmts	1,029,235		1,029,235		1,029,235	1,029,235	0
1460019 A/R-Assoc Co-AEPSC-Agent	0		0		0	0	0
1460024 A/R Assoc Co - System Sales	0		0		0	0	0
1460025 Fleet - M4 - A/R	27,886		27,886		27,886	27,886	0
1460045 A/R Assc Co-Realization Sharng	0		0		0	0	0
Acct Rec - Associated Companies	33,896,532		33,896,532	0	33,896,532	33,896,532	0
1510001 Fuel Stock - Coal	28,964,476		28,964,476	28,964,476	0		0
1510002 Fuel Stock - Oil	2,426,762		2,426,762	2,426,762	0		0
1510020 Fuel Stock Coal - Intransit	3,719,752		3,719,752	3,719,752	0		0
1520000 Fuel Stock Exp Undistributed	716,689		716,689	716,689	0		0
Fuel Stock	35,827,679		35,827,679	35,827,679	0		0
1540001 M&S - Regular	18,874,744		18,874,744	18,874,744	0		0
1540004 M&S - Exempt Material	126,237		126,237	126,237	0		0
1540006 M&S - Lime and Limestone	1,571,884		1,571,884	1,571,884	0		0
1540012 Materials & Supplies - Urea	503,764		503,764	503,764	0		0
1540013 Transportation Inventory	116,653		116,653	116,653	0		0
1540022 M&S-Lime & Limestone Intransit	0		0	0	0		0
1540023 M&S Inv - Urea In-Transit	1,036,552		1,036,552	1,036,552	0		0
Plant Materials and Supplies	22,229,833		22,229,833	22,229,833	0		0
Merchandise	0		0		0		0
1581003 SO2 Allowance Inventory - Curr	13,191,961		13,191,961	13,191,961	0	13,191,961	(13,191,961)
1581004 NOx Allowance Inventory - Curr	16,048		16,048	16,048	0	16,048	(16,048)
1581006 An. NOx Comp Inv - Curr	64,280		64,280	64,280	0	64,280	(64,280)
1581009 CSAPR Current SO2 Inv	350,000		350,000	0	350,000	350,000	0
Allowance Inventory	13,622,289		13,622,289	13,272,289	350,000	13,622,289	(13,272,289)
1630019 Stores Exp - Big Sandy Plant	0		0		0	0	0
Stores Expenses	0		0		0	0	0
Materials and Supplies	35,852,122		35,852,122	35,502,122	350,000	13,622,289	(13,272,289)
1730000 Accrued Utility Revenues	8,056,499		8,056,499		8,056,499	8,056,499	0
1730002 Acrd Utility Rev-Factored-Assc	(8,056,499)		(8,056,499)		(8,056,499)	(8,056,499)	0
Accrued Utility Revenues	0		0	0	0	0	0
1750001 Curr. Unreal Gains - NonAffil	4,345,901		4,345,901		4,345,901	4,345,901	0
1750021 S/T Asset MTM Collateral	0		0		0	0	0
1760010 S/T Asset for Commodity Hedges	0		0		0	0	0
Energy Trading	4,345,901		4,345,901	0	4,345,901	4,345,901	0
1650001 Prepaid Insurance	649,020		649,020	649,020	0		0
165000213 Prepaid Taxes	0		0	0	0		0
165000214 Prepaid Taxes	802,165		802,165	802,165	0		0
1650009 Prepaid Carry Cost-Factored AR	26,888		26,888	26,888	0		0
1650010 Prepaid Pension Benefits	53,709,968		53,709,968	53,709,968	0		0
165001113 Prepaid Sales Taxes	0		0	0	0		0
165001114 Prepaid Sales Taxes	352,658		352,658	352,658	0		0
165001213 Prepaid Use Taxes	0		0	0	0		0
165001214 Prepaid Use Taxes	31,883		31,883	31,883	0		0
1650014 FAS 158 Qual Contra Asset	(53,709,968)		(53,709,968)	(53,709,968)	0		0
1650021 Prepaid Insurance - EIS	641,774		641,774	641,774	0		0
1650023 Prepaid Lease	0		0	0	0		0
1650035 PRW Without MED-D Benefits	(2,969,075)		(2,969,075)	(2,969,075)	0		0
1650036 PRW for Med-D Benefits	5,838,946		5,838,946	5,838,946	0		0
1650037 FAS158 Contra-PRW Exclud Med-D	(2,869,871)		(2,869,871)	(2,869,871)	0		0
Prepayments	2,504,389		2,504,389	2,504,389	0		0
1240005 Spec Allowance Inv NOx	7		7		7	7	0
1340018 Spec Deposits - Elect Trading	900		900		900	900	0
1340043 Spec Deposit UBS Securities	0		0		0	0	0
1340048 Spec Deposits-Trading Contra	(45,747)		(45,747)		(45,747)	(45,747)	0
174001112 Non-Highway Fuel Tx Credt-2012	0		0		0	0	0
174001113 Non-Highway Fuel Tx Credt-2012	514		514		514	514	0
1860007 Billings and Deferred Projects	105,765		105,765		105,765	105,765	0
Other Current Assets	61,439		61,439	0	61,439	61,439	0
CURRENT ASSETS	127,408,543	0	127,408,543	73,834,190	53,574,353	96,578,571	(43,004,218)
1823007 SFAS 112 Postemployment Benef	4,401,367		4,401,367		4,401,367	4,401,367	0
1823009 DSM Incentives	2,741,216		2,741,216		2,741,216	2,741,216	0
1823010 Energy Efficiency Recovery	(31,307,123)		(31,307,123)		(31,307,123)	(31,307,123)	0
1823011 DSM Lost Revenues	6,673,849		6,673,849		6,673,849	6,673,849	0
1823012 DSM Program Costs	21,892,058		21,892,058		21,892,058	21,892,058	0
1823022 HRJ 765kV Post Service AFUDC	607,176		607,176		607,176	607,176	0
1823054 HRJ 765kV Depreciation Expense	94,615		94,615		94,615	94,615	0
1823063 Unrecovered Fuel Cost	8,990,089		8,990,089		8,990,089	8,990,089	0
1823077 Unreal Loss on Fwd Commitments	1,235,880		1,235,880		1,235,880	1,235,880	0
1823078 Deferred Storm Expense	15,669,833		15,669,833		15,669,833	15,669,833	0
1823099 Asset Retirement Obligations	1,172,796		1,172,796		1,172,796	1,172,796	0
1823115 Defd Equity Carry Chg-Non Fuel	(68,547)		(68,547)		(68,547)	(68,547)	0
1823118 BridgeCo TO Funding	198,584		198,584		198,584	198,584	0
1823119 PJM Integration Payments	36,426		36,426		36,426	36,426	0
1823120 Other PJM Integration	209,804		209,804		209,804	209,804	0
1823121 Carry Chgs-RTO Startup Costs	134,805		134,805		134,805	134,805	0
1823122 Alliance RTO Deferred Expense	103,937		103,937		103,937	103,937	0
1823165 REG ASSET FAS 158 QUAL PLAN	39,456,152		39,456,152		39,456,152	39,456,152	0
1823166 REG ASSET FAS 158 OPEB PLAN	(8,455,244)		(8,455,244)		(8,455,244)	(8,455,244)	0

KPCO Balance Sheet Detail

	ASSETS	Section IV Page 3 & 4 Per Books 9/30/2014	Section V Exhibit 1 Schedule 3 Capitalization	All Balance Sheet Items Funded by Capitalization	Section V Exhibit 1 Schedule 4 Rate Base	Difference in Capitalization & Rate Base	Included in Section II, Pg 392 Reconciliation	Not Included in Section II, Pg 392 Reconciliation
1823167	REG Asset FAS 158 SERP Plan	(135,151)		(135,151)		(135,151)	(135,151)	0
1823188	Deferred Carbon Mgmt Research	87,517		87,517		87,517	87,517	0
1823299	SFAS 106 Medicare Subsidy	2,220,355		2,220,355		2,220,355	2,220,355	0
1823301	SFAS 109 Flow Thru Defd FIT	88,836,376		88,836,376		88,836,376	88,836,376	0
1823302	SFAS 109 Flow Thru Defrd SIT	69,583,721		69,583,721		69,583,721	69,583,721	0
1823306	Net CCS FEED Study Costs	872,858		872,858		872,858	872,858	0
1823325	CCS FEED Study Reserve	(872,858)		(872,858)		(872,858)	(872,858)	0
1823329	ATR Under-Recovery	3,615,459		3,615,459		3,615,459	3,615,459	0
	Miscellaneous Regulatory Assets	227,995,951		227,995,951	0	227,995,951	227,995,951	0
1890004	Loss Rec Debt-Debentures	611,282		611,282		611,282	611,282	0
	Unamortized Loss on Reacquired Debt	611,282		611,282	0	611,282	611,282	0
	REGULATORY ASSETS	228,607,234		228,607,234	0	228,607,234	228,607,234	0
1810002	Unamort Debt Exp - Inst Pur Cn	486,601		486,601		486,601	486,601	0
1810006	Unamort Debt Exp - Sr Unsec Nt	2,074,660		2,074,660		2,074,660	2,074,660	0
	Unamortized Debt Expense	2,561,260		2,561,260	0	2,561,260	2,561,260	0
1840029	Transp-Assigned Vehicles	0		0		0	0	0
	Clearing Accounts	0		0	0	0	0	0
1830000	Prelimin Surv&Investgtn Chrgs	32,130,173		32,130,173		32,130,173	32,130,173	0
1830004	Prelim Survey & Invstgtn Resrv	(31,973,318)		(31,973,318)		(31,973,318)	(31,973,318)	0
1860000	MDD-Internal Billing Only	0		0		0	0	0
1860001	Allowances	454		454		454	454	0
186000312	Deferred Property Taxes	0		0		0	0	0
186000313	Deferred Property Taxes	4,521,362		4,521,362		4,521,362	4,521,362	0
1860046	Railroad Cars Subleased	0		0		0	0	0
1860077	Agency Fees - Factored A/R	912,316		912,316		912,316	912,316	0
186008113	Defd Property Tax - Cap Leases	0		0		0	0	0
186008114	Defd Property Tax - Cap Leases	6,887		6,887		6,887	6,887	0
1860087	Estimated Barging Bills	0		0		0	0	0
1860153	Unamortized Credit Line Fees	408,955		408,955		408,955	408,955	0
1860160	Deferred Expenses - Current	0		0		0	0	0
1860166	Def Lease Assets - Non Taxable	153,388		153,388		153,388	153,388	0
1860179	Local Credit Line Fees	63,434		63,434		63,434	63,434	0
	Other Deferred Debits	6,223,651		6,223,651	0	6,223,651	6,223,651	0
1900006	ADIT Federal - SFAS 133 Nonaff	0		0		0	0	0
1900009	ADIT Federal - Pension OCI NAf	0		0		0	0	0
1900010	ADIT Federal - Pension OCI	4,002,242		4,002,242		4,002,242	4,002,242	0
1900011	ADIT Federal Non-UMWA PRW OCI	(675,730)		(675,730)		(675,730)	(675,730)	0
1900015	ADIT-Fed-Hdg-CF-Int Rate	94,893		94,893		94,893	94,893	0
1901001	Accum Deferred FIT - Other	17,089,502		17,089,502	17,089,502	0	0	0
1902001	Accum Defd FIT - Oth Inc & Ded	479,356		479,356		479,356	479,356	0
1903001	Acc Dfd FIT - FAS109 Flow Thru	24,377,084		24,377,084		24,377,084	24,377,084	0
1904001	Accum Dfd FIT - FAS 109 Excess	317,484		317,484		317,484	317,484	0
	Accumulated Deferred Income Taxes	45,684,831		45,684,831	17,089,502	28,595,329	28,595,329	0
	TOTAL DEFERRED CHARGES	54,469,742		54,469,742	17,089,502	37,380,240	37,380,240	0
	TOTAL ASSETS	**2,387,857,533**		**2,387,857,533**	**2,041,290,361**	**346,567,172**	**369,450,441**	**(22,883,269)**
	CAPITALIZATION and LIABILITIES							
	COMMON STOCK							
	Authorized: 2,000,000 Shares							
	Outstanding: 1,009,000 Shares							
2010001	Common Stock Issued-Affiliated	50,450,000	50,450,000	0		0		0
	Common Stock	50,450,000	50,450,000	0	0	0		0
	Premium on Capital Stock	0		0		0		0
2080000	Donations Recvd from Stckhldrs	514,648,268	514,648,268	0		0		0
2110000	Miscellaneous Paid-In Capital	0	0	0		0		0
2110018	DSIT Apportionment Adj.	2,811,185	2,811,185	0		0		0
2190006	OCI-Min Pen Liab FAS 158-Qual	(7,432,736)	(7,432,736)	0		0		0
2190007	OCI-Min Pen Liab FAS 158-OPEB	1,254,927	1,254,927	0		0		0
2190010	OCI for Commodity Hedges	0	0	0		0		0
2190015	Accum OCI-Hdg-CF-Int Rate	(176,230)	(176,230)	0		0		0
	Paid-In-Capital	511,105,415	511,105,415	0	0	0		0
	Retained Earnings	139,298,330	139,298,330	0	0	0		0
	COMMON SHAREHOLDERS' EQUITY	700,853,745	700,853,745	0	0	0		0

KPSC Case No. 2014-00396

KPCO Balance Sheet Detail

	ASSETS	Section IV Page 3 & 4 Per Books 9/30/2014	Section V Exhibit 1 Schedule 3 Capitalization	All Balance Sheet Items Funded by Capitalization	Section V Exhibit 1 Schedule 4 Rate Base	Difference in Capitalization & Rate Base	Included in Section II, Pg 392 Reconciliation	Not Included in Section II, Pg 392 Reconciliation
	PS Subject To Mandatory Redemption	0		0	0	0		0
	PS Not Subject Mandatory Redemption	0		0	0	0		0
	CUMULATIVE PREFERRED STOCK	0		0	0	0		0
	TRUST PREFERRED SECURITIES	0		0	0	0		0
2230000	Advances from Associated Co	0		0		0		0
2240005	Other Long Term Debt - Other	80,000,000	80,000,000	0		0		0
2240006	Senior Unsecured Notes	650,000,000	650,000,000	0		0		0
2260006	Unam Disc LTD-Dr-Sr Unsec Note	(486,281)		486,281		486,281		486,281
	Long-Term Debt Less Amt Due 1 Yr	729,513,719	730,000,000	486,281	0	486,281		486,281
	CAPITALIZATION	1,430,367,463	1,430,853,745	486,281	0	486,281		486,281
2270001	Obligatns Undr Cap Lse-Noncurr	3,370,535		(3,370,535)		(3,370,535)	(3,370,535)	0
2270003	Accrued Noncur Lease Oblig	0		0		0	0	0
	Obligations Under Capital Lease-NonCurrent	3,370,535		(3,370,535)	0	(3,370,535)	(3,370,535)	0
	Accumulated Provision Rate Relief	0		0		0		
2282003	Accm Prv I/D - Worker's Com	63,819		(63,819)		(63,819)	(63,819)	0
2283000	Accm Prv for Pensions&Benefits	135,302		(135,302)		(135,302)	(135,302)	0
2283002	Supplemental Savings Plan	141,521		(141,521)		(141,521)	(141,521)	0
2283003	SFAS 106 Post Retirement Benef	0		0		0	0	0
2283005	SFAS 112 Postemployment Benef	5,153,534		(5,153,534)		(5,153,534)	(5,153,534)	0
2283006	SFAS 87 - Pensions	0		0		0	0	0
2283007	Perf Share Incentive Plan	354,425		(354,425)		(354,425)	(354,425)	0
2283013	Incentive Comp Deferral Plan	72,550		(72,550)		(72,550)	(72,550)	0
2283015	FAS 158 SERP Payable Long Term	(135,166)		135,166		135,166	135,166	0
2283016	FAS 158 Qual Payable Long Term	0		0		0	0	0
2283017	FAS 158 OPEB Payable Long Term	0		0		0	0	0
2283018	SFAS 106 Med Part-D	0		0		0	0	0
2284027	Econ. Development Fund NonCurr	757,250		(757,250)		(757,250)	(757,250)	0
2300001	Asset Retirement Obligations	64,112,917		(64,112,917)		(64,112,917)	(64,112,917)	0
	Accumlated Provision - Miscellanous	70,656,153		(70,656,153)	0	(70,656,153)	(70,656,153)	0
	Other NonCurrent Liabilities	74,026,688	0	(74,026,688)	0	(74,026,688)	(74,026,688)	0
	Preferred Stock Due Within 1 Year	0		0		0		0
2220002	IPCs Reaquired - Current	0		0		0		0
2230500	Advances from Assoc Co-Current	20,000,000	20,000,000	0		0		0
2240502	Instl Purchase Contracts-Curr	65,000,000	65,000,000	0		0		0
2240505	Oth LTD - Other - Current	0		0		0		0
	Long-Term Debt Due Within 1 Year	85,000,000	85,000,000	0	0	0		0
	Accumulated Provision Due Within 1 Year	0		0		0		0
	Short-Term Debt	0		0		0		0
2330000	Corp Borrow Program (NP-Assoc)	0		0		0		0
	Advances from Affiliates	0		0	0	0		0
2320001	Accounts Payable - Regular	12,645,129		(12,645,129)		(12,645,129)	(12,645,129)	0
2320002	Unvouchered Invoices	10,498,636		(10,498,636)		(10,498,636)	(10,498,636)	0
2320003	Retention	1,432,905		(1,432,905)		(1,432,905)	(1,432,905)	0
2320011	Uninvoiced Fuel	40,366,240		(40,366,240)		(40,366,240)	(40,366,240)	0
2320050	Coal Trading	0		0		0	0	0
2320052	Accounts Payable - Purch Power	76,446		(76,446)		(76,446)	(76,446)	0
2320053	Elect Trad-Options&Swaps	141,783		(141,783)		(141,783)	(141,783)	0
2320054	Emission Allowance Trading	0		0		0	0	0
2320056	Gas Physicals	0		0		0	0	0
2320062	Broker Fees Payable	2,027		(2,027)		(2,027)	(2,027)	0
2320073	A/P Misc Dedic. Power	9,183		(9,183)		(9,183)	(9,183)	0
2320076	Corporate Credit Card Liab	59,092		(59,092)		(59,092)	(59,092)	0
2320077	INDUS Unvouchered Liabilities	1,033,753		(1,033,753)		(1,033,753)	(1,033,753)	0
2320079	Broker Commisn Spark/Merch Gen	0		0		0	0	0
2320083	PJM Net AP Accrual	0		0		0	0	0
2320086	Accrued Broker - Power	83,626		(83,626)		(83,626)	(83,626)	0
2320090	MISO AP Accrual	77,370		(77,370)		(77,370)	(77,370)	0
2320094	Customer A/P - REC Activity	0		0		0	0	0
	A/P General	66,426,190		(66,426,190)	0	(66,426,190)	(66,426,190)	0
2330012	PCRB Note-Assoc-Current	0		0		0	0	0
2330212	PCRB Note-Assoc-Reacq-Current	0		0		0	0	0
2340001	A/P Assoc Co - InterUnit G/L	21,163,128		(21,163,128)		(21,163,128)	(21,163,128)	0
2340005	A/P Assoc Co - Allowances	0		0		0	0	0
2340011	A/P-Assc Co-AEPSC-Agent	26,810		(26,810)		(26,810)	(26,810)	0
2340012	A/P Assoc-PCRB Interest	0		0		0	0	0
2340025	A/P Assoc Co - CM Bills	65,916		(65,916)		(65,916)	(65,916)	0
2340027	A/P Assoc Co - Intercompany	155,254		(155,254)		(155,254)	(155,254)	0
2340029	A/P Assoc Co - AEPSC Bills	3,481,873		(3,481,873)		(3,481,873)	(3,481,873)	0
2340030	A/P Assoc Co - InterUnit A/P	33,377		(33,377)		(33,377)	(33,377)	0
2340032	A/P Assoc Co - Multi Pmts	0		0		0	0	0
2340035	Fleet - M4 - A/P	13,929		(13,929)		(13,929)	(13,929)	0

KPCO Balance Sheet Detail

ASSETS	Section IV Page 3 & 4 Per Books 9/30/2014	Section V Exhibit 1 Schedule 3 Capitalization	All Balance Sheet Items Funded by Capitalization	Section V Exhibit 1 Schedule 4 Rate Base	Difference in Capitalization & Rate Base	Included in Section II, Pg 392 Reconciliation	Not Included in Section II, Pg 392 Reconciliation
2340037 A/P Assoc-Global Borrowing Int	350,000		(350,000)		(350,000)	(350,000)	0
2340212 A/P Assoc-PCRB Reacq Int	0		0		0	0	0
A/P Associated Companies	25,290,287		(25,290,287)	0	(25,290,287)	(25,290,287)	0
2350001 Customer Deposits-Active	25,260,450		(25,260,450)	(25,260,450)	0	(25,260,450)	25,260,450
2350003 Deposits - Trading Activity	307,092		(307,092)		(307,092)	(307,092)	0
2350005 Deposits - Trading Contra	0		0		0	0	0
Customer Deposits	25,567,542		(25,567,542)	(25,260,450)	(307,092)	(25,567,542)	25,260,450
2360001 Federal Income Tax	23,486,803		(23,486,803)		(23,486,803)	(23,486,803)	0
236000209 State Income Taxes	(63,670)		63,670		63,670	63,670	0
236000212 State Income Taxes	0		0		0	0	0
236000213 State Income Taxes	(940,194)		940,194		940,194	940,194	0
236000214 State Income Taxes	3,599,431		(3,599,431)		(3,599,431)	(3,599,431)	0
2360004 FICA	170,340		(170,340)		(170,340)	(170,340)	0
2360005 Federal Unemployment Tax	253		(253)		(253)	(253)	0
2360006 State Unemployment Tax	3,088		(3,088)		(3,088)	(3,088)	0
236000700 State Sales and Use Taxes	0		0		0	0	0
236000713 State Sales and Use Taxes	0		0		0	0	0
236000714 State Sales and Use Taxes	67,893		(67,893)		(67,893)	(67,893)	0
236000811 Real Personal Property Taxes	0		0		0	0	0
236000812 Real Personal Property Taxes	0		0		0	0	0
236000813 Real Personal Property Taxes	12,144,211		(12,144,211)		(12,144,211)	(12,144,211)	0
236000914 Federal Excise Taxes	0		0		0	0	0
236001212 State Franchise Taxes	0		0		0	0	0
236001213 State Franchise Taxes	3,782		(3,782)		(3,782)	(3,782)	0
236001313 State Business Occupatn Taxes	0		0		0	0	0
236001314 State Business Occupatn Taxes	331,048		(331,048)		(331,048)	(331,048)	0
236001600 State Gross Receipts Tax	71,358		(71,358)		(71,358)	(71,358)	0
236001613 State Gross Receipts Tax	0		0		0	0	0
236001614 State Gross Receipts Tax	15,000		(15,000)		(15,000)	(15,000)	0
236001714 Municipal License Fees Accrd	0		0		0	0	0
236003312 Pers Prop Tax-Cap Leases	0		0		0	0	0
236003313 Pers Prop Tax-Cap Leases	0		0		0	0	0
236003314 Pers Prop Tax-Cap Leases	23,507		(23,507)		(23,507)	(23,507)	0
236003513 Real Prop Tax-Cap Leases	0		0		0	0	0
236003514 Real Prop Tax-Cap Leases	19,125		(19,125)		(19,125)	(19,125)	0
2360037 FICA - Incentive accrual	365,540		(365,540)		(365,540)	(365,540)	0
2360502 State Inc Tax-Short Term FIN48	(160)		160		160	160	0
2360601 Fed Inc Tax-Long Term FIN48	(0)		0		0	0	0
2360602 State Inc Tax-Long Term FIN48	0		0		0	0	0
2360701 SEC Accum Defd FIT-Util FIN 48	0		0		0	0	0
2360702 SEC Accum Defd SIT - FIN 48	70		(70)		(70)	(70)	0
2360801 Federal Income Tax - IRS Audit	0		0		0	0	0
2360901 Accum Defd FIT- IRS Audit	0		0		0	0	0
Taxes Accrued	39,297,426		(39,297,426)	0	(39,297,426)	(39,297,426)	0
2370002 Interest Accrued-Inst Pur Con	2,618		(2,618)		(2,618)	(2,618)	0
2370005 Interest Accrd-Other LT Debt	3,194		(3,194)		(3,194)	(3,194)	0
2370006 Interest Accrd-Sen Unsec Notes	5,187,531		(5,187,531)		(5,187,531)	(5,187,531)	0
2370007 Interest Accrd-Customer Depsts	19,985		(19,985)		(19,985)	(19,985)	0
2370018 Accrued Margin Interest	523		(523)		(523)	(523)	0
2370048 Acrd Int.- FIT Reserve - LT	84,201		(84,201)		(84,201)	(84,201)	0
2370202 Interest Accrd - IPC Buybacks	0		0		0	0	0
2370248 Acrd Int. - FIT Reserve - ST	0		0		0	0	0
2370448 Acrd Int. - SIT Reserve - ST	0		0		0	0	0
Interest Accrued	5,298,052		(5,298,052)	0	(5,298,052)	(5,298,052)	0
Dividends Accrued	0		0		0		
2430001 Oblig Under Cap Leases - Curr	1,135,747		(1,135,747)		(1,135,747)	(1,135,747)	0
2430003 Accrued Cur Lease Oblig	0		0		0	0	0
Obligation Under Capital Leases	1,135,747		(1,135,747)	0	(1,135,747)	(1,135,747)	0
2440001 Curr. Unreal Losses - NonAffil	2,163,931		(2,163,931)		(2,163,931)	2,163,931	(4,327,861)
2440009 S/T Option Premium Receipts	0		0		0	0	0
2440021 S/T Liability MTM Collateral	(79,968)		79,968		79,968	(79,968)	159,936
2450010 S/T Liability-Commodity Hedges	0		0		0		0
Energy Contracts Current	2,083,963		(2,083,963)	0	(2,083,963)	2,083,963	(4,167,925)
2410001 Federal Income Tax Withheld	0		0		0	0	0
2410002 State Income Tax Withheld	139,546		(139,546)		(139,546)	(139,546)	0
2410003 Local Income Tax Withheld	23,092		(23,092)		(23,092)	(23,092)	0
2410004 State Sales Tax Collected	729,372		(729,372)		(729,372)	(729,372)	0
2410006 School District Tax Withheld	50		(50)		(50)	(50)	0
2410008 Franchise Fee Collected	504,791		(504,791)		(504,791)	(504,791)	0
2410009 KY Utility Gr Receipts Lic Tax	899,625		(899,625)		(899,625)	(899,625)	0
Tax Collections Payable	2,296,476		(2,296,476)	0	(2,296,476)	(2,296,476)	0
2420514 Revenue Refunds Accrued	1,149,493		(1,149,493)		(1,149,493)	(1,149,493)	0
Revenue Refunds Accured	1,149,493		(1,149,493)	0	(1,149,493)	(1,149,493)	0
Accrued Rents - Affiliated	0		0		0	0	0
2420504 Accrued Lease Expense	6,423		(6,423)		(6,423)	(6,423)	0
Accrued Rents - NonAffiliated	6,423		(6,423)	0	(6,423)	(6,423)	0
Accrued Rents	6,423		(6,423)	0	(6,423)	(6,423)	0
2420020 Vacation Pay - This Year	2,048,877		(2,048,877)		(2,048,877)	(2,048,877)	0
2420021 Vacation Pay - Next Year	2,950,022		(2,950,022)		(2,950,022)	(2,950,022)	0
Accrued Vacations	4,998,899		(4,998,899)	0	(4,998,899)	(4,998,899)	0
2420051 Non-Productive Payroll	151,944		(151,944)		(151,944)	(151,944)	0
2420053 Perf Share Incentive Plan	196,370		(196,370)		(196,370)	(196,370)	0
Miscellaneous Employee Benefits	348,314		(348,314)	0	(348,314)	(348,314)	0
Employee Benefits	5,347,213		(5,347,213)	0	(5,347,213)	(5,347,213)	0
2420002 P/R Ded - Medical Insurance	151,293		(151,293)		(151,293)	(151,293)	0
2420003 P/R Ded - Dental Insurance	12,580		(12,580)		(12,580)	(12,580)	0
2420013 P/R Ded - LTD Ins Premiums	1,053		(1,053)		(1,053)	(1,053)	0
2420016 P/R Ded-Crt Ordr/Grnshmt/Tx Lv	0		0		0	0	0
2420044 P/R Withholdings	799		(799)		(799)	(799)	0
Payroll Deductions	165,725		(165,725)	0	(165,725)	(165,725)	0
2420503 Worker's Comp Admin Fee	0		0		0	0	0
2420532 Adm Liab-Cur-S/Ins-W/C	711,604		(711,604)		(711,604)	(711,604)	0
Accrued Workers' Compensation	711,604		(711,604)	0	(711,604)	(711,604)	0
2420027 FAS 112 CURRENT LIAB	1,349,912		(1,349,912)		(1,349,912)	(1,349,912)	0
2420046 FAS 158 SERP Payable - Current	15		(15)		(15)	(15)	0
2420071 P/R Ded - Vision Plan	5,805		(5,805)		(5,805)	(5,805)	0
2420072 P/R - Payroll Adjustment	2,634		(2,634)		(2,634)	(2,634)	0
2420076 P/R Savings Plan - Incentive	200,793		(200,793)		(200,793)	(200,793)	0
2420087 Engage to Gain Incentive	0		0		0	0	0
2420088 Econ. Development Fund Curr	174,750		(174,750)		(174,750)	(174,750)	0
2420505 Workers Comp NC Admin Fee	0		0		0	0	0
2420506 Est Financing Cost - Bonds	(133,127)		133,127		133,127	133,127	0
2420511 Control Cash Disburse Account	1,053,290		(1,053,290)		(1,053,290)	(1,053,290)	0
2420512 Unclaimed Funds	62,948		(62,948)		(62,948)	(62,948)	0
2420542 Acc Cash Franchise Req	70,093		(70,093)		(70,093)	(70,093)	0

KPCO Balance Sheet Detail

ASSETS	Section IV Page 3 & 4 Per Books 9/30/2014	Section V Exhibit 1 Schedule 3 Capitalization	All Balance Sheet Items Funded by Capitalization	Section V Exhibit 1 Schedule 4 Rate Base	Difference in Capitalization & Rate Base	Included in Section II, Pg 392 Reconciliation	Not Included in Section II, Pg 392 Reconciliation
2420558 Admitted Liab NC-Self/Ins-W/C	2,077,548		(2,077,548)		(2,077,548)	(2,077,548)	0
242059213 Sales Use Tax - Lease Equip	0		0		0	0	0
242059214 Sales Use Tax - Lease Equip	291		(291)		(291)	(291)	0
2420618 Accrued Payroll	2,093,459		(2,093,459)		(2,093,459)	(2,093,459)	0
2420623 Distr, Cust Ops & Reg Svcs ICP	1,791,100		(1,791,100)		(1,791,100)	(1,791,100)	0
2420624 Corp & Shrd Srv Incentive Plan	242,837		(242,837)		(242,837)	(242,837)	0
2420635 Generation Incentive Plan	2,828,571		(2,828,571)		(2,828,571)	(2,828,571)	0
2420643 Accrued Audit Fees	118,004		(118,004)		(118,004)	(118,004)	0
2420653 Reorg Misc HR Exp Accrual	0		0		0	0	0
2420656 Federal Mitigation Accru (NSR)	554,326		(554,326)		(554,326)	(554,326)	0
2420660 AEP Transmission ICP	190,300		(190,300)		(190,300)	(190,300)	0
2420664 ST State Mitigation Def (NSR)	173,104		(173,104)		(173,104)	(173,104)	0
Miscellaneous Current and Accrued Liab	12,856,652		(12,856,652)	0	(12,856,652)	(12,856,652)	0
Other Current and Accrued Liabilities	22,533,587		(22,533,587)	0	(22,533,587)	(22,533,587)	0
Current Liabilities	272,632,793	85,000,000	(187,632,793)	(25,260,450)	(162,372,343)	(183,464,868)	21,092,525
2811001 Acc Dfd FIT - Accel Amort Prop	85,412,469		(85,412,469)	(85,412,469)	0		0
2821001 Accum Defd FIT - Utility Prop	307,650,137		(307,650,137)	(307,650,137)	0		0
2823001 Acc Dfrd FIT FAS 109 Flow Thru	57,737,500		(57,737,500)		(57,737,500)	(57,737,500)	0
2824001 Acc Dfrd FIT - SFAS 109 Excess	(589,613)		589,613		589,613	589,613	0
2830006 ADIT Federal - SFAS 133 Nonaff	0		0		0	0	0
2831001 Accum Deferred FIT - Other	12,631,818		(12,631,818)	(12,631,818)	0		0
2831002 Accum Deferred SIT - Other	4,723,865		(4,723,865)	(4,723,865)	0	(4,723,865)	4,723,865
2831102 Acc Dfd SIT-WV Pollution Cntrl	5,921,849		(5,921,849)	(5,921,849)	0	(5,921,849)	5,921,849
2832001 Accum Dfrd FIT - Oth Inc & Ded	135,279		(135,279)		(135,279)	(135,279)	0
2833001 Acc Dfd FIT FAS 109 Flow Thru	55,447,034		(55,447,034)		(55,447,034)	(55,447,034)	0
2833002 Acc Dfrd SIT FAS 109 Flow Thru	69,583,721		(69,583,721)		(69,583,721)	(69,583,721)	0
Deferred Income Taxes	598,654,060		(598,654,060)	(416,340,139)	(182,313,921)	(192,959,635)	10,645,714
2550001 Accum Deferred ITC - Federal	53,719	53,719	0		0	0	0
Deferred Investment Tax Credits	53,719	53,719	0	0	0	0	0
2540011 Over Recovered Fuel Cost	0		0		0	0	0
Over Recover of Fuel Cost	0		0		0	0	0
SFAS 106 OPEB	0		0		0		0
Demand Side Management Credit	0		0		0		0
2540000 Other Regulatory Liabilities	542,318		(542,318)		(542,318)	(542,318)	0
2540047 Unreal Gain on Fwd Commitments	4,172,897		(4,172,897)		(4,172,897)	(4,172,897)	0
2540105 Home Energy Assist Prgm - KPCO	103,175		(103,175)		(103,175)	(103,175)	0
2540173 Green Pricing Option	684		(684)		(684)	(684)	0
Other Regulatory Liability	4,819,075		(4,819,075)		(4,819,075)	(4,819,075)	0
2543001 SFAS109 Flow Thru Def FIT Liab	28,926		(28,926)		(28,926)	(28,926)	0
2544001 SFAS 109 Exces Deferred FIT	907,097		(907,097)		(907,097)	(907,097)	0
FAS109 DFIT Reclass (Acct 254)	936,023		(936,023)	0	(936,023)	(936,023)	0
Unamortized Gain on Reacquired Debt	0		0		0	0	0
Regulatory Liabilities	5,755,097		(5,755,097)	0	(5,755,097)	(5,755,097)	0
2440002 LT Unreal Losses - Non Affil	627,940		(627,940)		(627,940)	627,940	(1,255,880)
2440022 L/T Liability MTM Collateral	(12,514)		12,514		12,514	(12,514)	25,028
2450011 L/T Liability-Commodity Hedges	0		0		0	0	0
Long-Term Energy Trading Contracts	615,426		(615,426)	0	(615,426)	615,426	(1,230,852)
2520000 Customer Adv for Construction	117,511		(117,511)	(117,511)	0	0	0
Customer Advances for Construction	117,511		(117,511)	(117,511)	0	0	0
Deferred Gains on Sale/Leaseback	0		0		0		0
Deferred Gains on Dispostion of Utility Plant	0		0		0		0
2530000 Other Deferred Credits	3,738		(3,738)		(3,738)	(3,738)	0
2530004 Allowances	0		0		0	0	0
2530022 Customer Advance Receipts	1,505,492		(1,505,492)		(1,505,492)	(1,505,492)	0
2530050 Deferred Rev -Pole Attachments	247,227		(247,227)		(247,227)	(247,227)	0
2530067 IPP - System Upgrade Credits	275,431		(275,431)		(275,431)	(275,431)	0
2530092 Fbr Opt Lns-In Kind Sv-Dfd Gns	152,086		(152,086)		(152,086)	(152,086)	0
2530101 MACSS Unidentified EDI Cash	0		(0)		(0)	(0)	0
2530112 Other Deferred Credits-Curr	230,828		(230,828)		(230,828)	(230,828)	0
2530114 Federl Mitigation Deferal(NSR)	1,110,644		(1,110,644)		(1,110,644)	(1,110,644)	0
2530124 Contr In Aid of Constr Advance	38,321		(38,321)		(38,321)	(38,321)	0
2530137 Fbr Opt Lns-Sold-Defd Rev	93,007		(93,007)		(93,007)	(93,007)	0
2530177 Deferred Rev-Bonus Lease Curr	431,564		(431,564)		(431,564)	(431,564)	0
2530178 Deferred Rev-Bonus Lease NC	1,546,438		(1,546,438)		(1,546,438)	(1,546,438)	0
Other Deferred Credits	5,634,775		(5,634,775)		(5,634,775)	(5,634,775)	0
Deferred Credits	6,367,712	0	(6,367,712)	(117,511)	(6,250,201)	(5,019,349)	(1,230,852)
DEFERRED CREDITS & REGULATED LIABILITIES	610,830,589	53,719	(610,776,869)	(416,457,650)	(194,319,219)	(203,734,082)	9,414,862
CAPITAL & LIABILITIES	**2,387,857,533**	**1,515,907,464**	**(871,950,069)**	**(441,718,100)**	**(430,231,969)**	**(461,225,637)**	**30,993,668**
Accounts Receivable / Cash Working Capital		52,409,892	52,409,892	72,856,334	(20,446,442)	41,470,569	(61,917,011)
Adjusted Total	2,387,857,533	1,568,317,356	(819,540,177)	(368,861,766)	(450,678,411)	(419,755,068)	(30,923,343)
Assets	2,387,857,533	0	2,387,857,533	2,041,290,361	346,567,172	369,450,441	(22,883,269)
Liabilities	2,387,857,533	1,568,317,356	(819,540,177)	(368,861,766)	(450,678,411)	(419,755,068)	(30,923,343)
Total		**1,568,317,356**	**1,568,317,356**	**1,672,428,595**	**(104,111,239)**	**(50,304,628)**	**(53,806,611)**

* Three accounts inadvertantly included twice in Section II, Page 392 reconciliation.

EXHIBIT RCS-21

Kentucky Power Company

REQUEST

Big Sandy Unit 1 Operation Rider (BS1OR). Refer to the Direct Testimony of Company witness Wohnhas and Company Exhibit AEV 4, which was filed in conjunction with the Direct Testimony of Company witness Vaughn. On page 7 of his Direct Testimony, Mr. Wohnhas stated that KPCo is proposing to recover (1) the non-fuel costs of operating Big Sandy Unit 1 as a coal facility until the conversion to natural gas; (2) the non-fuel costs of operating Big Sandy Unit 1 as a natural gas-fired generating station; and (3) the return on and of the capital investment required for the conversion of Big Sandy Unit 1 to a natural gas-fired unit once the gas-fired unit is in place. In addition, Mr. Wohnhas stated that the annual revenue requirement for the BS1OR (without recovery of any capital costs associated with the conversion to natural gas) totals $18,245,413.

a. Please explain fully and in detail the Company's rationale for proposing the BS1OR and why each of the specific components related to Big Sandy Unit 1, as discussed on page 7 (lines 13-21) of Mr. Wohnhas' testimony, are being proposed to be recovered through the proposed BS1OR.

b. Please reconcile the $18,245,413 annual revenue requirement related to the BS1OR to each component of the BS1OR noted above and on the referenced page of Mr. Wohnhas' testimony. Identify, quantify and explain each reconciling item.

c. Please explain fully and in detail why the Company proposes that the BS1OR remain in place until the rates established in the Company's next base rate case become effective.

d. Please clarify whether Mr. Wohnhas was referring to the base rates established in the instant proceeding or a base rate case filed subsequent to the instant proceeding. Explain fully.

RESPONSE

a. See the Company's response to Staff 2-86.

b. See the Company's response to KIUC 1-17, specifically KIUC_1_17_Attachments 46, 47 and 39 for the requested information. The detail behind Big Sandy 1 items a and b included in KIUC_1_17_Attachment 46 can be found in KIUC_1_17_Attachment 47. The detail behind Big Sandy 1 item c included in KIUC_1_17_Attachment 46 can be found in KIUC_1_17_Attachment 39.

c. The BS1OR is being proposed as an interim ratemaking mechanism to permit the Company to comply with certain requirements of the Mitchell Stipulation in light of the short extended period of operation of Big Sandy Unit 1 as a coal-fired unit. See also the Company's response to part a.

d. Company witness Wohnhas was referring to a base rate case filing subsequent to the instant proceeding.

WITNESS: Alex E Vaughan

Kentucky Power Company

REQUEST

Refer to Exhibit JAR-9, Kentucky Power's proposed P.S.C. KY. No. 10, Sheet Nos. 39-1, the Big Sandy Unit 1 Operation Rider; the Vaughan Testimony, page 18; and the Direct Testimony of Ranie K. Wohnhas ("Wohnhas Testimony"), page 7. State whether recovery of Big Sandy Unit 1 operating expenses pursuant to the Mitchell Stipulation and Settlement Agreement is limited to recovery through a rider as proposed, or whether Kentucky Power has other options for cost recovery.

RESPONSE

Pursuant to the Stipulation and Settlement Agreement approved in Case No. 2012-00578, paragraph 3, "The Company agrees to remove all coal-related operating expenses related to Big Sandy 1....". With the one year extension to operate Big Sandy Unit 1 as coal leading up to the conversion to gas, the rider was the only option available that would keep the Company compliant with the Stipulation and Settlement Agreement. The rider gives transparency of the operating costs to all parties during the one year extension, during the conversion of the unit to gas, and through its operation as a gas-fired unit up until the next base rate filing after its conversion to gas.

WITNESS: Ranie K Wohnhas

EXHIBIT RCS-22

Kentucky Power Company

REQUEST

Please reference the Testimony of Gregory Pauley, p. 9, lines 21-24 and p. 10, lines 1-10. Explain why the Company will not continue to fund the KPCo Economic Advancement Program ("EAP") through shareholder funds, instead of proposing that the customers be forced to contribute to the surcharge.

RESPONSE

The Company is continuing to fund the KEAP program with shareholder funds through 2018. The KEDS program is in addition to the KEAP. The Company will match KEDS funds collected from customers with shareholder funds.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

Please reference the Company's response to AG 1-8.

a. Does the Company plan to continue to fund the Kentucky Power company Economic Advancement Program with shareholder funds beyond 2018, or will the contribution cease in 2018? Please explain the answer in full detail. If the contribution will cease in 2018 please explain why.

RESPONSE

The Company has not made a decision concerning shareholder funding of the Economic Advancement Program beyond 2018.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

Please reference Greg Pauley's Testimony p. 10, lines 3-10, as well as the Company's response to AG 1-32 and explain what "key economic development activities" within the region the Company plans to use the Kentucky Economic Development Surcharge ("K.E.D.S.") funds for if approved.

RESPONSE

The Company plans to expend the funds in a cost-effective fashion. Although specific projects have not been identified, K.E.D.S. funds may be applied toward economic development activities such as:

- Industrial and commercial site development to provide adequate access and utilities to enhance the usefulness of the site and help ensure that industrial sites are "move in" ready for prospective businesses.

- Improvements to and development of buildings to provide move-in ready buildings that can be tailored to a prospective business' specific needs.

- Site marketing to inform and attract prospective businesses to consider a specific location.

- Personnel development / training to enhance the abilities of local and regional economic development personnel to enable them to be more effective in the vital areas of planning, preparation and recruiting prospective industries to their communities and region.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

Refer to the Rogness Testimony, pages 16-20, describing the proposed Kentucky Economic Development Surcharge ("K.E.D.S.").

a. Does any other AEP subsidiary or related entity have a tariff provision to collect an economic development surcharge from its customers? if so, provide a copy of the tariff(s).

b. State whether Kentucky Power is aware of any other utility in any other jurisdiction having similar charges approved to support and promote economic development, if so, provide details concerning the utilities and related tariff provisions.

c. Explain whether and how the proposed K.E.D.S. differs from the economic development provision set forth in Paragraph 10 of the Stipulation and Settlement Agreement attached as Appendix A to the Final Order in Case No. 2012-00578.

d. Explain why Kentucky Power believes it is reasonable to collect an economic development surcharge from its customers to fund economic development initiatives that foster economic growth in Kentucky Power's service territory.

   Explain why Kentucky Power believes it is reasonable to collect the proposed K.E.D.S. from its customers, with matching funds from shareholders, rather than fund economic development initiatives with shareholder contributions only.

RESPONSE

a. There is a similar program in Ohio. See KPSC_2_51_Attachment1.pdf for a copy of the tariff.

b. The Company is not aware of any other utility in any other jurisdiction having similar charges approved to support and promote economic development.

c. The proposed K.E.D.S. tariff is separate from the economic development provision in Paragraph 10 of the Stipulation and Settlement Agreement (Agreement) attached to the final Order in Case No. 2012-00578. Paragraph 10 of the Agreement specifically addresses support for Lawrence and the contiguous counties.

The economic development initiatives funded through the K.E.D.S. tariff are available to the entire service territory and not just the seven Counties discussed in the Agreement. These funds are separate from the other funds discussed in the Commission's Order. Shareholder matching funds in the K.E.D.S. initiatives are in addition to the funds addressed by in the Commission's final Order in Case No. 2012-00578.

d. Both the Company and its customers reside and do business in Eastern Kentucky and all have a stake in the health of regional economy. Enhanced economic development efforts will lead to economic growth and increased employment. The funds raised through the K.E.D.S. tariff will be targeted to specific efforts that will help the counties within the service territory to compete for competitive economic development projects. The surcharge to customers and the matching funds from Company shareholders represents the shared responsibility to support and enhance economic development efforts to the benefit of all.

WITNESS: John A Rogness

OHIO POWER COMPANY

7th Revised Sheet No. 482-1
Cancels 6th Revised Sheet No. 482-1

P.U.C.O. NO. 20

ECONOMIC DEVELOPMENT COST RECOVERY RIDER

Effective Cycle 1 October 2014, all customer bills subject to the provisions of this Rider, including any bills rendered under special contract, shall be adjusted by the Economic Development Cost Recovery charge of 11.44664% of the customer's distribution charges under the Company's Schedules, excluding charges under any applicable Riders. This Rider shall be adjusted periodically to recover amounts authorized by the Commission.

Filed pursuant to Order dated September 17, 2014 in Case No. 14-1329-EL-RDR

Issued: September 29, 2014

Effective: Cycle 1 October 2014

Issued by
Pablo Vegas, President
AEP Ohio

KPSC Case No. 2014-00396 General Rate Adjustment
Commission Staff's Third Set of Data Requests
Dated February 24, 2015
Item No. 20
Page 1 of 1

Kentucky Power Company

REQUEST

Refer to the response to Item 51. Confirm that Ohio has enabling legislation providing for the cost of economic development programs to be recovered from utility customers.

RESPONSE

Confirmed.

WITNESS: Gregory G Pauley

EXHIBIT RCS-23

Kentucky Power Company

REQUEST

Refer to Exhibit JMS-3. If the transmission revenue requirement were to remain in KPCo's base rates, would that be accomplished by eliminating column 10 from Exhibit JMS-3?

a. If not, what other adjustments would be necessary to keep the transmission revenue requirement in KPCo's base rates?

RESPONSE

Yes, eliminating the OATT adjustment in Column 10 of Exhibit JMS-3 would keep the transmission function revenue requirement in base rates which would result in the KY retail jurisdictional revenue requirement increasing by $126,908 and customers' rates in aggregate and by class would not be aligned with the true cost of transmission service. Furthermore, the customer class revenue allocation would need to be re-examined since the effects of the OATT adjustment were taken into consideration when the Company decided not to remove any further inter-class subsidies.

a. None

WITNESS: Jason M Stegall

Kentucky Power Company

REQUEST

Refer to the Vaughan Testimony, page 21, lines 14-17. Mr. Vaughan states that the net effect of Kentucky Power's treatment of transmission revenues and expenses is $126,908 and that '[i]t is important to note that this value will change to the extent any other aspect of the Company's requests in this proceeding are modified." Explain what is meant by "any other aspect."

RESPONSE

Because the value of the transmission adjustment is related to the Company's authorized recovery of transmission revenues and expenses, changes in the manner in revenues and expenses are recovered will flow through to the transmission adjustment.

WITNESS: Alex E Vaughan

Kentucky Power Company

REQUEST

In the current proceeding, Kentucky Power proposes to include the charges that it incurs as an LSE under PJM's OATT in the new PJM Rider, whereas in the past, Kentucky Power had previously included the embedded cost of transmission service and the PJM OATT transmission owner revenues in the Company's cost of service. (See Vaughan page 20)

a. Please provide a more detailed explanation of how this was previously done and how it compares to the new procedure.

b. Please provide workpapers, electronically with all formulas intact, showing how transmission costs and revenues were removed from the Company's cost of service and identify where these costs and revenues appear in the schedules the Company filed.

c. Please provide an analysis, electronically with all formulas intact, demonstrating whether or not the impact of the transmission costs and revenues removed from the cost of service matches closely with the impact of charging for transmission costs through the new PJM Rate Rider.

RESPONSE

a. See KIUC_1_81_Attachment 1.

b. See the Company's response to KIUC 1-17, specifically KIUC_1_17_Attachment 35.

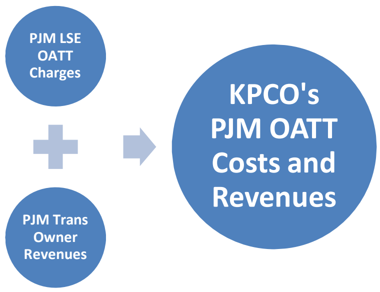
c. See the Company's response to KIUC 1-17, specifically KIUC_1_17_Attachment 35. Under the previous practice, the Company's requested revenue requirement would have been approximately $127,000 higher.

The Company's proposed PJM rider has an initial revenue requirement of $0. Adjusted test year amounts of the Company's PJM LSE OATT charges are included in its proposed base rate cost of service. The proposed PJM rider would recover amounts above and below the amount of PJM LSE OATT charges included in the Company's proposed base rate cost of service.

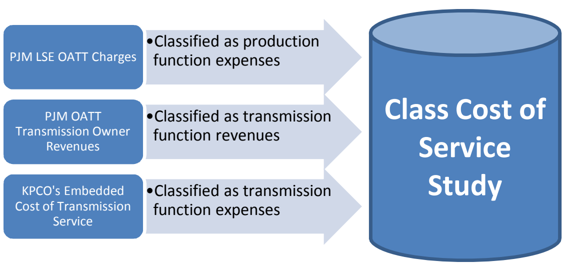
The removal of the transmission function costs and revenues and the recovery of the PJM LSE OATT charges through a combination of base rates and the proposed PJM rider are two separate items. The PJM LSE OATT charges represent the FERC approved cost of transmission service attributable to KPCo's internal load (LSE) incurred as part of the PJM RTO.

WITNESS: Alex E Vaughan

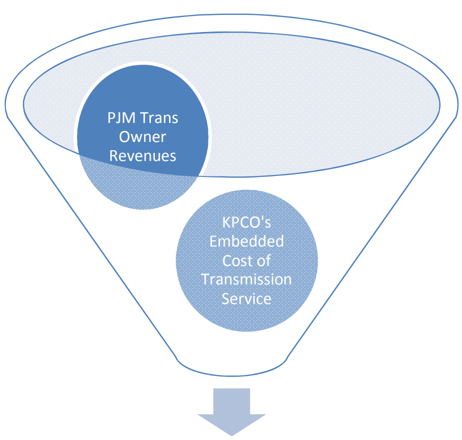
Diagram Explaining the PJM OATT Adjustment - KPCo Base Case



KPCo recieves load based LSE charges and wholesale revenues as a transmission owner under the PJM OATT.



For the purposes of the CCOS, the OATT LSE charges were classified as production function expenses. PJM OATT transmission owner revenues and KPCo's embedded cost of transmission serivice were classified as the transmission function.



The $127k OATT Adjustment

Mechanically speaking, the OATT adjustment is the removal of the transmission function from the CCOS. This leaves only the OATT LSE charges in the CCOS that were classified as production expense. This is what Kentucky ratepayers will pay for their transmission service. The PJM transmission owner revenues compensate KPCo for its embedded transmission function cost of service. The net of the PJM transmission owner revenues and KPCo's embedded cost of transmission service was a $127k expense which the OATT adj removes from the overall cost of service. Previously, KPCo's embedded cost of transmission service, the PJM transmission owner revenues and the PJM LSE OATT charges were all included in the Company's Kentucky retail cost of service.

It should be noted that the PJM LSE OATT charges are allocated to the customer classes the same way whether they are classified as transmission or production because both functions are allocated based on the classes' 12CP demands or total energy.

KPSC Case No. 2014-00396 General Rate Adjustment
KIUC First Set of Data Requests
Dated January 29, 2015
Item No. 82
Page 1 of 1

Kentucky Power Company

REQUEST

Refer to Vaughan page 21 at line 15, please provide detailed workpapers, electronically with all formulas intact, demonstrating the development of the $126,908 impact, which is the net effect of the Company's change to the treatment of transmission revenues and expenses. Also, please provide a narrative description explaining the calculations.

RESPONSE

See the Company's response to KIUC 1-17, specifically KIUC_1_17_Attachment 35 for the workpapers supporting the calculation of the $126,908.

For a narrative and illustrative explanation, see the Company's response to KIUC 1-81, specifically KIUC_1_81_Attachment 1.

WITNESS: Alex E Vaughan

KPSC Case No. 2014-00396 General Rate Adjustment
KIUC First Set of Data Requests
Dated January 29, 2015
Item No. 84
Page 1 of 1

Kentucky Power Company

REQUEST

Explain why a $126,908 transmission adjustment is being made to remove costs in JMS-3, when at the same time $53,779,456 is being added to the PJM Rider.

RESPONSE

$53,779,456 is not being added to the PJM Rider. KPCo proposes to continue to include the adjusted test year amount of PJM LSE OATT expense in base rates and track any over or under recovery of this expense through the PJM Rider.

The Company's proposal is to remove from base rates both the OATT revenues that KPCo receives from PJM as a transmission owner and KPCo's Kentucky retail jurisdictional transmission cost of service (return on and of transmission rate base and all transmission operating expenses).

The $126,908 in Adjustment JMS-3 represents the removal of the KPCo's transmission owner OATT revenues and KPCo's retail jurisdictional transmission cost of service from base rates.

The $53,779,456 represents the adjusted test year level of OATT expense in base rates.

See also the Company's response to KIUC 1-81 part a.

WITNESS: Alex E Vaughan

EXHIBIT RCS-24

Kentucky Power Company

REQUEST

Mitchell Plant. Refer to the response to AG 1-18. Specifically, the Mitchell Plant Operating Agreement at page 2 states in part: "AEPGR transferred its fifty percent (50%) undivided interest in the Mitchell Facility to Newco Wheeling Inc., exclusive of its interest in the Conner Run Fly Ash Impoundment and Dam ("Conner Run"), which interest in Conner Run was retained on the Transfer Date by AEPGR...". In addition, at page 3, the Mitchell Plant Operating Agreement states in part: "Whereas, the Owners desire that KPCo shall operate and maintain the Mitchell Facility, exclusive of Conner Run (the "Mitchell Plant"), in accordance with the provisions set forth herein;..."

a. As it is not clear from the Mitchell Plant Operating Agreement, please state whether AEPGR retained a 100% interest in the Conner Run Fly Ash Impoundment and Dam upon the 50/50 transfer of the Mitchell Facility between KPCo and Newco Wheeling Inc. If not, explain fully why not.

b. If the answer to part "a" is "no", please state whether KPCo's acquisition of its 50% undivided interest in the Mitchell Facility includes a 50% interest in the Conner Run Fly Ash Impoundment and Dam. If so, please explain fully and in detail why when AEPGR transferred its 50% undivided interest in the Mitchell Facility to Newco Wheeling Inc. exclusive of its interest in Conner Run.

c. If the answer to part "b" is "yes", please quantify and provide a breakout by amount and account of the costs associated with KPCo's 50% interest in Conner Run.

RESPONSE

a. No. AEPGR transferred a 50% interest in the Mitchell facility including Conner Run to KPCo upon the completion of the transfer on December 31, 2013. AEPGR transferred a 50% interest in the Mitchell facility excluding Conner Run to Newco Wheeling Inc. upon the completion of the transfer on January 31, 2015 and thus AEPGR retained a 50% interest in Conner Run.

Kentucky Power Company

b. See response to a. above. With respect to Wheeling Power Company's (WPCo) 50% interest in Mitchell Plant, the West Virginia Public Service Commission approved a settlement agreement between the parties in the Mitchell Plant transfer case that transferred the Mitchell Plant and generating facilities excluding the transfer of 50% of Conner Run (the Mitchell Settlement Interest), but it also approved the payment by WPCo of $20 million to AEPGR and the establishment of a $20 million regulatory asset to be included in WPCo's rate base that approximated AEPGR's book value of Conner Run. Reference page 8 of the WV Commission order in Case No. 14-0546-E-PC dated December 30, 2014 which states:

"The Stipulating Parties have agreed and proposed to the Commission that the Mitchell Settlement Interest be transferred at its net book value as of the date of transfer. The Stipulating Parties have also agreed and proposed to the Commission that on transfer WPCo will remit $20 million to Generation Resources as a regulatory adjustment. The Commission views the $20 million payment as a form of consideration for eliminating the Conner Run Impoundment and any future costs and liabilities related to the Conner Run Impoundment from the Mitchell Settlement Interest. WPCo will record a regulatory asset to be included in rate base and will be allowed to set rates based on a return on, and of, that $20 million amount. Costs associated with this regulatory asset will be recovered over the remaining life of the generating facilities associated with the Mitchell Settlement Interest. At the hearing on the Joint Stipulation, Company witness Ferguson described the treatment of this $20 million amount, and CAD witness Gregg testified that it was acceptable to CAD. Tr. At 21 (Ferguson); Tr. at 81 (Gregg). The Commission finds that these provisions of the Joint Stipulation are reasonable and will adopt them."

c. As indicated in a. above, Kentucky Power Company's 50% interest in the Mitchell facility includes Conner Run. The costs on Kentucky books related to Conner Run at September 30, 2014 were as follows:

Account 101 Gross Cost including ARO -	$24,693,773
Account 107 CWIP	117,521
Account 108 Accumulated Depreciation including ARO-	(4,459,698)
Net Book Value -	20,351,596
Account 403 Annualized Depreciation Expense -	553,731
Account 4031001 Adj. test year ARO Depreciation Expense-	394,685
Account 4111005 Adj. test year ARO Accretion Expense-	743,129

Kentucky Power Company

In addition, Kentucky Power Company has recorded an ARO liability of $13,910,746 in account 2300001 and has $279,149 for land recorded in account 1240029.

WITNESS: Ranie K Wohnhas

Exhibit RCS-24
Case No. 2014-00396
Page 4 of 9

CHARLOTTE
BUSINESS JOURNAL

From the Charlotte Business Journal
:http://www.bizjournals.com/charlotte/blog/power_city/2015/02/duke-energy-in-100-million-settlement-talks-over.html

Duke Energy in $100 million settlement talks over federal grand jury investigation

Feb 18, 2015, 7:51am EST | UPDATED: Feb 18, 2015, 8:41am EST

John Downey
Senior Staff Writer- *Charlotte Business Journal*
Email | Twitter | Google+

Duke Energy Corp. (NYSE:DUK) says it expects to file what will likely be a $100 million settlement in the federal grand jury investigation into the massive coal spill on the Dan River last year.

"The company expects a proposed agreement could be reached and filed in the next several days for consideration by the court," Duke says in a prepared statement. "If approved, the proposed agreement would resolve the ongoing grand jury investigation of the company's coal ash basin management."

Duke says simply it is "in settlement discussions with the U.S. government related to the ongoing federal grand jury investigation of the February 2014 Dan River coal ash spill and ash basin operations at other North Carolina coal plants."

See Also

- Duke Energy calculates coal-ash costs at $3.4 billion — for now
- Grand jury opens criminal probe into Duke Energy coal ash spill

No further comment

The company has included a charge of $100 million in its fourth-quarter earnings, released this morning, that represents "the company's assessment of probable financial exposure related to any agreement."

The charge amounts to 14 cents per share against its earnings for the quarter and the year.

Duke CEO Lynn Good and Chief Financial Officer Steve Young will hold a conference call on the earnings report Wednesday morning. But the company says they will not answer additional questions about the settlement because it involves a pending legal action.

Just over a year ago, a stormwater pipe running under the main coal ash pond at Duke's shuttered Dan River Steam Station spewed toxic coal ash into the river. It took days to seal the pipe, during which time an estimated 39,000 tons of ash escaped.

New regulation

Federal and state authorities say Duke has completed the cleanup of the river. But a federal grand jury in Raleigh started investigating the spill within two weeks of the accident to determine if it amounted to a crime. Subpoenas also made clear that the grand jury was investigating Duke's practice of storing ash in wet ponds and whether there was any improper relationship with state employees and officials over the regulation of those ponds.

The spill also prompted the N.C. General Assembly to adopt new regulations on the disposal of coal ash. The legislation calls for all of Duke's more than 30 coal ash ponds to be closed over the next 15 years. Duke currently estimates the cost of that effort at around $3.4 billion.

Justin Miczek, Greenpeace

The spill at the shuttered Dan River Steam Station started on Feb. 2, 2014, and took several days to staunch.

Exhibit RCS-24
Case No. 2014-00396
Page 5 of 9

CHARLOTTE
BUSINESS JOURNAL

From the Charlotte Business Journal
:http://www.bizjournals.com/charlotte/blog/energy/2014/11/duke-energy-calculates-coalash-costs-at-3-4.html

Duke Energy calculates coal-ash costs at $3.4 billion — for now

Nov 6, 2014, 2:59pm EST | UPDATED: Nov 6, 2014, 4:57pm EST

John Downey
Senior Staff Writer- *Charlotte Business Journal*
Email | Twitter | Google+

Duke Energy (NYSE:DUK) has set aside a $3.4 billion obligation in its accounting requirements for the costs of cleaning up its 32 ash ponds in North Carolina.

Duke had estimated the cleanup could cost $2 billion to $10 billion. Chief Financial Officer Steve Young emphasized to analysts this week that the obligation could rise or fall, depending on what is required in the cleanup.

"The ultimate cash spend will be impacted by the decisions made by (N.C. Department of Environment and Natural Resources) and the Coal Ash Commission regarding many of the sites," he said in a conference call on Wednesday.

Charlotte-based Duke is required by accounting rules to recognize the potential costs it will incur to comply with North Carolina's new law on the disposal of coal ash at 14 closed and operating coal plants in the state. The $3.4 billion obligation, Young said, is based on weighted risks concerning what state agencies will require Duke to do to resolve coal-ash issues.

Cheaper alternatives

Duke has said that if it were required to excavate all of its coal-ash ponds and rebury the waste in lined landfills, it could cost $10 billion. Environmental groups and some legislators support that solution.

Duke and some state regulators say lined landfills might not be necessary in every case. In some instances, Duke says, the ash can be safely used as construction fill or in products such as concrete. In other cases, it says, the company can remove the water from the ponds and cover them with a waterproof cap to prevent toxins from leaking.

Those alternatives would be less expensive. But opponents say they will not guarantee that toxins won't leach into groundwater, rivers and lakes.

The General Assembly passed the coal ash legislation in August. It was part of the state's response to a massive ash spill on the Dan River in February.

State reacts

Duke is scheduled to file plans to excavate and rebury ash at four sites — the closed Dan River, Riverbend and Cape Fear plants and the operating Asheville Plant — by the end of this month. Final decisions on what needs to be done at 10 other sites won't come until next year, at the earliest.

Already this week, state officials rejected Duke's first proposal for how it plans to assess groundwater conditions at the 14 plant sites.

"The plan as submitted fails to provide an adequate level of detail regarding the planned assessment activities, which if left unchanged may lead to an inadequate assessment of environmental conditions at the site," Jay Zimmerman, a section chief in the N.C. Division of Water Resources, wrote in a letter to Duke officials Wednesday.

Public statement

NANCY PIERCE

Duke Energy CFO Steve Young says the costs could rise or fall, depending on state rulings on treatment of ash in existing ponds.

Duke submitted those plans Sept. 26. It now has 30 days to submit new plans.

The company responded publicly with a prepared statement. It said the company shares DENR's "interest in conducting detailed groundwater assessments that will drive to appropriate closure decisions that are based on good science and engineering"

"We will incorporate the state's feedback to arrive at plans that meet their expectations," the statement says. "We remain focused on closing ash basins, which ultimately will address groundwater issues"

John Downey covers the energy industry and public companies for the Charlotte Business Journal.

Duke Energy Agrees to Pay $102.2 Million for Coal-Ash Spill

U.S. government charges company violated Clean Water Act

By Rebecca Smith, Wall Street Journal
Updated Feb. 20, 2015 6:59 p.m. ET

Duke Energy Corp. has agreed to settle charges that it violated the federal Clean Water Act by spilling coal ash into the Dan River in North Carolina last year, and will pay $102.2 million in penalties and restitution.

The deal with federal investigators includes a five-year probationary period with a court-appointed monitor to ensure compliance with provisions of the agreement. The terms are subject to review by the U.S. District Court for the Eastern District of North Carolina.

The settlement amount would be paid by shareholders, not customers, the Charlotte, N.C., company said.

The investigation into Duke's coal-ash practices, conducted by U.S. attorneys in North Carolina, was prompted by a large release of coal-ash waste in February 2014 from a storage basin at the retired Dan River Steam Station owned by Duke.

A break in a pipe released large amounts of sludge and waste into the bucolic Dan River in Rockingham County, N.C. Subsequent inspections at other coal-waste dumps by federal and state officials identified numerous problems.

Federal officials on Friday charged Duke with nine misdemeanor violations of the federal Clean Water Act in connection with the spill and unauthorized discharges at Dan River, as well as problems at four other power plant locations.

The company said it is addressing problems at each site with upgrades or new permits.

"We are accountable for what happened at Dan River and have learned from this event," said Lynn Good, president and CEO, in a written statement. "We are setting a new standard for coal ash management and implementing smart, sustainable solutions for all of our ash basins."

Representatives of the U.S. attorney for the Eastern District of North Carolina and Duke declined to comment on the settlement.

The Dan River spill focused national attention on the legacy problem of coal incineration near rivers. The river meanders through Virginia and North Carolina for 200 miles and its shallow waters are a favorite of inner-tubers and paddlers.

Duke is still working with state officials to fix problems at coal-waste sites and has said it potentially could spend more than $3 billion in coming years to shore up waste storage.

The company estimates it has about 150 million tons of coal waste stored in 4,500 acres of ash dumps in the half dozen states where it has coal power plants, with about 70% of the waste in North Carolina.

Write to Rebecca Smith at rebecca.smith@wsj.com

Duke Energy faces charges, $102 million in fines over coal ash spills

By Ralph Ellis, CNN

Updated 6:55 AM ET, Sat February 21, 2015

*(CNN)*A year after a massive coal ash spill into a North Carolina river, Duke Energy said Friday it would pay $102 million in a proposed settlement of nine criminal charges filed against the company by the U.S. government.

The charges, all misdemeanors alleging violations of the Clean Water Act, were filed Friday in U.S. district courts in North Carolina. A federal judge would have to approve the settlement.

Duke Energy faces federal charges for toxic spills 01:24

The case concerns problems at several Duke Energy locations, but the major problem occurred at the Dan River Steam Station in Rockingham County, near the Virginia border.

On February 2, 2014, a leak in a 48-inch stormwater pipe at that retired plant sent about 39,000 tons of coal ash and wastewater and up to 27 million gallons of basin water pouring into the Dan River.

The utility originally said 82,000 tons of coal ash spilled, but later revised the number.

Parts of the river turned into gray sludge. Coal ash, the byproduct of burning coal, is made up of aluminum oxide, iron oxide and silicon oxide. It also contains arsenic, mercury and other metals.

Researchers from Wake Forest University who used cameras on an unmanned aerial aircraft to create a 3-D image of the spill said as many as 35 million gallons of arsenic-contaminated water and ash may have made its way into the river.

A filing of criminal information said Duke "negligently" discharged pollutants and that employees failed to "exercise the degree of care that someone of ordinary prudence would have exercised in the same circumstances with respect to the discharge of ash and coal ash wastewater. ..."

The criminal charges were filed against the company, not individuals.

The $102 million in payments would be paid by shareholders, not customers, a company press release said. The company said $68.2 million would go toward fines and restitution and $34 million for community service and mitigation projects.

The company said Clean Water Act violations concerning unauthorized discharges occurred at these company facilities in North Carolina: the Dan River plant in Eden; the Riverbend Steam Station in Mount Holly; the H.F. Lee Steam Electric Plant in Goldsboro; and the Asheville Steam Electric Generating Plant. A maintenance issue occurred at the Cape Fear Steam Electric Plant in Moncure, the company said.

The agreement would include five years of probation and a court-appointed monitor to make sure Duke Energy complies with all provisions of the settlement, the company said.

Duke has apologized for the spills -- both when they happened and Friday.

"We are accountable for what happened at Dan River and have learned from this event," said Lynn Good, president and CEO of Duke Energy.

EXHIBIT RCS-25

KPSC Case No. 2014-00396 General Rate Adjustment
KIUC First Set of Data Requests
Dated January 29, 2015
Item No. 54
Page 1 of 1

Kentucky Power Company

REQUEST

Please explain why the Company seeks to retain 40% of all off-system sales margins above the amount included in base rates. In your response, please explain whether the sharing percentage will affect how the Company's generation is dispatched into PJM.

RESPONSE

In short, continued sharing of the benefits of optimizing OSS margins between the Company and its customers aligns customer benefits with utility incentives. The Company believes that a mechanism that allows the Company to retain 40% of all margins above the amount included in base rates and to absorb 40% of the margins below the amount included in base rates provides a reasonable balance between the Company's incentive to maximize OSS margins, while sharing a large portion with customers, and the volatility that would exist for customers if 100% of the risk and reward of OSS margins was provided to customers.

The practice of providing utilities with an incentive to pursue off-system sales (OSS) through some kind of sharing mechanism has been in use by the Kentucky Commission since long before the emergence of RTOs. In today's complex and often volatile energy markets, the need for the OSS sharing incentive is stronger than ever. Participation in PJM requires a significant level of attention to detail and market intelligence to optimize the Company's resources and serve its load. The ability of the Commercial Operations personnel to get the most value for the Company's generating resources also enables them to maximize the off-system sales margins for the benefit of the customers and the Company. Active participation in all facets of the interrelated PJM markets provides the greatest benefits for the customer – and aligns the interest of the Company and customers. The absence of an OSS sharing mechanism would negatively impact the value received from the Company's generation in the PJM markets.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Reference the response to KIUC 1-54 Data Request regarding off-system sales margins.

a. Explain the percentage of off-system sales (OSS) margins that are derived as a result of offering units into the PJM market that are subsequently dispatched by PJM.

b. Explain what actions KPCo or AEC on KPCo's behalf actually takes beyond prudently offering units into the centrally dispatched PJM market to maximize OSS margins.

c. Explain what actions KPCo or AEC on KPCo's behalf could take that would lessen OSS margins if they are prudently offering ratebase units into the PJM market if no incentive is provided to keep part of the OSS margins.

d. Provide details on all OSS margins that are derived on behalf of KPCo that are not a result of participating in the PJM market with KPCo ratebased units.

e. Does KPCo propose to share OSS margins that are not directly related to KPCo ratebased units (i.e. other AEC asset or non asset based market sales) with customers?

f. Are the costs necessary for KPCo (or AEC on KPCo's behalf) to offer its units into the PJM market recovered from customers?

g. Are the personnel involved already offered incentive pay reflecting their performance in offering KPCo generation into the PJM market?

h. Is this incentive pay entirely taken from the OSS margins or is this part of the payroll package that KPCo proposes to recover separately in its revenue requirements?

i. Is there a distinction made between OSS margins obtained merely because KPCo's generation units are prudently offered into the PJM market and other OSS margins obtained?

j. Has KPCo ever justified buying, building, purchasing, improving, selling or decommissioning any generation facility in an application before the PSC by studies that involved future OSS margins?

  i. Did such studies assume that 40% of the OSS margins would not be used to benefit KPCo's customers?

  ii. If not how does this claw back affect every study provided to the PSC in the last 10 years?

k. How did KPCo arrive at the 40% "incentive" for OSS margins?

  i. Wouldn't 30% retention of OSS margins also be an incentive?
  ii. What about 10%, wouldn't this still be an incentive?
  iii. What about 1%, wouldn't this still be an incentive?

RESPONSE

In answering this data request, the Company assumes "AEC" as used throughout the data request refers to American Electric Power Service Corporation.

a. As discussed on page 32 (lines 4-5) of Company Witness Vaughan's direct testimony, the Company's proposed adjusted test year margins from energy sales into PJM are $24.28 million, while the other components of the total Company OSS margins are a negative $9.79 million which result in the Kentucky Power adjusted test year total OSS margins $14.5 million.

b. American Electric Power Service Corporation Commercial Operations Group, on behalf of Kentucky Power, engages in many activities beyond prudently offering units into the centrally dispatched PJM market. These actions further allow the Company to maximize OSS margins. For example, the Commercial Operations Group actively participates in the trading of futures/forward contracts within the PJM region. In addition to the potential for OSS margins directly related to this activity, this participation also has numerous other benefits that optimize the Company's generation. The Commercial Operations Group also improves OSS margins by enhancing the timing of unit outages and helps identify opportunities for hedging either a short or long generation position. Commercial Operations is also actively involved in managing the Company's FTR portfolio in order to minimize the cost of congestion for customers.

Even operating within the PJM markets, optimizing OSS margins is not a matter of prudently offering the Company's generation into the market. Utilizing the expertise of the Commercial Operations Group to respond to and anticipate the significant volatility between the day-ahead and real-time markets results in both increased OSS margins as well as lower fuel costs for customers. One final example of the methods the Commercial Operations Group employs to optimize OSS margins is the scheduling of the Company's generating units into the PJM day-ahead market. PJM bases its economic decision to select a unit to run in the day-ahead market based on a one day (or two days for the weekend period) analysis. However, such a short term look at the market can lead to less than optimal results for individual generators. For example, PJM may not clear some of the Company's units for the weekend and they would thus be shut down. However, within the parameters of the PJM rules, if the Company expects the units to be profitable and clear the market at the beginning of the following week, it could elect to self-schedule those units for the weekend. The units may incur a small loss on the sale of energy over the weekend, but they would avoid shut down and start-up costs, and would be ready to serve retail customers and make profitable sales in the market in the following days. By taking a longer term view of the unit's characteristics, and the expected PJM market conditions, the Commercial Operations Group's expertise and active management of the Company's resources leads to increased OSS margins and reduced costs for customers.

c. In the absence of a reasonable OSS margin sharing mechanism Kentucky Power would not take action to lessen OSS margins. Without financial compensation for incurring the costs and risks associated with taking the actions described in subpart (b) that are beyond the prudent offering of units into the market, however, the OSS margins realized could be reduced. The alignment of customer and Company incentives over the years has resulted in an OSS sharing mechanism that has provided significant customer benefits.
See the Company's response to part (b).

d. See the Company's response to part (b). Furthermore, the portion of OSS margins directly attributable to the expertise of and the broad scope of activities the Commercial Operations Group that are above and beyond the prudent offering of the Company's units in the PJM market cannot be directly quantified. Simply put, the many activities engaged in by Commercial Operations in order to optimize the Company's OSS margins produces a whole that is greater than the sum of its parts. The Company's sharing proposal ensures that the interest of the customer and the Company continued to be aligned, to the ultimate benefit of both parties.

e. Yes, as it historically has done through its System Sales Clause.

f. All costs attributable to internal load customers are recovered from those customers. All costs attributable to making off system sales margins as defined in the Company's System Sales Clause are shared between the Company and Customers through the sharing of OSS margins.

g. The personnel involved in the bidding and dispatch of Kentucky Power's generating assets in the PJM market participate in the Company's ICP program. They do not take part in a special compensation program that directly aligns their ICP with the Company's OSS margins.

h. ICP payments are not included the calculation of OSS margins. However, to the extent that performance results in an ICP level that is greater than what is in base rates, that would not be recovered from customers. As described by Company witness Carlin, the level of ICP requested as part of base rates in this case is consistent with a market competitive pay package.

i. Yes. See also part b.

j. See subpart ii below.

i. No.

ii. The Company objects to the mischaracterization of the OSS margin sharing mechanism as a "clawback," and the characterization that the OSS sharing mechanism does not benefit the Company's customers. Without waiving this objection, the Company responds that the disposition analyses submitted by the Company focus on the least-cost alternative to meet the capacity and energy requirements of Kentucky Power's native load customers. Projections concerning possible OSS margins do not materially affect the Company's determination of the least-cost alternative.

k. See subpart i below.

i. In light of the fact that under the proposed OSS sharing mechanism customers will receive (to the extent the margins are realized) 100% of the OSS margins built into base rates, permitting the Company to retain 40% of the OSS margins above the amount built into base rates is an appropriate sharing percentage. Moreover, the 60%/40% sharing proposed by the Company represents a reduction in the Company's share of OSS margins above the amount built into base rates from the percentage received early in the operation of the sharing mechanism. Finally, assigning the Company less than 40% of the OSS margins above the amount built into base rates would unreasonably saddle Kentucky Power with a disproportionate risk of any shortfall without providing the Company with adequate compensation for that risk through a reasonable sharing of OSS margins above the amount built into base rates. For these reasons, the Company believes that the proposed 60% / 40% sharing of OSS margins above and below the monthly base credit between customers and the Company, respectively, is an appropriate incentive and sharing of the risks and returns of making OSS.

ii. See subpart i.

iii. See subpart i.

WITNESS: Alex E Vaughan

EXHIBIT RCS-26

Kentucky Power Company

REQUEST

Reference the response to AG 1-34.

a. Please provide information, including copies, of any public statements made, recognition granted or awards made by NERC, PJM, or any other related industry entity regarding AEPSC's cyber security plan and the systems developed in support thereof.

b. What steps is AEP taking to assure that the AEPSC cyber security plan is cost effective?

c. Identity all costs by account incurred by AEPSC (1) in total and (2) charged to KPCo, by month for cyber security from January 2011 through December 2014.

RESPONSE

a. Please see AG_2_5_Attachmen1.pdf through AG_2_5_Attachment3.pdf for this response. This includes program materials for PJM's GRID 20/20 event. AEP presented its "CSOC Threat and Information Sharing" program on November 12, 2013 at this event.

b. For more than a decade, AEP has worked continuously to strengthen its cybersecurity programs and to ensure that those programs evolve to meet new and emerging risks. AEP constantly scans the system for risks or threats and continuously assess its capacity, including cybersecurity knowledge, staffing, capabilities and the need for future investment. Cyber hackers have been able to breach other entity's very secure facilities including federal agencies, banks, retailers, health insurers, and social media sites. As these events become known, AEP assesses its cybersecurity tools and processes to determine if and where further enhancement is appropriate. When new investments are required, those project requests are processed through AEP's normal investment governance procedures.

c. See the Company's response to KPSC-2-7.

WITNESS: H Kevin Stogran

Kentucky Power Company

REQUEST

Rockport. Refer to the testimony of witness Elliott.

a. Identify and provide the FERC order that approved a 12.16% return on equity for the Rockport Plant.

b. Show in detail the capital structure and capital costs that KPCo is using for the Rockport Plant.

c. Is the Rockport Plant operated by KPCo's affiliate, Indiana and Michigan Electric Company?

d. Has the return on equity for the Rockport plant ever been addressed by the Indiana or Michigan regulatory commissions? (1) If so, identify the last three Indiana proceedings to address the return on equity. (2) Identify the last three Michigan PSC proceedings to address the return on equity.

e. Identify and provide the FERC Order and the filings in the FERC Docket where the Rockport UPA was approved, and identify the date when the 12.16% return on equity was allegedly approved.

f. Has KPCo ever used a 12.16% return on equity for the Rockport Plant in any other rate case or regulatory proceedings before the Kentucky PSC? (1) If not, explain fully why not. (2) If so, identify all previous proceedings before the Kentucky PSC wherein KPCo used a 12.16% return on equity for the Rockport Plant.

g. What risks are being borne by KPCo for the Rockport Plant that would justify using a return on equity of 12.16%?

h. What revenue requirement for the Rockport UPA was approved by FERC?

i. How does the Company's request in the current rate case for Rockport UPA costs compare with the Rockport UPA revenue requirement last approved by FERC? Identify, quantify and explain any differences.

RESPONSE

a. Please see AG_1_394_Attachment1.

b.. The Company updates its capital structure used in the Rockport environmental surcharge revenue requirement calculation on a monthly basis based on the month's Rockport Unit Power bill.

c. The Rockport Plant is operated by Indiana Michigan Power Company.

d. The return on equity and capital structure used in billings for purposes of the Rockport Unit Power Agreement are established in accordance with the FERC-approved agreement and not the decisions of the Indiana or Michigan commissions. The information sought thus is irrelevant and not reasonably calculated to lead to discovery of admissible evidence. Further, the Company has not compiled a list of cases in which the Indiana Utility Regulatory Commission (IURC) or the Michigan Public Service Commission (MPSC) has addressed the return on equity associated with the AEG share of the Rockport Plant. The orders of the IURC and the MPSC are public documents that all parties to this proceeding have access.

e. See the Company's response to item a above. Filings before the FERC are public documents that all parties to this proceeding have access to.

f. KPCo has always used 12.16% return on equity for the AEG share of the Rockport plant consistent with the UPA. Examples of proceedings in which Kentucky Power used 12.16% ROE for Rockport include but are not limited to:

KPSC Case No. 2005-00068;
KPSC Case No. 2006-00128;
KPSC Case No. 2006-00307;
KPSC Case No. 2007-00381;
KPSC Case No. 2009-00038;
KPSC Case No. 2009-00316;
KPSC Case No. 2010-00020;
KPSC Case No. 2010-00318;
KPSC Case No. 2011-00031;
KPSC Case No. 2012-00273;
KPSC Case No. 2013-00141;
KPSC Case No. 2013-00325;
KPSC Case No. 2014-00052; and
KPSC Case No. 2014-00322.

g. The 12.16% return on equity is established under the terms of the FERC-approved UPA.

h. See the Company's response to item a above.

i. All Rockport-associated costs flow through the FERC-approved UPA. The Company has not performed the requested analysis.

WITNESS: Amy J Elliott

Deposits and Working Funds (Accounts 132-134, 136, and 145) outstanding at the end of the previous month.

(b) Return on Other Capital, which shall be equal to the product of (i) the amount equal to the net interest expense associated with Long-Term and Short-Term Debt, net of any Temporary Cash Investments, Special Deposits and Working Funds, plus the preferred stock dividend requirement associated with the Preferred Stock outstanding at the end of the previous month; (ii) the Operating Ratio, as defined in Note 2 below; and (iii) the Unit No. 1 Net In-Service Investment Ratio, as defined in Note 3 below.

For the purposes of these calculations, net interest expense shall be equal to the sum of (i) the amount of Long-Term Debt outstanding at the end of the previous month multiplied by the weighted cost of such Long-Term Debt and (ii) the amount of Short-Term Debt outstanding at the end of the previous month multiplied by the weighted cost of such Short-Term Debt, less (iii) the amount of Temporary Cash Investments, Special Deposits and Working Funds outstanding at the end of the previous month multiplied by the weighted cost of Long Term and Short-Term Debt combined determined pursuant to (i) and (ii) above.

(c) Recovery of Operating Expenses, excluding federal income taxes, which shall consist of provision for depreciation and amortization (Accounts 403-407, 411), including Asset Retirement Obligation (ARO) depreciation and accretion expenses (Accounts 403.1 and 411.10), taxes other than federal income taxes (Accounts 408-411) and operating and maintenance expenses associated with Unit No. 1 (including Common Facilities) offset by other operating revenues as recorded on the Company's books during the month in accordance with the FERC Uniform System of Accounts for Major Electric Utilities (See Note 6). Recovery of expenses for test energy shall be limited to recovery of actual fuel expense as recorded on the Company's books during the month in accordance with the FERC Uniform System of Accounts for Major Electric Utilities. Operating and maintenance expenses shall include, and reflect the recovery of, Steam Power Generation Expenses (Accounts 500-515 including lease rental payments recorded in Account 507), Other Power Supply Expenses (Accounts 555-557), Transmission Expenses (Accounts 560-574), Distribution Expenses (Accounts 580-598), Customer Accounts Expenses (Accounts 901-905), Customer Service and Informational Expenses (Accounts 906-910), Sales Expenses (Accounts 911-917) and Administrative and General Expenses (Accounts 920-933 and 935). Recovery of 501 fuel expenses shall be adjusted to reflect the deferral and/or feedback of unrecovered levelized fuel expenses as may be recorded on the Company's books or as is currently recorded on the books of I&M.

(d) Provision for Unit No. 1's (including Common Facilities) allocated share of net current and deferred federal income tax expense and investment tax credit included in operating income as determined by the Company in accordance with federal income tax law, SEC approved consolidated current tax allocation procedures, and FERC rules and regulations.

For purposes of computing federal income taxes, the interest expense deduction shall be equal to the sum of the net interest expense computed in accordance with paragraph (b)

Kentucky Power Company

REQUEST

Reference the Direct Testimony of Jeffery D. LaFleur on page 4 regarding Kentucky Power's 15% ownership in the Rockport Plant. Please provide the following:

a. Current ownership agreement or any other related documents that detail how management decisions are made among the owners of the Rockport Plant.

b. A complete list of all owners, with percentage ownership.

c. Any affiliates of each owner and the related organization structure.

d. Membership of plant ownership management committee or equivalent owners' representative organization.

e. Minutes, agendas, handouts and presentations from all meetings of the ownership management committee (or equivalent) for the last 3 years.

f. The amount of the demand charge KPCo pays for power produced at the Rockport plant. Confirm this sum is paid regardless of whether KPCo uses any power from Rockport.

g. Complete supporting information for the return on equity that KPCo is requesting in the current rate case on its 15% ownership in the Rockport Plant.

RESPONSE

a-e. The Company does not have an ownership interest in the Rockport Plant. Kentucky Power has a unit power agreement for 15% of the generation from the Rockport Plant. The Rockport Plant is maintained and operated solely by Indiana Michigan Power Company.

Please see the Company's response to AG 1-375 for a copy of the unit power agreement.

Kentucky Power Company

f. Confirmed. Please see AG_1_19_Attachment1.xls for the demand charges for 2014.

g. Kentucky Power does not own a share of the Rockport Plant. Please see the Company's responses to AG 1-375 and AG 1-394 for additional detail regarding the Unit Power Agreement for Rockport.

WITNESS: Jeffery D LaFleur

Kentucky Power Company
Rockport's Demand Charges
Calendar Year 2014

January 2014	KY U1	KY U2	Total
Demand/Capacity Charge	1,423,709	2,353,104	3,776,813

February 2014	KY U1	KY U2	Total
Demand/Capacity Charge	1,807,838	2,366,099	4,173,937

March 2014	KY U1	KY U2	Total
Demand/Capacity Charge	1,487,345	2,320,092	3,807,437

April 2014	KY U1	KY U2	Total
Demand/Capacity Charge	1,544,779	2,401,160	3,945,939

May 2014	KY U1	KY U2	Total
Demand/Capacity Charge	2,349,064	2,234,596	4,583,660

June 2014	KY U1	KY U2	Total
Demand/Capacity Charge	1,767,204	2,618,278	4,385,482

July 2014	KY U1	KY U2	Total
Demand/Capacity Charge	1,773,423	2,028,662	3,802,085

Kentucky Power Company
Rockport's Demand Charges
Calendar Year 2014

Aug 2014	KY U1	KY U2	Total
Demand/Capacity Charge	1,434,137	2,351,063	3,785,200
Sept 2014	**KY U1**	**KY U2**	**Total**
Demand/Capacity Charge	2,237,254	2,723,590	4,960,844
Oct 2014	**KY U1**	**KY U2**	**Total**
Demand/Capacity Charge	1,823,809	2,206,222	4,030,031
Nov 2014	**KY U1**	**KY U2**	**Total**
Demand/Capacity Charge	1,840,637	3,802,096	5,642,733
Dec 2014	**KY U1**	**KY U2**	**Total**
Demand/Capacity Charge	2,183,001	1,972,446	4,155,447
YTD TOTALS 2014	**KY U1**	**KY U2**	**Total**
Demand/Capacity Charge	21,672,200	29,377,408	51,049,608

KPSC Case No. 2014-00396 General Rate Adjustment
Attorney General's Second Set of Data Requests
Dated February 24, 2015
Item No. 28
Page 1 of 1

Kentucky Power Company

REQUEST

Rockport. Refer to the response AG 1-389(b).

a. What fixed charges and demand charges would KPCo propose if the fixed Rockport costs were to be recovered through fixed charges and demand charges? Show how KPCo would develop fixed charge and demand charge rates.

b. Is it KPCo's position that the Rockport fixed costs must be recovered in per-kWh rates in perpetuity with no possibility of regulatory review to apply cost/causation principles? If not, explain fully why not.

RESPONSE

a. Kentucky Power is not proposing to change its recovery methods for costs associated with Rockport.

b. Kentucky Power is recovering costs associated with Rockport in accordance with the Kentucky Public Service Commission's order dated December 13, 2004 in Case No. 2004-00420. This Order extends recovery for the life of the purchased power agreement which currently is scheduled to terminate on December 7, 2022.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Rockport. Refer to the response to AG 1-394.

a. Provide a copy of the FERC Approved PPA or UPA which specifies that a 12.16% return in equity is to be used.

b. What is the term of the Rockport PPA/UPA?

c. Has the 12.16% been reviewed in any FERC proceeding since 2005? If so, identify the proceeding.

d. What portion of the Rockport plant is owned by AEG?

e. When did AEG acquire that ownership?

f. Why isn't the AEG owned part of the Rockport plant being transferred to KPCo at net book value, similar to the 50% interest in the Mitchell plant?

RESPONSE

a. Please see AG_1_394_Attachment1.

b. The Rockport UPA will expire on December 7, 2022.

c. Please see the Company's response to AG 1-375.

d. AEP Generating Company (AEG) owns a 50% interest in Rockport Unit 1.

e. The 50% interest in Rockport Unit 1 that AEG owns was acquired by AEG in two transactions in December of 1983 and October 1984.

f. Please see the Company's response to subpart b above. AEP Generating Company and Indiana Michigan Power Company co-own Rockport Unit 1. Rockport Unit 2 is owned by an unrelated third-party and leased to AEP Generating Company and Indiana Michigan Power Company. Kentucky Power originally proposed to acquire a portion of the interest in the Rockport generating station held by AEP Generating Company. Its application for a certificate of public convenience and necessity to acquire that interest was opposed and ultimately denied. The current contractual arrangement was created in response to provide the Company with the necessary generation. Further, there is no current need for Kentucky Power to acquire AEP Generating Company's interest in the units.

WITNESS: Ranie K Wohnhas

Kentucky Power Company
Test Year Affiliated Charges for Rockport Unit Power Sales Agreement
Including Charges for Return on Common Equity and Estimated Savings to KPCo from Reducing the Affiliate ROE from 12.16 Percent
Test Year Ended September 30, 2014

			Unit 1			Unit 2			Total		
Line No.	Year	Month	Non-Fuel	Fuel	Total	Non-Fuel	Fuel	Total	Non-Fuel	Fuel	Total
		Account:	5550027	5550046		5550027	5550046		5550027	5550046	
	I. Total Charges										
1	2013	10	$1,426,670	$2,411,414	$3,838,084	$2,336,133	$3,432,031	$5,768,164	$3,762,803	$5,843,445	$9,606,248
2	2013	11	$1,915,781	$3,041,035	$4,956,816	$2,275,249	$3,332,736	$5,607,985	$4,191,030	$6,373,771	$10,564,801
3	2013	12	$1,287,319	$3,642,557	$4,929,876	$2,936,813	$3,538,537	$6,475,350	$4,224,132	$7,181,094	$11,405,226
4	2014	1	$1,423,709	$3,427,731	$4,851,440	$2,353,104	$3,221,395	$5,574,499	$3,776,813	$6,649,126	$10,425,939
5	2014	2	$1,807,838	$2,557,972	$4,365,810	$2,366,099	$2,645,208	$5,011,307	$4,173,937	$5,203,180	$9,377,117
6	2014	3	$1,487,345	$3,345,188	$4,832,533	$2,320,092	$3,224,976	$5,545,068	$3,807,437	$6,570,164	$10,377,601
7	2014	4	$1,544,779	$2,889,005	$4,433,784	$2,401,160	$2,449,507	$4,850,667	$3,945,939	$5,338,512	$9,284,451
8	2014	5	$2,349,064	$46,273	$2,395,337	$2,234,596	$3,749,337	$5,983,933	$4,583,660	$3,795,610	$8,379,270
9	2014	6	$1,767,204	$2,857,653	$4,624,857	$2,618,278	$3,031,712	$5,649,990	$4,385,482	$5,889,365	$10,274,847
10	2014	7	$1,773,423	$2,358,315	$4,131,738	$2,028,662	$3,023,080	$5,051,742	$3,802,085	$5,381,395	$9,183,480
11	2014	8	$1,434,137	$3,169,563	$4,603,700	$2,351,063	$2,558,853	$4,909,916	$3,785,200	$5,728,416	$9,513,616
12	2014	9	$2,237,254	$2,489,039	$4,726,293	$2,723,590	$2,378,724	$5,102,314	$4,960,844	$4,867,763	$9,828,607
13	Total		$20,454,523	$32,235,745	$52,690,268	$28,944,839	$36,586,096	$65,530,935	$49,399,362	$68,821,841	$118,221,203
	II. Charges for Return on Common Equity (Note A)										
14	2013	10	$255,046		$255,046	(38,227)		(38,227)	$216,819		$216,819
15	2013	11	$259,107		$259,107	(53,883)		(53,883)	$205,224		$205,224
16	2013	12	$260,055		$260,055	(64,027)		(64,027)	$196,028		$196,028
17	2014	1	$251,680		$251,680	(28,386)		(28,386)	$223,294		$223,294
18	2014	2	$254,445		$254,445	(42,480)		(42,480)	$211,965		$211,965
19	2014	3	$252,800		$252,800	(53,053)		(53,053)	$199,747		$199,747
20	2014	4	$254,330		$254,330	(57,626)		(57,626)	$196,704		$196,704
21	2014	5	$258,229		$258,229	(73,355)		(73,355)	$184,874		$184,874
22	2014	6	$250,878		$250,878	(83,920)		(83,920)	$166,958		$166,958
23	2014	7	$243,646		$243,646	(39,753)		(39,753)	$203,893		$203,893
24	2014	8	$232,228		$232,228	(49,775)		(49,775)	$182,453		$182,453
25	2014	9	$230,021		$230,021	(59,043)		(59,043)	$170,978		$170,978
26	Total		$3,002,465		$3,002,465	(643,528)		(643,528)	$2,358,937		$2,358,937

III. Estimated Annual and Total Savings to KPCo

Line No.	**If the 12.16% ROE Was Adjusted to:**	Ratio to 12.16% ROE	Estimated Annual Savings (Unit 1)	Estimated Annual Savings Carried Through Expiration Date (Note B)	Estimated Annual Savings (Both Units Combined)	Estimated Annual Savings Carried Through Expiration Date (Note B)
27	KPCo's requested ROE of 10.62%	0.873355263	$380,000	$3,111,000	$299,000	$2,448,000
28	KPCo's currently authorized ROE of 10.5%	0.863486842	$410,000	$3,356,000	$322,000	$2,636,000
29	AG's recommended ROE of 8.65%	0.711348684	$867,000	$7,097,000	$681,000	$5,575,000

Notes and Source

Note A: Agreement provides for a 12.16% Return on Common Equity

Note B: Per KPCo's responses to AG 2-28(b) and AG 2-29(b), the Rockport UPA will expire on December 7, 2022

Years from end of test year (9/30/2014) through Rockport UPA expiration (12/7/2022) 12/7/2022 9/30/2014 8.19 years

KPCo response to AG 2-5CS, Attachments 1 and 2

Under the Rockport Unit Power Sale agreements with AEP Generating Company, and as shown on the AEPGenCo invoices, 30 percent is billed to KPCo and 70 percent is billed to Indiana & Michigan Power Company, a utility affiliate. The amounts listed above are the AEPGenCo billings to KPCo.