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

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PUBLIC SERVICE COMMISSION

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August 7, 2006

RE: *In the Matter Of:* *The Application Of Kentucky Utilities Company For A Certificate Of Public Convenience And Necessity To Construct A Selective Catalytic Reduction System And Approval Of Its 2006 Compliance Plan For Recovery By Environmental Surcharge* - **Case No. 2006-00206**

Dear Ms. O'Donnell:

Enclosed please find an original and five (5) copies of Kentucky Utilities Company's ("KU") Response to the First Data Request of Commission Staff dated July 24, 2006, in the above-referenced docket.

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

Sincerely,

Kent Blake

Kent Blake

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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AUG 07 2006

PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT A SELECTIVE CATALYTIC REDUCTION SYSTEM AND APPROVAL OF ITS 2006 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	CASE NO. 2006-00206

RESPONSE OF
KENTUCKY UTILITIES COMPANY
TO
FIRST DATA REQUEST OF
COMMISSION STAFF
DATED JULY 24, 2006

FILED: AUGUST 7, 2006

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 1

Responding Witness: Kent W. Blake

Q-1. Refer to the Application, page 4. On June 23, 2006, KU filed an application seeking a Certificate of Public Convenience and Necessity for its proposed Selective Catalytic Reduction ("SCR") facilities at Ghent Unit 2 and approval of an amended environmental compliance plan and amended surcharge tariff. KU requested that the Commission rule on the Certificate of Public Convenience and Necessity no later than December 20, 2006. Under the provisions of KRS 278.183, the Commission must rule upon KU's amended environmental compliance plan and surcharge mechanism within 6 months of the filing of its application. As KU filed its application on June 23, 2006, the Commission must rule on the environmental compliance plan and surcharge application no later than December 22, 2006. Explain why KU believes the Certificate of Convenience and Public Necessity is needed two days prior to the date the Commission must rule on the amended environmental compliance plan and amended surcharge tariff.

A-1. KU did not intend to request an order for the Certificate of Public Convenience and Necessity ("CCN") two days prior to the date the Commission must rule on the amended environmental compliance plan. In determining the December 20, 2006 date, KU utilized 180 days as representative of 6 months. KU agrees with the position expressed in the data request that the Commission must rule on the environmental compliance plan and surcharge application no later than December 22, 2006.

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 2

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

Q-2. Refer to the Direct Testimony of Kent W. Blake ("Blake Testimony"), pages 3 through 5. Mr. Blake notes that in Case No. 2000-00112, the Commission had previously granted certificates of public convenience and necessity to KU to construct SCRs at Ghent Units 1, 3, and 4 and Brown Unit 3. It was noted in that case that KU's consultant, Sargent & Lundy, had recommended SCRs be constructed at Ghent Units 1 through 4, but that KU's analysis showed its substitution of an SCR at Brown Unit 3 for Ghent Unit 2 resulted in $15 million in capital cost savings. Mr. Blake states that KU did not construct the SCR at Brown Unit 3, based on KU's determination that this SCR was not needed or cost-effective to achieve compliance with allowed nitrogen oxide ("NO_x") emission limits.

a. When did KU make the determination that the SCR at Brown Unit 3 was not needed or cost-effective for compliance with NOx emission limits?

b. Describe in detail the analysis performed by KU that supported its decision concerning the SCR at Brown Unit 3 and provide copies of any written studies or reports that recommended an SCR at Brown Unit 3 should not be constructed.

c. The SCR proposed for Ghent Unit 2 in this proceeding has an estimated project cost of $95.0 million. Provide the estimated project cost for the Ghent Unit 2 SCR as recommended by Sargent & Lundy in conjunction with Case No. 2000-00112.

A-2. a. The Commission's Order dated June 22, 2000 in Case No. 2000-112 granted a CCN to construct seven SCRs "as needed to comply with EPA requirements". The Companies continuously review the least cost means of complying with environmental regulation. In April of 2002 as part of the development of the Companies' 2002 Joint Integrated Resource Plan (Case No. 2002-00367), the Companies began an updated analysis of the recommended NO_x compliance plan associated with Case Nos. 2000-386 and 2000-439. The updated analysis was completed in June of 2002 and sought to ascertain whether the prior recommended plan of constructing seven SCRs as presented in the March

2000 CCN application (Case No. 2000-112) remains the most cost effective plan in light of the fact that several significant changes had occurred since the previous study. In August of 2002, documentation on the study was completed and the revised study was included in the 2002 Joint Integrated Resource Plan of LG&E and KU filed with the Commission on October 1, 2002.

The results of the August 2002 updated analysis are summarized in the last two paragraphs of the Executive Summary:

> *The combined impact of receiving more allowances and a delay in the compliance deadline, allowed for the replacing of the Brown 3 SCR with combustion modifications on Brown 3, Ghent 2, Brown 2, and Cane Run 4. This modified version of the original compliance plan will allow the companies to comply through 2009, after which the plan will rely on purchased NOx allowances. The original plan complied through 2008. The economics of purchasing allowances over the installation of a new technology will continue to be evaluated and the Companies will pursue the lowest cost alternative.*
>
> *The Companies will continue to monitor the evolution of NOx control technologies and strive to maintain flexibility in their implementation of the compliance plan. The Companies will also keep a close watch on air pollution control legislative activities, regulatory rulings, and judicial actions and further refine the technology cost estimates so that they can meet their on-going emissions reduction requirements in a prudent and least-cost manner.*

The Companies met with the Commission Staff at the offices of the Commission on August 8, 2002 to provide an update to the Companies' environmental compliance plans. During this meeting, the Companies presented to the Commission Staff a progress status report in regards to the Companies' NO_x compliance projects. The presentation given on that date has been attached in its entirety.

b. See the response to part a. The analysis is contained in the report titled *2002 NOx Compliance Study* (August 2002) contained in Volume III, Technical Appendix of the 2002 Joint Integrated Resource Plan of LG&E and KU filed with the Commission on October 1, 2002 in Case No. 2002-00367.

c. As indicated on page 1 of 2 of LEB-Appendix B of the jointly filed 2000 CCN (Case No. 2000-112) the S&L 1999 cost estimate for an SCR at Ghent 2 was $61.6 million. This value was based on 1998 dollars.

2000 ECR Compliance Plan -- Progress Report

LG&E and KU

August 8, 2002

2000 Amended Compliance Plan

Case No. 2000-386

LGE projects at Cane Run, Mill Creek, and Trimble Co.

Project scope includes:

- 3 Selective Catalytic Reduction (SCR) systems (Mill Creek 3 & 4; Trimble 1)
- Neural Network technology; Overfire air systems; Low NOx Burners (Cane Run; Mill Creek 1 & 2)

Case No. 2000-439

KU projects at Brown, Ghent, Green River, Pineville, and Tyrone

Project scope includes:

4 SCRs (Brown 3; Ghent 1, 3 &4)

Overfire air systems (Brown 1 & 2)

Neural Network (Brown 2)

Advanced Low NO_x burner (Ghent 2)

Low NO_x burners (Green River 3, Pineville 3, Tyrone 3)

Case 2000-389: SCR Status

- Trimble County: in service May 2002
- Mill Creek 3: scheduled completion 4th quarter 2002
- Mill Creek 4: scheduled completion 1st quarter 2003

Case 2000-439: SCR Status

SCR current status

- Ghent 3: scheduled completion 1st quarter 2003
- Ghent 4: scheduled completion 1st quarter 2004
- Ghent 1: scheduled completion 2nd quarter 2004
- Brown 3: Not started

Explanation of Changes to Original Cost Estimate

- Labor Escalation Factor
  - Cash flow projection based on 2%; actual to date 8.5%
  - Total labor escalation: $20 million
- Existing Plant Modifications Necessary to Accommodate SCR's
  - Original projections based on preliminary engineering study
  - Detailed, 2-year study of each site identified additional considerations
  - Total Balance of Plant modifications: $76 million

Compliance Plan: Mid-Plan Review

PSC approved a project consisting of 3 SCR's at LG&E; 4 SCR's at KU

Build 6 SCR's

- Replace Brown 3 SCR with boosted overfire air
- Achieves compliance for 5 years

Replace 1 SCR with combined SO_2/NO_x facility

- Install combined technology on Ghent 2
- Make no improvements to Brown 3
- Eliminates need for Ghent 2 FGD
- Achieves compliance for 9 years
- Allows for increased flexibility to meet varying generation requirements and developing technology

Build 7 SCR's as originally approved

- Cost increase is estimated to be $107 million
- Achieves compliance for 15 years

Summary

- KU/LGE remain committed to achieving environmental compliance at lowest reasonable cost
- KU/LGE will not compromise commitment to safety and quality
- Environmental compliance requires ability to respond to changes in technology
- Updated compliance strategies will be included in the Companies' Integrated Resource Plan and communicated to interested parties

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 3

Responding Witness: Sharon L. Dodson / John P. Malloy

Q-3. Refer to the Direct Testimony of Sharon L. Dodson ("Dodson Testimony"), pages 5 through 7. Provide a schedule showing for each of KU's generating units the following emissions data for sulfur dioxide ("SO_2"), NO_x, and mercury, if available:

a. The level of emissions for calendar year 2005.

b. The expected level of emissions for calendar year 2006.

c. The expected level of emissions permitted under the first phase of the Clean Air Interstate Rule ("CAIR") or the Clean Air Mercury Rule ("CAMR").

d. The expected level of emissions permitted under the second phase of the CAIR or CAMR.

A-3. a. Please see the table included in the response to Part b for 2005 historical emissions of SO_2, NO_x and mercury ("Hg"). Please note that the annual Hg emissions are estimated values, using the Electric Power Research Institute's ("EPRI") Lark-Tripp model, and have been reported to the United States Environmental Protection Agency ("USEPA") in the Companies' 2005 Toxic Release Inventory Report. The EPRI Lark-Tripp model is a computational software package that has been accepted by the USEPA for use in estimating emissions of toxic substances. While the Company presently is not required, under current regulations, to monitor mercury emissions, the USEPA's adoption of CAMR requires the Company to install and certify continuous mercury emission monitors prior to January 1, 2009. This will require purchasing the monitoring equipment in 2008 as discussed on page 21 of Mr. Malloy's testimony.

b. Historical 2005 emissions and 2006 projections for SO_2, NO_x (both annual and ozone season) and Hg are shown in the table below. Note that the 2005 annual Hg emissions are an estimate as described in Part a above.

	Historical Emissions				Projected Emissions			
	2005				2006			
Unit	SO_2 (Tons)	Ozone NO_x (Tons)	Annual NO_x (Tons)	Estimated Hg (Pounds)	SO_2 (Tons)	Ozone NO_x (Tons)	Annual NO_x (Tons)	Annual Hg (Pounds)
Brown 1	8,682	646	1,693	30	8,055	528	1,456	37
Brown 2	13,803	552	1,607	51	14,470	702	1,614	66
Brown 3	20,376	1,093	2,503	78	33,412	1,441	3,727	152
Ghent 1	5,302	339	4,349	60	7,368	313	3,665	80
Ghent 2	13,959	1,621	3,738	100	18,119	1,754	4,254	272
Ghent 3	15,054	190	2,585	131	19,530	283	3,411	294
Ghent 4	15,666	188	2,809	121	19,395	288	3,263	292
Green River 3	8,998	333	901	23	7,171	289	691	21
Green River 4	6,901	145	655	21	11,798	441	1,137	34
Tyrone 3	3,192	322	955	7	2,478	235	589	19
Peakers	5	110	142	1	0	91	109	0
	111,938	5,539	21,938	625	141,795	6,364	23,916	1,267

c. Please see response to Part d below.

d. CAIR and CAMR have been promulgated as "cap-and-trade" programs. Therefore, emission caps have been placed on the respective pollutant emissions such that all emissions of that pollutant affected by the program do not exceed the applicable cap. CAIR and CAMR do not have "permitted" levels of emissions on a unit by unit basis. The regulations do however allocate emission allowances to the individual states affected by the regulation. The states then allocate their allowances to the individual affected sources within the state on a unit by unit basis. These allowance programs do not prohibit a unit from emitting at a level greater than its given allocation because the unit could obtain allowances from other sources that are emitting at a level less than their number of allocated allowances.

The State of Kentucky's regulations incorporating CAIR and CAMR are expected to be completed in early 2007. Therefore, the exact number of allowances each affected unit will be given is unknown at this time. However, KU is providing a projection of the potential allowance allocation. Projected ozone season NO_X allowances, annual NO_X allowances, SO_2 allowances and Hg allowances by boiler or unit by year through 2023 are shown in the following tables. These values are the Company's best estimate of the probable distribution of allowances, based on currently available information on how Kentucky is likely to structure its program.

Ozone Season NO_x Allowances

		NOx SIP Call			CAIR NOX Phase 1						CAIR NOX Phase 2								
Plant	Boiler/CT	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
E W Brown	01	235	253	253	253	245	245	245	232	232	232	227	227	227	222	222	222	217	217
E W Brown	02	346	400	400	400	388	388	388	367	367	367	359	359	359	351	351	351	343	343
E W Brown	03	831	937	937	937	908	908	908	861	861	861	841	841	841	822	822	822	803	803
E W Brown	05		29	29	29	28	28	28	27	27	27	26	26	26	25	25	25	25	25
E W Brown	06	7	26	26	26	25	25	25	24	24	24	23	23	23	23	23	23	22	22
E W Brown	07	9	23	23	23	22	22	22	21	21	21	21	21	21	20	20	20	20	20
E W Brown	08	46	29	29	29	28	28	28	27	27	27	26	26	26	25	25	25	25	25
E W Brown	09	44	21	21	21	20	20	20	19	19	19	19	19	19	18	18	18	18	18
E W Brown	10	41	15	15	15	15	15	15	14	14	14	13	13	13	13	13	13	13	13
E W Brown	11	32	8	8	8	8	8	8	7	7	7	7	7	7	7	7	7	7	7
Ghent	01	1093	1160	1160	1160	1,124	1,124	1,124	1,065	1,065	1,065	1,042	1,042	1,042	1,018	1,018	1,018	994	994
Ghent	02	1090	1050	1050	1050	1,018	1,018	1,018	964	964	964	943	943	943	921	921	921	900	900
Ghent	03	1104	1127	1127	1127	1,093	1,093	1,093	1,035	1,035	1,035	1,012	1,012	1,012	989	989	989	966	966
Ghent	04	1113	1061	1061	1061	1,029	1,029	1,029	974	974	974	953	953	953	931	931	931	909	909
Green River	01	36	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
Green River	02	36	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
Green River	03	35	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
Green River	04	197	128	128	128	124	124	124	118	118	118	115	115	115	112	112	112	110	110
Green River	05	242	188	188	188	182	182	182	173	173	173	169	169	169	165	165	165	161	161
Pineville	03	79	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
Tyrone	01	1	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
Tyrone	02	1	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
Tyrone	03	1	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
Tyrone	04	2	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
Tyrone	05	143	152	152	152	147	147	147	140	140	140	136	136	136	133	133	133	130	130
	Total	6.764	6.607	6.607	6,607	6.405	6,405	6.405	6,068	6,068	6.068	5.933	5.933	5.933	5.798	5.798	5.798	5.663	5.663

Annual NO_x Allowances

		CAIR NOX Phase 1						CAIR NOX Phase 2								
Plant	Boiler/CT	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
E W Brown	1	572	572	572	572	542	542	451	441	441	441	431	431	431	421	421
E W Brown	2	852	852	852	852	807	807	672	657	657	657	642	642	642	627	627
E W Brown	3	2,068	2,068	2,068	2,068	1,960	1,960	1,633	1,597	1,597	1,597	1,560	1,560	1,560	1,524	1,524
E W Brown	5	38	38	38	38	36	36	30	29	29	29	29	29	29	28	28
E W Brown	6	59	59	59	59	56	56	47	46	46	46	45	45	45	44	44
E W Brown	7	47	47	47	47	44	44	37	36	36	36	35	35	35	35	35
E W Brown	8	23	23	23	23	22	22	18	18	18	18	18	18	18	17	17
E W Brown	9	17	17	17	17	16	16	14	13	13	13	13	13	13	13	13
E W Brown	10	14	14	14	14	13	13	11	10	10	10	10	10	10	10	10
E W Brown	11	8	8	8	8	7	7	6	6	6	6	6	6	6	6	6
Ghent	1	2,735	2,735	2,735	2,735	2,591	2,591	2,159	2,111	2,111	2,111	2,063	2,063	2,063	2,015	2,015
Ghent	2	2,382	2,382	2,382	2,382	2,257	2,257	1,881	1,839	1,839	1,839	1,797	1,797	1,797	1,755	1,755
Ghent	3	2,397	2,397	2,397	2,397	2,271	2,271	1,892	1,850	1,850	1,850	1,808	1,808	1,808	1,766	1,766
Ghent	4	2,368	2,368	2,368	2,368	2,243	2,243	1,869	1,828	1,828	1,828	1,786	1,786	1,786	1,745	1,745
Green River	1	26	26	26	26	24	24	20	20	20	20	19	19	19	19	19
Green River	2	29	29	29	29	27	27	23	22	22	22	22	22	22	21	21
Green River	3	22	22	22	22	21	21	17	17	17	17	17	17	17	16	16
Green River	4	305	305	305	305	289	289	241	235	235	235	230	230	230	225	225
Green River	5	393	393	393	393	372	372	310	303	303	303	296	296	296	289	289
Pineville	3	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
Tyrone	1	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
Tyrone	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tyrone	3	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
Tyrone	4	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
Tyrone	5	282	282	282	282	267	267	222	218	218	218	213	213	213	208	208
	Total	14,635	14,635	14,635	14,635	13,865	13,865	11,554	11,297	11,297	11,297	11,040	11,040	11,040	10,784	10,784

SO_2 Allowances

	Title IV of CAAA				CAIR SO2 Phase 1					CAIR SO2 Phase 2								
Plant	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Brown 1	3,066	3,066	3,066	3,066	1,455	1,455	1,455	1,455	1,455	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020
Brown 2	5,807	5,807	5,807	5,807	2,757	2,757	2,757	2,757	2,757	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933
Brown 3	11,254	11,254	11,254	11,254	5,343	5,343	5,343	5,343	5,343	3,745	3,745	3,745	3,745	3,745	3,745	3,745	3,745	3,745
Ghent 1	12,252	12,252	12,252	12,252	5,816	5,816	5,816	5,816	5,816	4,077	4,077	4,077	4,077	4,077	4,077	4,077	4,077	4,077
Ghent 2	12,737	12,737	12,737	12,737	4,757	4,757	4,757	4,757	4,757	3,335	3,335	3,335	3,335	3,335	3,335	3,335	3,335	3,335
Ghent 3	13,960	13,960	13,960	13,960	6,628	6,628	6,628	6,628	6,628	4,646	4,646	4,646	4,646	4,646	4,646	4,646	4,646	4,646
Ghent 4	13,717	13,717	13,717	13,717	6,513	6,513	6,513	6,513	6,513	4,565	4,565	4,565	4,565	4,565	4,565	4,565	4,565	4,565
Green River 1	130	130	130	130	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Green River 2	851	851	851	851	8	8	8	8	8	5	5	5	5	5	5	5	5	5
Green River 3	744	744	744	744	6	6	6	6	6	4	4	4	4	4	4	4	4	4
Green River 4	2,826	2,826	2,826	2,826	1,341	1,341	1,341	1,341	1,341	940	940	940	940	940	940	940	940	940
Green River 5	3,372	3,372	3,372	3,372	1,600	1,600	1,600	1,600	1,600	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122
Pineville 3	914	914	914	914	201	201	201	201	201	141	141	141	141	141	141	141	141	141
Tyrone 5	1,713	1,713	1,713	1,713	320	320	320	320	320	224	224	224	224	224	224	224	224	224
Total	83.343	83.343	83.343	83.343	36.746	36.746	36.746	36.746	36.746	25.759	25.759	25.759	25.759	25.759	25.759	25.759	25.759	25 759

Hg Allowances

		CAMR Phase I								CAMR Phase II					
Plant	Boiler/CT	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
E W Brown	1	21.20	21.20	21.20	21.20	21.20	21.20	21.20	21.20	7.93	7.93	7.93	7.93	7.93	7.93
E W Brown	2	31.57	31.57	31.57	31.57	31.57	31.57	31.57	31.57	11.81	11.81	11.81	11.81	11.81	11.81
E W Brown	3	76.70	76.70	76.70	76.70	76.70	76.70	76.70	76.70	28.68	28.68	28.68	28.68	28.68	28.68
Ghent	1	101.39	101.39	101.39	101.39	101.39	101.39	101.39	101.39	37.92	37.92	37.92	37.92	37.92	37.92
Ghent	2	88.33	88.33	88.33	88.33	88.33	88.33	88.33	88.33	33.03	33.03	33.03	33.03	33.03	33.03
Ghent	3	88.87	88.87	88.87	88.87	88.87	88.87	88.87	88.87	33.24	33.24	33.24	33.24	33.24	33.24
Ghent	4	87.79	87.79	87.79	87.79	87.79	87.79	87.79	87.79	32.83	32.83	32.83	32.83	32.83	32.83
Green River	4	11.30	11.30	11.30	11.30	11.30	11.30	11.30	11.30	4.23	4.23	4.23	4.23	4.23	4.23
Green River	5	14.57	14.57	14.57	14.57	14.57	14.57	14.57	14.57	5.45	5.45	5.45	5.45	5.45	5.45
Tyrone	5	10.45	10.45	10.45	10.45	10.45	10.45	10.45	10.45	3.91	3.91	3.91	3.91	3.91	3.91
	Total (lbs)	532.17	532.17	532.17	532.17	532.17	532.17	532.17	532.17	199.02	199.02	199.02	199.02	199.02	199.02

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 4

Responding Witness: Sharon L. Dodson / John P. Malloy

Q-4. Refer to the Dodson Testimony, pages 8 and 9.

a. Are there currently federal, state, or local emission limits established for sulfur trioxide ("SO_3")?

b. If yes to part (a), provide the current emission limits.

c. For calendar year 2005, what were the actual SO_3 emissions for Ghent Units 1, 3, and 4?

d. If there are no established emission limits for SO_3, how can KU determine whether the actions it takes to limit these emissions are adequate?

A-4. a. SO_3 emissions are subject to oversight and regulation, according to Kentucky Division for Air Quality's ("KDAQ") interpretation of its statutory authority, under the Clean Air Act even in the absence of a specific emissions limit. The Clean Air Act and its state counterparts have requirements that are not expressed in terms of specific emission limits. According to directives from the KDAQ, the "general duty" provisions of KRS Chapter 224 impose an obligation on a permittee to undertake appropriate action on a case by case basis to mitigate "air pollution" that could potentially impact human health or the environment. As indicated in Exhibit SLD-4, KDAQ has determined that "emissions of SO_3 that may subsequently be converted to a fine acidic mist certainly falls within the purview of [the general duty provisions]" and that "it is necessary and appropriate that such emission be controlled."

b. See Part a above.

c. KU does not have continuous emission monitors for monitoring SO_3 emissions that would report the actual 2005 SO_3 emissions for Ghent Units 1, 3 and 4. However, KU can provide an estimate of the emissions from the 2005 Toxic Release Inventory ("TRI") Report submitted to the USEPA. Sulfuric acid emissions estimates are supplied in the annual submission. An estimate of the SO_3 emissions can be obtained by applying a ratio of the molecular weights of the two substances. The following table provides the estimate of the 2005 SO_3 emission for Ghent Units 1, 3 and 4.

	Ghent Unit 1	Ghent Unit 3	Ghent Unit 4
2005 SO_3 Emission (pounds) (estimated)	1,081,837*	120,201	143,968

*Note: The large SO_3 emissions seen on Ghent Unit 1 compared to Ghent Units 3 and 4 is due to the burning of higher sulfur coal in Ghent Unit 1.

d. As indicated in Exhibit SLD-4, KDAQ requirements regarding SO_3 emissions focus primarily on the potential for its conversion to sulfuric acid mist contributing to the formation of visible stack plumes that may descend to ground level under certain conditions. KU has performed testing of sorbent injection technology at the Ghent Station to identify control measures sufficient to prevent SO_3/sulfuric acid conversion contributing to the formation of such visible stack plumes. The findings in the Sargent and Lundy SO_3 Mitigation Study, Exhibit JPM-4, established that a visible stack plume (discounting the portion consisting of water vapor) dissipates rapidly when stack gases are controlled to an SO_3 concentration level of approximately five (5) parts per million ("ppm"). Hence, based on this study, the Company has identified a value of 5 ppm SO_3 which can be used as a practical guideline for its compliance efforts. The Company can determine the adequacy of its SO_3 mitigation measures by using an EPA-certified observer to conduct visual emissions tests of the stack plume, in accordance with the objective protocols of EPA Method 9, to identify any ongoing SO_3 related plume problems. Based on this approach, KU believes its compliance plans and actions are adequate under and required by current environmental regulations.

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 5

Responding Witness: Sharon L. Dodson

Q-5. Refer to the Dodson Testimony, Exhibits SLD-2 and SLD-5.

a. Explain why the Title V Operating Permit for the Ghent Station does not reference the flue gas desulfurization systems ("scrubbers") at Ghent Units 2 through 4 and the SCRs at Ghent Units 1, 3, and 4.

b. Explain why the Title V Operating Permit for the Brown Station does not reference the scrubber for Brown Units 1 through 3.

A-5. a. The absence of a reference to the flue gas desulfurization systems ("FGD") at Ghent Units 2 through 4 and the SCRs at Ghent Units 1, 3, and 4 in the Title V Operating Permit for the Ghent Station does not relieve KU of its compliance obligations under the Clean Air Act and other applicable environmental regulations. The Ghent Station Title V Operating Permit provided as Exhibit SLD-2 was issued on December 8, 1999, prior to the issuance of the CCN to install SCRs and FGDs. In accordance with Kentucky Division for Air Quality ("KDAQ") permitting procedures, KDAQ will incorporate the minor permit revisions to reference the SCRs and FGDs into the Title V Operating Permit upon renewal of the permit. The existing Title V permit for this station expired on December 8, 2004. The station is operating under these permit conditions with a permit shield until the permit is reissued. KDAQ is currently drafting a renewal permit that will include the SCRs and FGDs.

b. The absence of a reference in the Title V Operating Permit for the E.W. Brown Station to the scrubber for E.W. Brown Units 1 through 3 does not relieve KU of its compliance obligations under the Clean Air Act and other applicable environmental regulations. The E.W. Brown Station Title V Operating Permit provided as Exhibit SLD-5 was issued on March 1, 2005, prior the issuance of the CCN to install FGDs. In accordance with KDAQ permitting procedures, KDAQ will incorporate the minor permit revisions to reference the FGDs into the Title V Operating Permit upon renewal of the permit. The existing Title V permit for this station will expire on March 10, 2010. KDAQ should issue a renewal permit by this date or shortly thereafter.

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 6

Responding Witness: John P. Malloy

Q-6. Refer to the Direct Testimony of John P. Malloy ("Malloy Testimony"), Exhibit JPM-2, the 2006 NO_x Compliance Strategy, page 35 of 74. For each of the general assumptions listed below, describe the basis for the assumption and explain why the assumption is reasonable. Include any calculations, workpapers, or other documentation that supports the assumption.

a. Discount Rate of 7.85 percent.

b. Environmental Projects Book Life of 34 years.

c. Annual capital cost escalation rate of 5 percent.

d. Annual Fixed Operation and Maintenance ("O&M") escalation rate of 2 percent.

e. Annual Variable O&M escalation rate of 2 percent.

f. No unit retirements occur on the Companies' generating system within the 2006 through 2035 study period.

A-6. a. The use of 7.85% for KU's discount rate is based on the KU's capital structure for the year ending 2005 and the allowed ECR return on equity of 10.5%.

	Per Books Electric Capitilization	Weighting	Cost Rate	Weighting x Cost Rate
		KU		
Short-Term Debt	69,665	3.75%	4.21%	0.16%
Long-Term Debt	746,604	40.19%	4.50%	1.81%
Common Equity	1,041,377	56.06%	10.50%	5.89%
Totals	1,857,646	100.00%		7.85%
				Overall Rate of Return

b. The book life of 34 years is based on the average depreciation rate for Kentucky Utilities total steam production plant approved by the Commission in Case No. 2001-140.

c. The 5% escalation in capital cost is based on recent financial data as reported by the construction arm of McGraw Hill Company in Engineering News Record ("ENR"). The ENR is an industry report published on a weekly basis and highlights various construction material trends and associated costs. Based on the ENR the General Construction Cost Index was 4.6% in Q1 of 2006 over 2005.

d. See response to part e below.

e. The Companies have contracted with Global Insight to provide national macroeconomic data to generate local economic and demographic forecasts. The assumption for the O&M escalation rates are based on Global Insight's average forecasted percent increase for O&M expenses over a 10 year period for the South Atlantic Region.

ESCALATION RATES FOR O&M

Source: GLOBAL INSIGHT (Using South Atlantic Region)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Coal Production											
STEAM PRODUCTION PLANT											
Steam Production Plant: JEFOMMS	1.292	1.345	1.359	1.368	1.382	1.401	1.429	1.459	1.490	1.522	1.556
% Increase	5.2	4.1	1.1	0.7	1.0	1.4	2.0	2.1	2.1	2.2	2.2

10 Year Average % Increase for 2005-2014 period: 1.9 **or 2.0%**

f. This assumption is consistent with the assumption made in the Companies' most recently filed Integrated Resource Plan (Case No. 2005-00162) and the planning assumptions the Companies typically make in the absence of a specific life assessment study of a generation unit.

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 7

Responding Witness: John P. Malloy

Q-7. Refer to the Malloy Testimony, Exhibit JPM-2. The 2006 NO_x Compliance Strategy states on page 11 of 74 that the most significant contributors of NO_x emissions for KU are Ghent Unit 2 and Brown Unit 3. Appendix 3 of the 2006 NO_x Compliance Strategy, page 29 of 74, states that compliance with the CAIR NO_x limits will require the installation of SCRs at Ghent Unit 2 and Brown Unit 3. The 2006 NO_x Compliance Strategy evaluated the installation of an SCR at either Ghent Unit 2 or Brown Unit 3 separately with various in-service dates between 2008 and 2016. The 2006 NO_x Compliance Strategy concluded and recommended that an SCR be installed at Ghent Unit 2 with an in service date of 2009. The 2006 NO_x Compliance Strategy also briefly evaluated the installation of an SCR at Ghent Unit 2 in 2009 and the installation of an SCR at Brown Unit 3 in either 2013, 2014, 2015, or 2016. Among the options looking at two SCRs, the 2006 NO_x Compliance Strategy concluded that the installation of SCRs at Ghent Unit 2 in 2009 and Brown Unit 3 in 2013 was the least cost alternative.

a. The majority of the 2006 NO_x Compliance Strategy focuses on the evaluation of adding an SCR at <u>either</u> Ghent Unit 2 or Brown Unit 3. Given that these units have been identified as the most significant contributors of NO_x emissions and that compliance with the CAIR NO_x limits requires the installation of SCRs at <u>both</u> units, explain in detail why the 2006 NO_x Compliance Strategy focuses so much on the installation of only one SCR.

b. Did KU consider and evaluate the option of installing SCRs at Ghent Unit 2 in 2009 and Brown Unit 3 in either 2009, 2010, 2011, or 2012?

(1) If yes, provide the results of these alternatives and explain in detail why such alternatives were not discussed in the 2006 NO_x Compliance Strategy.

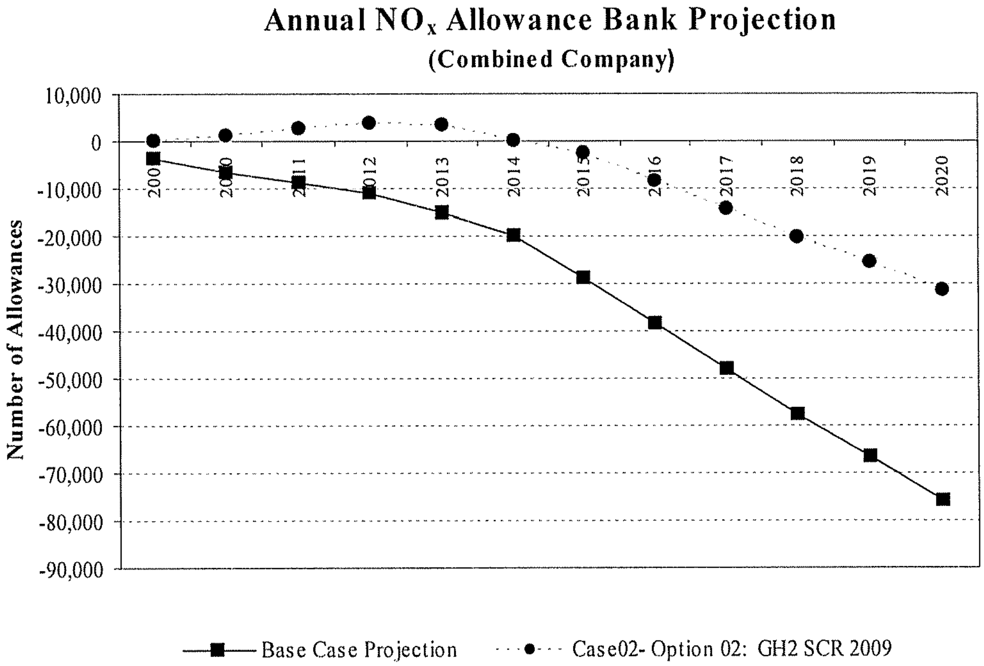
(2) If no, explain why these alternatives were not evaluated.

A-7. a. The 2006 NO_x Compliance strategy identifies the <u>next</u> least-cost step in the continued compliance with environmental regulations as constructing an SCR at Ghent 2 in 2009. As identified in the table labeled "Case Summary" on page 15 of 74 of the *2006 NO_x Compliance Strategy* (Exhibit JPM-2) construction of an SCR at Ghent 2 in 2009 lowers the customer's PVRR by $18.1 million more than constructing an SCR at Brown 3 in the same year. Furthermore, a Ghent 2 SCR in 2009 delays the depletion of the NO_x allowance bank by six years (from 2009 to 2015). The Companies will continue to monitor the post-CAIR NO_x allowance market and applicable NO_x emission reduction technologies to insure that the least cost alternative associated with the projected 2015 shortfall in NO_x allowances is selected.

b. Yes, however a formal evaluation was not required in absence of a need at the time. Therefore, the option of constructing an SCR at Ghent Unit 2 in 2009 and Brown Unit 3 in any year within the 2009-2012 period was not formally evaluated. These accelerated Brown alternatives would necessitate investing $90+ million of capital sooner than KU compliance requirements would indicate in the Companies 2006 NO_x Compliance Strategy Report included in original testimony as Exhibit JPM-2. The following paragraph from Exhibit JPM-2, 2006 NO_x Compliance Strategy For E.ON-US Subsidiaries Kentucky Utilities Company and Louisville Gas and Electric Company, on page 17 of 74, documents that study's conclusion of a potential need for an additional SCR as early as 2015.

> *With the Ghent 2 SCR in service January 2009, the issue remains of the least cost means to address the shortfall in the Companies' annual NO_x allowance bank starting in 2015. Therefore, the Brown 3 SCR, having been shown to be more costly than the Ghent 2 SCR for construction in 2009, should be evaluated in and around the time the Companies' annual NO_x allowance bank is projected to expire--2015.*

The potential need for an additional SCR as early as 2015 is also demonstrated in the graph below which can be found on page 16 of 74 of Exhibit JPM-2. However, the Companies continue to annually evaluate the changing environmental compliance needs, inclusive of the cost of market allowances.


Annual NO_x Allowance Bank Projection
(Combined Company)
Number of Allowances
10,000
0
-10,000
-20,000
-30,000
-40,000
-50,000
-60,000
-70,000
-80,000
-90,000
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Base Case Projection
Case02- Option 02: GH2 SCR 2009

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 8

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

Q-8. Refer to the Malloy Testimony, Exhibit JPM-4, the Sargent & Lundy SO_3 Mitigation Study dated March 29, 2006 ("Sargent & Lundy Study"). The Commission granted KU Certificates of Public Convenience and Necessity to construct a scrubber at Ghent Unit 1 in Case No. 1992-00005 and at Ghent Units 2 through 4 in Case No. 2004-00426. On page 1 of 42 of the Sargent & Lundy Study are the following statements concerning the scrubbers at Ghent:

> An FGD system is currently being installed for Unit 3, with future FGD installations for Units 1&4 in the planning stages. The existing FGD system on Unit 1 will be switched to serve Unit 2.

a. Explain in detail the basis for Sargent & Lundy making these statements. Include in this explanation a discussion of why such a switch is contemplated.

b. Was KU planning on seeking an amendment to the already issued Certificates of Public Convenience and Necessity for Ghent Unit 2 and a new Certificate of Public Convenience and Necessity for Ghent Unit 1? Explain the response.

c. Under KRS 278.020(1), unless the authority granted by a Certificate of Public Convenience and Necessity is exercised within one year, such authority expires. Provide details of the actual construction that has taken place on the scrubbers for Ghent Units 2 and 4 or the financial commitments entered into for the scrubbers on those units.

A-8. a. The basis for Sargent & Lundy making the statements referenced in the Data Request above is contained in drawings filed as part of an exhibit to KU's Application and the study *Construction and Minor Revision of Title V Operating Permit* by Kentuckiana Engineering Company (January 5, 2005) filed in response to KPSC Data Request No. 1-4 on February 9, 2005 in Case No. 2004-00426. At page 2 of 6, the report states:

> Currently, there is a single wet-limestone force oxidation flue gas desulfurization unit controlling the effluent emissions from Ghent

Unit 1. KU plans to reroute the flue gas from Unit 2 to the existing WFGD and install three new WFGD's to control flue gas emissions from Unit 1, Unit 3, and Unit 4.

Please also see Figure 1: *Existing Stack Configuration for the Ghent Generating Station* and Figure 2: *Final Configuration of Existing and Proposed Stacks for the Ghent Generating Station* both of which are attached to the above referenced Kentuckiana Engineering Company study. A copy of these illustrations is attached to this response for reference.

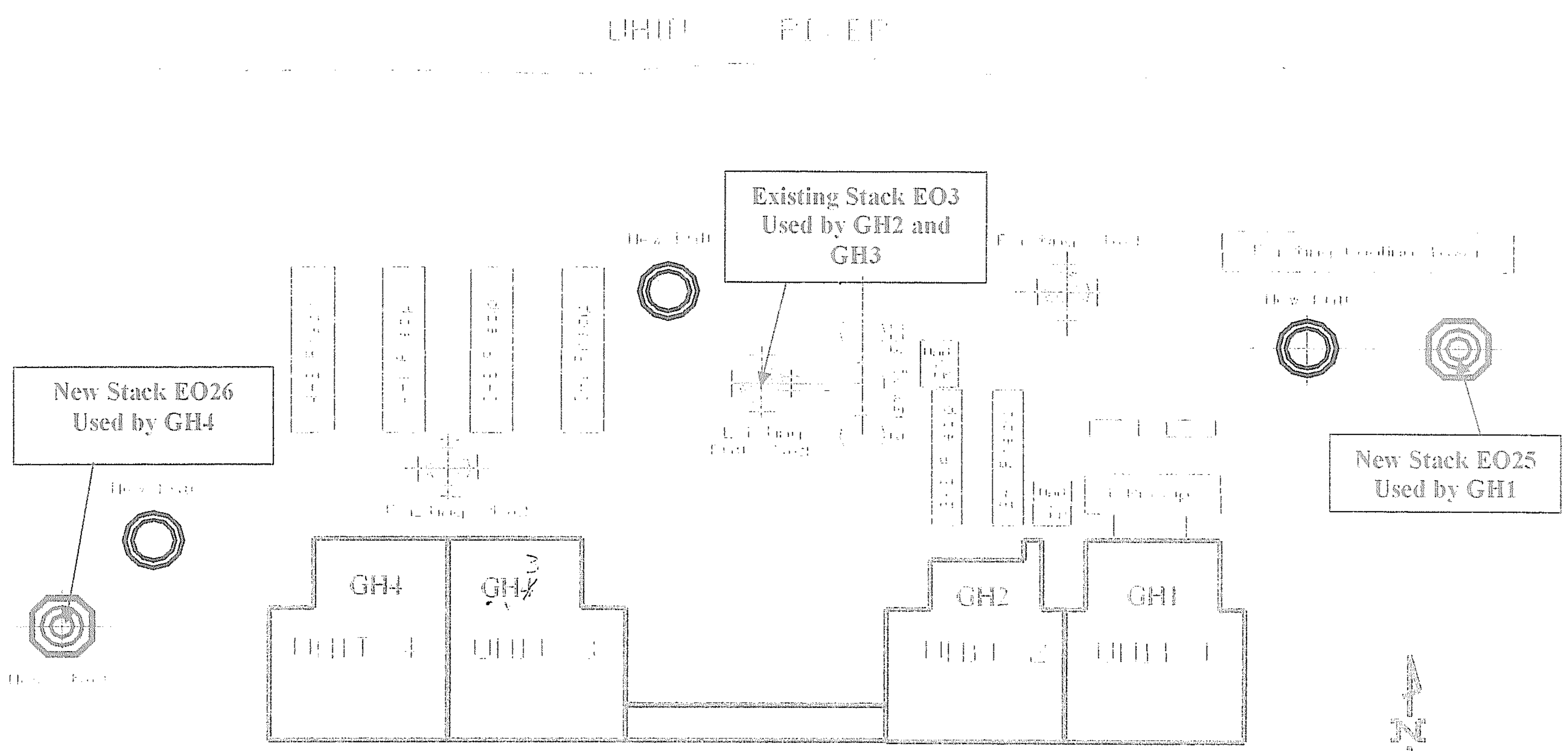
KDAQ subsequently advised KU in a letter dated February 15, 2005, that the application for the minor permit revision to "install three wet flue gas desulfurization ("WFGD") units" was considered complete, that the project "will be processed as a minor permit revision" and may begin construction upon the submittal of a complete application. On March 9, 2005, KU filed in Case No. 2004-00426, a copy of the KDAQ letter as a supplemental response to Question No. 4 of the Commission's 1st Data Request.

Thus, the duct work between the units and the scrubbers described on page 1 of 42 of the Sargent & Lundy Study was documented in Case No. 2004-00426. This design more effectively utilizes the available real estate and minimizes the operational difficulties associated with other footprint arrangements.

b. KU does not believe an amendment to the already issued Certificate of Public Convenience and Necessity for Ghent Unit 2 FGD in Case No. 2004-00426 is necessary because, as shown in the Response to 8(a), the construction of the scrubbers at the Ghent Power Station is consistent with KU's plans and evidence in the record in Case No. 2004-000426. KU does not believe a new Certificate of Public Convenience and Necessity for Ghent Unit 1 or its scrubber is necessary because public convenience and necessity requiring these facilities and the function of those facilities has not changed. KU will, however, if ordered to do so by this Commission, request an amendment to the Certificate of Public Convenience and Necessity granted for Ghent Unit No. 1 in Case No. 1992-00005 in a separate filing.

c. Construction on all FGD projects associated with Case No. 2004-00426 has taken place. The pictures and brief descriptions in the attachment to this response document construction that has taken place in regard to the FGDs at Ghent. Additionally, effective June 15, 2005, KU entered into an Alliance Agreement with Fluor Enterprises, Inc. to install the WFGD systems at both Ghent and Brown. The value of this agreement is approximately $600 million. Fluor worked with KU to bid, on a lump sum basis, the design for the WFGD's and Babcock Power Environmental, Inc. (BPEI), a subcontractor of Fluor, was the successful bidder.

FIGURE 2
FINAL CONFIGURATION OF EXISTING and PROPOSED STACKS
for the
GHENT GENERATING STATION

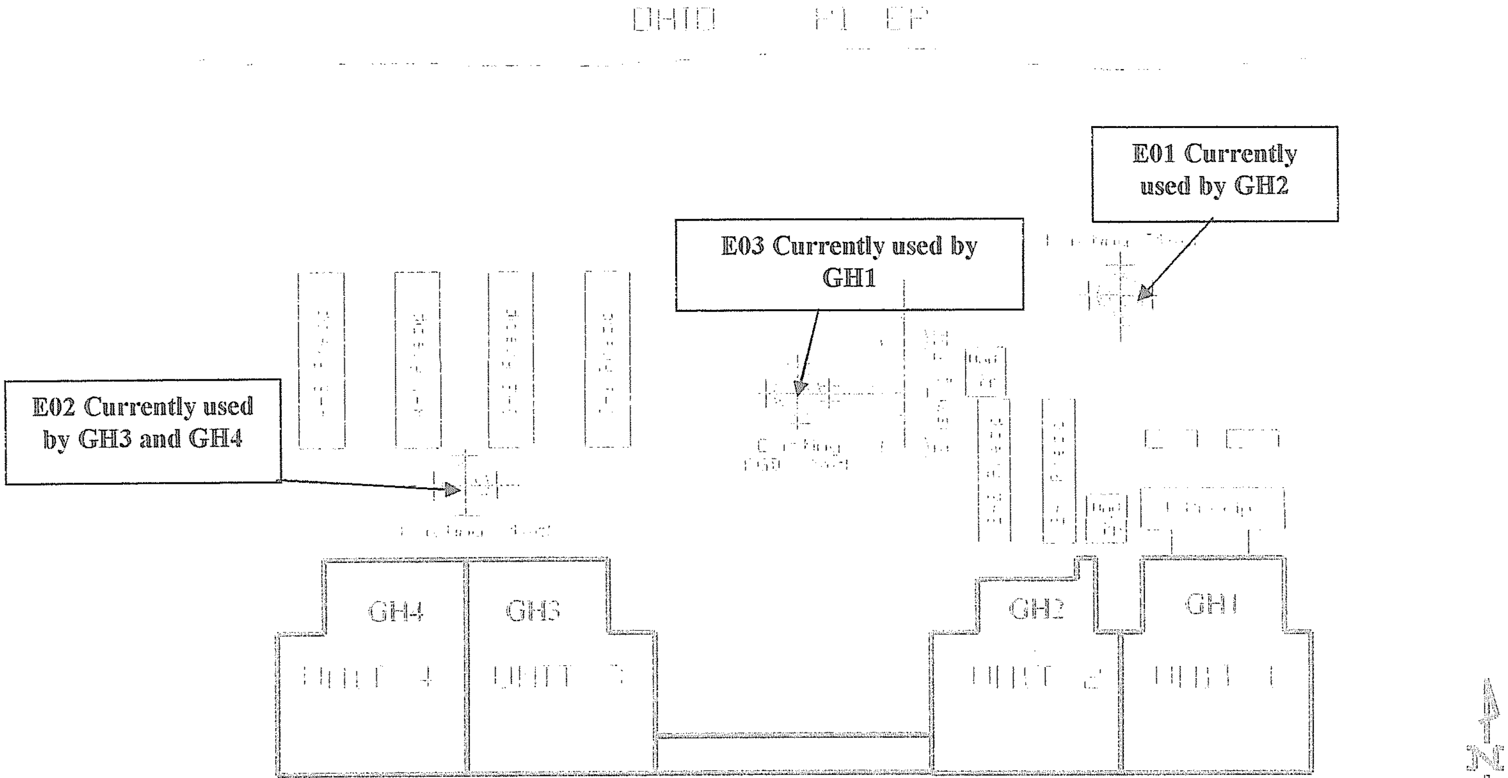


LEGEND
The new stacks and stack configuration are presented in Green.
The new FGDs are presented in Red.
Existing equipment is presented in Black.

GH1 = Unit 1 Boiler
GH2 = Unit 2 Boiler
GH3 = Unit 3 Boiler
GH4 = Unit 4 Boiler

E01 = Existing Stack 1
E02 = Existing Stack 2
E03 = Existing Stack 3
E025 = New Stack
E026 = New Stack

FIGURE 1
EXISTING STACK CONFIGURATION
for the
GHENT GENERATING STATION

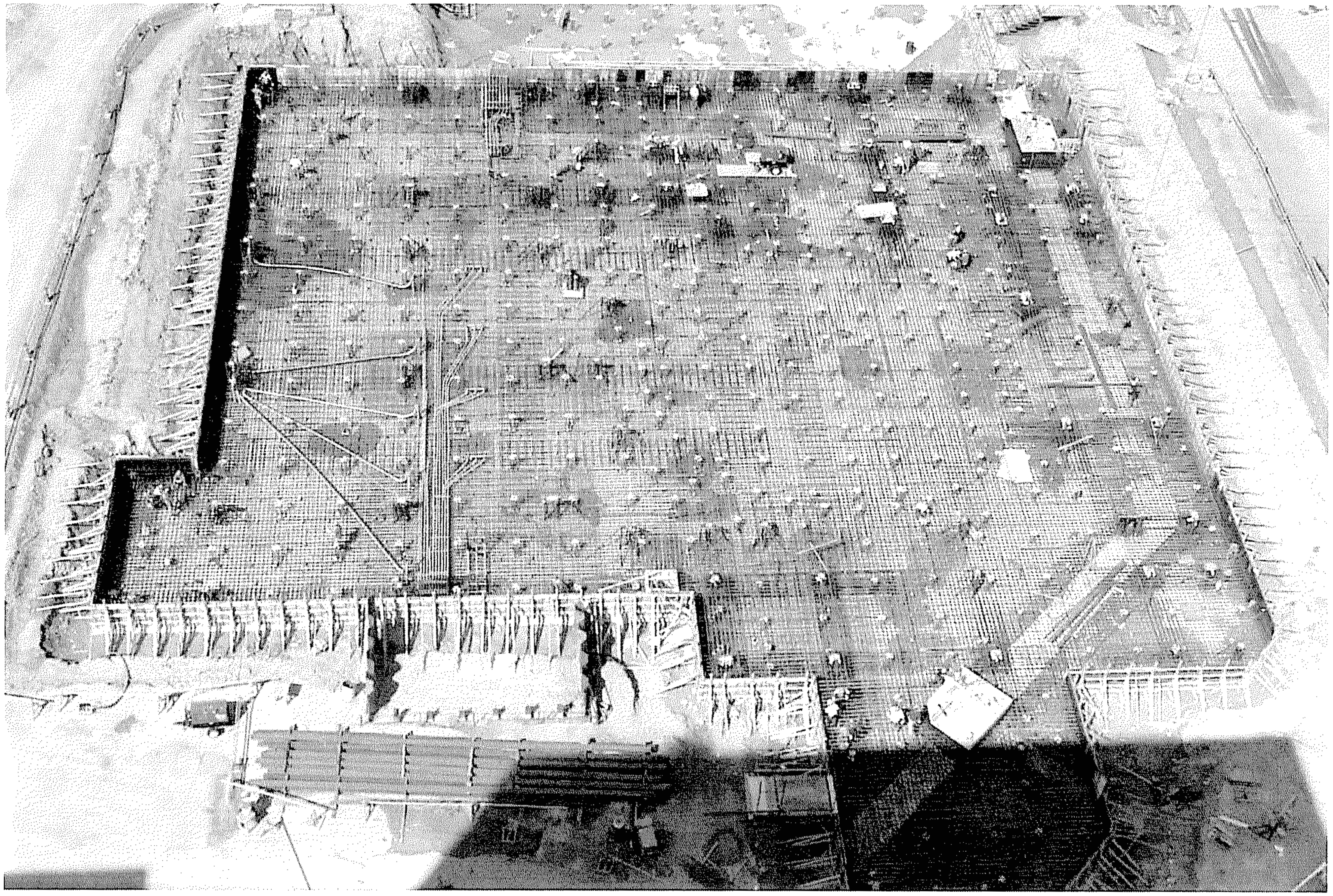


GH1 = Unit 1 Boiler
GH2 = Unit 2 Boiler
GH3 = Unit 3 Boiler
GH4 = Unit 4 Boiler

E01 = Existing Stack 1
E02 = Existing Stack 2
E03 = Existing Stack 3

Ghent 3 WFGD Absorber: Height – 85 ft. / Final Height 105ft.

Ghent 4 WFGD Absorber: Poured July, 2006 – 5,690 cubic yards



Ghent FGD Common Warehouse: Completed July, 2006

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 9

Responding Witness: John P. Malloy

Q-9. Refer to the Malloy Testimony, Exhibit JPM-4.

a. On pages 24 through 28 of 42 of the Sargent & Lundy Study is a risk assessment of the various SO_3 mitigation technologies. The risk assessment notes that sorbent injection technologies have the risk of producing deposits in the ductwork, the air preheater, and on turning vanes and internal struts and bracing, as well as process scale-up risk. Explain in detail how these risks were quantified in the present value revenue requirements ("PVRR") analysis of SO_3 mitigation technologies.

b. On page 38 of 42 of the Sargent & Lundy Study is the statement that KU has agreed to prepare a life cycle cost analysis based on data presented in the study. Provide copies of this life cycle cost analysis. If the analysis has not been prepared, explain in detail why not.

A-9. a. On page 29 of 42 of the referenced report, S&L provides a summary table of the risk levels associated with all aspects of each technology. The overall risk assessment is identified in table 4-1 below.

Table 4-1: Risk Assessment Summary

Technology	Capital Cost	O&M Cost	Performance	Reliability	Overall
Alkaline Additives on Coal Belt	Low	Low	High	Low	High
Ammonia	Low	Low	High	Low	High
Humidification	Low	Low	High	Medium	High
Hydrated Lime	Low	Medium	Medium	Medium	Medium
Magnesium Hydroxide	Medium	Medium	Medium	Medium	Medium
Magnesium Oxide	Medium	Medium	High	Medium	High
Micronized Limestone	High	Medium	High	Medium	High
Sodium Bisulfite (SBS)	Low	Medium	Low	Medium	Low to Medium
Soda Ash	Low	Medium	Low	Medium	Low to Medium
Trona	Low	High	Low	Medium	Low to Medium
Vertical Wet ESP	High	Medium	Low	Medium	High
Horizontal Wet ESP	High	Medium	Low	Medium	High
Low Conversion Catalyst	Low	Low	Low	Low	Low

This risk assessment determined the feasibility of each technology's ability to obtain the SO_3 emission target of <5ppm. As a result of the full evaluation, only technologies with "low", "low to medium" or "medium" overall risk are recommended. To minimize scale-up risks and the risk of deposit buildup as a result of sorbent injection, the injection system will be designed using Computational Fluid Dynamics ("CFD") analysis. (CFD is a sophisticated computationally-based design and analysis technique. CFD software has the capability to simulate flows of gases and liquids, heat and mass transfer, moving particles, multiphase physics, chemical reaction, fluid-structure interaction and acoustics through computer modeling, thereby producing a thorough analysis of likely operational parameters.)

The balance of deposits is typically controllable by soot blowers or acoustic horns and the cost of this equipment is within the contingency of the capital cost estimate developed by S&L. No additional quantification of these risks was included in the PVRR.

b. An electronic copy of the spreadsheet used in determining the minimum PVRR associated with each of the SO_3 mitigation technologies is being provided on CD.

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 10

Responding Witness: John P. Malloy

Q-10. Refer to the Malloy Testimony, Exhibit JPM-5, the 2006 SO_3 Mitigation Strategy. On pages 26 and 27 of 42 in the Sargent & Lundy Study, the risk assessment has the following statements concerning hydrated lime and Trona:

> Hydrated Lime: The data presented in the literature for this technology is old, and full scale results from any utility are not documented to serve as the basis for performance estimates. The dry sorbent storage and delivery system is subject to moisture, plugging and erosion problems. The effectiveness of the hydrated lime sorbent depends on high surface area, which varies between lime sources. Fly ash resistivity increases may result in ESP performance degradation.
>
> * * * * *
>
> Trona (Sodium sesquicarbonate): Trona is an expensive reagent with a long shipping distance from Green River, Wyoming and has been limited by transportation availability at Zimmer Station. Typically shipped by rail, the Trona would have to be transferred to trucks as a centrally located storage and transfer facility. In addition, there is currently only one source of supply. AEP has applied for a patent for this technology, so a licensing fee may apply.

The Executive Summary of the 2006 SO_3 Mitigation Strategy, page 3, recommends that KU proceed with testing of hydrated lime and Trona at Ghent Unit 1 and that hydrated lime and Trona be tested at Ghent Units 3 and 4 while burning high sulfur coal. Given the risks identified in the Sargent & Lundy Study, explain in detail why this recommendation was considered to be reasonable.

A-10. Technology for particle sizing and porosity sizing of dry chemicals is developing rapidly, and as a result new hydrated lime products are being introduced to the market that allow lower stoichiometric ratios (lower sorbent flow rates) for the same SO_3 reduction. To the extent that desired emission reduction can be achieved with less sorbent injection, variable O&M expense will decrease. The Company tested the Trona and improved hydrated lime product successfully and confirmed the sorbent injection technology's ability to meet the desired SO_3 emission level of approximately 5 ppm. The sorbent injection system design will mitigate the material handling risks described by S&L. The sorbent was successfully injected in a dual point configuration before and after the ESP to minimize potential ESP performance degradation. Trona and improved hydrated lime are both dry sorbents and require the same injection equipment. The Company chose to test improved hydrated lime and Trona to confirm the effectiveness of both. By having two possible sorbent materials the Company will build in supplier flexibility, further mitigating exposure to material cost fluctuation.

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CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 11

Responding Witness: John P. Malloy

Q-11. Refer to the Malloy Testimony, Exhibit JPM-5. In both the executive summary and recommendation sections of the 2006 SO_3 Mitigation Strategy it is stated that KU should proceed with the "testing" of different types of sorbent injection options. The recommendation for testing could imply that a final course of action has not been selected.

a. Why does the 2006 SO_3 Mitigation Strategy recommend further testing rather than proposing a final course of action?

b. Given the discussion contained in the 2006 SO_3 Mitigation Strategy, explain in detail how this report supports the statements on page 20 of the Malloy Testimony, lines 3 through 9, that the use of sorbent injection technology is the least cost alternative to mitigate SO_3 emissions.

A-11. a. Further testing was required to: (1) determine the effectiveness of currently available hydrated lime products which claim improved performance and efficiency and reduced cost, (2) evaluate the impact of sorbent injection on ESP performance, and (3) evaluate the most effective sorbent injection location. Testing of the Trona material was required to confirm the viability of Trona as an alternative sorbent to allow system flexibility and hedge sorbent supply issues. The Companies have completed testing of dry sorbent injection at Ghent Unit 1 and Trimble Unit 1. Test results confirm through SO_3 emissions testing and comparison with visual observations using USEPA Method 9, that the sorbent injection technology will successfully meet the desired SO_3 emission level of approximately 5 ppm. These test results are applicable across the fleet for units with cold-side ESPs (Trimble 1, Ghent 1, Mill Creek 3 and 4). Dry sorbent injection is the Companies' selected course forward as presented in the PVRR analysis and the table below.

Unit	Selected SO_3 Removal Technology
Ghent 1	Dry Sorbent Injection
Ghent 3	Dry Sorbent Injection + Low Conversion Catalyst + Boiler Sorbent Injection
Ghent 4	Dry Sorbent Injection + Low Conversion Catalyst + Boiler Sorbent Injection
Mill Creek 3	Dry Sorbent Injection
Mill Creek 4	Dry Sorbent Injection
Trimble County 1	Dry Sorbent Injection

b. If the SCRs are to stay in service in absence of wet electrostatic precipitators (wet ESP) then effective SO_3 control (defined on page 4 of 42 of the S&L study as achieving an SO_3 target of 5ppm) is necessary. Should the targeted levels of SO_3 control not be achieved and visible plume problems occur, then under certain operating conditions, either the SCR must be taken out of service or the generation unit removed from service. The operation of the SCRs is necessary for continued economic compliance with environmental regulations. Thus, the Companies' strategy is to control SO_3 and to allow continued operation of units with SCRs; and as Table III-KU on page 8 of Exhibit JPM-5 indicates, the least cost approach to SO_3 control includes sorbent injection and not construction of a wet ESP.

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 12

Responding Witness: John P. Malloy

Q-12. Refer to the Malloy Testimony, Exhibit JPM-5, page 7. Table II on this page lists the viability of combination technologies.

a. Were the various combination technologies shown on this page evaluated using a PVRR analysis?

b. If yes to part (a), provide the results of the PVRR analysis for each combination technology evaluated.

c. If no to part (a), explain why a PVRR analysis was not performed and how the viability of the combination technologies was determined.

A-12. a. Yes, all appropriate combinations were evaluated in the PVRR analysis.

b. The results of the PVRR analysis are shown on the attachment. Summarized results are provided in Table III-KU, on page 8 of Exhibit JPM-5

c. Not applicable.

SO_3 Mitigation Cost for Technologies located at Ghent 1

	Hydrated Lime	Sodium BiSulfite	Trona	Soda Ash	Wet ESP (Vertical)	Wet ESP (Horizontal)	Magnesium Hydroxide + Hydrated Lime	Magnesium Hydroxide + Trona	Magnesium Hydroxide + Sodium BiSulfite	Magnesium Hydroxide + Soda Ash	LCC + Sodium BiSulfite	LCC + Hyd Lime	LCC + Trona	LCC + Soda Ash
2007	1.84	1.77	2.68	1.16	9.39	7.60	2.93	3.48	3.00	2.53	2.03	1.88	2.27	1.63
2008	2.13	2.15	2.99	1.45	12.67	10.23	3.60	4.17	3.78	3.21	2.63	2.38	2.78	2.14
2009	3.85	3.28	5.99	2.01	12.76	10.42	5.30	6.71	5.10	4.17	3.15	3.13	4.15	2.40
2010	3.90	3.28	6.10	1.99	12.27	10.03	5.29	6.74	5.06	4.12	3.08	3.10	4.15	2.33
2011	3.95	3.28	6.22	1.98	11.78	9.65	5.28	6.78	5.01	4.07	3.02	3.07	4.15	2.27
2012	4.01	3.30	6.35	1.98	11.37	9.33	5.29	6.83	4.99	4.03	2.97	3.05	4.16	2.22
2013	4.07	3.31	6.48	1.97	10.96	9.00	5.30	6.89	4.97	4.00	2.92	3.03	4.18	2.17
2014	4.14	3.33	6.62	1.97	10.54	8.68	5.31	6.96	4.95	3.97	2.88	3.01	4.19	2.12
2015	4.21	3.35	6.76	1.96	10.13	8.36	5.33	7.03	4.93	3.94	2.83	2.99	4.21	2.07
2016	4.28	3.38	6.91	1.96	9.73	8.04	5.35	7.10	4.91	3.91	2.79	2.98	4.23	2.02
2017	4.35	3.40	7.07	1.96	9.32	7.72	5.38	7.18	4.90	3.89	2.75	2.96	4.26	1.97
2018	4.43	3.43	7.23	1.96	8.91	7.40	5.41	7.26	4.89	3.87	2.70	2.95	4.29	1.92
2019	4.51	3.45	7.39	1.96	8.51	7.08	5.44	7.35	4.88	3.85	2.66	2.94	4.32	1.87
2020	4.60	3.49	7.57	1.97	8.10	6.77	5.47	7.44	4.88	3.83	2.62	2.93	4.35	1.82
2021	4.69	3.52	7.75	1.97	7.70	6.45	5.51	7.54	4.88	3.81	2.58	2.92	4.38	1.78
2022	4.78	3.56	7.93	1.98	7.30	6.14	5.55	7.64	4.88	3.80	2.55	2.92	4.42	1.73
2023	4.88	3.59	8.12	1.98	6.89	5.83	5.60	7.75	4.89	3.78	2.51	2.91	4.46	1.69
2024	4.98	3.63	8.32	1.99	6.50	5.52	5.65	7.86	4.89	3.77	2.48	2.91	4.51	1.64
2025	5.08	3.68	8.52	2.00	6.10	5.21	5.70	7.99	4.90	3.77	2.44	2.91	4.56	1.60
2026	5.19	3.73	8.74	2.01	5.70	4.90	5.76	8.11	4.92	3.76	2.41	2.91	4.61	1.56
	======	======	======	======	======	======	======	======	======	======	======	======	======	======
PVRR (M$)	41.45	33.56	66.14	19.88	108.54	89.26	53.58	69.93	50.03	40.24	29.29	30.46	42.26	21.62
Rank	7	5	11	1	14	13	10	12	9	6	3	4	8	2

SO_3 Mitigation Cost for Technologies located at Ghent 3

	Wet ESP (Vertical)	Wet ESP (Horizontal)	LCC + Mag Hyd+ Hyd Lime	LCC + Mag Hyd+ Sodium BiSulfite	LCC + Mag Hyd+ Trona	LCC + Mag Hyd+ Soda Ash
2007	9.39	7.28	3.04	3.17	3.15	3.11
2008	12.66	9.79	3.93	4.12	4.03	4.06
2009	12.77	10.02	4.76	4.90	5.12	4.73
2010	12.29	9.66	4.67	4.80	5.04	4.62
2011	11.80	9.29	4.58	4.70	4.97	4.52
2012	11.39	8.99	4.51	4.62	4.92	4.44
2013	10.98	8.68	4.45	4.55	4.87	4.35
2014	10.57	8.38	4.38	4.47	4.82	4.27
2015	10.16	8.07	4.32	4.40	4.78	4.19
2016	9.76	7.77	4.26	4.33	4.73	4.12
2017	9.35	7.47	4.20	4.26	4.69	4.04
2018	8.95	7.17	4.15	4.19	4.65	3.97
2019	8.54	6.87	4.09	4.13	4.62	3.89
2020	8.14	6.57	4.04	4.06	4.58	3.82
2021	7.74	6.28	3.99	4.00	4.55	3.75
2022	7.34	5.98	3.94	3.94	4.53	3.68
2023	6.94	5.69	3.89	3.88	4.50	3.62
2024	6.55	5.40	3.84	3.82	4.48	3.55
2025	6.15	5.11	3.80	3.77	4.46	3.49
2026	5.76	4.82	3.76	3.72	4.44	3.43
	======	======	======	======	======	======
PVRR (M$)	108.79	86.12	44.59	45.55	48.92	43.56
Rank	6	5	2	3	4	1

SO_3 Mitigation Cost for Technologies located at Ghent 4

	Wet ESP (Veritcal)	Wet ESP (Horizontal)	LCC + Mag Hyd+ Hyd Lime	LCC + Mag Hyd+ Sodium BiSulfite	LCC + Mag Hyd+ Trona	LCC + Mag Hyd+ Soda Ash
2007						
2008	9.85	7.50	3.10	3.26	3.25	3.18
2009	13.91	10.70	4.96	5.15	5.35	4.96
2010	13.40	10.32	4.86	5.04	5.27	4.85
2011	12.89	9.95	4.77	4.94	5.20	4.74
2012	12.38	9.57	4.68	4.83	5.12	4.63
2013	11.95	9.26	4.62	4.76	5.07	4.55
2014	11.51	8.94	4.55	4.68	5.02	4.46
2015	11.08	8.63	4.48	4.60	4.97	4.38
2016	10.65	8.32	4.42	4.53	4.92	4.30
2017	10.23	8.00	4.36	4.45	4.88	4.22
2018	9.80	7.69	4.30	4.38	4.84	4.15
2019	9.37	7.39	4.24	4.31	4.80	4.07
2020	8.95	7.08	4.19	4.24	4.76	4.00
2021	8.53	6.77	4.14	4.18	4.73	3.92
2022	8.10	6.47	4.08	4.11	4.69	3.85
2023	7.68	6.16	4.03	4.05	4.66	3.78
2024	7.26	5.86	3.99	3.99	4.64	3.72
2025	6.85	5.56	3.94	3.93	4.61	3.65
2026	6.43	5.26	3.90	3.88	4.59	3.59
	======	======	======	======	======	======
PVRR (M$)	113.22	88.10	45.57	46.77	50.45	44.57
Rank	6	5	2	3	4	1

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 13

Responding Witness: John P. Malloy

Q-13. Refer to the Malloy Testimony, Exhibit JPM-5, pages 8 and 10.

a. Provide all workpapers, calculations, assumptions and other documentation supporting the PVRR values presented in the charts on page 8. In addition, explain why the PVRR analyses were not provided along with Exhibit JPM-5.

b. Explain in detail why a combination technology of hydrated lime and Trona was not included in the option ranking shown on page 8.

c. On pages 26 and 27 of 42 in the Sargent & Lundy Study, the risk assessment has the following statements concerning sodium bisulfite and soda ash:

> Sodium Bisulfite: In addition to the proprietary technology, single source of supply, the yearly licensing fee, and the reagent (sodium bisulfite powder) delivered cost, the major drawback of this technology is O&M cost. The cost of the project installed at Gibson Station increased significantly from start to finish. While byproduct SBS is a less costly sorbent, Vectren may not continue to produce the material.
>
> * * * * *
>
> Soda Ash: In addition to the proprietary technology, this sorbent injection technology requires longer duct residence time due to the multiple reactions which need to take place and does not have the experience level of SBS. Injection of soda ash upstream of the air preheater is not feasible for the LG&E/KU plants due to residence time requirements.

Given these concerns, explain in detail how it was concluded in the 2006 SO_3 Mitigation Strategy, on page 10, that soda ash and sodium bisulfite are the top sorbent options.

A-13. a. Please see the response to Question No. 9b. The complete analysis should have been provided as an appendix to Exhibit JPM-5 but was inadvertently omitted.

b. The combination of hydrated lime and Trona injection was proposed to mitigate potential ESP degradation. Ghent Unit 1 test results demonstrated the most effective sorbent injection configuration is a dual point injection of a single dry sorbent before and after the ESP. Thus, injection of two different sorbents is not necessary nor is it economically viable in relation to other post ESP single injection point systems for cold-side ESP units.

c. All of the SO_3 mitigation technologies come with some level of engineering and operational risk. The overall risk assessment for injection of soda ash or sodium bisulfite ("SBS") is low to medium, while the overall risk assessment for injection of hydrated lime is medium. Please see Table 4-1: Risk Assessment Summary, from the S&L report, provided below. Soda ash has the same chemical reaction process as SBS, but requires more residence time (i.e. time for the flue gas and sorbent to mix and react) and therefore cannot be injected upstream of the air preheater due to the physical arrangement of the ductwork. However, soda ash can be injected downstream of the air preheater where longer ductwork allows for adequate residence time. These technologies demonstrated the lowest evaluated costs when using the S&L cost estimates. Improvements in hydrated lime quality will reduce the cost of this technology and it is therefore the technology of choice.

Table 4-1: Risk Assessment Summary

Technology	Capital Cost	O&M Cost	Performance	Reliability	Overall
Alkaline Additives on Coal Belt	Low	Low	High	Low	High
Ammonia	Low	Low	High	Low	High
Humidification	Low	Low	High	Medium	High
Hydrated Lime	Low	Medium	Medium	Medium	Medium
Magnesium Hydroxide	Medium	Medium	Medium	Medium	Medium
Magnesium Oxide	Medium	Medium	High	Medium	High
Micronized Limestone	High	Medium	High	Medium	High
Sodium Bisulfite (SBS)	Low	Medium	Low	Medium	Low to Medium
Soda Ash	Low	Medium	Low	Medium	Low to Medium
Trona	Low	High	Low	Medium	Low to Medium
Vertical Wet ESP	High	Medium	Low	Medium	High
Horizontal Wet ESP	High	Medium	Low	Medium	High
Low Conversion Catalyst	Low	Low	Low	Low	Low

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 14

Responding Witness: John P. Malloy

Q-14. Has KU made a final determination of exactly what SO_3 mitigation approach should be installed at Ghent Units 1, 3, and 4? Explain the response.

A-14. KU plans to install dry sorbent injection at Ghent 1, and a combination of dry sorbent injection, sorbent injection in the boiler, plus low conversion catalyst replacement at Ghent 3 and 4 (due to the hot-side ESP configuration), per the table below. Catalyst purchased in 2005/2006 for Ghent 1 is low conversion type, and all new catalyst purchased per the Companies' current Catalyst Management Plan will be low SO_2 to SO_3 conversion type catalyst.

Unit	**Selected SO_3 Removal Technology**
Ghent 1	Dry Sorbent Injection
Ghent 3	Dry Sorbent Injection + Low Conversion Catalyst + Boiler Sorbent Injection
Ghent 4	Dry Sorbent Injection + Low Conversion Catalyst + Boiler Sorbent Injection
Mill Creek 3	Dry Sorbent Injection
Mill Creek 4	Dry Sorbent Injection
Trimble County 1	Dry Sorbent Injection

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 15

Responding Witness: Kent W. Blake / Shannon L. Charnas / John P. Malloy / Robert M. Conroy

Q-15. Refer to the Direct Testimony of Shannon L. Charnas, page 4. Explain in detail why KU is not seeking to include O&M expenses associated with the pollution control equipment to be installed at Trimble County Unit 2 and the electrostatic precipitators to be installed at Brown.

A-15. <u>Trimble County Unit 2:</u> With regard to O&M expenses associated with the pollution control equipment to be installed at Trimble County Unit 2, the Company did not include estimates of such expenses in its application as such expenses would not be incurred until Trimble County Unit 2 is placed in service in 2010. The Company expected that such amounts would be considered in a future proceeding under KRS 278.183 or KRS 278.190.

However, the Company believes it would be appropriate to include O&M expenses associated with the Air Quality Control System ("AQCS") at Trimble County Unit 2 as part of its 2006 Environmental Compliance Plan, provided such inclusion does not impact the Commission's ability to issue an Order in this case by December 22, 2006. The Companies' environmental compliance with CAIR will be adversely impacted by any delay in the Commission's issuance of an Order approving KU's requested CCN.

Therefore, the Company respectfully requests that this Commission consider the O&M expenses associated with Project Number 23 in connection with its decision on the Company's application in this proceeding. In the event the Commission decides not to consider these expenses in this proceeding, the Company reserves the right to seek recovery of these expenses in a subsequent filing under KRS 278.183 or KRS 278.190.

Based on the variable O&M expense estimates contained in the evaluation for Trimble County Unit 2 (Case No. 2004-00507) the Companies estimate that KU's portion of the variable O&M expense associated with the Trimble County Unit 2 AQCS for the first full year of operation (2011) will be approximately $4.5 million. The incremental bill impact on a residential customer using 1,000-killowatt hours per month for the first full year of operation for Trimble County

Unit 2 in 2011 is $0.21. The total monthly impact for the 2006 Plan, inclusive of O&M expenses for Project 23, is estimated to be $2.75 in 2011 as detailed in Attachment 2 to Response to Question No. 18(a).

Attachment 1 to this response presents the estimated variable operations and maintenance expenses associated the AQCS on Trimble County Unit 2. Estimated O&M expenses were initially presented to the Commission in response to Staff Initial Data Request, Question No. 20 in Case No. 2004-00507, the Companies' Application for a Certificate of Public Convenience and Necessity and A Site Compatibility Certificate For the Expansion of the Trimble County Generating Station. Attachment 1 explains how the original estimate of O&M expenses was revised to reflect expected operating conditions.

KU will use the following accounts to report appropriate O&M expenses for Trimble County Unit 2 AQCS systems:

502006	Scrubber Operations
512005	Scrubber Maintenance
506001	Electrostatic precipitator operations expense
512011	Electrostatic precipitator maintenance expense
501251	Ash handling operations expense
512017	Ash handling maintenance expense
506104	NOx Operation – Consumables
506105	NOx Operation – Labor and Other
512101	NOx Maintenance
506109	Sorbent Injection Operation
512102	Sorbent Injection Maintenance
506110	Mercury Monitors Operation
512103	Mercury Monitors Maintenance

Attachment 2 to this response presents KU's revised ES Form 2.50 as well as the original ES Form 2.50, which will be used to report monthly O&M expenses for all approved projects in the 2006 Amended Compliance Plan as well as in earlier approved compliance plans. Individual unit expenses will be tracked by location code as discussed on page 3 of Ms. Charnas' testimony.

<u>E. W. Brown Precipitators:</u> No incremental O&M expenses are anticipated for the work associated with the existing electrostatic precipitators at E.W. Brown Station.

Louisville Gas and Electric Company
Kentucky Utilities Company
Trimble County 2

Modification to Burns & McDonnell Fixed and Variable O&M

(All Input Costs are in 2002 Year $)

		Units	
Net Output	(0)	(kW)	750,000
Original Fixed O&M Annual Cost	(1)	($)	2,685,000
Original Non-Fuel Variable O&M	(2)	($)	11,705,000
Other VO&M (Included in Original Non-Fuel VOM)	(3)	($)	6,625,000
New Total Non-Fuel Variable O&M	(4)=(2)-(3)	($)	5,080,000
SCR Ammonia & Replacements	(5)	($)	500,000
New Total Fixed O&M	(6)=(1)+(3)	($)	9,310,000
2004 New LG&E Total Fixed O&M	(7)=(6)*75%*1.02^2	($)	7,264,593
2004 New LG&E Total Variable O&M	(8)=(4)*75%*1.02^2	($)	3,963,924

Annual O&M esc = 2%

Modification to Burns & McConnell Fixed and Variable O&M

(All Input Costs are in 2002 Year $)

		Units	
Net Output	(0)	(kW)	750,000
Original Fixed O&M Annual Cost	(1)	($)	2,685,000
Original Non-Fuel Variable O&M	(2)	($)	11,705,000
Other VO&M (Included in Original Non-Fuel VOM)	(3)	($)	6,625,000
New Total Non-Fuel Variable O&M	(4)=(2)-(3)	($)	5,080,000
SCR Ammonia & Replacements	(5)	($)	500,000
New Total Fixed O&M	(6)=(1)+(3)	($)	9,310,000
2004 New LG&E Total Fixed O&M	(7)=(6)*75%*1 02^2	($)	7,264,593
2004 New LG&E Total Variable O&M	(8)=(4)*75%*1 02^2	($)	3,963,924

Annual O&M esc = 2%

Net LG&E/KU Generation at an 80% Capacity Factor	(9)=(0)*75%*8760*80%/1000	MWh	3,942,000
2004 Annual LG&E Variable O&M without SCR O&M	(10)=(8)-(5)*75%*1 02^2	($)	3,573,774
2004 Non-Ozone Season LG&E Variable O&M	(11)=(10)/(9)	$/MWh	0.90
2004 Ozone Season LG&E Variable O&M Adder	(12)=[(5)*75%*1 02^2]/[(9)*5/12	$/MWh	0.24

Model LG&E/KU Generation Output at 93% Availability				(a) Ozone	(b) Non-Ozone	(c) Total
	2010	(13)	MWh	1,383,100	1,132,870	2,515,970
	2011	(14)	MWh	1,712,900	2,568,110	4,281,010
	2012	(15)	MWh	1,724,790	2,600,860	4,325,650

Model LG&E/KU Variable O&M in Nominal Year Dollars				(a) Ozone	(b) Non-Ozone	(c) Total
	2010	Ozone: (16)=[(11)+(12)]*(13a)	($)	1,775,659	1,148,216	2,923,875
	2011	Non-Ozone: (17)=(11)*(14b)	($)	2,243,045	2,654,956	4,898,001
	2012		($)	2,303,788	2,742,590	5,046,377

LG&E/KU Variable O&M in Nominal Year Dollars with Annual SCR Operation					LG&E	KU
	2010	(18)=(13c)*[(11)+(12)]*1 02^6	($)	3,230,066	613,712	2,616,353
	2011	(19)=(14c)*[(11)+(12)]*1 02^7	($)	5,605,990	1,065,138	4,540,852
	2012	(20)=(15c)*[(11)+(12)]*1 02^8	($)	5,777,735	1,097,770	4,679,965

Notes:

This is a modified version of the attachment to PSC-20 (Page 2 of 2) of the Response to Commission Staff's 1st Data Request dated 2/10/05 Volume 1 in Case No. 2004-00507 (TC2 CCN)

Model generation and variable O&M are taken from TC2 CCN filing

CAIR was not finalized at the time the TC2 CCN analysis was being performed; therefore annual SCR operation was not modeled.

The above costs are estimates and actual expenses recovered through the ECR mechanism may vary depending on unit run time and consumable costs

ES FORM 2.50
Original Proposed

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses
For the Month Ended:

O&M Expense Account	E. W. Brown	Ghent	Green River	Tyrone	Total
2001 Plan					
506104 - NOx Operation -- Consumables					
506105 - NOx Operation -- Labor and Other					
512101 - NOx Maintenance					
Total 2001 Plan O&M Expenses					
2005 Plan					
502006 - Scrubber Operations					
512005 - Scrubber Maintenance					
Total 2005 Plan O&M Expenses					
2006 Plan					
506104 - NOx Operation -- Consumables					
506105 - NOx Operation -- Labor and Other					
512101 - NOx Maintenance					
506109 - Sorbent Injection Operation					
512102 - Sorbent Injection Maintenance					
506110 - Mercury Monitors Operation					
512103 - Mercury Monitors Maintenance					
Total 2006 Plan O&M Expenses					

Current Month O&M Expense for All Plans	

ES FORM 2.50
Revised Proposed

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses
For the Month Ended:

O&M Expense Account	E. W. Brown	Ghent	Green River	Trimble County Unit 2	Tyrone	Total
2001 Plan						
506104 - NOx Operation -- Consumables						
506105 - NOx Operation -- Labor and Other						
512101 - NOx Maintenance						
Total 2001 Plan O&M Expenses						
2005 Plan						
502006 - Scrubber Operations						
512005 - Scrubber Maintenance						
Total 2005 Plan O&M Expenses						
2006 Plan						
502006 - Scrubber Operations						
512005 - Scrubber Maintenance						
506001 - Preciptator Operation						
512011 - Preciptator Maintenance						
501251 - Ash Handling Operation						
512017 - Ash Handling Maintenance						
506104 - NOx Operation -- Consumables						
506105 - NOx Operation -- Labor and Other						
512101 - NOx Maintenance						
506109 - Sorbent Injection Operation						
512102 - Sorbent Injection Maintenance						
506110 - Mercury Monitors Operation						
512103 - Mercury Monitors Maintenance						
Total 2006 Plan O&M Expenses						

Current Month O&M Expense for All Plans	

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 16

Responding Witness: Robert M. Conroy

Q-16. Refer to the Direct Testimony of Robert M. Conroy ("Conroy Testimony"), pages 2 through 4. Provide ES Form 3.00 for the expense month of June 2006 and a version of ES Form 3.00 for the expense month of June 2006 reflecting KU's proposed changes in determining R(m).

A-16. Please see the attachments for the requested information.

As shown on the attached original and revised ES Form 3.00, the proposed change in the determination of R(m) results in a minor change in the jurisdictional allocation factor. Using the attached June 2006 data, KU's jurisdictional allocation factor increases slightly, from 80.81% as filed using current procedures to 81.20% using KU's proposed method. This increase of 39 basis points in the jurisdictional allocation factor increases Jurisdictional E(m) by $14,203, or 0.5% for the expense month of June 2006.

Thus, because the proposed change to the determination of R(m) will classify Merger Surcredit and Value Delivery Surcredit revenues as "Reconciling Revenues" on Proposed ES Form 3.10, Kentucky Retail Revenues for Environmental Surcharge Purposes and Total Company Revenues for Environmental Surcharge Purposes will increase. The increase in these two revenue totals will result in a slight increase in the jurisdictional allocation factor. Additionally, the increase in Kentucky Retail Revenues for Environmental Surcharge Purposes will result in a decrease to the monthly Jurisdictional Environmental Surcharge Billing Factor. The change will more closely align the revenues used to determine the billing factor and the revenues to which the billing factor is applied, reduce the variability of the monthly true-up and not cause any unwarranted over-collection of surcharge revenues.

However, to reflect the results of the analysis provided in this response, my testimony at page 3 line 18 through 21 should be revised to state as follows:

> There will be a de minimus impact to customers by changing the determination of R(m). While the proposed change to the determination of R(m) does slightly change the environmental costs that KU is authorized to collect

through the ECR billing factor, this result is the function of eliminating the impacts of the MSR and VDT rate schedules which were approved after the establishment of the ECR rate schedule.

ES FORM 3.00
Current

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Monthly Average Revenue Computation of R (m)

For the Month Ended June 30, 2006

	Kentucky Jurisdictional Revenues					Non-Jurisdictional Revenues	Total Company Revenues	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	Base Rate Revenues	Fuel Clause Revenues	Environmental Surcharge Revenues	Total (2)+(3)+(4)	Total Excluding Environmental Surcharge (5)-(4)	Total Including Off-System Sales (See Note 1)	Total (5)+(7)	Total Excluding Environmental Surcharge (8)-(4)
Jul-05	75,008,054.39	2,039,678.20	1,597,764.26	$ 78,645,496.85	$ 77,047,732.59	20,895,831.78	$ 99,541,328.63	$ 97,943,564.37
Aug-05	73,522,297.54	14,895,921.33	3,098,331.67	91,516,550.54	88,418,218.87	22,006,165.67	113,522,716.21	110,424,384.54
Sep-05	73,790,825.52	11,154,685.58	2,493,515.84	87,439,026.94	84,945,511.10	25,977,976.72	113,417,003.66	110,923,487.82
Oct-05	63,859,204.92	10,743,309.05	875,784.58	75,478,298.55	74,602,513.97	16,590,996.15	92,069,294.70	91,193,510.12
Nov-05	59,180,424.02	8,664,839.77	1,475,512.85	69,320,776.64	67,845,263.79	24,055,674.66	93,376,451.30	91,900,938.45
Dec-05	72,177,957.44	9,216,688.78	2,346,498.33	83,741,144.55	81,394,646.22	26,085,678.71	109,826,823.26	107,480,324.93
Jan-06	76,013,168.72	4,201,311.72	2,199,122.31	82,413,602.75	80,214,480.44	23,892,499.86	106,306,102.61	104,106,980.30
Feb-06	69,306,192.05	3,954,027.20	1,739,100.84	74,999,320.09	73,260,219.25	15,643,022.56	90,642,342.65	88,903,241.81
Mar-06	68,178,508.99	2,724,080.58	1,696,176.86	72,598,766.43	70,902,589.57	14,530,098.90	87,128,865.33	85,432,688.47
Apr-06	62,706,935.54	6,048,757.96	2,010,082.68	70,765,776.18	68,755,693.50	14,807,103.52	85,572,879.70	83,562,797.02
May-06	58,862,169.00	9,372,096.75	2,154,868.90	70,389,134.65	68,234,265.75	19,207,994.42	89,597,129.07	87,442,260.17
Jun-06	65,716,049.31	8,890,419.27	2,709,709.75	77,316,178.33	74,606,468.58	17,721,553.74	95,037,732.07	92,328,022.32
Average Monthly Jurisdictional Revenues, Excluding Environmental Surcharge, for 12 Months Ending Current Expense Month.					**$75,852,300.30**			
Jurisdictional Allocation Percentage for Current Month (Environmental Surcharge Excluded from Calculations): Expense Month Kentucky Jurisdictional Revenues Divided by Expense Month Total Company Revenues: Column (6) / Column (9) =								**80.81%**
						Note 1 - Excludes Brokered Sales, Total for Current Month =		$ 337,677.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Monthly Average Revenue Computation of R(m)

For the Month Ended: June 30, 2006

Kentucky Jurisdictional Revenues								Non-Jurisdictional Revenues	Total Company Revenues	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Month	Base Rate Revenues	Fuel Clause Revenues	DSM Revenues	STOD Program Cost Recovery Factor Revenues	Environmental Surcharge Revenues	Total (2)+(3)+(4)+(5)+(6)	Total Excluding Environmental Surcharge (7)-(6)	Total Including Off-System Sales (See Note 1)	Total (7)+(9)	Total Excluding Environmental Surcharge (10)-(6)
Jul-05	76,910,974.29	2,039,678.20	331,507.87	5,583.02	1,597,764.26	80,885,507.64	79,287,743.38	20,895,831.78	101,781,339.42	100,183,575.16
Aug-05	75,476,049.28	14,895,921.33	329,458.79	5,316.05	3,098,331.67	93,805,077.12	90,706,745.45	22,006,165.67	115,811,242.79	112,712,911.12
Sep-05	75,708,051.12	11,154,685.58	315,393.13	5,603.36	2,493,515.84	89,677,249.03	87,183,733.19	25,977,976.72	115,655,225.75	113,161,709.91
Oct-05	65,534,841.65	10,743,309.05	237,496.22	5,025.23	875,784.58	77,396,456.73	76,520,672.15	16,590,996.15	93,987,452.88	93,111,668.30
Nov-05	60,724,293.31	8,664,839.77	219,527.78	4,307.99	1,475,512.85	71,088,481.70	69,612,968.85	24,055,674.66	95,144,156.36	93,668,643.51
Dec-05	73,987,838.60	9,216,688.78	338,208.44	4,627.78	2,346,498.33	85,893,861.93	83,547,363.60	26,085,678.71	111,979,540.64	109,633,042.31
Jan-06	77,804,454.19	4,201,311.72	352,777.64	4,658.93	2,199,122.31	84,562,324.79	82,363,202.48	23,892,499.86	108,454,824.65	106,255,702.34
Feb-06	70,699,987.00	3,954,027.20	303,363.28	4,276.91	1,739,100.84	76,700,755.23	74,961,654.39	15,643,022.56	92,343,777.79	90,604,676.95
Mar-06	69,509,012.03	2,724,080.58	285,154.81	29,925.76	1,696,176.86	74,244,350.04	72,548,173.18	14,530,098.90	88,774,448.94	87,078,272.08
Apr-06	64,161,554.14	6,048,757.96	281,253.39	29,953.18	2,010,082.68	72,531,601.35	70,521,518.67	14,807,103.52	87,338,704.87	85,328,622.19
May-06	60,338,319.97	9,372,096.75	232,308.14	31,580.70	2,154,868.90	72,129,174.46	69,974,305.56	19,207,994.42	91,337,168.88	89,182,299.98
Jun-06	67,350,050.21	8,890,419.27	284,790.32	33,882.98	2,709,709.75	79,268,852.53	76,559,142.78	17,721,553.74	96,990,406.27	94,280,696.52

Average Monthly Jurisdictional Revenues, Excluding Environmental Surcharge,
for 12 Months Ending Current Expense Month. **$77,815,601.97**

Jurisdictional Allocation Percentage for Current Month (Environmental Surcharge Excluded from Calculations):
Expense Month Kentucky Jurisdictional Revenues Divided by Expense Month Total Company Revenues: Column (8) / Column (11) = **81.20%**

Note 1 - Excludes Brokered Sales,
Total for Current Month = $ 337,677.00

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 17

Responding Witness: Robert M. Conroy

Q-17. Refer to the Conroy Testimony, page 5. Concerning the reporting of plant, construction work in progress, and depreciation expense, does KU agree that it would be reasonable to report the information for the four environmental compliance plans under one format reference number with net subtotals for each environmental compliance plan, even though this would probably become a multiple-page format, similar to the approach used for ES Form 2.50? Explain the response.

A-17. KU agrees it would be reasonable to report the information proposed to be contained on ES Form 2.11 and ES Form 2.12 on a single, multi-page ES Form (i.e. ES Form 2.10, page x of y) with subtotals for each amended compliance plan. A sample of such a form is attached.

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Description	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Deferred Tax Balance as of xx/dd/yyyy	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)			
2001 Plan:							
Project 16 - KU Nox modifications							
Project 17 - KU Nox SCR's							
Subtotal							
Less Retirements and Replacement resulting from implementation of 2001 Plan							
Net Total - 2001 Plan:							
2003 Plan:							
Project 18 - Ghent Ash Pond Dike Elevation							
Subtotal							
Less Retirements and Replacement resulting from implementation of 2003 Plan							
Net Total - 2003 Plan:							
2005 Plan:							
Project 19 - Ash Handling at Ghent 1 and Ghent Station							
Project 20 - Ash Treatment Basin Expansion at E.W. Brown Station							
Project 21 - FGD's at all E.W. Brown Units and at Ghent 2, 3, and 4							
Subtotal							
Less Retirements and Replacement resulting from implementation of 2005 Plan							
Net Total - 2005 Plan:							

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Description	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Deferred Tax Balance as of xx/dd/yyyy	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)			
2006 Plan:							
Project 23 - TC2 AQCS Equipment							
Project 24 - Sorbent Injection							
Project 25 - Mercury Monitors							
Project 26 - Ghent 2 SCR							
Project 27 - E.W. Brown Electrostatic Precipitators							
Subtotal							
Less Retirements and Replacement resulting from implementation of 2006 Plan							
Net Total - 2006 Plan:							
Net Total - All Plans:							

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 18

Responding Witness: Robert M. Conroy

Q-18. Refer to the Conroy Testimony, pages 8 and 9.

a. Provide the calculations, workpapers, assumptions, and other documents used to determine the 2006 Plan estimated 1,000 kWh per month residential customer bill increase of $0.82 in 2007 and $2.67 in 2010.

b. Provide the calculations, workpapers, assumptions, and other documents used to determine the 2005 Plan estimated 1,000 kWh per month residential customer bill increase of $3.25 in 2007 and $6.05 in 2010.

A-18. a. Please see Attachment 1 to Response to Question No. 18(a).

In preparing the attachment to this response, the Company determined that a full year of depreciation expense was included in 2010 for Project 23. Since the anticipated in-service date for Trimble County Unit 2 is mid-year 2010, the calculation of the estimated bill impact should actually use one-half of a year's depreciation expense.

In addition, Attachment 2 to Response to Question No. 18(a) details the calculation of the bill impact with the inclusion of O&M expenses for Project 23 as discussed in the response to Question No. 15. The maximum bill impact for the 2006 Amended Plan is expected to occur in 2011. For a residential customer using 1,000 kWh per month, the maximum bill impact will be $2.54 without the inclusion of O&M for Project 23 and $2.75 with the inclusion of O&M for Project 23.

b. Please see the Attachment to Response to Question No. 18(b).

Revenue Requirements Summary
2006 Amended Plan - KU

	2006	2007	2008	2009	2010	2011	2012
TC2							
Revenue Requirement							
Eligible Plant	11,707,000	67,252,000	150,483,000	179,176,000	185,289,000	185,289,000	185,289,000
Less: Retired Plant	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	-	-	(3,214,764)	(9,644,292)	(16,073,821)
Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	-	-	(1,328,823)	(3,801,160)	(5,916,066)
Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-
Environmental Compliance Rate Base	11,707,000	67,252,000	150,483,000	179,176,000	180,745,413	171,843,548	163,299,113
Rate of return	11.69%	11.42%	11.42%	11.42%	11.26%	11.26%	11.26%
	$ 1,368,337	$ 7,679,547	$ 17,183,746	$ 20,460,217	$ 20,344,710	$ 19,342,716	$ 18,380,954
Operating expenses	-	-	-	-	-	-	-
Annual Depreciation expense	-	-	-	-	3,214,764	6,429,528	6,429,528
Less depreciation on retired plant	-	-	-	-	-	-	-
Annual Property Tax expense	-	17,561	100,878	225,725	268,764	273,111	263,467
Total OE	$ -	$ 17,561	$ 100,878	$ 225,725	$ 3,483,528	$ 6,702,640	$ 6,692,995
Total E(m)	1,368,337	7,697,108	17,284,624	20,685,942	23,828,238	26,045,356	25,073,949

	2006	2007	2008	2009	2010	2011	2012
SO3							
Revenue Requirement							
Eligible Plant	1,187,000	23,384,000	39,591,000	39,591,000	39,591,000	39,591,000	39,591,000
Less: Retired Plant	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	(582,100)	(1,572,032)	(2,561,964)	(3,551,896)	(4,541,828)	(5,531,760)
Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	(106,810)	(791,110)	(1,398,134)	(1,916,378)	(2,369,229)	(2,761,757)
Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-
Environmental Compliance Rate Base	1,187,000	22,695,090	37,227,858	35,630,902	34,122,726	32,679,943	31,297,483
Rate of return	11.69%	11.42%	11.42%	11.42%	11.26%	11.26%	11.26%
	$ 138,739	$ 2,591,566	$ 4,251,072	$ 4,068,715	$ 3,840,855	$ 3,678,456	$ 3,522,846
Operating expenses	-	940,573	1,528,474	3,778,389	3,891,740	4,008,492	4,128,747
Annual Depreciation expense	-	582,100	989,932	989,932	989,932	989,932	989,932
Less depreciation on retired plant	-	-	-	-	-	-	-
Annual Property Tax expense	-	1,781	34,203	57,028	55,544	54,059	52,574
Total OE	$ -	$ 1,524,453	$ 2,552,609	$ 4,825,349	$ 4,937,216	$ 5,052,483	$ 5,171,253
Total E(m)	138,739	4,116,019	6,803,681	8,894,064	8,778,071	8,730,939	8,694,099

Revenue Requirements Summary
2006 Amended Plan - KU

	2006	2007	2008	2009	2010	2011	2012
CEMS							
Revenue Requirement							
Eligible Plant	87,000	2,969,000	2,969,000	2,969,000	2,969,000	2,969,000	2,969,000
Less: Retired Plant	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	(78,886)	(157,773)	(236,659)	(315,545)	(394,432)
Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	(11,909)	(61,615)	(104,094)	(141,290)	(173,583)
Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-
Environmental Compliance Rate Base	87,000	2,969,000	2,878,205	2,749,612	2,628,247	2,512,164	2,400,985
Rate of return	11.69%	11.42%	11.42%	11.42%	11.26%	11.26%	11.26%
	$ 10,169	$ 339,032	$ 328,664	$ 313,980	$ 295,836	$ 282,769	$ 270,255
Operating expenses	-	-	790,000	790,000	790,000	790,000	790,000
Annual Depreciation expense	-	-	78,886	78,886	78,886	78,886	78,886
Less depreciation on retired plant	-	-	-	-	-	-	-
Annual Property Tax expense	-	131	4,454	4,335	4,217	4,099	3,980
Total OE	$ -	$ 131	$ 873,340	$ 873,222	$ 873,103	$ 872,985	$ 872,867
Total E(m)	10,169	339,162	1,202,004	1,187,201	1,168,939	1,155,754	1,143,121

	2006	2007	2008	2009	2010	2011	2012
GH2 SCR							
Revenue Requirement							
Eligible Plant	1,000,000	29,000,000	64,000,000	95,000,000	95,000,000	95,000,000	95,000,000
Less: Retired Plant	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	-	(5,386,500)	(10,773,000)	(16,159,500)	(21,546,000)
Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	-	669,374	145,631	(194,852)	(366,277)
Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-
Environmental Compliance Rate Base	1,000,000	29,000,000	64,000,000	90,282,874	84,372,631	78,645,648	73,087,723
Rate of return	11.69%	11.42%	11.42%	11.42%	11.26%	11.26%	11.26%
	$ 116,882	$ 3,311,528	$ 7,308,199	$ 10,309,457	$ 9,496,986	$ 8,852,357	$ 8,226,757
Operating expenses	-	-	-	2,765,305	2,879,887	2,963,972	2,921,235
Annual Depreciation expense	-	-	-	5,386,500	5,386,500	5,386,500	5,386,500
Less depreciation on retired plant	-	-	-	-	-	-	-
Annual Property Tax expense	-	1,500	43,500	96,000	134,420	126,341	118,261
Total OE	$ -	$ 1,500	$ 43,500	$ 8,247,805	$ 8,400,808	$ 8,476,813	$ 8,425,996
Total E(m)	116,882	3,313,028	7,351,699	18,557,261	17,897,794	17,329,170	16,652,752

Revenue Requirements Summary
2006 Amended Plan - KU

	2006	2007	2008	2009	2010	2011	2012
BR1, BR2, BR3							
Revenue Requirement							
Eligible Plant	110,000	1,585,000	2,285,000	2,285,000	2,285,000	2,285,000	2,285,000
Less: Retired Plant	-	(267,426)	(267,426)	(267,426)	(267,426)	(267,426)	(267,426)
Less: Accumulated Depreciation	(4,301)	(51,212)	(125,493)	(199,774)	(274,055)	(348,336)	(422,617)
Plus: Accumulated Depreciation on retired plant	-	210,839	210,839	210,839	210,839	210,839	210,839
Less: Deferred Tax Balance	68	(5,930)	(30,075)	(59,996)	(84,857)	(105,870)	(123,324)
Plus: Deferred Tax Balance on retired plant	-	22,842	22,842	22,842	22,842	22,842	22,842
Environmental Compliance Rate Base	105,767	1,494,113	2,095,687	1,991,485	1,892,343	1,797,049	1,705,314
Rate of return	11.69%	11.69%	11.69%	11.69%	11.69%	11.69%	11.69%
	$ 12,362	$ 174,635	$ 244,948	$ 232,769	$ 221,181	$ 210,043	$ 199,321
Operating expenses	-	-	-	-	-	-	-
Annual Depreciation expense	4,301	46,911	74,281	74,281	74,281	74,281	74,281
Less depreciation on retired plant	-	(7,702)	(7,702)	(7,702)	(7,702)	(7,702)	(7,702)
Annual Property Tax expense	-	159	2,301	3,239	3,128	3,016	2,905
Total OE	$ 4,301	$ 39,368	$ 68,880	$ 69,818	$ 69,707	$ 69,596	$ 69,484
Total E(m)	16,663	214,003	313,828	302,587	290,888	279,638	268,805
Total E(m) - All KU Projects	1,650,790	15,679,320	32,955,836	49,627,055	51,963,930	53,540,856	51,832,727
Total Revenue Requirements							
Project 23	1,368,337	7,697,108	17,284,624	20,685,942	23,828,238	26,045,356	25,073,949
Project 24	138,739	4,116,019	6,803,681	8,894,064	8,778,071	8,730,939	8,694,099
Project 25	10,169	339,162	1,202,004	1,187,201	1,168,939	1,155,754	1,143,121
Project 26	116,882	3,313,028	7,351,699	18,557,261	17,897,794	17,329,170	16,652,752
Project 27	16,663	214,003	313,828	302,587	290,888	279,638	268,805
Total	1,650,790	15,679,320	32,955,836	49,627,055	51,963,930	53,540,856	51,832,727
	-	-	-	-	-	-	-
12 Month Average Jurisdictional Ratio	78.72%	78.72%	78.72%	78.72%	78.72%	78.72%	78.72%
Jurisdictional Allocation	1,299,557	12,343,283	25,943,933	39,068,072	40,907,738	42,149,147	40,804,450
12 Month Retail Revenue @ 2.42% Growth	884,237,088	905,594,197	927,467,147	949,868,398	972,810,710	996,307,151	1,020,371,105
Billing Factor	0.15%	1.36%	2.80%	4.11%	4.21%	4.23%	4.00%
KU Residential Bill Impact							
Customer Charge	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
Energy, 1,000 Kwh @$0.04720	$47.20	$47.20	$47.20	$47.20	$47.20	$47.20	$47.20
FAC billings (May-06 factor -$0.00720/kwh)	7.2	7.2	7.2	7.2	7.2	7.2	7.2
DSM billings (May-06 factor - $0.00057/kwh	0.57	0.57	0.57	0.57	0.57	0.57	0.57
ECR billings (March-06 factor: 3.08%)	$1.85	$1.85	$1.85	$1.85	$1.85	$1.85	$1.85
Adidtional ECR factor	$0.09	$0.82	$1.68	$2.47	$2.52	$2.54	$2.40

Revenue Requirements Summary
2006 Amended Plan - KU

with O&M included for Project 23

	2006	2007	2008	2009	2010	2011	2012
TC2							
Revenue Requirement							
Eligible Plant	11,707,000	67,252,000	150,483,000	179,176,000	185,289,000	185,289,000	185,289,000
Less: Retired Plant	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	-	-	(3,214,764)	(9,644,292)	(16,073,821)
Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	-	-	(1,328,823)	(3,801,160)	(5,916,066)
Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-
Environmental Compliance Rate Base	11,707,000	67,252,000	150,483,000	179,176,000	180,745,413	171,843,548	163,299,113
Rate of return	11.69%	11.42%	11.42%	11.42%	11.26%	11.26%	11.26%
	$ 1,368,337	$ 7,679,547	$ 17,183,746	$ 20,460,217	$ 20,344,710	$ 19,342,716	$ 18,380,954
Operating expenses	-	-	-	-	2,616,353	4,540,852	4,679,965
Annual Depreciation expense	-	-	-	-	3,214,764	6,429,528	6,429,528
Less depreciation on retired plant	-	-	-	-	-	-	-
Annual Property Tax expense	-	17,561	100,878	225,725	268,764	273,111	263,467
Total OE	$ -	$ 17,561	$ 100,878	$ 225,725	$ 6,099,881	$ 11,243,491	$ 11,372,961
Total E(m)	1,368,337	7,697,108	17,284,624	20,685,942	26,444,591	30,586,207	29,753,915

	2006	2007	2008	2009	2010	2011	2012
SO3							
Revenue Requirement							
Eligible Plant	1,187,000	23,384,000	39,591,000	39,591,000	39,591,000	39,591,000	39,591,000
Less: Retired Plant	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	(582,100)	(1,572,032)	(2,561,964)	(3,551,896)	(4,541,828)	(5,531,760)
Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	(106,810)	(791,110)	(1,398,134)	(1,916,378)	(2,369,229)	(2,761,757)
Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-
Environmental Compliance Rate Base	1,187,000	22,695,090	37,227,858	35,630,902	34,122,726	32,679,943	31,297,483
Rate of return	11.69%	11.42%	11.42%	11.42%	11.26%	11.26%	11.26%
	$ 138,739	$ 2,591,566	$ 4,251,072	$ 4,068,715	$ 3,840,855	$ 3,678,456	$ 3,522,846
Operating expenses	-	940,573	1,528,474	3,778,389	3,891,740	4,008,492	4,128,747
Annual Depreciation expense	-	582,100	989,932	989,932	989,932	989,932	989,932
Less depreciation on retired plant	-	-	-	-	-	-	-
Annual Property Tax expense	-	1,781	34,203	57,028	55,544	54,059	52,574
Total OE	$ -	$ 1,524,453	$ 2,552,609	$ 4,825,349	$ 4,937,216	$ 5,052,483	$ 5,171,253
Total E(m)	138,739	4,116,019	6,803,681	8,894,064	8,778,071	8,730,939	8,694,099

Revenue Requirements Summary
2006 Amended Plan - KU

with O&M included for Project 23

	2006	2007	2008	2009	2010	2011	2012
CEMS							
Revenue Requirement							
Eligible Plant	87,000	2,969,000	2,969,000	2,969,000	2,969,000	2,969,000	2,969,000
Less: Retired Plant	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	(78,886)	(157,773)	(236,659)	(315,545)	(394,432)
Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	(11,909)	(61,615)	(104,094)	(141,290)	(173,583)
Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-
Environmental Compliance Rate Base	87,000	2,969,000	2,878,205	2,749,612	2,628,247	2,512,164	2,400,985
Rate of return	11.69%	11.42%	11.42%	11.42%	11.26%	11.26%	11.26%
	$ 10,169	$ 339,032	$ 328,664	$ 313,980	$ 295,836	$ 282,769	$ 270,255
Operating expenses	-	-	790,000	790,000	790,000	790,000	790,000
Annual Depreciation expense	-	-	78,886	78,886	78,886	78,886	78,886
Less depreciation on retired plant	-	-	-	-	-	-	-
Annual Property Tax expense	-	131	4,454	4,335	4,217	4,099	3,980
Total OE	$ -	$ 131	$ 873,340	$ 873,222	$ 873,103	$ 872,985	$ 872,867
Total E(m)	10,169	339,162	1,202,004	1,187,201	1,168,939	1,155,754	1,143,121

	2006	2007	2008	2009	2010	2011	2012
GH2 SCR							
Revenue Requirement							
Eligible Plant	1,000,000	29,000,000	64,000,000	95,000,000	95,000,000	95,000,000	95,000,000
Less: Retired Plant	-	-	-	-	-	-	-
Less: Accumulated Depreciation	-	-	-	(5,386,500)	(10,773,000)	(16,159,500)	(21,546,000)
Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-
Less: Deferred Tax Balance	-	-	-	669,374	145,631	(194,852)	(366,277)
Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-
Environmental Compliance Rate Base	1,000,000	29,000,000	64,000,000	90,282,874	84,372,631	78,645,648	73,087,723
Rate of return	11.69%	11.42%	11.42%	11.42%	11.26%	11.26%	11.26%
	$ 116,882	$ 3,311,528	$ 7,308,199	$ 10,309,457	$ 9,496,986	$ 8,852,357	$ 8,226,757
Operating expenses	-	-	-	2,765,305	2,879,887	2,963,972	2,921,235
Annual Depreciation expense	-	-	-	5,386,500	5,386,500	5,386,500	5,386,500
Less depreciation on retired plant	-	-	-	-	-	-	-
Annual Property Tax expense	-	1,500	43,500	96,000	134,420	126,341	118,261
Total OE	$ -	$ 1,500	$ 43,500	$ 8,247,805	$ 8,400,808	$ 8,476,813	$ 8,425,996
Total E(m)	116,882	3,313,028	7,351,699	18,557,261	17,897,794	17,329,170	16,652,752

Revenue Requirements Summary
2006 Amended Plan - KU

with O&M included for Project 23

	2006	2007	2008	2009	2010	2011	2012
BR1, BR2, BR3							
Revenue Requirement							
Eligible Plant	110,000	1,585,000	2,285,000	2,285,000	2,285,000	2,285,000	2,285,000
Less: Retired Plant	-	(267,426)	(267,426)	(267,426)	(267,426)	(267,426)	(267,426)
Less: Accumulated Depreciation	(4,301)	(51,212)	(125,493)	(199,774)	(274,055)	(348,336)	(422,617)
Plus: Accumulated Depreciation on retired plant	-	210,839	210,839	210,839	210,839	210,839	210,839
Less: Deferred Tax Balance	68	(5,930)	(30,075)	(59,996)	(84,857)	(105,870)	(123,324)
Plus: Deferred Tax Balance on retired plant	-	22,842	22,842	22,842	22,842	22,842	22,842
Environmental Compliance Rate Base	105,767	1,494,113	2,095,687	1,991,485	1,892,343	1,797,049	1,705,314
Rate of return	11.69%	11.69%	11.69%	11.69%	11.69%	11.69%	11.69%
	$ 12,362	$ 174,635	$ 244,948	$ 232,769	$ 221,181	$ 210,043	$ 199,321
Operating expenses	-	-	-	-	-	-	-
Annual Depreciation expense	4,301	46,911	74,281	74,281	74,281	74,281	74,281
Less depreciation on retired plant	-	(7,702)	(7,702)	(7,702)	(7,702)	(7,702)	(7,702)
Annual Property Tax expense	-	159	2,301	3,239	3,128	3,016	2,905
Total OE	$ 4,301	$ 39,368	$ 68,880	$ 69,818	$ 69,707	$ 69,596	$ 69,484
Total E(m)	16,663	214,003	313,828	302,587	290,888	279,638	268,805
Total E(m) - All KU Projects	1,650,790	15,679,320	32,955,836	49,627,055	54,580,283	58,081,708	56,512,692
Total Revenue Requirements							
Project 23	1,368,337	7,697,108	17,284,624	20,685,942	26,444,591	30,586,207	29,753,915
Project 24	138,739	4,116,019	6,803,681	8,894,064	8,778,071	8,730,939	8,694,099
Project 25	10,169	339,162	1,202,004	1,187,201	1,168,939	1,155,754	1,143,121
Project 26	116,882	3,313,028	7,351,699	18,557,261	17,897,794	17,329,170	16,652,752
Project 27	16,663	214,003	313,828	302,587	290,888	279,638	268,805
Total	1,650,790	15,679,320	32,955,836	49,627,055	54,580,283	58,081,708	56,512,692
	-	-	-	-	-	-	-
12 Month Average Jurisdictional Ratio	78 72%	78 72%	78 72%	78 72%	78 72%	78 72%	78 72%
Jurisdictional Allocation	1,299,557	12,343,283	25,943,933	39,068,072	42,967,418	45,723,857	44,488,675
12 Month Retail Revenue @ 2.42% Growth	884,237,088	905,594,197	927,467,147	949,868,398	972,810,710	996,307,151	1,020,371,105
Billing Factor	0 15%	1 36%	2 80%	4 11%	4 42%	4 59%	4 36%
KU Residential Bill Impact							
Customer Charge	$5 00	$5 00	$5 00	$5 00	$5 00	$5.00	$5 00
Energy, 1,000 Kwh @$0 04720	$47 20	$47 20	$47 20	$47 20	$47 20	$47 20	$47 20
FAC billings (May-06 factor -$0 00720/kwh)	$7 20	$7 20	$7 20	$7 20	$7 20	$7 20	$7 20
DSM billings (May-06 factor - $0 00057/kwh	0 57	0 57	0 57	0 57	0 57	0 57	0 57
ECR billings (March-06 factor: 3 08%)	$1 85	$1 85	$1 85	$1 85	$1 85	$1 85	$1 85
Adidtional ECR factor	$0 09	$0 82	$1 68	$2 47	$2 65	$2 75	$2 61

Revenue Requirements Summary
2005 Amended Plan - KU

		2006	2007	2008	2009	2010	2011	2012
Project 19	**Ghent Ash Pipe Replacements & Ash Booster Pumps**							
	Revenue Requirement							
	Eligible Plant	450,000	700,000	3,200,000	3,700,000	4,200,000	4,200,000	4,200,000
	Less: Retired Plant	(276,470)	(552,941)	(829,411)	(829,411)	(829,411)	(829,411)	(829,411)
	Less: Accumulated Depreciation	(14,040)	(33,480)	(105,320)	(188,260)	(282,000)	(375,740)	(469,480)
	Plus: Accumulated Depreciation on retired plant	230,742	76,914	153,828	230,742	230,742	230,742	230,742
	Less: Deferred Tax Balance	(1,090)	(9,318)	(60,469)	(115,492)	(172,146)	(228,719)	(278,548)
	Plus: Deferred Tax Balance on retired plant	84,811	28,270	56,541	84,811	84,811	84,811	84,811
	Environmental Compliance Rate Base	473,953	209,446	2,415,168	2,882,390	3,231,995	3,081,683	2,938,114
	Rate of return	11.69%	11.42%	11.42%	11.42%	11.26%	11.26%	11.26%
		$ 55,397	$ 23,917	$ 275,790	$ 329,142	$ 363,794	$ 346,874	$ 330,714
	Operating expenses	-	-	-	-	-	-	-
	Annual Depreciation expense	14,040	19,440	71,840	82,940	93,740	93,740	93,740
	Less depreciation on retired plant	(25,878)	(8,626)	(17,252)	(25,878)	(25,878)	(25,878)	(25,878)
	Annual Property Tax expense	-	654	1,000	4,642	5,268	5,877	5,736
	Total OE	$ (11,838)	$ 11,468	$ 55,588	$ 61,704	$ 73,130	$ 73,739	$ 73,599
	Total E(m)	43,559	35,385	331,378	390,846	436,924	420,614	404,313

		2006	2007	2008	2009	2010	2011	2012
Project 20	**Brown Ash Pond**							
	Revenue Requirement							
	Eligible Plant	12,076,066	37,876,066	46,076,066	52,576,066	73,176,066	73,176,066	73,176,066
	Less: Retired Plant	-	-	-	-	-	-	-
	Less: Accumulated Depreciation	-	-	-	(2,055,724)	(4,916,908)	(7,778,092)	(10,639,277)
	Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-
	Less: Deferred Tax Balance	-	-	-	30,871	(830,933)	(1,551,577)	(2,141,999)
	Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-
	Environmental Compliance Rate Base	12,076,066	37,876,066	46,076,066	50,551,213	67,428,225	63,846,397	60,394,790
	Rate of return	11.69%	11.42%	11.42%	11.42%	11.26%	11.26%	11.26%
		$ 1,411,475	$ 4,325,091	$ 5,261,454	$ 5,772,474	$ 7,589,723	$ 7,186,553	$ 6,798,040
	Operating expenses	-	-	-	-	-	-	-
	Annual Depreciation expense	-	-	-	2,055,724	2,861,184	2,861,184	2,861,184
	Less depreciation on retired plant	-	-	-	-	-	-	-
	Annual Property Tax expense	-	18,114	56,814	69,114	75,781	102,389	98,097
	Total OE	$ -	$ 18,114	$ 56,814	$ 2,124,838	$ 2,936,965	$ 2,963,573	$ 2,959,281
	Total E(m)	1,411,475	4,343,205	5,318,268	7,897,312	10,526,688	10,150,126	9,757,321

Revenue Requirements Summary
2005 Amended Plan - KU

		2006	2007	2008	2009	2010	2011	2012
Project 21	FGD's at Brown & Ghent							
	Revenue Requirement							
	Eligible Plant	177,922,885	421,340,885	588,435,885	658,988,885	658,988,885	658,988,885	658,988,885
	Less: Retired Plant	-	-	-	-	-	-	-
	Less: Accumulated Depreciation	-	(7,314,107)	(21,290,645)	(57,271,565)	(93,252,486)	(129,233,406)	(165,214,326)
	Plus: Accumulated Depreciation on retired plant	-	-	-	-	-	-	-
	Less: Deferred Tax Balance	-	908,915	1,003,561	2,257,506	(1,162,976)	(3,365,617)	(4,443,660)
	Plus: Deferred Tax Balance on retired plant	-	-	-	-	-	-	-
	Environmental Compliance Rate Base	177,922,885	414,935,693	568,148,801	603,974,826	564,573,422	526,389,861	489,330,899
	Rate of return	11.69%	11.42%	11.42%	11.42%	11.26%	11.26%	11.26%
		$ 20,795,981	$ 47,381,761	$ 64,877,259	$ 68,968,255	$ 63,548,405	$ 59,250,462	$ 55,079,104
	Operating expenses	-	2,941,576	5,749,894	13,359,135	13,359,135	13,359,135	13,359,135
	Annual Depreciation expense	-	7,314,107	13,976,538	35,980,920	35,980,920	35,980,920	35,980,920
	Less depreciation on retired plant	-	-	-	-	-	-	-
	Annual Property Tax expense	-	266,884	621,040	850,718	902,576	848,605	794,633
	Total OE	$ -	$ 10,522,567	$ 20,347,473	$ 50,190,773	$ 50,242,631	$ 50,188,660	$ 50,134,689
	Total E(m)	20,795,981	57,904,328	85,224,732	119,159,028	113,791,036	109,439,122	105,213,792
	Total E(m) - All KU Projects	22,251,015	62,282,918	90,874,378	127,447,187	124,754,648	120,009,861	115,375,426
	Total Revenue Requirements							
	Project 19	43,559	35,385	331,378	390,846	436,924	420,614	404,313
	Project 20	1,411,475	4,343,205	5,318,268	7,897,312	10,526,688	10,150,126	9,757,321
	Project 21	20,795,981	57,904,328	85,224,732	119,159,028	113,791,036	109,439,122	105,213,792
	Total	22,251,015	62,282,918	90,874,378	127,447,187	124,754,648	120,009,861	115,375,426
		-	-	-	-	-	-	-
	12 Month Average Jurisdictional Ratio	78 72%	78 72%	78 72%	78 72%	78 72%	78 72%	78 72%
	Jurisdictional Allocation	17,516,741	49,031,189	71,539,339	100,330,674	98,211,017	94,475,763	90,827,381
	12 Month Retail Revenue @ 2.42% Growth	884,237,088	905,594,197	927,467.147	949,868,398	972,810,710	996,307,151	1,020,371,105
	Billing Factor	1 98%	5 41%	7 71%	10 56%	10 10%	9 48%	8 90%
	KU Residential Bill Impact							
	Customer Charge	$5 00	$5 00	$5 00	$5.00	$5 00	$5 00	$5 00
	Energy, 1,000 Kwh @$0.04720	$47 20	$47 20	$47 20	$47 20	$47 20	$47 20	$47 20
	FAC billings (May-06 factor -$0 00720/kwh)	7 2	7 2	7 2	7 2	7.2	7 2	7 2
	DSM billings (May-06 factor - $0 00057/kwh	0 57	0 57	0 57	0 57	0 57	0 57	0 57
	ECR billings (May-06 factor: 3 08%)	$1 85	$1 85	$1 85	$1 85	$1 85	$1 85	$1 85
	Adidtional ECR factor	$1 19	$3 25	$4 63	$6 33	$6 05	$5 69	$5 34

KENTUCKY UTILITIES COMPANY

CASE NO. 2006-00206

Response to First Data Request of Commission Staff
Dated July 24, 2006

Question No. 19

Responding Witness: Robert M. Conroy

Q-19. Refer to the Conroy Testimony, Exhibit RMC-1.

a. Under the section titled "Definitions" in the proposed tariff the following phrase is included for operating expenses, "adjusted for the Average Month Expense already included in existing rates." Does KU agree that this adjustment is no longer part of its environmental surcharge mechanism and should be deleted from the proposed tariff? Explain the response.

b. KU's current Environmental Cost Recovery Surcharge ("ECR") tariff shows it was effective "with service rendered on and after July 1, 2005." Explain in detail why KU's proposed ECR tariff is to be effective "with bills rendered" rather than "with service rendered."

A-19. a. No. KU's ECR filings reduce monthly emission allowance expense by 1/12th of the annual expense incurred during the test year ended September 30, 2003. Prior to July 2004, emission allowance expense was associated with KU's "1994 Plan" which was eliminated from ECR filings beginning with the July 2004 expense month filing. In its base rate case filing in Case No. 2003-00434, KU made no adjustments for environmental rate base or operating expenses associated with the 1994 Plan, since the 1994 Plan was being removed from ECR filings on a going-forward basis. However, consistent with the terms of the approved Partial Settlement Agreement, Stipulation and Recommendation in Case No. 2003-00434, KU continues to recover emission allowance expense through the monthly ECR filings. Since KU made no test year adjustments for emission allowance expense, KU's base rates include recovery of allowance expenses incurred during the 12 months ending September 30, 2003. Therefore, KU continues to reduce its monthly allowance expense included for recovery through the ECR by the amount that is included in base rates.

b. A change to the ECR monthly billing factor cannot be implemented on a "service-rendered" basis. KU's billing system applies additional billing factors only on a billing-cycle basis. If the Commission issues an Order approving recovery of KU's proposed 2006 Compliance Plan in December

2006, the impact of such an Order will be included on customer bills in February 2007, the second month following the month in which the Order is issued. The ECR monthly billing factor for February 2007 will only be assessed on services rendered subsequent to the date the Order is issued. This is consistent with the methodology used in every prior KU ECR proceeding.

As an explanatory note, although the current tariff states "with service rendered on and after July 1, 2005," the environmental costs approved for recovery by this Commission in its June 20, 2005 Order in Case No. 2004-00426[1] were included in the ECR billing factor applied to customers' bills beginning with the billing month of August 2005. The ECR billing factor for August 2005 was only assessed on service rendered subsequent to the date the Order was issued.

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[1] In the Matter of: *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.*