COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

IN THE MATTER OF: APPLICATION OF KENTUCKY UTILITIES COMPANY FOR APPROVAL OF AN ALTERNATIVE METHOD OF REGULATION OF ITS RATES AND SERVICE	:	CASE NO. 98-474
and	:	
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. Complainant v. KENTUCKY UTILITIES COMPANY Defendant	:	CASE NO. 99-083

ADDITIONAL DIRECT TESTIMONY AND EXHIBITS OF LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

MAY 1999

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and	:	
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. Complainant	:	CASE NO. 99-083
v.	:	
KENTUCKY UTILITIES COMPANY Defendant	:	

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and

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.	:	
Complainant	:	**CASE NO. 99-083**
v.	:	
KENTUCKY UTILITIES COMPANY	:	
Defendant	:	

ADDITIONAL DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 35 Glenlake Parkway, Suite 475, Atlanta, Georgia 30328.

Q. Have you previously filed testimony in this proceeding?

A. Yes. I previously filed Direct Testimony on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC") in this proceeding addressing the Company's overearnings and the necessity for a base revenue reduction.

Q. What is the purpose of your Additional Direct Testimony?

A. The purpose of this testimony is to update and refine the quantification of Kentucky Utilities Company's (the "Company" or "KU") overearnings and the appropriate base revenue reduction.

Q. Please summarize your testimony.

A. The Company's base revenues should be reduced by $58.412 million, or $47.812 million more than the $10.600 million base revenue reduction that will be implemented on July 2, 1999 pursuant to the Commission's April 13, 1999 Order in this proceeding. The Company's ratemaking return on common for the test year 1998 is 16.2% compared to a required return of 9.55%. Thus, the Company's current base revenues are excessive and are not fair, just and reasonable. The computations underlying my quantification of the base revenue reduction are summarized on my Exhibit___(LK-1).

Q. Please generally describe the changes that you made to the revenue requirement analysis in your Direct Testimony.

A. I utilized the same revenue requirement methodology, based upon the Commission's historic utilization of rate of return regulation. I updated the test year to the calendar year 1998 from the test year ending September 30, 1998 due to the availability of more detailed information provided by the Company in response to discovery. I relied upon the Company's supplemental response to Item 11 of the Commission's Order dated December 2, 1998, other responses to Commission Staff and KIUC discovery in this proceeding, and other publicly available information.

The Company proposed numerous proforma adjustments to the 1998 calendar year per books data. These adjustments were proposed in both the supplemental response to Item 11 of the Commission's Order dated December 2, 1998 and the response to PSC#4-KU-7. I have accepted certain of these adjustments and included others of my own. In addition, I have rejected other proforma adjustments proposed by the Company. The following two sections of my testimony address the proformas that I have incorporated and those proposed by the Company that I have rejected.

Q. Did you segregate the base, environmental surcharge ("ECR"), and fuel adjustment clause ("FAC") components of operating income?

A. No. I assumed that the environmental surcharge cost of service would be incorporated into the base revenue requirement and then reset to zero concurrent with the effective date of the Commission's base revenue reduction in this proceeding. Net incremental environmental costs after that date would be recovered through the ECR. I assumed that FAC revenues were equal to recoverable fuel and purchased power expenses.

Q. Did you update the rate of return on common equity reflected in your quantification?

A. Yes. I utilized the updated 9.55% recommended by KIUC witness Mr. Baudino.

Q. Are the results of your update for the test year 1998 significantly different than for the test year ending September 30, 1998 presented in your Direct Testimony?

A. No. The base revenue reduction that I recommend is slightly higher for the test year 1998.

II. PROFORMA ADJUSTMENTS INCORPORATED

Q. Please identify the proforma adjustments that you have incorporated to the per books data for the calendar year 1998.

A. I have incorporated certain adjustments to operating income, to capitalization, and to rate base. The adjustments that I have incorporated to operating income are as follows:

1. Increase revenues to eliminate provision for rate refund.

2. Increase revenues to reflect increase in customers and sales.

3. Increase sales for resale revenues to reallocate off-system sales revenue to all jurisdictions, including Kentucky retail.

4. Increase transmission services revenues to reallocate to all jurisdictions, including Kentucky retail.

5. Increase O&M expense due to reallocation of sales for resale and transmission services revenues to all jurisdictions, including Kentucky retail.

6. Increase O&M expense to reflect net retained shareholder savings from merger.

7. Reduce O&M expense to remove actual Year 2000 costs and replace with amortization over five years.

8. Increase O&M expense to remove actual Risk Management Trust refund and replace with amortization over five years.

The only adjustment to capitalization that I have incorporated is to reduce common equity to remove nonutility investments.

The adjustments to rate base that I have incorporated are as follows:

1. Reduce rate base to eliminate cash working capital.

2. Reduce rate base to eliminate prepayments.

3. Reduce rate base to reflect customer deposits.

Q. Please explain why the Commission should eliminate the provision for rate refund.

A. The provision for rate refund is due primarily to the ECR refund booked by the Company in December 1998 related to the settlement of the retroactivity issue. The provision for rate refund is nonrecurring and represents a refund for periods back to 1994. It would be inappropriate to allow the Company to recover the effects of this ECR rate refund as a base revenue requirement. It should be noted that the Company also proposed this proforma adjustment as detailed in its supplemental response to Item 11 of the Commission's Order dated December 2, 1998.

Q. Please explain why the Commission should reflect an increase in revenues in order to annualize customer and sales growth during the test year.

A. The Company achieved customer and sales growth during the test year. However, the test year revenues reflect only one half of that growth going forward. For example, if the number of customers increased by 5% during the year, revenues would reflect only 2.5% of that growth on average. Consequently, the Commission should annualize the effects of the customer and sales growth in the computation of base and ECR revenues.

Q. Please describe how you quantified the increase in revenues in order to annualize customer and sales growth during the test year.

A. I determined the weighted average composite growth in customers and applied one half of that growth to the combined test year base and ECR revenues. I determined the weighting of customer growth for this purpose by the combined base and ECR revenues.

Q. Please explain why the Commission should adopt a proforma adjustment to allocate to Kentucky retail a portion of the revenues from the off-system sales to non-all requirements customers (sales for resale).

A. First, such an allocation is consistent with the Commission's prior ratemaking treatment of these amounts. The Company has offered no rationale as to why the Commission's precedent should be overturned and the entirety of these revenues allocated to other jurisdictions.

Second, such an allocation is consistent with the most basic of cost of service principles. The investment and operating costs necessary to support these off-system sales are allocated to all jurisdictions including Kentucky retail. Thus, the net margins (revenues less incremental costs) also should be allocated to all jurisdictions including Kentucky retail. Without this adjustment, Kentucky ratepayers would be required to pay for the tree, but would receive none of the fruit.

Q. Please describe the quantification of the change in sales for resale revenues proforma adjustment.

A. The Company performed a jurisdictional cost of service study in response to KIUC-3-

38 that provided the reallocation of sales for resale revenues to all jurisdictions, including Kentucky retail. The Company quantified the adjustment to increase Kentucky retail revenues as $108.690 million.

Q. Please explain why the Commission should adopt a proforma adjustment to allocate to Kentucky retail a portion of transmission service revenues.

A. First, such an allocation is consistent with the Commission's prior ratemaking treatment of these amounts. The Company has offered no rationale as to why the Commission's precedent should be overturned and the entirety of these revenues allocated to other jurisdictions.

Second, such an allocation is consistent with cost of service principles. The investment and operating costs necessary to support these transmission services are allocated to all jurisdictions including Kentucky retail. Thus, the revenues also should be allocated to all jurisdictions including Kentucky retail. Again, the Company's position would have Kentucky ratepayers pay for the tree and have shareholders receive the fruit.

Q. Please describe the quantification of the change in transmission services revenues proforma adjustment.

A. The Company performed a jurisdictional cost of service study in response to KIUC-3-38 that provided the reallocation of transmission services revenues to all jurisdictions, including Kentucky retail. The Company quantified the adjustment to increase Kentucky retail revenues as $6.033 million.

Q. **Are reallocations of certain expenses necessary in order to be consistent with the proforma adjustments to reallocate sales for resale and transmission services revenues?**

A. Yes.

Q. **Please describe the quantification of the proforma adjustment to reallocate certain expenses in order to be consistent with the adjustments to reallocate sales for resale and transmission services revenues.**

A. The Company performed a jurisdictional cost of service study in response to KIUC-3-38 that provided the reallocation of related expenses to all jurisdictions, including Kentucky retail. The Kentucky jurisdictional allocation of operating expenses increased by $82.235 million, the difference between the $322.096 million allocation provided by the Company in its supplemental response to Item 11 of the Commission's Order dated December 2, 1998 and the $404.331 million provided by the Company in response to KIUC-3-38.

Q. **Please explain why the Commission should reflect an increase to O&M expense in order to reflect net retained shareholder savings from the merger.**

A. This proforma adjustment is necessary in order to provide the Company with its retained shareholder savings from the merger. Absent this adjustment, all merger savings would flow through to ratepayers. It should be noted that the Company proposed a similar adjustment in its supplemental response to Item 11 of the

Commission's Order dated December 2, 1998.

Q. Please describe how you quantified the increase to O&M expense in order to reflect the net retained shareholder savings from the merger.

A. I utilized the first year net merger savings of $26.312 million quantified in the merger proceeding. I allocated the net merger savings 47% to LGE and 53% to KU in accordance with the Merger Order. I then quantified the net retained savings at 50% for the Company, also in accordance with the Merger Order. Finally, I multiplied KU's net retained savings by the Kentucky retail jurisdictional factor of 86.708%.

Q. Please explain why the Commission should reflect a reduction to O&M expense in order to remove actual Year 2000 costs and an amortization expense based upon a five year amortization period.

A. Year 2000 costs are nonrecurring. In addition, Year 2000 costs generally extend the useful lives of or otherwise enhance existing software and hardware applications. In some instances, Year 2000 costs replace existing software and hardware applications, thereby creating significant future value. Nevertheless, most Year 2000 costs must be expensed in accordance with generally accepted accounting principles for book accounting purposes. However, the Commission can and should treat these costs as assets with future value and require the Company to defer the costs and amortize them over an appropriate time period. It should be noted the Company also has proposed a similar Year 2000 proforma adjustment in its response to PSC#4-LGE-11 in this proceeding, although it proposed a three year amortization period.

Q. Why is a five year amortization period for the Year 2000 costs appropriate?

A. A five year amortization period is appropriate for several reasons. First, five years more closely parallels the merger surcredit period. The amortization period is a matter of judgment and should attempt to balance the effects on ratepayers with the Company's need to recover these costs. It would not be appropriate to set the base revenue requirement to recover these costs over one, two, three, or four years if the Commission does not reasonably anticipate another base rate proceeding within the next four years.

Second, software and hardware costs are commonly amortized or depreciated over five to ten year periods. The Company has provided no rationale for a three year amortization period.

Third, a five year amortization period provides the Company full recovery of its Year 2000 costs incurred during the test year, although these costs are nonrecurring and the Company already has recovered the costs through retained overearnings.

Q. Please explain why the Commission should adopt a proforma adjustment for the Risk Management Trust refund.

A. The Company has proposed a proforma adjustment to increase O&M expense in order to reverse the effect of a refund received during the test year. The Company did not propose to amortize the refund. I agree that the refund should not be reflected in a single year because it is nonrecurring. However, the ratepayers should receive the benefit of the refund through an amortization, much as the Company proposed to recover its Year 2000 costs over an amortization period rather than in a single test year. To the extent the discontinuation of the Trust resulted in a refund, the Company overcontributed in prior years through revenues that were paid by ratepayers.

Q. What amortization period do you propose for the Risk Management Trust refund?

A. I recommend a five year amortization period, consistent with my recommendation regarding the Year 2000 costs.

Q. Have you incorporated the Company's proforma adjustment to remove nonutility investments from the common equity component of capitalization?

A. Yes. The Company provided the support for this proforma adjustment in its supplemental response to Item 11 of the Commission's Order dated December 2, 1998.

Q. Did the Company provide a computation of rate base at December 31, 1998?

A. Yes. The Company provided a computation of rate base in response to the PSC#4-KU-8. I utilized this computation of rate base as a starting point for my computation.

Q. Did you utilize rate base in the KIUC quantification of the Company's revenue requirement?

A. Instead of a return on rate base, I utilized the return on capitalization in accordance with the approach historically employed by the Commission. However, I utilized the rate base computations for the purpose of allocating the Company's capitalization to the Kentucky retail jurisdiction.

Q. Please explain why the Commission should set cash working capital equal to zero.

A. First, the Company's claim for cash working capital is based upon the one-eighth formula developed by the FERC in the early part of this century, prior to the development and adoption of today's sophisticated cash management techniques and cash flow measurement capabilities. The one-eight formula ensures a positive cash working capital result regardless of the timing of the Company's actual cash flows and simply assumes that investors supply capital for cash working capital purposes.

Second, the FERC has recognized that the one-eighth formula no longer provides a reasonable quantification of cash working capital requirements. For gas pipeline utilities, FERC assumes that cash working capital is equal to zero unless a party can show differently through a lead-lag study. 18 CFR § 154.306.

Third, in my experience, it is unusual for an electric utility today to have a positive cash working capital requirement as measured through a properly performed cash lead/lag study. Perhaps understandably, the Company has not performed a cash lead/lag study to enable the Commission actually to quantify the negative amount representing customer supplied cash working capital. Nor has it performed such a study as affirmative evidence that it has a positive cash working capital requirement. In lieu of such a study, it would be reasonable simply to set cash working capital equal to zero for rate base purposes.

Q. Please explain why the Commission should set prepayments equal to zero.

A. The reason to set prepayments equal to zero is that the actual cash working capital is or should be sufficiently negative that it would exceed the Company's rate base claim for prepayments.

Q. Please explain why the customer deposits should be subtracted from rate base.

A. Customer deposits typically are considered customer supplied capital.

III. PROFORMA ADJUSTMENTS REJECTED

Q. Please identify the proforma adjustments proposed by the Company that you have rejected.

A. I have rejected certain adjustments to operating income and capitalization proposed by the Company. The adjustments to operating income that I have rejected are as follows:

1. Increase to O&M expense for merger dispatch OATT.
2. Reduction to annual ECR revenues.
3. Increase revenues to reflect "normal" weather.
4. Increase to O&M to reflect Team Incentive Award annualization.
5. Increase to purchased power expense to reflect projected 1999 market prices.
6. Reduction of off-system sales margins to reflect historic levels.
7. Reduction to revenues to reflect hypothetical implementation of EPBR tariff in 1998.
8. Reduction to revenues to reflect EPBR rate reduction.

In addition, I have rejected the Company's adjustment to increase the common equity capitalization to reverse the effects of a writeoff of certain merger costs.

Q. Please explain why the Commission should reject the Company's proforma adjustment for merger dispatch OATT.

A. The merger dispatch savings inure to the benefit of the ratepayers in accordance with the Company's Application and the Commission's Merger Order in Case No. 97-300.

Q. Please explain why the Commission should reject the Company's adjustment to reduce annual ECR revenues.

A. The KIUC quantification of the Company's revenue requirement is based upon combining the base and ECR revenue requirement for the test year and setting the initial ECR rate to zero on the effective date of the base revenue reduction. The integration of the base and ECR revenue requirement provides the Company full (and higher compared to the current ECR) recovery of its environmental costs. Thus, any deficiency in ECR recovery, represented in part by the Company's proforma adjustment to reduce annual ECR revenues, already is included in the KIUC recommendation. If the Company's adjustment is accepted, there will be a double recovery.

Q. Please explain why the Commission should reject the Company's proforma adjustment to reduce revenues to reflect "normal" weather.

A. First, the Commission historically has not adopted weather normalization adjustments for electric utilities. Clearly, the adoption of such an adjustment for the Company would be considered precedential in base revenue proceedings involving other utilities and in future proceedings involving the Company.

Second, the selection of data series and the development of the regression equations and other aspects of the methodologies are subject to considerable judgment. Consequently, a weather normalization adjustment is not a factual determination, but rather an assessment of opinions as to what constitutes "normal" weather for purposes of quantifying this ratemaking adjustment. In the broadest sense, there is disagreement among scientists regarding the extent of global warming, if any, and the duration and measurement of warming cycles. More specifically, the Company has performed its own computation of temperature normals in lieu of the NOAA computations.

Third, this proceeding is not conducive to a thorough assessment of alternative quantifications of this adjustment, if the Commission were to change its historic rejection of such adjustments for electric utilities. There are procedural limitations to the development of a comprehensive record on this issue.

Q. Please explain why the Commission should reject the Company's proposed adjustment for the Team Incentive Award extension to all KU employees.

A. First, this proforma adjustment is a selective single issue post test year adjustment. The Company adamantly has refused to provide 1999 budget information in response to KIUC discovery, alleging that to do so would violate federal securities laws. Nevertheless, the Company specifically relied upon its 1999 budget (response to PSC#4-KU-7 page 6 of 60) to compute this adjustment. On a procedural basis alone, this adjustment should be rejected. However, it also should be rejected as a matter of regulatory principle. This adjustment fails to consider all other increases and decreases in the cost of service that should be considered if the test year was calendar year 1999. Yet, no party other than the Company has access to calendar year 1999 budget information. It would be unfair, inequitable, and unreasonable to allow this adjustment in this proceeding.

Second, the Company failed to provide any rationale for this adjustment, other than a statement that the Team Incentive Award would be extended to all KU employees. If this award is based on cost savings achievement, then there should be a proforma for cost savings. If this award is based upon earning excessive rates of return for shareholders at the expense of the Company's ratepayers, then this award should not be recoverable from ratepayers. In any event, the Commission should reject this proforma adjustment as unsupported and incomplete.

Third, if the award is based upon actual achievement in 1999, then not only is it a post test year adjustment, it cannot possibly be known and measurable. Thus, it also should be rejected on that basis.

Q. Please explain why the Commission should reject the Company's proposed adjustment to increase purchased power expense to reflect its projections of 1999 market prices.

A. First, this adjustment represents a selective single issue post test year adjustment. The Company adamantly has refused to provide 1999 budget information, alleging that to do so would violate federal securities laws. Yet, on this one issue, it understandably is willing to provide its projections of purchased power costs for 1999. Clearly, this adjustment is self-serving and inappropriate.

Second, the Company has assumed higher market prices for this adjustment, which would increase its revenue requirement, while also assuming lower market prices for its proposed off-system sales margins proforma adjustment. The Company's position is intractably ridiculous and should be rejected. If the Commission were to utilize historic purchased power costs for the Company, the proforma adjustment would be to significantly <u>reduce</u> purchased power costs. For example, purchased power costs were at a three year high in 1998 at $126.584 million compared to $72.542 million in 1997 and $62.490 million in 1996. A three year average of purchased power expense would result in a <u>reduction</u> to purchased power expense of $39.379 million.

Third, apparently the Company believes that "forward prices" will increase for purposes of its proposed purchased power adjustment, but that "forward prices" also will decrease, according to its response to KIUC-3-12, a copy of which is attached as my Exhibit ____(LK-2)

Fourth, the Company's proforma adjustment to increase purchased power expense and thus the base revenue requirement is premised, at least in part, upon the assumed non-existence of the FAC. Historically, purchased power costs, to the extent they were shown to be purchased on an economic dispatch basis, were allowed recovery through the FAC. If the FAC remains in effect, then all or part of the higher purchased power costs will be recoverable through the FAC.

Fifth, the Company's proforma adjustment is dependent upon the same level of purchases in 1999. There is no evidence to suggest that will be the case. In fact, there is virtually no probability that 1999 purchased power will be at the same levels as in 1998 since new CTs will be operational in 1999, loads will be different, fuel costs will be different, forced outages will be different, and the economics of market purchases will be different.

Q. Please explain why the Commission should reject the Company's proposed adjustment to reduce the off-system sales margins to hypothetical levels based upon historic margins.

A. First, this adjustment is conceptually absurd for the reasons discussed in conjunction with the Company's proposed purchased power adjustment. If the Company believes that market prices are increasing, then its off-system sales margins also should increase, not decline.

Second, this adjustment is an overt attempt to leverage into the future a higher retention of off-system sales margins. These off-system sales margins are possible largely because of the costs (investment and fixed operating) paid for by ratepayers through the base and ECR revenue requirements. Nevertheless, between base revenue proceedings, the Company is allowed to retain the entirety of off-system sales margins in excess of the levels reflected in the test year utilized in its last base revenue proceeding. Unfortunately, the Company apparently is not satisfied with that arrangement and now has proposed that the test year sales margins not be fully reflected in the revenue requirement. This proposed adjustment is inequitable, unfair, and unreasonable. The balance should not be tipped further toward the Company.

Third, it would be complete speculation at this time to adjust the test year level of off-system sales margins based upon the expectation that the Company's units may face extended outages to comply with the pending NOx regulations. The NOx regulations are being challenged in court, the state SIP-call is not due until September 1999, and affected sources have until May 2003 to install control measures (unless granted extensions so that the compliance date is delayed). The Company has not proposed a NOx compliance plan detailing which units will receive certain NOx control technology or when. The Commission certainly has not approved any such compliance plan. Therefore, the NOx rules cannot be the justification for a "known and measureable" change to the test year level of off-system sales margins. To the contrary, the resolution of that matter is uncertain.

Q. Please explain why the Commission should reject the Company's proposed adjustment to reflect the hypothetical implementation of the EPBR tariff in 1998.

A. First, the Commission should determine the base revenue requirement without consideration of the EPBR. Conceptually, the EPBR tariff is structured as a reward or penalty to the Company. It would be inappropriate to embed either a reward or penalty pursuant to the EPBR into base rates.

Second, the Company's adjustment would increase fuel costs in the test year compared to actual for 1998, the FCR component of the EPBR would have resulted in higher fuel costs of $1.322 million to ratepayers than the currently effective fuel adjustment clause.

This fact illustrates the poor design and the detrimental impact of the FCR component of the Company's EPBR, if not the entirety of the EPBR.

Third, the Company's adjustment would result in a double recovery of the FCR reward both through base rates and the EPBR tariff. That double recovery should not be allowed.

Fourth, the Company's computation of the SQ component of the EPBR is incorrect. The sign is wrong. The Company's service quality during the test year was less than the standard in the tariff. Therefore, there should have been a penalty, not a reward. However, in the Company's computation, the SQ penalty was incorrectly translated into a reward and an increase in the base revenue requirement. In addition, assuming there had been an SQ reward, the amount is not incrementally recoverable from ratepayers, but only can be utilized to offset the GP component. Company witness Mr. Willhite stated the following in his Direct Testimony in Case No. 98-426:

> **"Combined service quality measures that result in a reward for the current quarter will only be included in the EPBR formula to the extent that the Generation Performance amounts are available to offset this reward. Any Service Quality reward in excess of the Generation Performance will be banked and included in the following quarter's Service Quality computation. Any rewards not recovered after four quarters will be relinquished. As a result, <u>Service Quality rewards do not directly cause an increase in</u>**

<u>customers' bills</u>." (emphasis added)

Q. Please explain why the Commission should reject the Company's proposed adjustment for the EPBR rate reduction.

A. The Commission should first determine the Company's revenue requirement and the appropriate base revenue reduction absent consideration of the EPBR. It then can determine the necessary incremental adjustment to the rate reduction already in effect. In this manner, the rate reduction is not dependent upon the adoption of the EPBR, but rather upon the Company's cost of service.

Q. Does this complete your Additional Direct Testimony?

A. Yes.

KENTUCKY UTILITIES COMPANY
SUMMARY OF REVENUE REQUIREMENT
12 MONTHS ENDING DECEMBER 31, 1998
($000)

	Unadjust Total KU	Unadjust "Other Juris"	Unadjust "KY Retail Juris"	Adjust to "KY Retail Juris"	Adusted "KY Retail Juris"
Capitalization (1)	1,206,941	160,707	1,046,234	NA	1,046,234
Required Overall Rate of Return	8.12%	8.12%	8.12%	8.12%	8.12%
Required Operating Income	97,948	13,042	84,906	0	84,906
Per Books Operating Income	125,388	36,947	88,441	31,294	119,735
Operating Income Surplus	27,440	23,905	3,535	31,294	34,829
Revenue Surplus	46,020	40,091	5,929	52,483	58,412
Electric Revenues before Rate Reduction	810,115	225,561	584,554	141,478	726,032
Rate Reduction as % of Electric Revenues	5.68%	17.77%	1.01%		8.05%
Return on Common Equity before Rate Reduction	14.10%	39.33%	10.23%		16.22%
Effect of 1% Change in ROE					8,764

Note 1: Capitalization utilized by Kentucky PSC in lieu of rate base. Approximately equal.

KENTUCKY UTILITIES COMPANY
SUMMARY OF OPERATING INCOME
12 MONTHS ENDING DECEMBER 31, 1998
($000)

	Unadjust Total KU	Unadjust "Other Juris"	Unadjust "KY Retail Juris"	Adjust to "KY Retail Juris"		Adusted "KY Retail Juris"
Operating Revenues						
Residential	238,898	18,107	220,791		(1),(2)	220,791
Commercial and Industrial	344,907	18,048	326,859	4,598	(1),(2)	331,457
Public Street and Highway Lighting	6,483	207	6,276		(1),(2)	6,276
Other Sales to Public Authorities	52,332	2,497	49,835		(1),(2)	49,835
Sales for Resale	179,118	179,118	0	108,690	(3)	108,690
Provision for Refund	(23,724)	(1,567)	(22,157)	22,157	(4)	0
Other Operating Revenues	12,101	9,151	2,950	6,033	(5)	8,983
Total Operating Revenues	810,115	225,561	584,554	141,478		726,032
Operating Expenses						
Fuel, Purchased Power, and Other Oper Exp	465,630	143,534	322,096	88,995	(3),(5),(6)	411,091
Maintenance Expense	63,608	9,756	53,852			53,852
Depreciation	86,657	12,016	74,641			74,641
Other Taxes	15,946	2,746	13,200			13,200
Federal and State Income Taxes	53,256	20,615	32,641	21,189		53,830
Other	(370)	(53)	(317)			(317)
Total Operating Expenses	684,727	188,614	496,113	110,184		606,297
Net Operating Income	125,388	36,947	88,441	31,294		119,735

Note 1: Annualization to year end customers/sales levels.

Note 2: No annualization of merger surcredit revenues and no annualization of customers' savings.

Note 3: Reallocation of sales for resale revenues and related expenses to retail and FERC jurisdictions (KU response KIUC#3-38(a) page 3 of 4.

Note 4: $21.5 million of this provision for rate refund is due to the ECR settlement in December 1998.

Note 5: Reallocation of transmission service revenues and related expenses to retail and FERC jurisdictions (KU response to KIUC#3-38(a) page 3 of 4.

Note 6: $6.046 million first year annual amount of KU net retained savings (projected by KU in merger proceeding as $26.312 million times 53% KU share times 50% retained share times .86708 KY retail jur). Reversal of Risk Management Trust refund of $1.852 million less one year amortization of $0.370 million (over 5 years). Reversal of Year 2000 expense of $0.960 million less one year amortization of $0.192 million (over five years).

KENTUCKY UTILITIES COMPANY
SUMMARY OF COST OF CAPITAL
12 MONTHS ENDING DECEMBER 31, 1998
($000)

	Capital $ w/o ITC (1)	Capital % without ITC	COC w/o ITC (2)	Wtd COC without ITC	Capital $ with ITC	Capital % with ITC	COC with ITC	Wtd COC with ITC	Capital $ ITC Alloc
Long and Short Term Debt	543,584	45.83%	6.99%	3.20%	532,077	44.08%	6.99%	3.08%	541,909
Preferred Equity	39,799	3.36%	5.64%	0.19%	40,000	3.31%	5.64%	0.19%	40,739
Common Equity	602,808	50.82%	9.55%	4.85%	612,562	50.75%	9.55%	4.85%	623,881
Total Capitalization	1,186,191			8.25%	1,184,639				
Investment Tax Credit (3)					22,302	1.85%	0.00%	0.00%	
Total Capitalization with ITC					1,206,941			8.12%	1,206,529

Note 1: Capitalization amounts are for total Company and were provided by Company in supplemental response to Commission Question No. 11 parts (a) and (b) attached to Commission Order dated December 2, 1998.

Note 2: Cost of debt and preferred were provided by Company in response to PSC-4-KU-10(c). Cost of common provided by KIUC witness Baudino.

Note 3: Obtained from KU 1998 SEC Form 10-K page 153.

KENTUCKY UTILITIES COMPANY
SUMMARY OF RATE BASE
12 MONTHS ENDING DECEMBER 31, 1998
($000)

	Unadjust Total KU	Unadjust "Other Juris"	Unadjust "KY Retail Juris"	Adjust to "KY Retail Juris"	Adusted "KY Retail Juris"
Plant in Service	2,602,167	368,761	2,233,406	NA	2,233,406
CWIP	83,361	10,516	72,845	NA	72,845
Accumulated Depreciation	(1,208,183)	(177,620)	(1,030,563)	NA	(1,030,563)
Accumulated Deferred Inc Taxes (Net)	(291,840)	(44,302)	(247,538)	NA	(247,538)
Fuel Inventories	23,927	3,432	20,495	NA	20,495
M&S Inventories	24,248	3,502	20,746	NA	20,746
Net Regulatory Assets/Liabilities	(26,999)	(3,702)	(23,297)	NA	(23,297)
Customer Deposits	(10,354)	(659)	(9,695)	NA	(9,695)
Customer Advances	(1,265)	(53)	(1,212)	NA	(1,212)
Investment Tax Credit	(22,302)	(3,719)	(18,583)	NA	(18,583)
Total Rate Base	1,172,760	156,156	1,016,604	NA	1,016,604

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY
CASE NOS. 98-426 AND 98-474

Response to KIUC's 3rd Data Request dated April 30, 1999

Question: KIUC#3-12 Responding Witness: Ronald L. Willhite

Q-12 Provide all documents, memoranda, and other written information to support the assertion that off-system sales are expected to decrease by 40% by 2001.

a) Explain how this forecast includes the added capacity available to KU and LG&E from the two 164 MW CT's currently being built at the Brown site.

b) Explain how this forecast includes the new all requirements sale by KU to the municipal electric system of Pitcarin, Pennsylvania.

A-12. Please see the response to AG Data Request No. 96.

a) The forecast levels of off-system sales include three major considerations: available capacity, native load, and the forward price curve. The CTs being built at the Brown site are included in off-system sales forecast simulations. As such, the CTs increase the amount of capacity available to KU and LG&E. However, the forecast for native load also increases over the period. The magnitude of the increase in native load is partially offset by the increase in available capacity provided by the CT addition. The third factor is the forward price curve, i.e., expected market prices for power for future time periods. Forward prices have a significant impact on the off-system sales forecast because those prices determine how much power may be sold on an economic basis. Data that represent the decline in forward prices is provided in the attached Question AG-16 in PSC Case No. 99-056.

b) The load requirements of the Borough of Pitcarin are included in the KU base load forecast. As such, the sale is included in the forecast for future off-system sales.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY
CASE NO 99-056

Response to Attorney General's 1st Data Request Dated April 1, 1999

Question: AG-16 Responding Witness: James Kasey

Q-16. On page 9 of his testimony, Mr. Kasey provides January and February forward prices for the summer of 1999. Please provide the present forward prices for future months for power as far into the future as prices are available. For these prices please provide details of the type of power (ex. on-peak 5x16).

A-16. As of April 8, 1999, the following are the prices in $/MWh for 50 MW of On-Peak (5x16 excluding holidays) firm power with liquidated damages delivered into Cinergy with Seller's choice of interface. (Where two or more months are listed together, the months trade as a package for the same price per MWh.) These prices are subject to change on a daily basis.

Term	Bid ($/MWh)	Offer ($/MWh)
May 1999	26.00	26.30
Jun 1999	51.00	52.50
Jul & Aug 1999	104.00	110.00
Sep 1999	32.50	33.50
Q4 1999	24.00	24.40
Jan & Feb 2000	28.25	29.00
Mar 2000	23.25	24.50
Apr 2000	21.75	23.00
May 2000	25.50	26.25
Jun 2000	44.00	48.00
Jul & Aug 2000	80.00	86.00
Jul & Aug 2001	70.00	77.00