Kent W. Blake
Director
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March 9, 2005

RECEIVED
MAR 0 9 2005
PUBLIC SERVICE
COMMISSION

Ms. Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602-0615

RE: ***The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct Flue Gas Desulfurization Systems and Approval of its 2004 Compliance Plan for Recovery by Environmental Surcharge***
Case No. 2004-00426

Dear Ms. O'Donnell:

Enclosed please find an original and eight (8) copies of Kentucky Utilities Company's ("KU") responses to the Second Data Requests of Commission Staff dated February 23, 2005, in the above-referenced docket.

Should you have any questions concerning the enclosed, please do not hesitate to contact me.

Sincerely,

Kent W Blake

Kent W. Blake

cc: Hon. Elizabeth E. Blackford
Hon. Michael L. Kurtz

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

MAR 09 2005

PUBLIC SERVICE
COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR A CERTIFICATE OF PUBLIC	)	
CONVENIENCE AND NECESSITY TO CONSTRUCT	)	CASE NO. 2004-00426
FLUE GAS DESULFURIZATION SYSTEMS AND	)	
APPROVAL OF ITS 2004 COMPLIANCE PLAN FOR	)	
RECOVERY BY ENVIRONMENTAL SURCHARGE	)	

RESPONSE OF KENTUCKY UTILITIES COMPANY
TO
SECOND DATA REQUESTS OF COMMISSION STAFF
DATED FEBRUARY 23, 2005

FILED: MARCH 9, 2005

KENTUCKY UTILITIES COMPANY

CASE NO. 2004-00426

Response to Second Data Requests of Commission Staff Dated February 23, 2005

Question No. 1

Responding Witnesses: Valerie L. Scott / Kent W. Blake

Q-1. Refer to the response to the First Data Request of Commission Staff dated January 26, 2005 ("Staff's First Request"), Item 3. For KU's Kentucky jurisdictional operations only, provide a calculation of the overall rate of return using the capital structure as of December 31, 2004, the weighted cost of debt and preferred stock as of December 31, 2004, and the effect of the new income tax law for 2005 as stated in the response to the First Data Request of the Kentucky Industrial Utility Customers, Inc., Item 24. Provide all supporting calculations, assumptions, and workpapers.

A-1. Please see attached tables.

Kentucky Utilities
Weighted Cost of Capital

	1	2 Percent of Total	3 Annual Cost Rate	4 Weighted Cost of Capital	5 Weighted Cost of Capital with Tax Gross-Up
1	Long-Term Debt	40.73%	3.43%	1.40%	1.40%
2	Short-Term Debt	1.95%	2.22%	0.04%	0.04%
3	Preferred Stock	2.23%	5.68%	0.13%	0.21%
4	Common Equity	55.09%	11.00%	6.06%	10.00%
5	Total	100.00%		7.63%	11.65%

4. Column 2 x Column 3.
5. Based on a composite tax rate of 39.3991%. Resulting total can also be computed using the formula established in Case No. 2000-459 of (ROR + (ROR - DR) x (TR / 1 - TR))) where:
   ROR = Return on Rate Base
   DR = Debt Cost Rate
   TR = Composite Tax Rate

KENTUCKY UTILITIES COMPANY
ANALYSIS OF THE EMBEDDED COST OF CAPITAL AT
December 31, 2004

LONG-TERM DEBT

	Due	Rate	Principal	Annualized Cost: Interest(income)	Annualized Cost: Amortized Debt Issuance Expense	Annualized Cost: Premium	Annualized Cost: Amortized Loss-Reaquired Debt	Annualized Cost: Total	Embedded Cost
First Mortgage Bonds:									
Series P	05/15/07	7.920%	53,000,000	4,197,600	41,088	-	209,016	4,447,704	8.390
Series R	06/01/25	7.550%	50,000,000	3,775,000	18,180	-	-	3,793,180	7.590
Series S	01/15/06	5.990%	36,000,000	2,156,400	38,256	-	61,416	2,256,072	6.270
Pollution Control Bonds - SECURED:									
Series 10	11/01/24	1.731% *	54,000,000	934,740	20,472	-	-	955,212	1.770
Series 11 - Series A	05/01/23	1.750% *	12,900,000	225,750	17,292	-	16,788	259,830	2.010
Series 12	02/01/32	1.930% *	20,930,000	403,949	4,104	-	36,300	444,353	2.120
Series 13	02/01/32	1.930% *	2,400,000	46,320	2,856	-	4,152	53,328	2.220
Series 14	02/01/32	1.930% *	2,400,000	46,320	3,204	-	12,900	62,424	2.600
Series 15	02/01/32	1.930% *	7,400,000	142,820	3,168	-	12,744	158,732	2.150
Series 16	10/01/32	1.736% *	96,000,000	1,666,560	72,648		186,024	1,925,232	2.010
Series 17	10/01/34	1.777% *	50,000,000	888,500	37,356		53,940	979,796	1.960
Called Bonds			-	-	-	-	185,268 [2]	185,270	-
Interest Rate Swaps:									
JP Morgan Chase Bank-Series P	05/15/07	1		(1,809,773)				(1,809,773)	
Bank of Monteal-Series R	06/01/25	1		(2,659,000)				(2,659,000)	
Marked-to-Market Liability Series P	05/15/07		5,088,000						
Marked-to-Market Liability Series R	06/01/25		3,092,817						
Notes Payable to Fidelia Corp.	04/30/13	4.55%	100,000,000	4,550,000	-	-	-	4,550,000	4.550
Notes Payable to Fidelia Corp.	08/15/13	5.31%	75,000,000	3,982,500	-	-	-	3,982,500	5.310
Notes Payable to Fidelia Corp.	11/24/10	4.24%	33,000,000	1,399,200	-	-	-	1,399,200	4.240
Notes Payable to Fidelia Corp.	12/19/05	2.29%	75,000,000	1,717,500	-	-	-	1,717,500	2.290
Notes Payable to Fidelia Corp.	01/16/12	4.39%	50,000,000	2,195,000	-	-	-	2,195,000	4.390
		Total	726,210,817	23,859,386	258,624	-	778,548	24,896,560	3.428%

PREFERRED STOCK

	Rate	Principal	Annualized Cost: Expense	Annualized Cost: Premium/ Discount	Annualized Cost: Gain	Annualized Cost: Adjusted Principal	Annualized Cost: Dividends	Embedded Cost
Series - 4.75%	4.75%	20,000,000		-	-	20,000,000	950,000	4.750
Series - 6.53%	6.53%	20,000,000	(273,105)	-	-	19,726,895	1,306,000	6.620
	Total	40,000,000	(273,105)	-	-	39,726,895	2,256,000	5.679%

SHORT TERM DEBT

	Rate	Principal	Annualized Cost: Interest	Annualized Cost: Expense	Annualized Cost: Premium	Annualized Cost: Loss	Annualized Cost: Total	Embedded Cost
Notes Payable to Associated Company	2.220% *	34,820,000	773,004	-	-		773,004	2.220
Commercial Paper			-	-	-		-	
	Total	34,820,000	773,004	-	-	-	773,004	2.220%

* Composite rate at end of current month.

1 Additional interest due to Swap Agreements:

Underlying Debt Being Hedged	Notional Amount	Expiration of Swap Agreement	Variable KU Swap Position	Fixed Counterparty Swap Position
Series P - FMB	53,000,000	May 15, 2007	To Pay: 3 mo. LIBOR +207 bps	7.920%
Series R - FMB	50,000,000	June 1, 2025	To Pay: 3 mo LIBOR -24 bps	7.550%
	103,000,000			

2 Series L and M FMB bonds were redeemed in 1993 and series P was redeemed in 2003. They were not replaced with other bond series. The remaining unamortized expense is being amortized over the remainder of the original life (due 4/1/2004, 6/1/2006 and 5/15/27, respectively) of the bonds as loss on reacquired debt.

KENTUCKY UTILITIES COMPANY

CASE NO. 2004-00426

Response to Second Data Requests of Commission Staff Dated February 23, 2005

Question No. 2

Responding Witness: John P. Malloy

Q-2. Refer to the response to the Staff's First Request, Item 13(b). Based upon this response, is it correct that the total expected annual reduction in SO_2 emissions resulting from the proposed scrubbers at Ghent and Brown is 110,000 tons? If no, provide the correct total expected annual reduction.

A-2. Yes, during the first full year after all scrubbers are in-service (2010), it is estimated that SO_2 emissions on the Companies' generating units will decrease by 110,000 tons annually. Without the FGDs the Companies' SO_2 allowance shortfall is projected to exceed 130,000 tons in 2010.

KENTUCKY UTILITIES COMPANY

CASE NO. 2004-00426

Response to Second Data Requests of Commission Staff Dated February 23, 2005

Question No. 3

Responding Witnesses: Kent W. Blake / John P. Malloy

Q-3. Refer to the response to the Staff's First Request, Items 14(a) and 14(b). In Case No. 1997-00300, the Commission approved the merger of the holding companies for KU and Louisville Gas and Electric Company ("LG&E"). In that case, KU and LG&E requested approval of their Corporate Policies and Guidelines for Intercompany Transactions ("Guidelines") that would govern their merged activities. The Guidelines provided that transfers or sales of assets between KU and LG&E would be priced at cost. It was noted in the Guidelines that through this policy, the utilities would receive the full benefit from intercompany transfers or sales. The Commission ordered KU and LG&E to comply with the Guidelines after the merger. In subsequent cases, KU has committed to continue following the Guidelines to the extent those conditions were not superseded by KRS 278.2201 through 278.2219 or the jurisdiction of the Securities and Exchange Commission or the Federal Energy Regulatory Commission.

a. Would KU agree that the Guidelines' requirements concerning the transfer or sale of assets between KU and LG&E apply to emission allowances? Explain the response.

b. In the response to Item 14(b), KU states, "transferring allowances between companies as needed, priced at market, results in the lowest net present value to all customers." Explain the basis for this statement.

A-3. a. The Company does not believe the referenced sections of its Corporate Policies and Guidelines for Intercompany Transactions ("Guidelines") prevented it from proposing transfers of emission allowances between LG&E and KU be made at market prices nor do the Guidelines restrict the Commission from approving the proposed transfer of emission allowances in this proceeding prior to such transfer occuring. The primary purpose of the Guidelines is to ensure that there is no subsidization of one LG&E Energy subsidiary to the detriment of the other, particularly if that involves a utility subsidiary subsidizing a non-utility subsidiary.

The reference in these Guidelines to asset transfers clearly applies to capital assets included in rate base. For such assets, the utility is allowed the opportunity to earn a fair, just and reasonable return on the cost of such assets. The policy of transferring assets at cost between LG&E and KU in the

Guidelines reflects that as between two full rate-of-return regulated utilities, the cost of the asset essentially represents the fair market price of the asset because each Company earns a regulated return (i.e. regulation's substitute for the fair market rate of return) on its rate base assets. Thus, transferring the assets at cost is the functional equivalent of transferring the assets at their fair market value as between the two utility companies.

The application of the Guidelines to emission allowances, however, is less clear because of the nature of emission allowances. Emission allowance transfers are more akin to operating expenses when they are purchased or transferred on an as needed basis. In the current case, KU has a need for emission allowances which it can either purchase from the market at prevailing rates or purchase from LG&E. If such purchases from LG&E are made at prevailing market rates, KU should be indifferent as to the source. However, LG&E currently holds allowances which allows it to meet environmental requirements at a cost well below current market rates. If LG&E was to sell allowances to KU at a price below market, its customers would be adversely impacted as LG&E would be transferring this emission right to KU without being fairly compensated.

Please note that to the extent one utility maintains inventory balances resulting from the transfer of allowances by the other utility at market, the receiving utility has the opportunity to increase its return through the ECR mechanism. Of course, that utility would be in the same position if it purchased those allowances from the market rather than from the other utility. The Company receiving the transferred allowances could lower its return by either making transfers only on an as needed basis without maintaining an inventory or by removing the "step up to market" when calculating its inventory value for purposes of the ECR. The former alternative would not be a prudent operating decision. The latter carries the adverse incentive for the utility to acquire such allowances from the market which would result in a higher revenue requirement for the customers of the combined utilities. Moreover, the latter alternative also results in a lack of symmetry in accounting between the two utilities if customers of the transferring utility receive an ECR credit based on market prices.

The Company requests that the Commission make a determination as to whether the Guidelines apply to the proposed transfer of emission allowances between LG&E and KU at market prices, and, if the Commission determines the Guidelines apply, grant the Companies a deviation from the Guidelines to permit the transfer of the allowances as proposed.

b. See the attached table for the projected present value differences on both KU and LG&E's systems of transferring SO_2 allowances at market prices or at cost.

Net Present Value Allowance Expense

Present Value Rate= 7.14%

Projections for Kentucky Utilities Company

	Transfer @ Market		Transfer @ Cost	
	Emissions	ECR Credit	Emissions	ECR Credit
2004	$5,107,773	$0	$5,107,773	$0
2005	$10,743,610	$0	$2,475,982	$0
2006	$22,111,052	$0	$6,120,542	$0
2007	$19,329,790	$0	$12,084,626	$0
2008	$9,294,418	$0	$5,637,444	$0
2009	$688,252	$16,931	$475,386	$291
2010	$163,430	$8,314,807	$112,884	$41,633
Present Value=	$57,763,956	$5,509,203	$27,266,452	$27,731
Net Present Value=	**$52,254,753**		**$27,238,721**	

Projections for Louisville Gas and Electric Company

	Transfer @ Market		Transfer @ Cost	
	Emissions	ECR Credit	Emissions	ECR Credit
2004	$12,936	$0	$12,936	$0
2005	$7,174	$11,739,602	$7,174	$3,877
2006	$3,041	$18,971,855	$3,041	$2,587
2007	$309	$2,841,358	$309	$38
2008	$31	$1,908,168	$31	$3
2009	$12,264	$0	$215	$0
2010	$7,522,921	$0	$1,584,102	$0
Present Value=	$5,004,908	$31,243,181	$1,070,012	$5,905
Net Present Value=	**($26,238,273)**		**$1,064,107**	

Projections for KU + LGE

KU+LGE NPV with Allowances Transferred @ Cost =	$28,302,828
KU+LGE NPV with Allowances Transferred @ Market =	$26,016,480
Savings with SO_2 Allowances Being Priced at Market =	**$2,286,348**

KENTUCKY UTILITIES COMPANY

CASE NO. 2004-00426

Response to Second Data Requests of Commission Staff Dated February 23, 2005

Question No. 4

Responding Witnesses: Kent W. Blake / Sharon L. Dodson / John P. Malloy

Q-4. Refer to the response to the Staff's First Request, Items 14(c) and 14(e).

a. In the attachment to the response to Item 14(c), pages 6 through 10 of 10, the tables show SO_2 emission allowances allocated to the gas-fired combustion turbines ("CTs") at the Brown generating station. Between 2000 and 2004, did KU include any of the SO_2 emission allowances allocated to CTs in the allowance inventory included in KU's environmental surcharge? Explain the response.

b. Between 2000 and 2004, did KU include the cost of any of the SO_2 emission allowances allocated to CTs in the weighted average cost of allowances used to determine the allowance expense recovered through the environmental surcharge? Explain the response.

c. Does KU agree that any inventory of SO_2 emission allowances and the expense of any allowances associated with gas-fired generation cannot be recovered through the environmental surcharge? Explain the response.

d. Do the SO_2 emission allowance bank projections shown in the response to Item 14(e) include allowances allocated to CTs? If yes, indicate the amount included for each year shown.

e. Explain in detail how KU determined the "Desired Bank Level" as shown in the response to Item 14(e).

A-4. a. The EPA does not allocate SO_2 emission allowances to KU's combustion turbine units. The allowances shown in the table attached to the Company's response to the Staff's First Request, Item 14(c), for the CTs at the Brown generating station were not technically allocated to the CTs (as defined by the Clean Air Act) but were transferred to the CTs' allowance accounts from other units. The CTs were not allocated any allowances by the USEPA because they are classified as "new units" under the Acid Rain Control Program since they began operation after November 1990. However, USEPA requires that such units must hold allowances in their accounts and surrender them in a number equal to their emissions. By definition, this means that allowances must be transferred to these accounts from other accounts. KU

transferred enough allowances to the CT accounts to ensure that the accounts would hold sufficient allowances for compliance purposes, rather than risk holding insufficient allowances and being subject to severe penalties.

In accordance with FERC General Instruction 21, Allowances, Part A, in 18 CFR Chapter 1, KU's allowance inventory balance is not associated with specific allowances. FERC requires only that the cost of allowance purchases be matched with allowances by vintage; current vintage allowances and their associated acquisition costs are included in FERC Account 158.1; future vintage allowances and their associated acquisition costs are included in FERC Account 158.2. (The only non-current allowances KU owns are the future year allowances allocated by the EPA at zero cost.) The dollar value of KU's inventory balance is not assigned to specific generating units and KU's monthly environmental rate base includes total allowance inventory balance for the current expense month.

b. KU inadvertently charged through the ECR filing the following expenses related to SO_2 emissions for CTs.

2000	$ 14.13	9 allowances
2001	$ 76.92	65 allowances
2002	$ 18.62	28 allowances
2003	$ 2.64	4 allowances
2004	$328.41	9 allowances
Total	$440.72	115 allowances

When the Company discovered that the amounts above were mistakenly included in the ECR filings, KU corrected this by removing the allowances related to CT emissions through a credit adjustment of $3,898.39 (allowances priced at November 2004 current unit cost) in the November 2004 expense month ECR filing. KU had included and charged to customers in the ECR filings $440.72 for CT emission allowances and then removed and credited to customers CT emission costs of $3,898.39.

c. KU agrees that the ECR recovery is limited to the current recovery of KU's costs of complying with the Federal Clean Air Act as amended and those federal, state or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal in accordance with the utility's compliance plan. In that regard, KU does not include in its monthly ECR filings any emission allowance expense associated with combustion turbine emissions.

When determining the expense associated with monthly SO_2 allowances, KU follows the FERC General Instruction 21, Allowances, Part D, in 18 CFR Chapter 1, which mandates a monthly weighted-average method of cost determination rather than a specific assignment method. The average cost of allowances is applied to all allowances committed for surrender, regardless of the source of the emissions. That is, steam units and combustion turbines will incur the same average cost of allowances used, but only allowances used by the steam units are included in KU's monthly ECR filings.

d. No. There are no SO_2 emissions from combustion turbines or allowances allocated to combustion turbines included in KU's response to the Staff's First Request, Item 14(e).

e. The minimum desired bank level represents KU's next year's EPA allowance allocation less KU's next year's projected emissions, rounded to the closest 1,000 tons. This minimum bank level would allow the Company to maintain compliance through all of the next year and much of the following year since the EPA allocated allowances would be available again in January of the following year. Anything less than that amount would result in the available allowances providing for less than one year of compliance. The desired bank level had a floor of 7,000 tons. This inventory level allows for unexpected outages of scrubbed units, periods of lower scrubber removal efficiencies, and higher than planned generation levels.

KENTUCKY UTILITIES COMPANY

CASE NO. 2004-00426

Response to Second Data Requests of Commission Staff Dated February 23, 2005

Question No. 5

Responding Witness: Robert M. Conroy

Q-5. Refer to the response to the Staff's First Request, Item 17. Estimate the net impact to a residential customer's monthly bill after all the scrubbers have been installed. Net impact as used in this question refers to both the environmental surcharge and the fuel adjustment clause. Include all supporting workpapers, calculations, and assumptions.

A-5. The estimated monthly bill impact based on a residential customer usage of 1,000 kWh, utilizing a 11.19% cost of capital is $6.94 (see Response to Commission Staff's 1st Data Request, Question No. 3). The fuel adjustment clause ("FAC") component is estimated to be $2.00 per month as explained in the Response to Commission Staff's 1st Data Request, Question No. 17(b). Actual fuel cost impact will depend on market conditions at the time. Based on the estimated FAC impact noted above, the net monthly bill impact for a residential customer using 1,000 kWh after all scrubbers have been installed is $4.94 ($6.94 - $2.00). If the FAC impact as noted in the Response to Commission Staff's 1st Data Request, Question No. 17(c) for December 2004 ($4.83) is utilized, the net monthly bill impact for a residential customer using 1,000 kWh would be $2.11 ($6.94 - $4.83).

KENTUCKY UTILITIES COMPANY

CASE NO. 2004-00426

Response to Second Data Requests of Commission Staff Dated February 23, 2005

Question No. 6

Responding Witness: Valerie L. Scott

Q-6. Refer to the response to the Staff's First Request, Item 18. Does KU's weighted average cost per ton of eligible vintage allowances in inventory include the estimated cost of allowances expected to be purchased or only allowances actually purchased? Explain the response.

A-6. KU has recorded and will record in FERC Account No. 158.1, the actual purchases for emission allowances. KU will not record allowances into inventory until an actual purchase transaction has taken place.