BOEHM, KURTZ & LOWRY
ATTORNEYS AT LAW
36 EAST SEVENTH STREET
SUITE 2110
CINCINNATI, OHIO 45202
TELEPHONE (513) 421-2255
TELECOPIER (513) 421-2764

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MAR 23 2004
PUBLIC SERVICE COMMISSION

VIA OVERNIGHT MAIL

March 22, 2004

Thomas M. Dorman, Esq.
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: **Case No. 2003-00433 and 2003-00434**

Dear Mr. Dorman:

Please find enclosed the original and twelve copies each of the following: 1) Direct Testimony and Exhibits of Lane Kollen on behalf of Kentucky Industrial Utility Customers, Inc., 3) Direct Testimony and Exhibits of Richard A. Baudino on behalf of Kentucky Industrial Utility Customers, Inc.; and 3) Direct Testimony and Exhibits of Stephen J. Baron on behalf of Kentucky Industrial Utility Customers, Inc. filed in the above-referenced matters.

By copy of this letter, all parties listed on the attached Certificate of Service been served. Please place this document of file.

Very Truly Yours,

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Attachment
cc: Certificate of Service
Richard Raff, Esq.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by mailing a true and correct copy, by regular U.S. mail (unless otherwise noted) to all parties on the 22nd day of March, 2004.

Michael S. Beer, Vice President, Rates & Regulatory
Louisville Gas and Electric Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40232-2010

Honorable Elizabeth E. Blackford
Office of the Attorney General
Utility & Rate Intervention Division
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601-8204
betsy.blackford@law.state.ky.us

Mr. Kent W. Blake, Director, Regulatory Initiatives
Louisville Gas and Electric Company
220 W. Main Street, P. O. Box 32010
Louisville, KY 40232-2010

Honorable David R. Brown
Stites & Harbison
421 West Main Street, P. O. Box 634
Frankfort, KY 40602-0634

Honorable Joe F. Childers
201 West Short Street, Suite 310
Lexington, KY 40507
childerslaw@yahoo.com

Honorable Lisa Kilkelly
Legal Aid Society
425 West Muhammad Ali Boulevard
Louisville, KY 40202
lkilkelly@laslou.org

Honorable David A. McCormick
DAJA-RL 4118
901 N. Stuart Street, Room 700
Arlington, VA 22203-1837

Honorable Linda S. Portasik
Senior Corporate Attorney
Louisville Gas and Electric Company
220 W. Main Street, P. O. Box 32010
Louisville, KY 40232-2010
linda.portasik@lgeenergy.com
Via Electronic Mail and Overnight Mail

Honorable Kendrick R. Riggs
Ogden, Newell & Welch, PLLC
1700 Citizens Plaza, 500 West Jefferson Street
Louisville, KY 40202
kriggs@ogdenlaw.com
Via Electronic Mail and Overnight Mail

Honorable Iris Skidmore
Office of Legal Services
Natural Resources and Environmental
Protection Cabinet
5th Floor, Capital Plaza Tower, 500 Mero Street
Frankfort, KY 40601
iris.skidmore@ky.gov

Honorable Allyson K. Sturgeon
Ogden, Newell & Welch, PLLC
1700 Citizens Plaza
500 West Jefferson Street
Louisville, KY 40202
asturgeon@ogdenlaw.com

Honorable Robert M. Watt, III
Stoll, Keenon & Park, LLP
300 West Vine Street, Suite 2100
Lexington, KY 40507-1801
watt@skp.com

John Wolfram
Manager, Regulatory Policy/Strategy
Louisville Gas and Electric Company
220 W. Main Street, P. O. Box 32010
Louisville, KY 40232-2010

Michael L. Kurtz, Esq.

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PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	CASE NO. 2003-00434

DIRECT TESTIMONY AND EXHIBITS OF LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

MARCH 2004

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	**CASE NO.**
KENTUCKY UTILITIES COMPANY	)	**2003-00434**

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS, AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	CASE NO. 2003-00434

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"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree from the University of Toledo. I also earned a Master of Business Administration degree from the University of Toledo. I am a Certified Public Accountant, with a practice license, and a Certified Management Accountant.

I have been an active participant in the utility industry for more than twenty-five years, both as an employee and as a consultant. Since 1986, I have been a consultant with Kennedy and Associates, providing services to state government agencies and large consumers of utility services in the ratemaking, financial, tax, accounting, and management areas. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions encompassing accounting, tax, financial, and planning functions.

I have appeared as an expert witness on accounting, finance, ratemaking, and planning issues before regulatory commissions and courts at the federal and state levels on more than one hundred occasions. I have developed and presented papers at industry conferences on ratemaking, accounting, and tax issues.

I have testified before the Kentucky Public Service Commission on numerous occasions, including the two most recent Louisville Gas and Electric Company ("LG&E" or "Company") base rate cases, Case Nos. 90-158 and 98-474; the most recent Kentucky Utilities Company ("KU" or "Company") base rate case, 98-426; the merger proceeding, Case No. 97-300; numerous LG&E and KU environmental cost recovery ("ECR") and fuel adjustment clause ("FAC") proceedings, and proceedings involving Kentucky Power Company ("KPC" or "Company") and Big Rivers Electric Corporation. Most recently, I filed testimony before the Commission in the LG&E and KU Earnings Sharing Mechanism ("ESM") proceedings, Case Nos. 2003-0335 and 2003-0334, respectively. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a group a large users taking electric service on the KU system.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the revenue requirement requests of KU for electric service, to address the continuation or termination of the ESMs as an alternative form of regulation, and to address the change in base rates that should occur upon the expiration of the merger savings surcredit and the expiration of the VDT surcredit.

Q. Please summarize your testimony.

A. I recommend that the Commission reduce the Company's requested electric base rate increase for the issues listed and amounts quantified on the following table. I address each of these issues, except for the return on common equity, which Mr. Baudino addresses, and quantify the effects of each issue on the revenue requirements.

Kentucky Utilities Company
Summary of KIUC Revenue Requirement Issues

Issues	$000
Operating Income Adjustments	
Unbilled Revenues	-$675
Imputed Lost Revenues - NAS Rate Switching	$1,899
O&M - Labor Savings VDT	$6,121
O&M - Pension and OPEB	$3,015
O&M - Amortization of Ice Storm Costs	$1,319
O&M - OMU NOx Expense	$1,960
Depreciation - Gross Salvage and Cost of Removal	$19,817
Depreciation - Post Test Year Plant Additions	$5,700
Rate of Return Adjustments	
Return on Common Equity	$29,538
Additional Annualized Reduction	$68,694
KU Claimed Revenue Deficiency	-$58,254
KIUC Adjusted Revenue Surplus	$10,440

I also recommend that the Company's ESM be discontinued. I recommend that the ESM surcharge based on the test year 2003 be discontinued on the effective date of any electric base rate increase authorized in this proceeding. The Commission should consider the ESM terminated by virtue of the Company's filing of its electric base rate increase request in December 2003.

The Commission should not allow two alternative and mutually exclusive forms of regulation to remain in effect simultaneously. The simultaneous operation of two ratemaking paradigms could not have been envisioned by the Commission when it offered the Company the choice of the ESM or continued traditional regulation in Case No. 98-426. It cannot possibly meet the statutory requirement for just and reasonable rates.

The simultaneous operation of two ratemaking paradigms will result in excessive rates through rate pancaking and the simultaneous imposition of two separate rate increases. Under both ratemaking paradigms, base rates are set prospectively. The ESM was not established as a historic test year true-up mechanism, despite the Company's position to the contrary.

If the Commission does not terminate the ESM surcharge upon the effective date of any rate increase from this proceeding, and continues the ESM, then the Commission should annualize the rate increase for the ESM 2004 test year in the same manner that it annualized the rate reduction for the ESM 2000 test year when it was initially implemented.

In addition, I recommend that the Commission specifically order in this proceeding that base rates be reduced by the amounts included in the revenue requirement for the merger savings surcredit upon its expiration in 2008 and for the VDT surcredit upon its expiration in 2006. Base rates pursuant to the ESM would have been adjusted annually to reflect the removal of these amounts; however, base rates determined in this proceeding will not be adjusted downward upon the expiration of these surcredit amounts unless the Commission specifically directs the Company to do so.

Finally, I recommend that the Commission adopt a System Sales Clause to share off-system sales margins between the Company and ratepayers patterned after the System Sales Clause currently in effect for Kentucky Power Company. The System Sales Clause would share 50% to the Company and 50% to the ratepayers the net change in offsystem sales margins compared to the margin reflected in base rates.

II. REVENUE REQUIREMENT

Unbilled Revenues

Q. Please describe the Company's adjustments to remove unbilled revenues for ratemaking purposes.

A. The Company has increased electric operating revenues by $0.675 million to remove unbilled revenues for ratemaking purposes from its per books test year revenues. The Company's adjustment converts the Company's revenue accounting from the unbilled revenues methodology it actually uses for per books accounting purposes to a meters read methodology for ratemaking purposes.

Q. Please describe the difference between the unbilled revenues and meters read methodologies for recognizing revenues.

A. The Company recognizes actual revenues on its accounting books based upon the unbilled revenues methodology. The unbilled revenues methodology matches the revenues in the month with the service provided and the costs incurred to provide that service. The unbilled revenues methodology adjusts the billed revenues in the month to properly recognize the revenues actually earned in the month based on the electricity delivered. It removes the effects on revenues of delays in meter reading and billing due to the fact that all meters are not read and bills issued on the last day of the month in which the service was provided. Each month, the Company quantifies and accrues the unbilled revenues for that month and reverses the accrual for the preceding month. The reason the accrual for the preceding month is reversed is that the preceding month unbilled revenues actually are billed in the current month. Unbilled revenues may be positive or negative.

In contrast to the unbilled revenues methodology, the meters read methodology recognizes revenues on a lagged basis only after meters are read and bills are issued. There is no match in any given month between the revenues recognized and the service provided because a portion of the billings in the month are due to service provided in the preceding month and do not include billings for all the service provided in the current month.

Q. Has the Commission previously addressed the issue of whether the Company's revenues should be adjusted from the unbilled revenues methodology actually used by the Company to the meters read methodology for ratemaking purposes?

A. No. The Commission has not specifically addressed the issue of whether the Company should be allowed to restate its revenues for ratemaking purposes to a methodology the Company no longer uses. However, in Case No. 8624, the Commission did not adopt an adjustment proposed by the Attorney General to restate revenues from the meters read methodology then used by KU for both accounting and ratemaking purposes to the unbilled revenues methodology for ratemaking purposes. Since Case No. 8624, the Company has changed its accounting for revenues to reflect the unbilled revenues methodology.

Q. Should the Commission accept the Company's adjustment to restate its per books accounting revenues to utilize the meters read methodology?

A. No. There is no principled basis to accept this adjustment. First, the adjustment does not comport with reality. Second, it creates an inappropriate difference between the revenues for ratemaking and accounting. Third, it creates a ratemaking mismatch between the revenues that should be and actually were recognized compared to the service and costs to provide that service actually incurred during the test year.

<u>Imputed Lost Revenues from NAS Rate Switching</u>

Q. Please describe this adjustment proposed by the Company.

A. The Company proposes to reduce revenues by $1.899 million to reflect its estimate of the effects of a customer , North American Stainless ("NAS"), switching from a special contract rate to KU's proposed Non-Conforming Load Service Rate (NCLS) with interruptible service.

Q. Should the Commission adopt this proposed adjustment?

A. No. There has been no switching and there has been no loss of revenue. The Commission has a pending case, Case No. 2003-396, in which it will consider this proposed transfer, along with the potential effect on both NAS and KU. It is my understanding that there is significant disagreement between NAS and KU over the issues, including the ability of NAS to accept the terms of the proposed NCLS tariff, how NAS will respond depending on the Commission's decision in that case, and the resulting revenue effect on NAS and KU.

At this time, any quantification of the revenue effect is speculative and effectively would prejudge the outcome of another pending proceeding. The effects of the Commission's decision on the revenues from NAS to KU, whether an increase or a decrease and how much, can be addressed in KU's next base rate proceeding along with all other future changes in KU's revenue requirement.

<u>Operation and Maintenance Expense – Failure to Achieve Labor Savings from VDT</u>

Q. Please describe the premise underlying the incurrence by the Company of $56.300 million in severance costs related to its workforce reduction program initiated in the first quarter 2001.

A. The premise underlying the incurrence of this huge cost was that the Company would achieve savings by reducing the number of employees. Some positions were to be eliminated permanently, some were to be filled with lower cost employees, and some were to be eliminated permanently but effectively filled through the use of contractors. The Company projected that savings over five years would exceed the costs of the employee buyout.

Q. Please describe the ratemaking treatment of the employee buyout costs and the projected savings.

A. In Case No. 2001-169, the Company sought to defer the entirety of the employee buyout costs and to amortize the deferred debits as an expense recoverable through its annual Earnings Sharing Mechanism filings. Pursuant to a settlement of the ratemaking treatment of these costs and savings, along with other issues in other proceedings, the Company was allowed to defer the employee buyout costs and amortize them over five years. The Company agreed to provide 50% of the projected savings to ratepayers through a value delivery ("VDT") surcredit. In addition, the Company was allowed to include 50% of the projected savings as an expense in its annual ESM filings in 2001 and 2002 and in any "successor earnings sharing ratemaking mechanism."

Q. What was the effect of this ratemaking treatment in the ESM proceedings?

A. In 2002 and 2003, the Company was below the lower threshold of the ESM return on equity deadband. As such, it was or will be able to recover from ratepayers at least 40% of the VDT amortization expense, at least 40% of the savings amounts that were flowed through the VDT surcredit, and at least 40% of the retained savings it included as an expense.

Q. How has the Company reflected this ratemaking treatment in its filing in this proceeding and what is the effect?

A. The Company has included the entirety of the VDT amortization expense, 100% of the savings amounts that were flowed through the VDT surcredit, and 100% of the retained savings as an expense adjustment, which it has included as Adjustment 23, reflected on Rives Exhibit 1 Reference Schedule 1.20. The Company has included $11.500 million for the VDT amortization, $1.930 million for the VDT surcredit, and $2.895 million for the retained savings as an expense adjustment. In total, the Company has included $16.325 million for the workforce reduction costs in its revenue requirement.

Q. What labor savings amounts actually were reflected in the Company's filing compared to the costs it incurred in 2000, the year prior to the implementation of the VDT?

A. The Company claims that it is unable to quantify the labor savings. However, it was able to quantify its direct labor costs in total and separated between expense and capital in response to PSC 1-23(c). In the test year, its total direct labor, including the costs charged from Servco, the LG&E Energy mutual services company, was $77.779 million. In 2000, the year prior to the workforce reduction program, its total direct labor was $76.612 million. The comparable expense amount for the test year was $63.392 million and for 2000 was $65.817 million. In other words, the actual total direct labor savings were nonexistent, or negative $1.167 million. There was only $2.425 million in expense savings ($2.154 million Kentucky jurisdictional). I have replicated the Company's response to PSC 1-23(c) as my Exhibit___(LK-2).

Q. How do the actual labor cost savings in the test year from 2000 compare to the costs of the workforce reduction included in the revenue requirement?

A. The were no savings in total direct labor costs. The expense savings represents only 13% of the workforce reduction costs included in the revenue requirement by the Company in this proceeding.

Q. Does this comparison include all the costs that have been incurred in the test year compared to the year before the workforce reduction?

A. No. It does not include any increases in contractor costs incurred by the Company due to reductions in employees. In addition, it does not include the related costs of pensions, other postretirement benefits, or any other overhead costs, all of which would have or should have been lower if indeed the Company had reduced its direct labor costs to the levels used to justify the VDT deferral and amortization.

Q. Do you recommend that the Commission disallow a portion of the O&M expense due to the Company's failure actually to achieve savings that equaled or exceeded the cost of the employee buyout?

A. Yes. I recommend that the Commission disallow at least 50% of the net harm to ratepayers from the Company's failure to achieve these labor savings. The disallowance at 50% is $6.121 million. I have computed the net harm to ratepayers as $12.241 million, consisting of the total $16.325 million included in the filing to recover these costs less the $1.930 million returned to ratepayers through the VDT surcredit, and less the $2.154 million (KY jurisdictional) in direct labor expense savings reflected in the filing.

The Commission has an obligation to ensure that rates are just and reasonable. It is not just and reasonable for ratepayers to bear the burden not only of the costs of the workforce reduction, but also the imputed savings retained by shareholders, the sum of which are substantially in excess of the direct labor savings actually achieved. It would be reasonable for the Commission to disallow the entirety of the workforce reduction costs included that exceed the direct labor achieved savings.

<u>Post Test Year Adjustment to Increase Pension and Post Retirement Benefit Expense</u>

Q. Please describe the Company's request to increase pension and post-retirement benefit expense.

A. The Company proposes a selective post test year adjustment to increase its pension and post-retirement benefit expense to projected 2004 levels. These projections are preliminary estimates based upon computations provided by Mercer prior to the filing of the Company's case. However, the actual pension and postretirement benefit expense booked in 2004 will be based, in part, upon actual December 31, 2003 plan assets and obligations, which were not available and therefore, could not be known and measurable at the date the Company prepared its rate case filing, let alone at the date it was actually filed.

Q. Please describe the basis for your conclusion that the projections relied upon by the Company were preliminary estimates and are not known and measurable at the date the Company prepared its rate case filing.

A. The Company's proforma adjustment relies upon certain "disclosure statements," which Mercer prepared prior to December 31, 2003. The Company has not yet received an actuarial study from Mercer for 2004, according to its responses to PSC 2-16(e) and KIUC 1-88. Indeed, Mercer could not have prepared or released such an actuarial study because actual December 31, 2003 information was not yet available for that purpose. Thus, the disclosure statements, of necessity, were predicated upon estimates in lieu of actual amounts for the December 31, 2003 valuations. The actual December 31, 2003 valuation ultimately will be determined by Mercer to compute the Company's 2004 pension and postretirement benefit expense, not the estimates it prepared based on December 31, 2003 projections for the Company's rate case filing. It isn't at all clear what assumptions Mercer made on behalf of the Company to project the December 31, 2003 valuations for this purpose. Nevertheless, it is clear that the Company will book its 2004 pension and post retirement benefit expense based upon actual December 31, 2003 valuations, not the estimates prepared by Mercer for use by the Company in its rate case filing.

The Company was asked to provide the actuarial report relied on for its adjustment in PSC 2-16(e) and KIUC 1-88. The Company's response to PSC 2-16(e) stated "Please see that attached actuarial reports from Mercer for the fiscal year ending December 31, 2002. The actuarial reports from Mercer for the fiscal year ending December 31, 2003 are not yet available." However, that representation is not correct. A reading of the titles of the actuarial reports provided by LG&E in its response indicate that these were the actuarial reports relied upon for the Company's pension and postretirement benefit expense actually booked in calendar year 2003. The titles of the actuarial reports for LG&E are as follows, with all indicating that they are for the year 2003, not 2002:

- LG&E Energy Corp. Retirement Plan; Revised Actuarial Valuation Report As of January 1, 2003 for the Plan Year and Taxable Year Ending December 31, 2003 Including FAS 87 Expense for the Fiscal Year Ending December 31, 2003 (dated October 2003).

- Louisville Gas and Electric Company Bargaining Employees' Retirement Plan; Actuarial Valuation Report As of January 1, 2003 for the Plan Year and Taxable Year Ending December 31, 2003 Including FAS 87 Expense for the Fiscal Year Ending December 31, 2003 (dated September 2003).

- LG&E Energy Corp. Postretirement Benefit Valuation Report Under FAS 106; Expense for the Fiscal Year Ending December 31, 2003 (dated December 2003).

Q. Should the Commission accept the Company's proforma adjustment to increase pension and postretirement benefit expense?

A. No. First, this adjustment represents a selective post test year adjustment to increase the Company's revenue requirement. As such, it is one-sided and inequitable. It violates the test year principle of consistent quantification of all components of the revenue requirement. If the Commission accepts this post test year adjustment, then it should also make other post test year adjustments. For example, it could increase revenues to reflect expected customer growth in 2004. It could project increased off-system sales revenues due to the significant capacity additions when the Trimble County gas turbines commence operation in 2004. It could project reduced O&M expense for 2004 due to the substantial nationwide increases in productivity that exceed inflation as measured by the Bureau of Labor Statistics.

Second, the estimates relied on by the Company are not known and measurable. They do not reflect actual valuations as of December 31, 2003, consistent with the manner in which the Company relied on the Mercer actuarial reports for 2003. Third, they are estimates that cannot be verified based on the schedules provided in response to discovery.

Nonrecurring Expenses and Credits

Q. Please describe the adjustment the Company made to defer and amortize the costs associated with the ice storm during the test year.

A. The Company reduced expense by $5.277 million to reflect a five-year amortization of the Company's costs net of insurance recovery rather than by $6.597 million to remove this nonrecurring cost altogether, thus including $1.319 million in amortization expense in the revenue requirement for this cost.

Q. Should the Commission allow the Company to defer and amortize the ice storm amount?

A. No. This nonrecurring amount was subject to the ESM for the 2003 test year. As such, it is necessary to remove this nonrecurring amount in its entirety to set base rates prospectively. It would be inappropriate to allow the Company to recover these costs through the ESM surcharge and also the through base rates set in this proceeding. It should be noted that LG&E simply removed two nonrecurring credits to expense (for LG&E corporate office lease expense and the Cane Run insurance recovery) that occurred during the test year. As I noted in my LG&E testimony, I agree with the removal of these nonrecurring credits, but only if all nonrecurring costs are treated consistently for each Company and between the two Companies.

OMU NOx Expense

Q. Please describe the Company's request to include an adjustment to increase operating expenses for the OMU NOx compliance.

A. The Company's has included a selected post test year adjustment to increase purchased power expenses by $1.960 million for costs associated with OMU NOx compliance.

These costs are related to OMU debt service that KU must commence paying on July 1, 2004 and are estimated.

Q. Should the Commission allow this post test year expense in the revenue requirement?

A. No. First, this is a selective post test year adjustment with no consideration of other test year revenue requirement components that could reduce the revenue requirement. Second, the Company could seek to have the Commission include such costs in its environmental compliance plan and recover them through the ECR once they are known and measurable.

Depreciation Expense – Gross Salvage and Cost of Removal

Q. Please describe how net salvage on interim retirements is reflected in the Company's proposed depreciation rates.

A. The Company includes net salvage on interim retirements as an increase to its proposed depreciation rates if the property grouping has projected net negative salvage (cost of removal exceeds gross salvage proceeds) and as a reduction to its proposed depreciation rates if the property grouping has projected net salvage (gross salvage proceeds exceed cost of removal).

In its depreciation study, the Company multiplies the net negative salvage rate against the interim retirement rate to determine the estimated net future salvage on estimated interim retirements. The Company then adds the estimated net future salvage on estimated interim retirements to the estimated net terminal salvage in order to compute the total net salvage rate. These computations are detailed on Table 2-a in Section 2 of the AUS depreciation study. I have replicated Table 2-a as my Exhibit___(LK-3).

The total net salvage rates from Table 2-a are multiplied by the original plant in service amounts to compute the net salvage dollars for each property grouping. The net salvage dollars are in turn added to the original plant in service amounts to compute the depreciation expense and depreciation rate based on the average remaining life for the property grouping. These latter computations are detailed on Table 2 in Section 2 of the AUS depreciation study. I have replicated Table 2 as my Exhibit___(LK-4).

Q. Please describe the methodology utilized by the Company to compute the net salvage on interim retirements included in its proposed depreciation rates.

A. The AUS depreciation study analyzed historic gross salvage and historic cost of removal by FERC plant account. The AUS analyses are detailed in Section 7 of the study and were performed by FERC plant account based upon actual historic data from the Company's property accounting records.

For gross salvage, the AUS depreciation study computed 3 year rolling bands, and from that data, computed the average actual historic gross salvage rate, and computed a 20-year trend rate, a 15-year trend rate, a 10-year trend rate, and a 5-year trend rate. In lieu of the average actual historic gross salvage rate, the AUS depreciation study then simply utilized the 5-year trend rate as the gross salvage rate against which it would net the proposed cost of removal rate. . For some FERC plant accounts, the gross salvage rate derived by AUS using this methodology actually is negative, meaning that gross salvage is represented in the proposed depreciation rates as an additional cost of removal.

For cost of removal, the AUS depreciation study utilized the average of the actual data for the 20-year period, but then escalated the historic average to the midpoint of the average remaining service life by a projected annual inflation factor of 2.75%. This methodology had the effect of significantly increasing the cost of removal, and thus, the depreciation rates, for most property groupings. For some FERC plant accounts, the cost of removal rate was increased by several fold compared to the actual historic data for cost of removal.

Q. Should the Commission utilize the 5-year trend for gross salvage on interim retirements?

A. No. The Commission should utilize the average of the actual historic data. First, the actual data correctly establishes the relationship between gross salvage and interim retirements. There is no reason to assume that this known and measurable relationship will change in the future.

Second, the depreciation study substitutes a percentage trend for the actual gross salvage rate. Aside from the fact that the study utilizes the lowest percentage trend for the gross salvage rate, a problem in and of itself, a trend is itself meaningless and inappropriate to apply to estimated interim retirements.

Q. Should the Commission adjust the actual historic cost of removal rate for projected inflation?

A. No. The Commission should utilize the average of the historic data. The historic data already reflects labor escalation in the year of the interim retirement compared to the vintage original plant cost of the retirement. As such, in future years, the same relationship is likely to hold as older vintage plant is retired. The Company has offered no evidence to demonstrate that the historic relationship will not hold prospectively.

The only rationale offered by the Company for this inflation factor is that labor costs will increase in the future. Yet inflation in labor costs already is reflected in the historic cost of removal compared to the older vintage plant that was retired. In the past, the labor costs included in the historic cost of removal also have increased due to inflation. The AUS study utilizes the current cost of removal in those historic years divided by the older vintage plant dollars that were retired in order to compute the cost of removal percentage for that year. As such, the effects of inflation already are reflected in the actual historic data. The Company's proposal to further increase the cost of removal double counts the effects of inflation by adding more inflation to the inflation already reflected in the actual historic data. The Commission should reject this methodology.

In addition, the Company's application of an inflation rate to the historic cost of removal represents a significant post test year adjustment, reaching forward many years into the future based on the average remaining service life of the property grouping. As I subsequently discuss in conjunction with the Company's inclusion of post test year NOx compliance plant additions, the Commission in the past has rejected attempts to include post test year costs on a selective basis such as this. The Commission should reject this methodology.

Q. Have you quantified the effects on the depreciation rates and the resulting depreciation expense of using the actual historic gross salvage and cost of removal rates on interim retirements (for electric production) and retirements (for electric non-production plant accounts)?

A. Yes. The effect on the depreciation rates and on test year depreciation expense is summarized on my Exhibit___(LK-5). For electric production, I first corrected the net salvage rates for interim retirements on the spreadsheet underlying Table 2-a. I used the resulting interim retirement percentages from the corrected Table 2-a in the spreadsheet underlying Table 2 to recompute the depreciation rates by FERC production plant account. In the next step of the computation, I used another spreadsheet provided by the Company to recompute the depreciation rates by production plant location using the recomputed depreciation rates for the production FERC plant accounts. To correct the net salvage rates on the spreadsheet underlying Table 2-a, I simply used the FERC plant account historic net salvage rates from Section 7 of the depreciation study. In the final step, I computed annualized depreciation expense and the proforma depreciation expense adjustment utilizing the spreadsheet provided by the Company for its

Adjustment 1.11, substituting the corrected electric depreciation rates with the net salvage rates properly computed for the Company's proposed depreciation rates.

For electric nonproduction plant, I utilized the depreciation rates provided by the Company in response to PSC 2-24(b), which recomputed the depreciation rates using the FERC plant historic net salvage rates from Section 7 of the depreciation study. To compute annualized depreciation expense and the proforma depreciation expense adjustment, I utilized the spreadsheet provided by the Company for its Adjustment 14, Rives Exhibit 1 Reference Schedule 1.11, substituting the corrected nonproduction plant depreciation rates reflecting the actual historic net salvage rates for the Company's proposed rates. Although I used the Company's computation of these depreciation rates for nonproduction plant, the results suggest that the Company's computations or data may be in error, at least for some accounts, such as FERC plant accounts 353.1, 356, 362, 364, 365, and 367.

Q. The effect on the depreciation rates reflected on your Exhibit___(LK-5) for electric production plant does not agree with the effect quantified by the Company in response to PSC 2-24(b). Please explain why.

A. The effects quantified by the Company for electric production plant are erroneous. Removing the inflation factor from the cost of removal as requested by the Staff should have resulted in lower net negative salvage for certain production FERC plant accounts, and thus, lower depreciation rates for those plant accounts. Instead, the depreciation rates increased for those accounts. The error appears to be due a change in methodology compared to the depreciation study itself. In the response, the Company applied the actual net salvage rate percentages to the original cost of the assets rather than the interim retirements as it did in the AUS depreciation study. This methodological error in the response to PSC 2-24(b) had the effect of improperly increasing the net salvage reflected in the resulting depreciation rates.

Depreciation Expense – Post Test Year Plant Additions

Q. Did the Company reflect future plant additions in its proposed electric depreciation rates?

A. Yes. The Company included plant additions for NOx emission compliance that it projects for the years 2004-2006. The inclusion of these projected plant additions has the effect of significantly increasing the Company's proposed depreciation rates for FERC plant account 312, the FERC plant account with the largest proposed increase in depreciation rate.

Q. Should the Commission reflect future plant additions in depreciation rates?

A. No. These plant additions represent post test year adjustments and should not be reflected in the depreciation rates and depreciation expense included in the historic test year. These post test year adjustments violate the test year principle of consistency among all revenue requirement components. It is inequitable to selectively include projected post-test year cost increases without updating all revenue requirement components, including post-test year cost reductions and revenue increases that would reduce the revenue requirement.

The Commission previously has addressed this very issue of post test year additions and their inclusion in rate base and depreciation expense. In Case No. 90-158, the Commission rejected LG&E's request to include post test year Trimble County plant additions in the revenue requirement. It stated in that Order that "The Commission cannot and will not include in rate base the post test-period plant additions for Trimble County or the related first year depreciation expense. To do otherwise would disregard established, and we feel fair, just and reasonable rate-making practices enunciated and adopted in prior Commission decisions concerning post test-period plant additions."

In addition, the costs to reduce NOx emissions are recoverable by the Company through the ECR surcharge mechanism. Some or all of these projected NOx compliance costs already have been approved by the Commission in conjunction with the Company's ECR compliance plans and are eligible for recovery through the ECR. Thus the Company already has an established cost recovery mechanism in place to recover such costs on a timely basis once they are incurred and are known and measurable. If and when the Company actually incurs these projected NOx compliance costs, and if it is unable recover them through the ECR, then it may seek to recover them through base rates in a future base rate proceeding.

Finally, if the Commission allows depreciation rates to be increased for post test year projected capital additions for NOx compliance, then there no longer will exist any test year boundary requiring the exclusion of any post test year capital additions. Unfortunately, such a precedent could be relied upon by the Company or other Companies in the future to justify other selective post test year adjustments that will increase their revenue requirements.

Q. Have you quantified the effects on the depreciation rates and the resulting depreciation expense of removing the future plant additions projected for NOx compliance from FERC plant account 312?

A. Yes. I have quantified the effects of removing the future plant additions projected for NOx compliance from FERC plant account 312 as an additional adjustment to the depreciation rates by FERC production plant location and depreciation expense previously computed with the removal of the Company's adjustments to historic gross salvage and cost of removal rates. The quantification is summarized on my Exhibit___(LK-6). In the final step, I utilized the rates that I previously computed in "present rates" column lieu of the Company's present rates in order to quantify the incremental effects of this recommendation compared to my preceding recommendation.

Return on Common Equity

Q. Have you quantified the effect on the Company's revenue requirement of KIUC witness Mr. Baudino's recommendation for the required return on common equity?

A. Yes. I utilized the Company's cost of capital obtained from Rives Exhibit 2 and simply replaced the Company's requested return on common equity with Mr. Baudino's recommendation of 8.7%. The Company's requested return on common equity of 11.25% translates to a grossed-up return recoverable from ratepayers of 18.99%.

KIUC's recommended return on common equity translates to a grossed-up return recoverable from ratepayers of 14.69%. The quantification of the revenue requirement effect is detailed on my Exhibit___(LK-7).

III. TERMINATION OF THE EARNINGS SHARING MECHANISM

The ESM should be Terminated; It is Not a Supplemental Form of Regulation

Q. Should the Commission discontinue the ESM?

A. Yes. Although the ESM represented a reasonable alternative to the traditional form of regulation during the trial period, it no longer is reasonable or an alternative. To the contrary, the ESM likely will harm ratepayers through two simultaneous forms of regulation, resulting in the combination of traditional base rate increases and annual ESM rate increases. There no longer is any need to utilize the ESM as a means to transition to potential deregulation. It is highly unlikely that Kentucky will deregulate in the foreseeable future. In addition, the ESM has not served to reduce costs or improve the quality of service. In any event, particularly in a period of increasing costs, traditional regulation provides a greater incentive to reduce costs than does ESM regulation because the Company retains the entire benefit of any such cost reductions between traditional base rate increases.

Q. How have circumstances changed since the Commission offered the Company the ESM as an alternative form of regulation in lieu of traditional regulation?

A. First, the Company filed for substantial base rate increases in December 2003 pursuant to traditional ratemaking, thus belying the notion that the ESM is an alternative form of regulation. The net import of the Company's decision to file for a traditional base rate increase is that any increase from such a filing will be effective mid-year 2004, which will follow in short order the anticipated 2003 ESM increases that will be effective in April 2004, and which will again be compounded by the anticipated 2004 ESM increases that will be effective in April 2005 and continue through March 2006.

Second, the Company now projects increasing costs, at least through 2006, according to financial projections developed by the Company and shared with BWG during the conduct of the management audit. Also, the Company plans to add additional generating capacity in the next two years, according to recent press releases announcing its intent to file for a traditional base rate increase in December 2003. These increases in costs have the potential to result in additional traditional base rate increases compounded by a continuing series of annual rate increases pursuant to the ESM.

Third, deregulation of generation in Kentucky and nationwide no longer appears inevitable or even likely. The ESM was conceived, according to statements by the Commission in its Case Nos. 98-426 Order, as an interim step toward the potential deregulation of generation and the related market pricing for such generation.

Fourth, the Company acknowledges that the ESM has not operated to reduce costs or improve the quality of service. The Company attributes any reductions in costs or improvements in the quality of service that have been achieved to its own independent initiatives undertaken for the benefit of their shareholder.

Q. Does the Company view the ESM as an *alternative* form of regulation or as a *supplemental* form of regulation?

A. The Company clearly views the ESM as a supplemental form of regulation that can exist simultaneously with the traditional cost of service form of regulation. As evidenced by its request for a substantial base rate increase in this proceeding, the Company does not consider the ESM to be a mutually exclusive form of regulation precluding the filing of traditional base rate cases. In Case No. 2003-00334, Company witness Mr. Beer states unequivocally that "LG&E and KU have a fundamental statutory right to seek a base rate increase regardless of whether they are operating under an ESM. . . The statutory grants of authority to the Commission from the General Assembly do not provide the Commission the power to alter or amend these rights." (Beer Direct, 4-5).

If the Company legally is correct in its position that the ESM and traditional ratemaking are not mutually exclusive, then the ESM necessarily will operate to supplement the traditional ratemaking process. The ESM provides for annual rate changes, which likely will be increases based on the Company's projection of increasing costs, on an interim basis until traditional base rate increases are implemented. Thus, the ESM will operate as a supplemental form of regulation, not an alternative form of regulation.

Q. Has the ESM operated as an effective incentive to increase the Company's managerial efficiency or to reduce its costs compared to traditional regulation?

A. No. Neither the Company nor the Commission's auditor, Barrington-Wellesley Group ("BWG") have identified a single initiative, cost reduction, or quality of service improvement that was the result of the ESM. To the contrary, the Company's initiatives to achieve efficiency and customer service have been independent of the existence of the ESM. In its Final Report Section V-5, BWG claimed that the ESM had increased managerial incentives. However, in Case No. 2003-00334, Company witness Mr. Beer disputed that conclusion, stating that "This particular finding has no application to companies like LG&E and KU. LG&E and KU will continue in the future, as they have in the past, to operate through innovation and achieve efficiencies with high quality customer service. Thus, while the ESM has not created a new corporate mindset for LG&E and KU, it has served to re-enforce corporate initiatives to achieve efficiency and customer service." (Beer Direct, 6-7).

Q. Does the Company project for the years 2003-2006 that it will earn less than the 10.5% lower threshold of the ESM earning deadband?

A. Yes. The BWG audit report stated that "Current projections indicate that the Companies will remain in an under-earning position for the next several years." (Final Report, I-10). For this conclusion, BWG relied upon the Companies' forecasts for the years 2003-2006 and confirmed these projections in interviews with Mr. Rives and Ms. Scott. The Company also confirmed its projections of underearnings in response to KIUC 1-10 in that proceeding.

Q. What is the significance of the Company's projections that it will underearn the lower threshold of the ESM earnings deadband at least through 2006 absent a traditional rate increase?

A. The Company may file traditional rate increase requests in addition to the request in this proceeding. In addition to these traditional base rate increases, the Company may obtain additional annual rate increases through the ESM, to the extent it is continued.

Q. Does the ESM provide greater incentives to the Company to reduce costs than traditional ratemaking?

A. No. To the extent ratemaking provides any incentives to the Company to reduce costs, then traditional ratemaking provides greater incentives than the ESM simply due to the ability of the Company to retain the entirety of the savings benefits and for longer periods of time. I generally agree with BWG that "COSR provides incentives for the regulated utility to control costs and optimize the utilization of rate base, some of the benefits of such efficiencies eventually flow to the utility's customers. COSR provides short-term immediate incentives to the utility to control costs between rate cases, but a large share of the benefits of efficiency improvements flow to the customers in the longer term." (BWG Report, I-9).

Q. How should the Commission discontinue the ESM?

A. The Commission should discontinue the ESM surcharge related to the ESM 2003 test year effective on the same date as any increase from this proceeding becomes effective.

Q. Why should the Commission discontinue the ESM surcharge related to the ESM 2003 test year effective on the same date as any increase from this proceeding becomes effective?

A. The ESM rate increase and the traditional base rate increase from this proceeding are mutually exclusive pursuant to alternative forms of regulation. Both represent prospective rate increases. The test years for the ESM and the traditional rate increase overlap for nine months, thus effectively providing double recovery of the revenue deficiencies associated with essentially the same revenue requirement. As such, the traditional rate increase from this proceeding will be piled on to the rate increase from the ESM if the ESM surcharge is not terminated on the same date as the traditional rate increase is effective. Doubling up on rate increases for essentially the same test period necessarily results in excessive rates that cannot be just and reasonable.

Q. The Commission allowed the Company to continue the ESM beyond the initial three year period subject to prospective change in Case No. 2002-00472 and retained BWG to conduct a management audit to determine whether the ESM should be continued. BWG issued its Final Report on August 31, 2003, recommending the continuation of the ESM. The Commission initiated "new investigations" of the ESM in its Order in Case No. 2003-00334 dated September 4, 2003. When did the Company decide to develop a traditional base rate filing?

A. The Company made this decision in June 2003 or before. The Company's consultants and counsel retained to support its efforts in this proceeding commenced billing on the project in June 2003, according to the Company's response to PSC 1-57.

Q. What is the significance of the fact that the Company already was preparing a base rate increase filing at the very time the Commission's auditor was conducting the management audit to determine whether the ESM should be continued.

A. This information was a material fact and directly relevant to the very issue being investigated by the Commission. This fact should have been disclosed to the Commission's auditors during the conduct of the management audit so that it could be reported to the Commission, Staff, and other parties with an interest in the Company's rates. Such information could have been considered by the Commission prior to its decision on September 4, 2003 to continue the ESM. It may have resulted in a completely different decision. Such information would have allowed KIUC and other parties to oppose the continuance of the ESM and seek an expedited hearing in order to terminate the ESM prior to the end of 2003.

The Commission should consider the failure of the Company to disclose this critical information to the Commission's auditors on the timing of the termination of the ESM surcharge. The Company's failure to disclose this critical and directly relevant information prior to the Commission's September 4, 2003 Order is an additional reason why the Commission should terminate the surcharge on the effective date of the rate change in this proceeding.

Q. The Company apparently considers the ESM to be a true-up mechanism for the historic period. Do you agree?

A. No. The Commission offered the Company the ESM as an alternative to traditional regulation. The structure of the ESM provides for annual rate changes prospectively on April 1 of the year following the calendar year test year based on that historic test year. The structure of the ESM follows that of traditional ratemaking with the use of a historic test year to set rates prospectively. The ESM simply established an annual and expedited ratemaking process for prospective rate changes, along with a sharing of revenue surpluses and deficiencies outside the earnings deadband.

The ESM did not disturb the fundamental ratemaking principle that base rates may be changed only prospectively. The Company's argument that the ESM operates as a true-up mechanism necessarily rests upon the assumption that the Commission can change a lawful rate retroactively. To the contrary, KRS §278.270 states that "Whenever the Commission, upon its own motion or upon complaint as provided in KRS 278.260, and after a hearing had upon reasonable notice, finds that any rate is unjust, unreasonable, insufficient, unjustly discriminatory or otherwise in violation of any of the provisions of this chapter, the commission shall by order prescribe a just and reasonable rate to be followed in the future."

Just and reasonable rates to be followed in the future may be set under either of the two different methodologies, but just and reasonable rates to be followed in the future cannot be established under two different methodologies based upon a largely overlapping test year and then implemented simultaneously as sought by the Company.

Q. How does the Company's request to implement simultaneous prospective rate increases under two alternative forms of regulation compare to the Commission's initial implementation of the ESM in conjunction with a base rate reduction under traditional ratemaking?

A. When the ESM initially was implemented, the Commission was careful to avoid the simultaneous operation of the two alternative forms of regulation and such doubling up. The base rate reduction based on traditional ratemaking was implemented prospectively on March 1, 2000 and used a 1998 test year. The first ESM rates were implemented prospectively on April 1, 2001 and used a 2000 test year. In contrast, the Company's request in this proceeding utilizes essentially the same test year to determine its revenue deficiencies under both the ESM and traditional forms of ratemaking with the simultaneous prospective implementation of the rate increases.

Q. Is there additional evidence that the Commission considered the ESM to set rates prospectively rather than operate as a true-up mechanism for a historic period?

A. Yes. The Commission offered the Company the ESM in its Order in Case No. 98-426, which the Company accepted in lieu of traditional regulation. The Commission also reduced the Company's base rates in accordance with traditional regulation effective March 1, 2000. Nevertheless, the Commission required the Company to annualize that rate reduction for the ESM test year 2000. Thus, when rates were reset prospectively on April 1, 2001, the rates did not double up the effects of the March 1, 2000 reduction. Consequently, rates were reduced less on April 1, 2001 pursuant to the new form of regulation than if the ESM had operated as a true-up mechanism.

The Company supported this treatment when the ESM was implemented and KIUC agreed with this treatment because the ESM reset base rates prospectively. The Commission should reject the Company's argument now to consider the ESM a true-up mechanism, an argument that is in direct contradiction to the position it took when the ESM was implemented.

Transitioning the ESM if It is Not Discontinued

Q. How should the Commission reflect the mid-year 2004 traditional base rate increases, if any, in the ESM 2004 test year if it is not discontinued?

A. The Commission should annualize the mid-year 2004 rate increases as if they were in effect the entire year.

Q. Why should the Commission annualize the mid-year 2004 traditional base rate increases, if any, in the ESM?

A. Such an approach is consistent procedurally and methodologically with the Commission's annualization of the March 1, 2000 rate reductions in the initial 2000 ESM test year. In Case No. 98-426, the Company specifically sought rehearing on this issue, proposing that the rate reductions be annualized to January 1, 2000 as if they had been in effect the entire year. No party contested the Companies' request. The Commission stated in its Orders on rehearing the following:

> **The impacts of the Orders issued in this proceeding should be reflected in the normalization of LG&E's [KU's] revenues for purposes of the initial ESM review. That initial review will cover LG&E's [KU's] operations for calendar year 2000. Since the Orders in this case were issued during this**

> **calendar year, the Commission finds it reasonable to reflect a full 12 months of the impact of these Orders in the initial ESM review.**

Similarly, the Commission should annualize any rate increases to January 1, 2004 as if they had been in effect the entire year. The precedent has been established, and at the Company's request. There is no valid reason to depart from this precedent simply because the change in base rates is an increase rather than a decrease.

The failure to annualize any rate increases to January 1, 2004 would be inequitable and penalize ratepayers in addition to the excessive and doubled up rates resulting from the ESM 2003 test year coupled with any traditional rate increase in this proceeding. The annualization of the rate reductions in the initial ESM test year decreased the earnings available for sharing with ratepayers. To be symmetrical, just, and reasonable, the Commission should ensure that the rate increases in the ESM 2004 test year increase the earnings available (or reduce the amounts recoverable) for sharing with ratepayers.

<u>The ESM should be Modified If It is Continued</u>

Q. If the ESM is continued, should the Commission consider it as an alternative form of regulation, as originally intended, or allow it to be utilized in addition to

traditional regulation as a supplemental form of regulation between base rate cases?

A. The Commission should decide which form of regulation is appropriate for the Company. If the Commission decides to offer the Company another three years of ESM regulation, then it should include a condition whereby the Company would agree to refrain from filing another traditional base rate increase with an effective date during the term of the ESM regulation and surcharge period. If the Company is unwilling to accept that condition, then the ESM should be discontinued regardless of the other merits of termination.

The Commission should not change the nature of the ESM to provide a supplemental form of regulation in addition to traditional regulation. In Case Nos. 98-426, the Commission offered the Company the ESM as an alternative to traditional regulation, noting in its Orders that "[T]he Commission will now offer LG&E an alternative to traditional regulation in the form of an optional ESM plan." The Commission further noted that "[O]ur Order in Case No. 97-300 specified that LG&E could choose traditional or alternative rate-making."

Q. Should the Commission annualize any mid-year 2004 traditional base rate increases, if it continues the ESM?

A. Yes. Although I discussed this issue previously in conjunction with discontinuing the ESM, the same rationale for such annualization applies if the ESM is continued. The Commission already has established the precedent for such revenue annualizations and at the request of the Company. Thus, there is no valid rationale to argue against such annualizations, regardless of whether the ESM is continued or terminated.

Q. Should the Commission revise the return on equity utilized as the midpoint for the earnings deadband if it continues the ESM?

A. Yes. The Commission should revise the midpoint return on equity to the return authorized in this proceeding for the traditional base rate increase. The Commission should modify the terms of the ESM to reflect changed circumstances. The 11.5% ESM return on equity midpoint was established more than three years ago and does not reflect the current cost of common equity. The midpoint is used to set the upper and lower thresholds of the earnings deadband. The Commission's determination of the proper and current cost of common equity will directly impact the level of the ESM annual rate increases given that the Company projects it will earn below the lower threshold of the current deadband at least through 2006.

Q. **Should the Commission require that the earned returns be computed using average monthly capitalization rather than year-end capitalization?**

A. Yes. The Commission should explicitly require the use of average capitalization if the ESM is continued. This was a contested issue in the Company's initial ESM filing and was resolved through a Global Settlement in Case Nos. 2001-054 and 2001-055, but only through 2002.

The use of average capitalization provides a far superior measure of the earnings achieved during the ESM test year than does year-end capitalization. Average capitalization provides a better matching of all ratemaking components for the test year.

IV. BASE RATE REDUCTIONS UPON EXPIRATION OF MERGER SAVINGS AND VDT SURCREDITS

Q. Please describe the costs included in the Company's revenue requirement related to the LG&E and KU merger.

A. In total, the Company has included $37.938 million in the revenue requirement to reflect the merger savings. The Company has included $18.969 million in operating expense for the shareholder's portion of the merger savings. In addition, the Company has included the $18.969 million ratepayer share of the merger savings in the base revenue requirement. This latter amount is included by virtue of the Company using its total operating revenues as the starting point for operating income, but then not removing the effects of the merger surcredit in the same manner that it removes other surcharge revenues and costs such as those for the ESM, DSM, and ECR.

Q. Please describe the costs included in the Company's revenue requirement related to the 2001 employee buyout.

A. The Company has included $17.290 million in the revenue requirement to reflect the 2001 employee buyout. I described these costs previously in conjunction with the Company's failure to achieve labor cost savings.

Q. When are the merger surcredit and the VDT surcredit scheduled to terminate?

A. The merger surcredit is scheduled to terminate on June 30, 2008. The VDT surcredit is scheduled to terminate on March 31, 2006.

Q. Why should the Commission be concerned about the scheduled termination dates of the merger surcredit and VDT surcredit in this proceeding?

A. The Company's base revenue requirement includes more than $55 million of such costs. It is essential that when each of these surcredits terminate, and therefore the ratepayer sharing of the underlying savings terminates, that base rates be adjusted downward to remove all related costs included in the revenue requirement. Otherwise, ratepayers will be penalized, continuing to pay as if the surcredits remained in effect and as if there were continuing VDT costs to amortize even though they will be fully amortized upon the termination of the VDT surcredit.

Q. What is your recommendation?

A. I recommend that the Company direct the Company in this proceeding to reduce its base rates by the amounts included in its allowed revenue requirement related to each of the surcredits upon their expiration, March 31, 2006 for the VDT surcredit and June 30, 2008 for the merger surcredit.

V. IMPLEMENTATION OF SYSTEM SALES CLAUSE

Q. Please explain why the Commission should implement a System Sales Clause for the Company.

A. First, a System Sales Clause is essential in order to capture on a consistent basis the interrelated effects of the Company's variable fuel costs, purchased power costs, and off-system sales revenues. Currently, the Company's Fuel Adjustment Clause ("FAC") includes all recoverable fuel and purchased power costs, but only removes the fuel costs associated with off-system sales, net of the amounts rolled into base rates. All off-system sales margins above or below the amounts embedded into base rates in the last base rate proceeding are retained by the Company. Unlike recoverable fuel and purchased power costs, there currently is no rate mechanism to capture in whole or part the variability in the off-system sales margins compared to the amounts embedded into base rates.

Second, the Company has included $110 million in test year capitalization for the new Trimble County CTs (7-10) that are scheduled to enter commercial service in April 2004 and June 2004. This amount represents nearly 80% of the estimated completion cost. This additional capacity will provide the Company the opportunity to make additional off-system sales compared to the test year. As a matter of equity, if the ratepayers are required to pay for this capacity, then they should benefit at least in part from the additional off-system sales margins that will be achieved due to this capacity.

Q. How should the Commission implement such a System Sales Clause?

A. I recommend that the Commission pattern a System Sales Clause after the Kentucky Power Company ("KPC") Sales Clause. The KPC System Sales Clause provides for a 50% to Company and 50% to ratepayers sharing of the net change in off-system sales margins compared to the amount embedded into base rates. I have attached a copy of the KPC System Sales Clause tariff for reference purposes as my Exhibit___(LK-8).

Q. Does this complete your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE ELECTRIC	)	
RATES, TERMS, AND CONDITIONS OF	)	CASE NO.
KENTUCKY UTILITIES COMPANY	)	2003-00434

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

MARCH 2004

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than twenty-five years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present:

J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Minnesota, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, and West Virginia state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986:

Energy Management Associates: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983:

The Toledo Edison Company: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.

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7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric	Financial workout plan. Corp.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.

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Date	Case	Jurisdict.	Party	Utility	Subject
7/88	M-87017- -1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92
7/88	M-87017- -2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170- EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171- EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial Considerations, working capital.
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.

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Date	Case	Jurisdict.	Party	Utility	Subject
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements detailed investigation.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.

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12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92- 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
4/93	92-1464- EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92- 21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.

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Date	Case	Jurisdict.	Party	Utility	Subject
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co. The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14967	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers mechanisms.	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery
4/99	99-02-05	CT	Connecticut Industrial Utility Customers mechanisms.	Connecticut Light and Power Co.	Regulatory assets and liabilities stranded costs, recovery
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative regulation.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, and American Electric Power Co.	Merger Settlement Stipulation.
7/99	97-596 (Surrebuttal)	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 (Surrebuttal)	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 (Rebuttal)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
8/99	98-474 98-083 (Rebuttal)	KY	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative forms of regulation.
8/99	98-0452-E-GI (Rebuttal)	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/99	U-24182 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	21527	TX	Dallas-Ft.Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
04/00	99-1212-EL-ETPOH 99-1213-EL-ATA 99-1214-EL-AAM		Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
01/00	U-24182 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
05/00	2000-107	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 (Supplemental Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
07/00	22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.

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08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	PUC 22350 SOAH 473-00-1015	TX	The Dallas-Ft. Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 (Affidavit)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009		Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) (Surrebuttal)	LA	Louisiana Public Service Commission Staff f	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 (Direct)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925 and U-22092 (Subdocket B) (Surrebuttal)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc,.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.

Expert Testimony Appearances
of
Lane Kollen
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. and Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution (Rebuttal)	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, Separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Review requirements, Rate Plan, fuel clause recovery.
11/01 (Direct)	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.

Expert Testimony Appearances
of
Lane Kollen
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
11/01 (Direct)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	25230	TX	Dallas Ft.-Worth Hospital Council & the Coalition of Independent Colleges & Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02 (Surrebuttal)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02 (Rebuttal)	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear llife extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02 (Supplemental Surrebuttal)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 and U-22092 (Subdocket C)		Louisiana Public Service Commission Staff	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission Statt	Entergy Services, Inc. and The Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.

Expert Testimony Appearances
of
Lane Kollen
As of March 2004

Date	Case	Jurisdict.	Party	Utility	Subject
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
04/04	2002-00429 2002-00430	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527 I	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KU	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchase and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
04/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.

**Expert Testimony Appearances
of
Lane Kollen
As of March 2004**

Date	Case	Jurisdict.	Party	Utility	Subject
04/03	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.

EXHIBIT ____(LK-2)

Kentucky Utilities Company
Case No. 2003-00434
Analysis of Total Company Salaries and Wages
For the Calendar Years 1998 through 2002 and the Test Year
"000 Omitted"

Line No.	Item (a)	Calendar Years Prior to Test Year 5th Amount (b)	5th % (c)	4th Amount (d)	4th % (e)	3rd Amount (f)	3rd % (g)	2nd Amount (h)	2nd % (I)	1st Amount (j)	1st % (k)	Test Year Amount (l)	Test Year % (m)
1	Wages charged to expense												
2	Power Production Expense	24,957	-2.74%	24,905	-0.21%	30,705	23.29%	26,568	-13.47%	26,826	0.97%	27,129	1.13%
3	Transmission Expense	2,525	9.12%	2,910	15.25%	2,852	-1.99%	3,155	10.62%	3,097	-1.84%	3,235	4.46%
4	Distribution Expense	13,231	5.66%	12,840	-2.96%	15,891	23.76%	10,658	-32.93%	10,449	-1.96%	14,591	39.64%
5	Customer Accounts Expense	10,598	-6.38%	10,603	0.05%	10,566	-0.35%	6,819	-35.46%	6,299	-7.63%	8,527	35.37%
6	Sales Expense	1,792	1.07%	1,850	3.24%	1,555	-15.95%	0	-100.00%	0		45	
7	Administrative and General Expenses:												
	(a) Administrative and General Salaries	10,070	-23.20%	7,889	-21.66%	13,002	64.81%	17,018	30.89%	20,530	20.64%	17,884	-12.89%
	(b) Office Supplies and Expenses												
	(c) administrative Exp. Transferred - credit												
	(d) Outside services employed												
	(e) Property insurance												
	(f) Injuries and damages												
	(g) Employee pensions and benefits												
	(h) Franchise requirements												
	(I) Regulatory comminssion expense												
	(j) Duplicate charges - credit												
	(k) Miscellaneous general expense												
	(l) Maintenance of general plant												
8	Total Administrative and General Expenses L8(a) through L8(l)	10,070	-23.20%	7,889	-21.66%	13,002	64.81%	17,018	20.64%	20,530	20.64%	17,884	-12.89%
9	Total Salaries and Wages charged expense (L2 through L7 + L8)	63,173	-39.67%	60,997	-27.95%	74,571	158.39%	64,218	-119.72%	67,201	30.82%	71,411	54.82%

Kentucky Utilities Company
Case No. 2003-00434
Analysis of Total Company Salaries and Wages
For the Calendar Years 1998 through 2002 and the Test Year
"000 Omitted"

Line No.	Item (a)	Calendar Years Prior to Test Year: 5th Amount (b)	5th % (c)	4th Amount (d)	4th % (e)	3rd Amount (f)	3rd % (g)	2nd Amount (h)	2nd % (i)	1st Amount (j)	1st % (k)	Test Year Amount (l)	Test Year % (m)
10	Wages Capitalized	16,383	-4.76%	16,442	0.36%	12,399	-24.59%	13,900	18.89%	16,526	18.89%	17,264	4.47%
11	Total Salaries and Wages (1)	79,556	-44.42%	77,439	-2.66%	86,970	12.31%	78,118	-10.18%	83,727	7.18%	88,675	5.91%
12	Ratio of salaries and wages charged to expense to total wages (L9/L11)	0.79		0.79		0.86		0.82		0.80		0.81	
13	Ratio of salaries and wages capitalized to total wages (L10/L11)	0.21		0.21		0.14		0.18		0.20		0.19	

Note: Show percent increae of each year over the prior year in Columns (c), (e), (g), (i), (k), and (m).

Note: Salaries and wages above contain overhead amounts and represent total amount charged to KU. For example, Servco employees would charge KU for services performed for KU.

Total overtime dollars expended below represent all overtime charged to KU regardless of what company the employee works for.

	Amount	% Incr
Test Year	9,014,948	87.24%
1st Calendar Year Prior to Test Year	4,814,626	-25.53%
2nd Calendar Year Prior to Test Year	6,465,108	-1.15%
3rd Calendar Year Prior to Test Year	6,540,558	-1.58%
4th Calendar Year Prior to Test Year	6,645,313	-3.98%
5th Calendar Year Prior to Test Year	6,920,702	

(1) Does not include salaries and wages in balance sheet accounts other than Utility Plant and Removal

Kentucky Utilities Company
Case No. 2003-00434
Analysis of Jurisdictional Salaries and Wages
For the Calendar Years 1998 through 2002 and the Test Year
"000 Omitted"

Line No.	Item (a)	Calendar Years Prior to Test Year										Test Year	
		5th		4th		3rd		2nd		1st			
		Amount (b)	% (c)	Amount (d)	% (e)	Amount (f)	% (g)	Amount (h)	% (I)	Amount (j)	% (k)	Amount (l)	% (m)
1	Wages charged to expense												
2	Power Production Expense	21,139	-2.74%	21,162	0.11%	26,161	23.63%	22,614	-13.56%	22,822	0.92%	23,180	1.57%
3	Transmission Expense	1,980	9.12%	2,298	16.05%	2,264	-1.50%	2,502	10.53%	2,443	-2.36%	2,570	5.21%
4	Distribution Expense	12,329	5.66%	11,946	-3.11%	14,796	23.85%	9,946	-32.78%	9,773	-1.73%	13,680	39.97%
5	Customer Accounts Expense	9,887	-6.38%	9,879	-0.08%	9,845	-0.35%	6,353	-35.46%	5,951	-6.34%	8,034	35.01%
6	Sales Expense	1,682	1.07%	1,736	3.23%	1,459	-15.95%	0	-100.00%	0		42	
7	Administrative and General Expenses:												
	(a) Administrative and General Salaries	8,949	-23.20%	6,857	-23.37%	11,292	64.68%	14,976	32.62%	18,416	22.97%	15,886	-13.74%
	(b) Office Supplies and Expenses												
	(c) administrative Exp. Transferred - credit												
	(d) Outside services employed												
	(e) Property insurance												
	(f) Injuries and damages												
	(g) Employee pensions and benefits												
	(h) Franchise requirements												
	(I) Regulatory features comminssion expense												
	(j) Duplicate charges - credit												
	(k) Miscellaneous general expense												
	(l) Maintenance of general plant												
8	Total Administrative and General Expenses L8(a) through L8(l)	8,949	-23.20%	6,857	-23.37%	11,292	64.68%	14,976	22.97%	18,416	22.97%	15,886	-13.74%
9	Total Salaries and Wages charged expense (L2 through L7 + L8)	55,965	-39.67%	53,878	-30.54%	65,817	159.04%	56,391	-115.67%	59,405	36.43%	63,392	54.27%

Kentucky Utilities Company
Case No. 2003-00434
Analysis of Jurisdictional Salaries and Wages
For the Calendar Years 1998 through 2002 and the Test Year
"000 Omitted"

Line No.	Item (a)	Calendar Years Prior to Test Year										Test Year	
		5th		4th		3rd		2nd		1st			
		Amount (b)	% (c)	Amount (d)	% (e)	Amount (f)	% (g)	Amount (h)	% (I)	Amount (j)	% (k)	Amount (l)	% (m)
10	Wages Capitalized	14,316	-4.76%	14,374	0.40%	10,795	-24.90%	12,151	19.64%	14,538	19.64%	14,387	-1.04%
11	Total Salaries and Wages (1)	70,281	-44.42%	68,252	-2.89%	76,612	12.25%	68,542	-10.53%	73,943	7.88%	77,779	5.19%
12	Ratio of salaries and wages charged to expense to total wages (L9/L11)	0.80		0.79		0.86		0.82		0.80		0.82	
13	Ratio of salaries and wages capitalized to total wages (L10/L11)	0.20		0.21		0.14		0.18		0.20		0.18	

Note: Show percent increae of each year over the prior year in Columns (c), (e), (g), (i), (k), and (m).

Note: Salaries and wages above contain overhead amounts and represent total amount charged to KU. For example, Servco employees would charge KU for services performed for KU.

Overtime dollars expended on a jurisdictional basis are not available.

(1) Does not include salaries and wages in balance sheet accounts other than Utility Plant and Removal

Table 2-a

Kentucky Utilities
Electric Division

Summary of Original Cost of Utility Plant in Service and Interim and Terminal Net Salvage

Account No. (a)	Location Code (b)	Description (c)	Original Cost 12/31/02 (d)	Estimated Future Net Salvage: Interim Net Salvage % (e)	Interim Net Salvage Amount (f)	Terminal Net Salvage % (g)	Terminal Net Salvage Amount (h)	Total Net Salvage % (i)	Total Net Salvage Amount (j)	Interim Retirement Rate Calculation: Interim Ret ASL/Curve (k)	Avg Age At Ret. (Yrs) (l)	Iowa Curve Percent Surv (m)	Percent Retirement (n)	Interim Retired Amount (o)	Interim Retired Rate (p)	Factored Amount (q)	Interim Ret. % Of Total Investment (r)
		DEPRECIABLE PLANT															
		STEAM PLANT															
311.00		**Structures and Improvements**															
	5591	KU Generation-Common	805,715.82	-0.4%	-3,223	0.0%	0	-0.4%	-3,223	90-S1.5	39.9	92%	8%	64,457	-5%	-3,223	-0.4%
	5603	Trone Unit 3	5,293,882.85	-0.4%	-21,176	-7.7%	-407,629	-8.1%	-428,805	90-S1.5	39.9	92%	8%	423,511	-5%	-21,176	-0.4%
	5604	Tyrone Units 1 & 2	589,405.14	-0.4%	-2,358	-14.3%	-84,285	-14.7%	-86,643	90-S1.5	39.9	92%	8%	47,152	-5%	-2,358	-0.4%
	5613	Green River Unit 3	2,809,804.71	-0.4%	-11,239	-14.5%	-407,422	-14.9%	-418,661	90-S1.5	39.9	92%	8%	224,784	-5%	-11,239	-0.4%
	5614	Green River Unit 4	4,099,390.94	-0.4%	-16,398	-15.1%	-619,008	-15.5%	-635,406	90-S1.5	39.9	92%	8%	327,951	-5%	-16,398	-0.4%
	5615	Green River Units 1&2	3,797,160.20	-0.4%	-15,189	-10.9%	-413,890	-11.3%	-429,079	90-S1.5	39.9	92%	8%	303,773	-5%	-15,189	-0.4%
	5621	Brown Unit 1	4,088,137.49	-0.4%	-16,353	-15.2%	-621,397	-15.6%	-637,749	90-S1.5	39.9	92%	8%	327,051	-5%	-16,353	-0.4%
	5622	Brown Unit 2	1,452,821.22	-0.4%	-5,811	-16.9%	-245,527	-17.3%	-251,338	90-S1.5	39.9	92%	8%	116,226	-5%	-5,811	-0.4%
	5623	Brown Unit 3	12,078,731.61	-0.4%	-48,315	-21.6%	-2,609,006	-22.0%	-2,657,321	90-S1.5	39.9	92%	8%	966,299	-5%	-48,315	-0.4%
	5650	Ghent 1 Pollution Control Equip.	24,352,142.19	-0.4%	-97,409	-13.4%	-3,263,187	-13.8%	-3,360,596	90-S1.5	39.9	92%	8%	1,948,171	-5%	-97,409	-0.4%
	5651	Ghent Unit 1	16,838,431.28	-0.4%	-67,354	-19.4%	-3,266,656	-19.8%	-3,334,009	90-S1.5	39.9	92%	8%	1,347,075	-5%	-67,354	-0.4%
	5652	Ghent Unit 2	16,012,536.37	-0.4%	-64,050	-20.3%	-3,250,545	-20.7%	-3,314,595	90-S1.5	39.9	92%	8%	1,281,003	-5%	-64,050	-0.4%
	5653	Ghent Unit 3	40,539,913.20	-0.4%	-162,160	-8.0%	-3,243,193	-8.4%	-3,405,353	90-S1.5	39.9	92%	8%	3,243,193	-5%	-162,160	-0.4%
	5654	Ghent Unit 4	21,953,259.20	-0.4%	-87,813	-14.8%	-3,249,082	-15.2%	-3,336,895	90-S1.5	39.9	92%	8%	1,756,261	-5%	-87,813	-0.4%
		Total Account 311	154,711,332.22	-0.4%	-618,845	-14.0%	-21,680,827	-14.4%	-22,299,672								
312.00		**Boiler Plant Equipment**															
	5603	Trone Unit 3	8,663,220.42	-4.8%	-415,835	-8.2%	-710,384	-13.0%	-1,126,219	70-L1.5	34.7	81%	19%	1,646,012	-25%	-411,503	-4.8%
	5604	Tyrone Units 1 & 2	3,549,368.50	-4.8%	-170,370	-16.5%	-585,646	-21.3%	-756,015	70-L1.5	34.7	81%	19%	674,380	-25%	-168,595	-4.8%
	5613	Green River Unit 3	9,061,059.76	-4.8%	-434,931	-7.8%	-706,763	-12.6%	-1,141,694	70-L1.5	34.7	81%	19%	1,721,601	-25%	-430,400	-4.8%
	5614	Green River Unit 4	18,776,499.07	-4.8%	-901,272	-5.7%	-1,070,260	-10.5%	-1,971,532	70-L1.5	34.7	81%	19%	3,567,535	-25%	-891,884	-4.8%
	5615	Green River Units 1&2	12,249,873.99	-4.8%	-587,994	-5.8%	-710,493	-10.6%	-1,298,487	70-L1.5	34.7	81%	19%	2,327,476	-25%	-581,869	-4.8%
	5621	Brown Unit 1	32,815,581.55	-4.8%	-1,575,148	-3.3%	-1,082,914	-8.1%	-2,658,062	70-L1.5	34.7	81%	19%	6,234,960	-25%	-1,558,740	-4.8%
	5622	Brown Unit 2	26,010,201.59	-4.8%	-1,248,490	-6.5%	-1,690,663	-11.3%	-2,939,153	70-L1.5	34.7	81%	19%	4,941,938	-25%	-1,235,485	-4.8%
	5623	Brown Unit 3	71,536,455.78	-4.8%	-3,433,750	-5.4%	-3,862,969	-10.2%	-7,296,718	70-L1.5	34.7	81%	19%	13,591,927	-25%	-3,397,982	-4.8%
	5643	Pineville Unit 3	226,832.50	0.0%	0	0.0%	0	0.0%	0								
	5650	Ghent 1 Pollution Control Equip.	86,308,756.05	-4.8%	-4,142,820	-5.6%	-4,833,290	-10.4%	-8,976,111	70-L1.5	34.7	81%	19%	16,398,664	-25%	-4,099,666	-4.8%
	5651	Ghent Unit 1	88,268,090.96	-4.8%	-4,236,868	-5.4%	-4,766,477	-10.2%	-9,003,345	70-L1.5	34.7	81%	19%	16,770,937	-25%	-4,192,734	-4.8%
	5652	Ghent Unit 2	86,733,989.30	-4.8%	-4,163,231	-5.5%	-4,770,369	-10.3%	-8,933,601	70-L1.5	34.7	81%	19%	16,479,458	-25%	-4,119,864	-4.8%
	5653	Ghent Unit 3	169,648,430.42	-4.8%	-8,143,125	-2.8%	-4,750,156	-7.6%	-12,893,281	70-L1.5	34.7	81%	19%	32,233,202	-25%	-8,058,300	-4.8%
	5654	Ghent Unit 4	168,701,912.41	-4.8%	-8,097,692	-2.8%	-4,723,654	-7.6%	-12,821,345	70-L1.5	34.7	81%	19%	32,053,363	-25%	-8,013,341	-4.8%
	5659	Ghent 4 Rail Cars	7,647,232.19	-4.8%	-367,067	0.0%	0	-4.8%	-367,067	70-L1.5	34.7	81%	19%	1,452,974	-25%	-363,244	-4.8%
		Total Account 312	790,197,504.49	-4.8%	-37,918,592	-4.3%	-34,264,038	-9.1%	-72,182,630								
314.00		**Turbogenerator Units**															
	5603	Trone Unit 3	2,649,841.16	-6.3%	-166,940	-8.4%	-222,587	-14.7%	-389,527	60-S1.5	38.0	75%	25%	662,460	-25%	-165,615	-6.3%
	5604	Tyrone Units 1 & 2	1,592,029.04	-6.3%	-100,298	-11.6%	-184,675	-17.9%	-284,973	60-S1.5	38.0	75%	25%	398,007	-25%	-99,502	-6.3%
	5613	Green River Unit 3	2,651,645.58	-6.3%	-167,054	-8.4%	-222,738	-14.7%	-389,792	60-S1.5	38.0	75%	25%	662,911	-25%	-165,728	-6.3%
	5614	Green River Unit 4	8,323,622.30	-6.3%	-524,388	-4.1%	-341,269	-10.4%	-865,657	60-S1.5	38.0	75%	25%	2,080,906	-25%	-520,226	-6.3%
	5615	Green River Units 1&2	2,762,747.30	-6.3%	-174,053	-8.2%	-226,545	-14.5%	-400,598	60-S1.5	38.0	75%	25%	690,687	-25%	-172,672	-6.3%
	5621	Brown Unit 1	4,694,847.01	-6.3%	-295,775	-7.2%	-338,029	-13.5%	-633,804	60-S1.5	38.0	75%	25%	1,173,712	-25%	-293,428	-6.3%
	5622	Brown Unit 2	8,729,916.37	-6.3%	-549,985	-6.1%	-532,525	-12.4%	-1,082,510	60-S1.5	38.0	75%	25%	2,182,479	-25%	-545,620	-6.3%
	5623	Brown Unit 3	22,985,210.48	-6.3%	-1,448,068	-3.8%	-873,438	-10.1%	-2,321,506	60-S1.5	38.0	75%	25%	5,746,303	-25%	-1,436,576	-6.3%
	5651	Ghent Unit 1	22,672,666.15	-6.3%	-1,428,378	-4.8%	-1,088,288	-11.1%	-2,516,666	60-S1.5	38.0	75%	25%	5,668,167	-25%	-1,417,042	-6.3%
	5652	Ghent Unit 2	28,358,360.55	-6.3%	-1,786,577	-3.8%	-1,077,618	-10.1%	-2,864,194	60-S1.5	38.0	75%	25%	7,089,590	-25%	-1,772,398	-6.3%
	5653	Ghent Unit 3	38,111,389.85	-6.3%	-2,401,018	-2.8%	-1,067,119	-9.1%	-3,468,136	60-S1.5	38.0	75%	25%	9,527,847	-25%	-2,381,962	-6.3%
	5654	Ghent Unit 4	48,190,569.27	-6.3%	-3,036,006	-2.2%	-1,060,193	-8.5%	-4,096,198	60-S1.5	38.0	75%	25%	12,047,642	-25%	-3,011,911	-6.3%
		Total Account 314	191,722,845.06	-6.3%	-12,078,539	-3.8%	-7,235,023	-10.1%	-19,313,562								
315.00		**Accessory Electric Equipment**															
	5603	Trone Unit 3	570,736.22	0.0%	0	-11.3%	-64,493	-11.3%	-64,493	75-S2	43.8	89%	11%	62,781	0%	0	0.0%
	5604	Tyrone Units 1 & 2	828,016.44	0.0%	0	-6.4%	-52,993	-6.4%	-52,993	75-S2	43.8	89%	11%	91,082	0%	0	0.0%

Table 2-a

Kentucky Utilities
Electric Division

Summary of Original Cost of Utility Plant in Service and Interim and Terminal Net Salvage

Account No. (a)	Location Code (b)	Description (c)	Original Cost 12/31/02 (d)	Estimated Future Net Salvage: Interim Net Salvage % (e)	Interim Net Salvage Amount (f)	Terminal Net Salvage % (g)	Terminal Net Salvage Amount (h)	Total Net Salvage % (i)	Total Net Salvage Amount (j)	Interim Retirement Rate Calculation: Interim Ret ASL/Curve (k)	Avg Age At Ret. (Yrs) (l)	Iowa Curve Percent Surv (m)	Percent Retirement (n)	Interim Retired Amount (o)	Interim Retired Rate (p)	Factored Amount (q)	Interim Ret. % Of Total Investment (r)
	5613	Green River Unit 3	696,352.89	0.0%	0	-9.3%	-64,761	-9.3%	-64,761	75-S2	43.8	89%	11%	76,599	0%	0	0.0%
	5614	Green River Unit 4	809,269.35	0.0%	0	-12.1%	-97,922	-12.1%	-97,922	75-S2	43.8	89%	11%	89,020	0%	0	0.0%
	5615	Green River Units 1&2	584,072.29	0.0%	0	-11.2%	-65,416	-11.2%	-65,416	75-S2	43.8	89%	11%	64,248	0%	0	0.0%
	5621	Brown Unit 1	2,663,640.09	0.0%	0	-3.7%	-98,555	-3.7%	-98,555	75-S2	43.8	89%	11%	293,000	0%	0	0.0%
	5622	Brown Unit 2	970,596.10	0.0%	0	-15.9%	-154,325	-15.9%	-154,325	75-S2	43.8	89%	11%	106,766	0%	0	0.0%
	5623	Brown Unit 3	5,076,639.52	0.0%	0	-18.9%	-959,485	-18.9%	-959,485	75-S2	43.8	89%	11%	558,430	0%	0	0.0%
	5650	Ghent 1 Pollution Control Equip.	3,016,784.27	0.0%	0	-39.8%	-1,200,680	-39.8%	-1,200,680	75-S2	43.8	89%	11%	331,846	0%	0	0.0%
	5651	Ghent Unit 1	7,456,587.14	0.0%	0	-16.1%	-1,200,511	-16.1%	-1,200,511	75-S2	43.8	89%	11%	820,225	0%	0	0.0%
	5652	Ghent Unit 2	10,785,959.50	0.0%	0	-11.1%	-1,197,242	-11.1%	-1,197,242	75-S2	43.8	89%	11%	1,186,456	0%	0	0.0%
	5653	Ghent Unit 3	25,961,221.84	0.0%	0	-4.6%	-1,194,216	-4.6%	-1,194,216	75-S2	43.8	89%	11%	2,855,734	0%	0	0.0%
	5654	Ghent Unit 4	21,869,238.82	0.0%	0	-5.5%	-1,202,808	-5.5%	-1,202,808	75-S2	43.8	89%	11%	2,405,616	0%	0	0.0%
		Total Account 315	81,289,114.47	0.0%	0	-9.3%	-7,553,406	-9.3%	-7,553,406								
316.00		**Miscellaneous Power Plant Equipment**															
	5591	System Laboratory	1,330,284.07	0.0%	0	0.0%	0	0.0%	0	60-S1	33.5	81%	19%	252,754	0%	0	0.0%
	5603	Trone Unit 3	403,549.14	0.0%	0	-0.7%	-2,825	-0.7%	-2,825	60-S1	33.5	81%	19%	76,674	0%	0	0.0%
	5604	Tyrone Units 1 & 2	47,552.54	0.0%	0	-4.7%	-2,235	-4.7%	-2,235	60-S1	33.5	81%	19%	9,035	0%	0	0.0%
	5613	Green River Unit 3	70,833.53	0.0%	0	-3.8%	-2,692	-3.8%	-2,692	60-S1	33.5	81%	19%	13,458	0%	0	0.0%
	5614	Green River Unit 4	1,961,965.76	0.0%	0	-0.2%	-3,924	-0.2%	-3,924	60-S1	33.5	81%	19%	372,773	0%	0	0.0%
	5615	Green River Units 1&2	190,224.48	0.0%	0	-1.4%	-2,663	-1.4%	-2,663	60-S1	33.5	81%	19%	36,143	0%	0	0.0%
	5621	Brown Unit 1	293,859.48	0.0%	0	-1.4%	-4,114	-1.4%	-4,114	60-S1	33.5	81%	19%	55,833	0%	0	0.0%
	5622	Brown Unit 2	85,647.82	0.0%	0	-7.6%	-6,509	-7.6%	-6,509	60-S1	33.5	81%	19%	16,273	0%	0	0.0%
	5623	Brown Unit 3	3,695,436.94	0.0%	0	-1.7%	-62,822	-1.7%	-62,822	60-S1	33.5	81%	19%	702,133	0%	0	0.0%
	5650	Ghent 1 Pollution Control Equip.	985,410.01	0.0%	0	-8.0%	-78,833	-8.0%	-78,833	60-S1	33.5	81%	19%	187,228	0%	0	0.0%
	5651	Ghent Unit 1	1,683,635.89	0.0%	0	-4.7%	-79,131	-4.7%	-79,131	60-S1	33.5	81%	19%	319,891	0%	0	0.0%
	5652	Ghent Unit 2	1,478,017.69	0.0%	0	-5.3%	-78,335	-5.3%	-78,335	60-S1	33.5	81%	19%	280,823	0%	0	0.0%
	5653	Ghent Unit 3	3,135,971.64	0.0%	0	-2.5%	-78,399	-2.5%	-78,399	60-S1	33.5	81%	19%	595,835	0%	0	0.0%
	5654	Ghent Unit 4	5,356,692.15	0.0%	0	-1.5%	-80,350	-1.5%	-80,350	60-S1	33.5	81%	19%	1,017,772	0%	0	0.0%
		Total Account 316	20,719,081.14	0.0%	0	-2.3%	-482,833	-2.3%	-482,833								
		Total Steam Production Plant	1,238,639,877.38	-4.1%	-50,615,977	-5.7%	-71,216,126	-9.8%	-121,832,103								
		HYDRAULIC PLANT															
330.10		**Land Rights**															
	5691	Dix Dam	879,311.47	0.0%	0	0.0%	0	0.0%	0	50-R2.5			100%	879,311	0%	0	0.0%
	5692	Lock #7	0.00	0.0%	0	0.0%	0		0								
		Total Account 330.10	879,311.47	0.0%	0	0.0%	0	0.0%	0								
331.00		**Structures and Improvements**															
	5691	Dix Dam	429,524.71	-2.8%	-12,027	-12.2%	-52,402	-15.0%	-64,429	140-L1	49.5	86%	14%	60,133	-20%	-12,027	-2.8%
	5692	Lock #7	67,902.49	-2.8%	-1,901	-8.6%	-5,840	-11.4%	-7,741	140-L1	49.5	86%	14%	9,506	-20%	-1,901	-2.8%
		Total Account 331	497,427.20	-2.8%	-13,928	-11.7%	-58,242	-14.5%	-72,170								

Table 2-a

Kentucky Utilities
Electric Division

Summary of Original Cost of Utility Plant in Service and Interim and Terminal Net Salvage

Account No. (a)	Location Code (b)	Description (c)	Original Cost 12/31/02 (d)	Estimated Future Net Salvage: Interim Net Salvage % (e)	Interim Net Salvage Amount (f)	Terminal Net Salvage % (g)	Terminal Net Salvage Amount (h)	Total Net Salvage % (i)	Total Net Salvage Amount (j)	Interim Retirement Rate Calculation: Interim Ret ASL/Curve (k)	Avg Age At Ret. (Yrs) (l)	Iowa Curve Percent Surv (m)	Percent Retirement (n)	Interim Retired Amount (o)	Interim Retired Rate (p)	Factored Amount (q)	Interim Ret. % Of Total Investment (r)
332.00		**Reservoirs, Dams and Waterways**															
	5691	Dix Dam	7,818,030.36	0.0%	0	-0.1%	-7,818	-0.1%	-7,818	150-L1.5	53.0	89%	11%	859,983	0%	0	0.0%
	5692	Lock #7	324,145.88	0.0%	0	-1.8%	-5,835	-1.8%	-5,835	150-L1.5	53.0	89%	11%	35,656	0%	0	0.0%
		Total Account 332	8,142,176.24	0%	0	-0.2%	-13,653	-0.2%	-13,653								
333.00		**Waterwheel, Turbines and Generators**															
	5691	Dix Dam	418,543.74	0.0%	0	-25.8%	-107,984	-25.8%	-107,984	150-L1.5	62.0	87%	13%	54,411	0%	0	0.0%
	5692	Lock #7	114,085.49	0.0%	0	-10.5%	-11,979	-10.5%	-11,979	150-L1.5		87%	13%	14,831	0%	0	0.0%
		Total Account 333	532,629.23	0.0%	0	-22.5%	-119,963	-22.5%	-119,963								
334.00		**Accessory Electric Equipment**															
	5691	Dix Dam	85,383.13	0.0%	0	-29.4%	-25,103	-29.4%	-25,103	55-L1	23.6	74%	26%	22,200	0%	0	0.0%
	5692	Lock #7	264,485.91	0.0%	0	-1.1%	-2,909	-1.1%	-2,909	55-L1	23.6	74%	26%	68,766	0%	0	0.0%
		Total Account 334	349,869.04	0.0%	0	-8.0%	-28,012	-8.0%	-28,012								
335.00		**Miscellaneous Power Plant Equipment**															
	5691	Dix Dam	97,031.59	0.0%	0	-3.5%	-3,396	-3.5%	-3,396	55-R3	23.3	90%	10%	9,703	0%	0	0.0%
	5692	Lock #7	66,094.89	0.0%	0	-0.6%	-397	-0.6%	-397	55-R3	23.3	90%	10%	6,609	0%	0	0.0%
		Total Account 335	163,126.48	0.0%	0	-2.3%	-3,793	-2.3%	-3,793								
336.00		**Roads, Railroads and Bridges**															
	5691	Dix Dam	46,976.12	0.0%	0	0.0%	0	0.0%	0	80-R5	12.0	50%	50%	23,488	0%	0	0.0%
	5692	Lock #7	1,169.79	0.0%	0	0.0%	0	0.0%	0	80-R5	12.0	50%	50%	585	0%	0	0.0%
		Total Account 336	48,145.91	0.0%	0	0.0%	0	0.0%	0								
		Total Hydraulic Plant	10,612,685.57	0%	-13,928	-2.1%	-223,662	-2.2%	-237,590								
		OTHER PRODUCTION PLANT															
340.10		**Land Rights**															
	5645	Brown 9 Pipeline	176,409.31	0%	0	0.0%	0	0.0%	0	50-R2.5			100%	176,409	-15%	-26,461	-15.0%
		Total Account 340.10	176,409.31	0%	0	0.0%	0	0.0%	0								
341.00		**Structures and Improvements**															
	0432	Paddy's Run GT 13	1,910,327.76	-3.9%	-74,503	-4.3%	-82,144	-8.2%	-156,647	45-R0.5	18.8	74%	26%	496,685	-15%	-74,503	-3.9%
	0470	Trimble Co 5	3,566,217.06	-3.9%	-139,082	-3.0%	-106,987	-6.9%	-246,069	45-R0.5	18.8	74%	26%	927,216	-15%	-139,082	-3.9%
	0471	Trimble Co 6	3,564,353.91	-3.9%	-139,010	-3.0%	-106,931	-6.9%	-245,940	45-R0.5	18.8	74%	26%	926,732	-15%	-139,010	-3.9%
	5635	Brown 5	755,148.65	-3.9%	-29,451	-7.4%	-55,881	-11.3%	-85,332	45-R0.5	18.8	74%	26%	196,339	-15%	-29,451	-3.9%
	5636	Brown 6	133,678.33	-3.9%	-5,213	-81.3%	-108,680	-85.2%	-113,894	45-R0.5	18.8	74%	26%	34,756	-15%	-5,213	-3.9%
	5637	Brown 7	488,353.77	-3.9%	-19,046	-27.8%	-135,762	-31.7%	-154,808	45-R0.5	18.8	74%	26%	126,972	-15%	-19,046	-3.9%
	5638	Brown 8	2,012,654.95	-3.9%	-78,494	-6.1%	-122,772	-10.0%	-201,265	45-R0.5	18.8	74%	26%	523,290	-15%	-78,494	-3.9%
	5639	Brown 9	4,641,054.86	-3.9%	-181,001	-2.6%	-120,667	-6.5%	-301,669	45-R0.5	18.8	74%	26%	1,206,674	-15%	-181,001	-3.9%
	5640	Brown 10	1,865,718.20	-3.9%	-72,763	-6.6%	-123,137	-10.5%	-195,900	45-R0.5	18.8	74%	26%	485,087	-15%	-72,763	-3.9%
	5641	Brown 11	1,802,595.65	-3.9%	-70,301	-6.8%	-122,577	-10.7%	-192,878	45-R0.5	18.8	74%	26%	468,675	-15%	-70,301	-3.9%
	5696	Hafeling	434,853.46	-3.9%	-16,959	-14.1%	-61,314	-18.0%	-78,274	45-R0.5	18.8	74%	26%	113,062	-15%	-16,959	-3.9%
		Total Account 341	21,174,956.60	-3.9%	-825,823	-5.4%	-1,146,853	-9.3%	-1,972,676								

Table 2-a

Kentucky Utilities
Electric Division

Summary of Original Cost of Utility Plant in Service and Interim and Terminal Net Salvage

Account No. (a)	Location Code (b)	Description (c)	Original Cost 12/31/02 (d)	Estimated Future Net Salvage: Interim Net Salvage % (e)	Interim Net Salvage Amount (f)	Terminal Net Salvage % (g)	Terminal Net Salvage Amount (h)	Total Net Salvage % (i)	Total Net Salvage Amount (j)	Interim Retirement Rate Calculation: Interim Ret ASL/Curve (k)	Avg Age At Ret. (Yrs) (l)	Iowa Curve Percent Surv (m)	Percent Retirement (n)	Interim Retired Amount (o)	Interim Retired Rate (p)	Factored Amount (q)	Interim Ret. % Of Total Investment (r)
342.00		**Fuel Holders, Producers and Accessory**															
	0432	Paddy's Run GT 13	1,975,977.95	-3.2%	-63,231	-4.4%	-86,943	-7.6%	-150,174	55-R1	21.7	79%	21%	414,955	-15%	-62,243	-3.2%
	0470	Trimble Co 5	237,747.79	-3.2%	-7,608	-47.3%	-112,455	-50.5%	-120,063	55-R1	21.7	79%	21%	49,927	-15%	-7,489	-3.2%
	0471	Trimble Co 6	237,623.60	-3.2%	-7,604	-47.4%	-112,634	-50.6%	-120,238	55-R1	21.7	79%	21%	49,901	-15%	-7,485	-3.2%
	0473	Trimble Co Pipeline	4,474,853.28	-3.2%	-143,195	-15.0%	-671,228	-18.2%	-814,423	55-R1	21.7	79%	21%	939,719	-15%	-140,958	-3.2%
	5635	Brown 5	727,929.28	-3.2%	-23,294	-8.2%	-59,690	-11.4%	-82,984	55-R1	21.7	79%	21%	152,865	-15%	-22,930	-3.2%
	5636	Brown 6	146,514.66	-3.2%	-4,688	-34.5%	-50,548	-37.7%	-55,236	55-R1	21.7	79%	21%	30,768	-15%	-4,615	-3.2%
	5637	Brown 7	145,745.15	-3.2%	-4,664	-71.1%	-103,625	-74.3%	-108,289	55-R1	21.7	79%	21%	30,606	-15%	-4,591	-3.2%
	5638	Brown 8	19,612.88	-3.2%	-628	-665.5%	-130,524	-668.7%	-131,151	55-R1	21.7	79%	21%	4,119	-15%	-618	-3.2%
	5639	Brown 9	1,943,454.44	-3.2%	-62,191	-6.7%	-130,211	-9.9%	-192,402	55-R1	21.7	79%	21%	408,125	-15%	-61,219	-3.2%
	5640	Brown 10	31,737.96	-3.2%	-1,016	-411.2%	-130,506	-414.4%	-131,522	55-R1	21.7	79%	21%	6,665	-15%	-1,000	-3.2%
	5641	Brown 11	52,429.84	-3.2%	-1,678	-248.9%	-130,498	-252.1%	-132,176	55-R1	21.7	79%	21%	11,010	-15%	-1,652	-3.2%
	5645	Brown 9 Pipeline	8,151,131.81	-3.2%	-260,836	-15.0%	-1,222,670	-18.2%	-1,483,506	55-R1	21.7	79%	21%	1,711,738	-15%	-256,761	-3.2%
	5696	Hafeling	181,132.61	-3.2%	-5,796	-36.0%	-65,208	-39.2%	-71,004	55-R1	21.7	79%	21%	38,038	-15%	-5,706	-3.2%
		Total Account 342	18,325,891.25	-3.2%	-586,429	-16.4%	-3,006,739	-19.6%	-3,593,167								
343.00		**Prime Movers**															
	0432	Paddy's Run GT 13	17,355,293.47	0.0%	0	-1.9%	-329,751	-1.9%	-329,751	40-R0.5	20.8	70%	30%	5,206,588	0%	0	0.0%
	0470	Trimble Co 5	29,842,502.10	0.0%	0	-1.5%	-447,638	-1.5%	-447,638	40-R0.5	20.8	70%	30%	8,952,751	0%	0	0.0%
	0471	Trimble Co 6	29,826,880.91	0.0%	0	-1.5%	-447,403	-1.5%	-447,403	40-R0.5	20.8	70%	30%	8,948,064	0%	0	0.0%
	5635	Brown 5	12,440,942.32	0.0%	0	-1.9%	-236,378	-1.9%	-236,378	40-R0.5	20.8	70%	30%	3,732,283	0%	0	0.0%
	5636	Brown 6	31,591,711.55	0.0%	0	-1.3%	-410,692	-1.3%	-410,692	40-R0.5	20.8	70%	30%	9,477,513	0%	0	0.0%
	5637	Brown 7	39,071,447.54	0.0%	0	-1.1%	-429,786	-1.1%	-429,786	40-R0.5	20.8	70%	30%	11,721,434	0%	0	0.0%
	5638	Brown 8	18,625,319.58	0.0%	0	-2.7%	-502,884	-2.7%	-502,884	40-R0.5	20.8	70%	30%	5,587,596	0%	0	0.0%
	5639	Brown 9	20,674,801.66	0.0%	0	-2.4%	-496,195	-2.4%	-496,195	40-R0.5	20.8	70%	30%	6,202,440	0%	0	0.0%
	5640	Brown 10	18,800,096.69	0.0%	0	-2.7%	-507,603	-2.7%	-507,603	40-R0.5	20.8	70%	30%	5,640,029	0%	0	0.0%
	5641	Brown 11	33,050,028.28	0.0%	0	-1.5%	-495,750	-1.5%	-495,750	40-R0.5	20.8	70%	30%	9,915,008	0%	0	0.0%
		Total Account 343	251,279,024.10	0.0%	0	-1.7%	-4,304,079	-1.7%	-4,304,079								
344.00		**Generators**															
	0432	Paddy's Run GT 13	5,185,636.11	-0.2%	-10,371	-6.5%	-337,066	-6.7%	-347,438	42-R5	23.9	97%	3%	155,569	-5%	-7,778	-0.2%
	0470	Trimble Co 5	3,734,423.83	-0.2%	-7,469	-11.7%	-436,928	-11.9%	-444,396	42-R5	23.9	97%	3%	112,033	-5%	-5,602	-0.2%
	0471	Trimble Co 6	3,732,468.71	-0.2%	-7,465	-11.7%	-436,699	-11.9%	-444,164	42-R5	23.9	97%	3%	111,974	-5%	-5,599	-0.2%
	5635	Brown 5	2,831,528.33	-0.2%	-5,663	-8.2%	-232,185	-8.4%	-237,848	42-R5	23.9	97%	3%	84,946	-5%	-4,247	-0.2%
	5636	Brown 6	3,712,619.52	-0.2%	-7,425	-11.4%	-423,239	-11.6%	-430,664	42-R5	23.9	97%	3%	111,379	-5%	-5,569	-0.2%
	5637	Brown 7	3,722,788.46	-0.2%	-7,446	-11.3%	-420,675	-11.5%	-428,121	42-R5	23.9	97%	3%	111,684	-5%	-5,584	-0.2%
	5638	Brown 8	4,953,960.72	-0.2%	-9,908	-10.2%	-505,304	-10.4%	-515,212	42-R5	23.9	97%	3%	148,619	-5%	-7,431	-0.2%
	5639	Brown 9	5,452,040.97	-0.2%	-10,904	-9.3%	-507,040	-9.5%	-517,944	42-R5	23.9	97%	3%	163,561	-5%	-8,178	-0.2%
	5640	Brown 10	4,944,422.71	-0.2%	-9,889	-10.2%	-504,331	-10.4%	-514,220	42-R5	23.9	97%	3%	148,333	-5%	-7,417	-0.2%
	5641	Brown 11	5,187,040.30	-0.2%	-10,374	-9.7%	-503,143	-9.9%	-513,517	42-R5	23.9	97%	3%	155,611	-5%	-7,781	-0.2%
	5696	Hafeling	4,023,002.37	-0.2%	-8,046	-6.3%	-253,449	-6.5%	-261,495	42-R5	23.9	97%	3%	120,690	-5%	-6,035	-0.2%
		Total Account 344	47,479,932.03	-0.2%	-94,960	-9.6%	-4,560,059	-9.8%	-4,655,019								
345.00		**Accessory Electric Equipment**															
	0432	Paddy's Run GT 13	2,456,320.01	0.0%	0	-1.6%	-39,301	-1.6%	-39,301	45-R5	23.3	98%	2%	49,126	0%	0	0.0%
	0470	Trimble Co 5	1,664,234.64	0.0%	0	-3.0%	-49,927	-3.0%	-49,927	45-R5	23.3	98%	2%	33,285	0%	0	0.0%
	0471	Trimble Co 6	1,663,365.15	0.0%	0	-3.0%	-49,901	-3.0%	-49,901	45-R5	23.3	98%	2%	33,267	0%	0	0.0%
	5635	Brown 5	2,265,166.84	0.0%	0	-1.2%	-27,182	-1.2%	-27,182	45-R5	23.3	98%	2%	45,303	0%	0	0.0%
	5636	Brown 6	1,354,816.11	0.0%	0	-3.6%	-48,773	-3.6%	-48,773	45-R5	23.3	98%	2%	27,096	0%	0	0.0%

Table 2-a

Kentucky Utilities
Electric Division

Summary of Original Cost of Utility Plant in Service and Interim and Terminal Net Salvage

Account No. (a)	Location Code (b)	Description (c)	Original Cost 12/31/02 (d)	Estimated Future Net Salvage: Interim Net Salvage % (e)	Interim Net Salvage Amount (f)	Terminal Net Salvage % (g)	Terminal Net Salvage Amount (h)	Total Net Salvage % (i)	Total Net Salvage Amount (j)	Interim Retirement Rate Calculation: Interim Ret ASL/Curve (k)	Avg Age At Ret. (Yrs) (l)	Iowa Curve Percent Surv (m)	Percent Retirement (n)	Interim Retired Amount (o)	Interim Retired Rate (p)	Factored Amount (q)	Interim Ret. % Of Total Investment (r)
	5637	Brown 7	1,347,700.35	0.0%	0	-3.6%	-48,517	-3.6%	-48,517	45-R5	23.3	98%	2%	26,954	0%	0	0.0%
	5638	Brown 8	1,797,053.82	0.0%	0	-3.3%	-59,303	-3.3%	-59,303	45-R5	23.3	98%	2%	35,941	0%	0	0.0%
	5639	Brown 9	3,226,186.26	0.0%	0	-1.8%	-58,071	-1.8%	-58,071	45-R5	23.3	98%	2%	64,524	0%	0	0.0%
	5640	Brown 10	1,804,419.47	0.0%	0	-3.2%	-57,741	-3.2%	-57,741	45-R5	23.3	98%	2%	36,088	0%	0	0.0%
	5641	Brown 11	916,326.28	0.0%	0	-6.4%	-58,645	-6.4%	-58,645	45-R5	23.3	98%	2%	18,327	0%	0	0.0%
	5696	Hafeling	621,206.80	0.0%	0	-4.7%	-29,197	-4.7%	-29,197	45-R5	23.3	98%	2%	12,424	0%	0	0.0%
		Total Account 345	19,116,795.73	0.0%	0	-2.8%	-526,559	-2.8%	-526,559								
346.00		**Miscellaneous Power Plant Equipment**															
	0432	Paddy's Run GT 13	1,089,550.03	0.0%	0	-0.5%	-5,448	-0.5%	-5,448	30-R1	12.0	53%	47%	512,089	0%	0	0.0%
	5635	Brown 5	2,085,163.17	0.0%	0	-0.2%	-4,170	-0.2%	-4,170	30-R1	12.0	53%	47%	980,027	0%	0	0.0%
	5636	Brown 6	18,003.82	0.0%	0	-37.2%	-6,697	-37.2%	-6,697	30-R1	12.0	53%	47%	8,462	0%	0	0.0%
	5637	Brown 7	15,776.54	0.0%	0	-40.2%	-6,342	-40.2%	-6,342	30-R1	12.0	53%	47%	7,415	0%	0	0.0%
	5638	Brown 8	230,068.72	0.0%	0	-3.5%	-8,052	-3.5%	-8,052	30-R1	12.0	53%	47%	108,132	0%	0	0.0%
	5639	Brown 9	760,255.37	0.0%	0	-1.1%	-8,363	-1.1%	-8,363	30-R1	12.0	53%	47%	357,320	0%	0	0.0%
	5640	Brown 10	241,523.31	0.0%	0	-3.3%	-7,970	-3.3%	-7,970	30-R1	12.0	53%	47%	113,516	0%	0	0.0%
	5641	Brown 11	204,854.53	0.0%	0	-3.9%	-7,989	-3.9%	-7,989	30-R1	12.0	53%	47%	96,282	0%	0	0.0%
	5696	Hafeling	35,805.20	0.0%	0	-11.2%	-4,010	-11.2%	-4,010	30-R1	12.0	53%	47%	16,828	0%	0	0.0%
		Total Account 346	4,681,000.69	0.0%	0	-1.3%	-59,043	-1.3%	-59,043								
		Total Other Production Plant	362,234,009.71	-0.4%	-1,507,212	-3.8%	-13,603,331	-4.2%	-15,110,543								

Table 2

Kentucky Utilities
Electric Division

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2002

Account No. (a)	Description (b)	Original Cost 12/31/02 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	DEPRECIABLE PLANT										
	STEAM PLANT										
311.00	Structures and Improvements	154,711,332.22	-14.4%	-22,278,431.84	176,989,764.06	119,979,591.98	57,010,172.08 (1)	90-S1.5	21.1	2,701,903.89	1.75%
312.00	Boiler Plant Equipment	1,024,872,088.49	-9.0%	-92,238,487.96	1,117,110,576.45	478,215,496.00	638,895,080.45 (1)	70-L1.5	19.6	32,596,687.78	3.18%
314.00	Turbogenerator Units	191,722,845.06	-10.1%	-19,364,007.35	211,086,852.41	127,644,966.20	83,441,886.21 (1)	60-S1.5	20.1	4,151,337.62	2.17%
315.00	Accessory Electric Equipment	81,289,114.47	-9.3%	-7,559,887.65	88,849,002.12	58,564,628.73	30,284,373.39 (1)	75-S2	22.9	1,322,461.72	1.63%
316.00	Miscellaneous Power Plant Equipment	20,719,081.14	-2.3%	-476,538.87	21,195,620.01	10,449,909.86	10,745,710.15 (1)	60-S1	20.6	521,636.42	2.52%
	Total Steam Production Plant	1,473,314,461.38	-9.6%	-141,917,353.67	1,615,231,815.05	794,854,592.77	820,377,222.28			41,294,027.43	2.80%
	HYDRAULIC PLANT										
330.10	Land Rights	879,311.47	0.0%	0.00	879,311.47	879,311.47	0.00	50-R2.5	7.8	0.00	0.00%
331.00	Structures and Improvements	497,427.20	-14.5%	-72,126.94	569,554.14	397,997.88	171,556.26 (1)	140-L1	16.9	10,151.26	2.04%
332.00	Reservoirs, Dams and Waterways	8,142,176.24	-0.2%	-16,284.35	8,158,460.59	5,927,893.37	2,230,567.22 (1)	150-L1.5	17.9	124,612.69	1.53%
333.00	Waterwheel, Turbines and Generators	532,629.23	-22.5%	-119,841.58	652,470.81	652,592.49	-121.68 (1)	150-L1.5	14.5	-8.39	0.00%
334.00	Accessory Electric Equipment	349,869.04	-8.0%	-27,989.52	377,858.56	315,637.89	62,220.67 (1)	55-L1	3.1	20,071.18	5.74%
335.00	Miscellaneous Power Plant Equipment	163,126.48	-2.3%	-3,751.91	166,878.39	108,298.12	58,580.27 (1)	55-R3	8.7	6,733.36	4.13%
336.00	Roads, Railroads and Bridges	48,145.91	0.0%	0.00	48,145.91	42,173.02	5,972.89 (1)	80-R5	15.6	382.88	0.80%
	Total Hydraulic Plant	10,612,685.57	-2.3%	-239,994.30	10,852,679.87	8,323,904.23	2,528,775.64			161,942.99	1.53%
	OTHER PRODUCTION PLANT										
340.10	Land Rights	176,409.31	0.0%	0.00	176,409.31	49,181.12	127,228.19	50-R2.5	43.9	2,898.14	1.64%
341.00	Structures and Improvements	21,174,956.60	-9.3%	-1,969,270.96	23,144,227.56	3,088,998.33	20,055,229.23 (1)	45-R0.5	21.8	919,964.64	4.34%
342.00	Fuel Holders, Producers and Accessory	18,325,891.25	-19.6%	-3,591,874.69	21,917,765.94	3,253,075.18	18,664,690.76 (1)	55-R1	22.6	825,871.27	4.51%
343.00	Prime Movers	251,279,024.10	-1.7%	-4,271,743.41	255,550,767.51	28,681,301.92	226,869,465.59 (1)	40-R0.5	22.2	10,219,345.30	4.07%
344.00	Generators	47,479,932.03	-9.8%	-4,653,033.34	52,132,965.37	11,415,853.11	40,717,112.26 (1)	42-R5	24.0	1,696,546.34	3.57%
345.00	Accessory Electric Equipment	19,116,795.73	-2.8%	-535,270.28	19,652,066.01	3,271,734.71	16,380,331.30 (1)	45-R5	25.5	642,365.93	3.36%
346.00	Miscellaneous Power Plant Equipment	4,681,000.69	-1.3%	-60,853.01	4,741,853.70	552,760.39	4,189,093.31 (1)	30-R1	21.4	195,752.02	4.18%
	Total Other Production Plant	362,234,009.71	-4.2%	-15,082,045.69	377,316,055.40	50,312,904.75	327,003,150.65			14,502,743.65	4.00%
	TRANSMISSION PLANT										
350.10	Land Rights	22,991,433.46	0%	0.00	22,991,433.46	12,941,528.70	10,049,904.76	50-R2.5	22.9	438,860.47	1.91%
	Structures and Improvements										
352.10	Struct. and Improve. - Non Sys. Control/Com.	6,426,546.76	-25%	-1,606,636.69	8,033,183.45	3,333,642.20	4,699,541.25	45-R3	28.0	167,840.76	2.61%
352.20	Struct. and Improve. - Sys. Control/Com.	1,166,434.25	-25%	-291,608.56	1,458,042.81	693,961.91	764,080.90	40-R3	19.1	40,004.24	3.43%
	Total Account 352	7,592,981.01	-25.0%	-1,898,245.25	9,491,226.26	4,027,604.11	5,463,622.15			207,844.99	2.74%
	Station Equipment										
353.10	Station Equipment - Non Sys. Control/Com.	146,527,337.37	-15%	-21,979,100.61	168,506,437.98	55,262,160.21	113,244,277.77	50-R2.5	34.0	3,330,714.05	2.27%
353.20	Station Equip - Sys Control/Com. (Microwave)	14,284,914.20	-10%	-1,428,491.42	15,713,405.62	8,038,391.66	7,675,013.96	15-R3	7.1	1,080,987.88	7.57%
	Total Account 353	160,812,251.57	-14.6%	-23,407,592.03	184,219,843.60	63,300,551.87	120,919,291.73			4,411,701.93	2.74%

Table 2

Kentucky Utilities
Electric Division

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2002

Account No. (a)	Description (b)	Original Cost 12/31/02 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
354.00	Towers and Fixtures	60,533,459.11	-60%	-36,320,075.47	96,853,534.58	39,186,874.18	57,666,660.40	55-R4	33.2	1,736,947.60	2.87%
355.00	Poles and Fixtures	74,915,940.37	-60%	-44,949,564.22	119,865,504.59	41,752,871.90	78,112,632.69	43-R2.5	28.0	2,789,736.88	3.72%
356.00	Overhead Conductors and Devices	122,030,093.52	-75%	-91,522,570.14	213,552,663.66	87,456,803.12	126,095,860.54	50-R3	29.9	4,217,252.86	3.46%
357.00	Underground Conduit	435,926.80	0%	0.00	435,926.80	87,891.34	348,035.46	50-R3	39.2	8,878.46	2.04%
358.00	Underground Conductors and Devices	1,114,761.90	-20%	-222,952.38	1,337,714.28	610,385.26	727,329.02	30-R3	15.4	47,229.16	4.24%
	Total Transmission Plant	450,426,847.74	-44.0%	-198,320,999.49	648,747,847.23	249,364,510.47	399,383,336.76			13,858,452.36	3.08%
	DISTRIBUTION PLANT										
360.10	Land Rights	1,423,182.13	0%	0.00	1,423,182.13	920,753.34	502,428.79	50-R2.5	21.9	22,941.95	1.61%
361.00	Structures and Improvements	3,798,329.41	-15%	-569,749.41	4,368,078.82	1,436,285.62	2,931,793.20	50-R2.5	36.4	80,543.77	2.12%
362.00	Station Equipment	92,514,069.32	-10%	-9,251,406.93	101,765,476.25	28,771,438.30	72,994,037.95	50-R1.5	37.9	1,925,964.06	2.08%
364.00	Poles, Towers and Fixtures	167,558,546.62	-55%	-92,157,200.64	259,715,747.26	77,587,027.85	182,128,719.41	40-S0	29.9	6,091,261.52	3.64%
365.00	Overhead Conductors and Devices	160,511,631.53	-45%	-72,230,234.19	232,741,865.72	85,985,153.79	146,756,711.93	41-R2	28.2	5,204,138.72	3.24%
366.00	Underground Conduit	1,551,966.69	-10%	-155,196.67	1,707,163.36	790,660.29	916,503.07	50-R3	28.8	31,823.02	2.05%
367.00	Underground Conductors and Devices	49,804,065.26	-5%	-2,490,203.26	52,294,268.52	11,750,621.73	40,543,646.79	30-R3	23.9	1,696,386.89	3.41%
368.00	Line Transformers	209,705,230.76	-10%	-20,970,523.08	230,675,753.84	71,829,368.57	158,846,385.27	42-S0.5	30.8	5,157,350.17	2.46%
369.00	Services	81,680,930.54	-40%	-32,672,372.22	114,353,302.76	50,153,941.91	64,199,360.85	30-R3	18.9	3,398,791.58	4.16%
370.00	Meters	61,133,035.49	0%	0.00	61,133,035.49	17,824,755.03	43,308,280.46	44-R1	32.2	1,344,977.65	2.20%
371.00	Installations on Customers' Premises	18,270,303.32	-5%	-913,515.17	19,183,818.49	7,363,640.96	11,820,177.53	16-R0.5	10.7	1,104,689.49	6.05%
373.00	Street Lighting and Signal Systems	45,406,623.49	-10%	-4,540,662.35	49,947,285.84	14,352,579.64	35,594,706.20	28-R1	20.9	1,703,095.99	3.75%
	Total Distribution Plant	893,357,914.56	-26.4%	-235,951,063.92	1,129,308,978.48	368,766,227.04	760,542,751.44			27,759,964.83	3.11%
	GENERAL PLANT										
	Structures and Improvements										
390.10	Struct.. And Improve. To Owned Property	28,987,368.24	-5%	-1,449,368.41	30,436,736.65	11,099,276.95	19,337,459.70	50-R1.5	38.3	504,894.51	1.74%
390.20	Improvements to Leased Property	694,489.17	0%	0.00	694,489.17	493,238.08	201,251.09	20-R1	12.1	16,632.32	2.39%
	Total Account 390	29,681,857.41	-4.9%	-1,449,368.41	31,131,225.82	11,592,515.03	19,538,710.79			521,526.83	1.76%
	Office Furniture and Equipment										
391.10	Office Equipment	6,168,471.98	0%	0.00	6,168,471.98	2,186,764.50	3,981,707.48	15-L1	11.5	346,235.43	5.61%
391.30	Cash Processing Equipment	369,383.94	0%	0.00	369,383.94	250,365.99	119,017.95	12-R4	6.6	18,033.02	4.88%
	Total Account 391	6,537,855.92	0.0%	0.00	6,537,855.92	2,437,130.49	4,100,725.43			364,268.46	5.57%
393.00	Stores Equipment	571,858.05	0%	0.00	571,858.05	352,897.62	218,960.43	30-R3	17.9	12,232.43	2.14%
394.00	Tools, Shop and Garage Equipment	3,700,720.83	0%	0.00	3,700,720.83	1,569,236.24	2,131,484.59	30-R2.5	21.9	97,328.06	2.63%
395.00	Laboratory Equipment	3,306,885.77	0%	0.00	3,306,885.77	1,780,545.79	1,526,339.98	27-L3	17.5	87,219.43	2.64%
396.00	Power Operated Equipment	200,677.14	15%	30,101.57	170,575.57	126,436.76	44,138.81	18-S5	9.2	4,797.70	2.39%

Table 2

Kentucky Utilities
Electric Division

Summary of Original Cost of Utility Plant In Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2002

Account No. (a)	Description (b)	Original Cost 12/31/02 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)	Original Cost Less Salvage (f)	Book Depreciation Reserve (g)	Net Original Cost Less Salvage (h)	A S L / Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)	Annual Deprecation Rate (l)
	Communication Equipment										
397.10	Carrier Communication Equipment	3,093,194.70	0%	0.00	3,093,194.70	1,426,693.39	1,666,501.31	19-S6	13 8	120,760 96	3 90%
397.20	Remote Control Communication Equipment	3,889,910.58	0%	0.00	3,889,910.58	1,309,606.44	2,580,304.14	20-L5	15 8	163,310.39	4 20%
397.30	Mobile Communication Equipment	4,579,895.62	0%	0.00	4,579,895.62	1,190,962.85	3,388,932.77	18-S5	15.1	224,432 63	4 90%
	Total Account 397	11,563,000.90	0.0%	0.00	11,563,000.90	3,927,262.68	7,635,738.22			508,503 99	4.40%
398.00	Miscellaneous Equipment	457,348.94	10%	45,734.89	411,614.05	224,361.12	187,252.93	19-L1.5	12 5	14,980 23	3 28%
	Total General Plant	58,020,204.96	-2.5%	-1,373,531.95	57,393,736.91	22,010,385.72	35,383,351.19			1,610,857.12	2 88%
	Sub-Total Depreciable Plant	3,245,966,123.92	-18.3%	-592,884,989.02	3,838,851,112.94	1,493,632,524.98	2,345,218,587.96			99,187,988.37	3.06%
	Other Plant (Not Studied)										
391.20	Non PC Computer Equipment	9,611,731.44				3,963,686.38					
391.40	Personal Computers	9,814,322.00				8,735,674.86					
392.00	Transportation Equipment - Cars & Trucks	23,749,238.51				14,621,439.53					
	Total Other Plant (Not Studied)	43,175,291.95				27,320,800.77					
	Total Depreciable Plant	3,289,141,415.87				1,520,953,325.75					
	NON-DEPRECIABLE PLANT										
	INTANGIBLE PLANT										
301.00	Organization	44,455 58				0.00					
302.00	Franchises and Consents	81,350.32				60,321.44					
303.00	Miscellaneous Intangible Plant	17,297,387.08				18,197,711.00					
	Total Intangible Plant	17,423,192.98				18,258,032.44					
	LAND & LAND RIGHTS										
310.20	Production Land	10,478,524.55				0.00					
330.20	Hydraulic Plant	13,479.47				0.00					
340.20	Other Production Land	98,602.74				0 00					
350.20	Transmission Land	1,162,528.04				-8,503.92					
360.10	Distribution Land	1,584,825 82				0.00					
389.20	Land	2,826,347.43				154,183.00					
	Total Land	16,164,308.05				145,679.08					
	Total Non-Depreciable Plant	33,587,501.03				18,403,711 52					
	Total Electric Plant in Service	3,322,728,916.90				1,539,357,037.27					

(1) Life Span Method Utiized. Interim Retirement Rate. Service Lives Vary.

Kentucky Utilities Company
Annualized Depreciation
at September 30, 2003
Using Historical Gross Salvage and Cost of Removal

	Depreciable Balance 09/30/03		Current Rates Implemented 1-Jan-01	Proposed Rates KIUC	Depreciation Under Current Rates	Depreciation Under Adjusted Rates	Net Difference Current/Adjusted Rates
ntangible Plant							
301 Organization	44,456	ND	0.00%	0.00%	-	-	-
302 Franchises and Consents	83,453	ND	0.00%	0.00%	-	-	-
303 Misc. Intangible Plant	21,631,290	NG	20.00%	20.00%	4,326,258	4,326,258	-
otal Intangible Plant	**21,759,199**				**4,326,258**	**4,326,258**	-
Steam Production Plant							
Land	10,475,562	ND		0.00%	-	-	-
Brown Unit 1	45,247,316		2.90%	2.30%	1,312,172	1,040,688	(271,484)
Brown Unit 2	38,238,854		2.88%	2.76%	1,101,279	1,055,392	(45,887)
Brown Unit 3	116,091,020		3.91%	2.61%	4,539,159	3,029,976	(1,509,183)
Ghent Unit 1	138,894,035		3.12%	3.64%	4,333,494	5,055,743	722,249
Ghent Unit 2	144,169,095		1.84%	1.98%	2,652,711	2,854,548	201,837
Ghent Unit 3	276,892,827		2.22%	2.43%	6,147,021	6,728,496	581,475
Ghent Unit 4	271,961,803		2.16%	2.51%	5,874,375	6,826,241	951,866
Green River Units 1&2	20,081,091		0.00%	0.00%	-	-	-
Green River Units 3	16,872,163		1.94%	1.12%	327,320	188,968	(138,352)
Green River Units 4	35,240,942		3.10%	1.77%	1,092,469	623,765	(468,705)
Pineyville	226,833		2.28%	0.00%	5,172	-	(5,172)
Tyrone Units 1&2	6,639,170		0.00%	1.13%	-	75,023	75,023
Tyrone Unit 3	18,792,326		2.13%	0.82%	400,277	154,097	(246,179)
System Laboratory					-	-	-
1311	805,716		4.22%	1.95%	34,001	15,711	(18,290)
1316	1,965,213		4.22%	2.94%	82,932	57,777	(25,155)
Coal Cars	7,647,232	NG	4.59%	1.96%	351,008	149,886	(201,122)
Pollution Control Equipment	114,781,009		5.67%	4.08%	6,508,083	4,683,065	(1,825,018)
Total Steam Production Plant	**1,265,022,207**				**34,761,473**	**32,539,376**	**(2,222,096)**
Hydraulic Production Plant							
Land	13,479	ND	0.00%	0.00%	-	-	-
Dix Dam	9,914,306		1.59%	1.16%	157,637	115,006	(42,632)
Lock # 7	840,028		2.46%	5.84%	20,665	49,058	28,393
otal Hydraulic Production Plant	**10,767,813**				**178,302**	**164,064**	**(14,239)**
Other Production Plant							
Land	98,603	ND	0.00%	0.00%	-	-	-
Haefling	5,296,000		0.00%	3.36%	-	177,946	177,946
Brown CT 5	20,296,408		3.43%	2.97%	696,167	602,803	(93,363)
Brown CT 6	36,701,293		3.39%	2.95%	1,244,174	1,082,688	(161,486)
Brown CT 7	38,256,129		3.28%	2.88%	1,254,801	1,101,777	(153,025)
Brown CT 8	27,638,671		3.51%	2.40%	970,117	663,328	(306,789)
Brown CT 9	36,697,794		3.39%	2.79%	1,244,055	1,023,868	(220,187)
Brown CT 10	27,720,786		3.48%	2.90%	964,683	803,903	(160,781)
Brown CT 11	42,757,087		3.55%	3.06%	1,517,877	1,308,367	(209,510)
Brown CT Gas Pipeline	8,364,109		3.39%	3.43%	283,543	286,889	3,346
Paddy's Run Generator 13	29,973,105		3.43%	3.01%	1,028,078	902,190	(125,887)
Trimble County CT 5	39,045,125		3.43%	3.00%	1,339,248	1,171,354	(167,894)
Trimble County CT 6	39,024,692		3.43%	3.00%	1,338,547	1,170,741	(167,806)
Trimble County CT Pipeline	4,474,853		3.43%	3.51%	153,487	157,067	3,580
Total Other Production Plant	**356,344,656**				**12,034,777**	**10,452,921**	**(1,581,856)**
Transmission Plant							
350.1 Land Rights	23,341,271		1.34%	2.44%	312,773	569,527	256,754
350.2 Land	1,162,528	ND			-	-	-
352 Structures & Improvements	7,758,006		2.65%	7.41%	205,587	574,868	369,281
353.1 Station Equipment	154,930,533		2.21%	0.69%	3,423,965	1,069,021	(2,354,944)
353.2 Syst Control/Microwave EquipStation Equi	14,789,869		6.18%	6.20%	914,014	916,972	2,958
354 Towers & Fixtures	62,743,597		2.84%	2.44%	1,781,918	1,530,944	(250,974)
355 Poles & Fixtures	80,841,658		4.03%	3.73%	3,257,919	3,015,394	(242,525)
356 Overhead Conductors & Devices	125,832,855		3.25%	0.00%	4,089,568	-	(4,089,568)
357 Undergound Conduit	448,760		2.01%	2.04%	9,020	9,155	135
358 Underground Conductors & Devices	1,114,762		3.52%	2.94%	39,240	32,774	(6,466)
359 Transmission ARO's	0				-	-	-
Total Transmission Plant	**472,963,839**				**14,034,003**	**7,718,654**	**(6,315,349)**
Distribution Plant							
360.1 Land Rights	1,423,182		1.14%	0.62%	16,224	8,824	(7,401)
360.2 Land	1,713,366	ND	0.00%	0.00%	-	-	-
361 Structures and Improvements	4,126,448		1.89%	1.84%	77,990	75,927	(2,063)

Kentucky Utilities Company
Annualized Depreciation
at September 30, 2003
Using Historical Gross Salvage and Cost of Removal

	Depreciable Balance 09/30/03		Current Rates Implemented 1-Jan-01	Proposed Rates KIUC	Depreciation Under Current Rates	Depreciation Under Adjusted Rates	Net Difference Current/Adjusted Rates
362 Station Equipment	96,700,056		2.24%	0.89%	2,166,081	860,630	(1,305,451)
364 Poles Towers & Fixtures	176,881,754		3.52%	1.46%	6,226,238	2,582,474	(3,643,764)
365 Overhead Conductors & Devices	165,135,703		3.02%	1.70%	4,987,098	2,807,307	(2,179,791)
366 Underground Conduit	1,664,173		1.75%	1.93%	29,123	32,119	2,996
367 Underground Conductors & Devices	56,772,724		3.29%	0.50%	1,867,823	283,864	(1,583,959)
368 Line Transformers	219,930,197		2.41%	2.27%	5,300,318	4,992,415	(307,902)
369 Services	82,837,019		3.75%	3.75%	3,106,388	3,106,388	-
370 Meters	62,508,577		2.79%	2.13%	1,743,989	1,331,433	(412,557)
371 Installations on Customer Premises	18,268,926		6.27%	6.41%	1,145,462	1,171,038	25,576
373 Street Lighting & Signal Systems	50,814,837		3.85%	2.39%	1,956,371	1,214,475	(741,897)
Total Distribution Plant	**938,776,962**				**28,623,105**	**18,466,893**	**(10,156,212)**
General Plant							
389.2 Land	2,825,417	ND	0.00%	0.00%	-	-	-
390.1 Structures & Improvements	30,511,481		1.76%	0.24%	537,002	73,228	(463,775)
390.2 Improvements to Leased Property	756,079		0.00%	2.40%	-	18,146	18,146
391.1 Office Furniture & Equipment	6,631,398		5.82%	5.50%	385,947	364,727	(21,220)
391.2 Non PC Computer Equipment	13,732,616		20.00%	20.00%	2,746,523	2,746,523	-
391.3 Cash Processing Equipment	817,575		10.00%	4.88%	81,758	39,898	(41,860)
391.4 Personal Computer Equipment	11,716,009		33.33%	33.33%	3,904,946	3,904,946	-
392 Transportation Equipment	23,749,239		20.00%	20.00%	4,749,848	4,749,848	-
393 Stores Equipment	674,815		2.87%	2.14%	19,367	14,441	(4,926)
394 Tool, Shop, and Garage Equipment	4,637,322		2.74%	1.46%	127,063	67,705	(59,358)
395 Laboratory Equipment	3,307,714		3.16%	1.96%	104,524	64,831	(39,693)
396 Power Operated Equipment	225,500		3.56%	4.02%	8,028	9,065	1,037
397 Communication Equipment	13,113,712		3.55%	4.40%	465,537	577,003	111,467
398 Misc Equipment	463,335		5.19%	0.00%	24,047	-	(24,047)
Total General Plant	**113,162,212**				**13,154,589**	**12,630,360**	**(524,229)**
TOTAL PLANT excluding ARO Assets	**3,178,796,889**						
ARO Assets excluded from Plant in service	**8,608,030**						
Total Plant in Service	**3,187,404,919**						
Total Annual Depreciation					**107,112,508**	**86,298,526**	**(20,813,981)**
Less Amounts not included in Income Statement Depreciation							
Coal Cars					351,008	152,180	**(198,828)**
Brown Gas Pipeline					283,543	376,385	**92,842**
TC Gas Pipeline					153,487	192,419	**38,932**
Account 139200 Transportation Equipment					4,749,848	4,749,848	-
Subtotal					**5,537,886**	**5,470,832**	**(67,054)**
Less ECR Depreciation					**194,434**	**223,677**	**29,243**
Total Annualized Depreciation					**101,380,187**	**80,604,017**	**(20,776,170)**

Kentucky Utilities Company
Annualized Depreciation
at September 30, 2003
Using Historical Gross Salvage and Cost of Removal

	Depreciable Balance 09/30/03	Current Rates Implemented 1-Jan-01	Proposed Rates KIUC	Depreciation Under Current Rates	Depreciation Under Adjusted Rates	Net Difference Current/Adjusted Rates
Pro Forma Depreciation Adjustment						
Twelve months ended 9/30/03 per books						
Depreciation						96,724,719
Amortization						4,509,128
Less:Depreciation SFAS 143 Assets						(131,239)
Less:Depreciation of ECR Assets						(194,436)
						100,908,171
Annualized Depreciation under current rates						101,380,187
(1) Adjustment due to annualizing current rates						472,016
12 months depreciation under KIUC rates for adjusted Gross Salv/COR						80,604,017
Less:Annualized Depreciation under current rates						(101,380,187)
(2) Adjustment due to proposed rates						(20,776,170)
Total Adjustment (1) + (2)						(20,304,154)
KU Proposed Adjustment						2,395,535
Total Net Difference Between KIUC Adjustment for Gross Salv/COR and KU Proposed Adjustment						**(22,699,689)**
Kentucky Jurisdiction Percentage						**87.299%**
Kentucky Jurisdiction Amount						**(19,816,602)**

Kentucky Utilities Company
Annualized Depreciation
at September 30, 2003
Using Historical Gross Salvage and Cost of Removal and Removing Interim Additions for NOX Compliance

	Depreciable Balance 09/30/03		KIUC Rates W/Adjust. Gross Salv/COR	Proposed Rates KIUC	Depreciation Under KIUC Rates W/Adjust. Gross Salv/COR	Depreciation Under KIUC Rates	Net Difference KIUC Rates W/Adjust. Gross Salv/COR/ KIUC Rates
ntangible Plant							
301 Organization	44,456	ND	0.00%	0.00%	-	-	-
302 Franchises and Consents	83,453	ND	0.00%	0.00%	-	-	-
303 Misc. Intangible Plant	21,631,290	NG	20.00%	20.00%	4,326,258	4,326,258	-
'otal Intangible Plant	**21,759,199**				**4,326,258**	**4,326,258**	-
Steam Production Plant							
Land	10,475,562	ND		0.00%	-	-	-
Brown Unit 1	45,247,316		2.90%	2.21%	1,312,172	999,966	(312,206)
Brown Unit 2	38,238,854		2.88%	2.45%	1,101,279	936,852	(164,427)
Brown Unit 3	116,091,020		3.91%	2.35%	4,539,159	2,728,139	(1,811,020)
Ghent Unit 1	138,894,035		3.12%	2.00%	4,333,494	2,777,881	(1,555,613)
Ghent Unit 2	144,169,095		1.84%	1.86%	2,652,711	2,681,545	28,834
Ghent Unit 3	276,892,827		2.22%	1.78%	6,147,021	4,928,692	(1,218,328)
Ghent Unit 4	271,961,803		2.16%	2.04%	5,874,375	5,548,021	(326,354)
Green River Units 1&2	20,081,091		0.00%	0.00%	-	-	-
Green River Units 3	16,872,163		1.94%	0.41%	327,320	69,176	(258,144)
Green River Units 4	35,240,942		3.10%	1.73%	1,092,469	609,668	(482,801)
Pineyville	226,833		2.28%	0.00%	5,172	-	(5,172)
Tyrone Units 1&2	6,639,170		0.00%	1.08%	-	71,703	71,703
Tyrone Unit 3	18,792,326		2.13%	0.26%	400,277	48,860	(351,416)
System Laboratory					-	-	-
1311	805,716		4.22%	1.95%	34,001	15,711	(18,290)
1316	1,965,213		4.22%	2.94%	82,932	57,777	(25,155)
Coal Cars	7,647,232	NG	4.59%	1.90%	351,008	145,297	(205,711)
Pollution Control Equipment	114,781,009		5.67%	3.98%	6,508,083	4,568,284	(1,939,799)
'otal Steam Production Plant	**1,265,022,207**				**34,761,473**	**26,187,573**	**(8,573,900)**
Hydraulic Production Plant							
Land	13,479	ND	0.00%	0.00%	-	-	-
Dix Dam	9,914,306		1.59%	1.16%	157,637	115,006	(42,632)
Lock # 7	840,028		2.46%	5.84%	20,665	49,058	28,393
Total Hydraulic Production Plant	**10,767,813**				**178,302**	**164,064**	**(14,239)**
)ther Production Plant							
Land	98,603	ND	0.00%	0.00%	-	-	-
Haefling	5,296,000		0.00%		-	-	-
Brown CT 5	20,296,408		3.43%	2.97%	696,167	602,803	(93,363)
Brown CT 6	36,701,293		3.39%	2.95%	1,244,174	1,082,688	(161,486)
Brown CT 7	38,256,129		3.28%	2.88%	1,254,801	1,101,777	(153,025)
Brown CT 8	27,638,671		3.51%	2.40%	970,117	663,328	(306,789)
Brown CT 9	36,697,794		3.39%	2.79%	1,244,055	1,023,868	(220,187)
Brown CT 10	27,720,786		3.48%	2.90%	964,683	803,903	(160,781)
Brown CT 11	42,757,087		3.55%	3.06%	1,517,877	1,308,367	(209,510)
Brown CT Gas Pipeline	8,364,109		3.39%	3.43%	283,543	286,889	3,346
Paddy's Run Generator 13	29,973,105		3.43%	3.01%	1,028,078	902,190	(125,887)
Trimble County CT 5	39,045,125		3.43%	3.00%	1,339,248	1,171,354	(167,894)
Trimble County CT 6	39,024,692		3.43%	3.00%	1,338,547	1,170,741	(167,806)
Trimble County CT Pipeline	4,474,853		3.43%	3.51%	153,487	157,067	3,580
Total Other Production Plant	**356,344,656**				**12,034,777**	**10,274,975**	**(1,759,802)**
Transmission Plant							
350.1 Land Rights	23,341,271		1.34%	2.44%	312,773	569,527	256,754
350.2 Land	1,162,528	ND			-	-	-
352 Structures & Improvements	7,758,006		2.65%	7.41%	205,587	574,868	369,281
353.1 Station Equipment	154,930,533		2.21%	0.69%	3,423,965	1,069,021	(2,354,944)
353.2 Syst Control/Microwave EquipStation Equi	14,789,869		6.18%	6.20%	914,014	916,972	2,958
354 Towers & Fixtures	62,743,597		2.84%	2.44%	1,781,918	1,530,944	(250,974)
355 Poles & Fixtures	80,841,658		4.03%	3.73%	3,257,919	3,015,394	(242,525)
356 Overhead Conductors & Devices	125,832,855		3.25%	0.00%	4,089,568	-	(4,089,568)
357 Undergound Conduit	448,760		2.01%	2.04%	9,020	9,155	135
358 Underground Conductors & Devices	1,114,762		3.52%	2.94%	39,240	32,774	(6,466)
359 Transmission ARO's	0				-	-	-
Total Transmission Plant	**472,963,839**				**14,034,003**	**7,718,654**	**(6,315,349)**
Distribution Plant							
360.1 Land Rights	1,423,182		1.14%	0.62%	16,224	8,824	(7,401)
360.2 Land	1,713,366	ND	0.00%	0.00%	-	-	-

Kentucky Utilities Company
Annualized Depreciation
at September 30, 2003
Using Historical Gross Salvage and Cost of Removal and Removing Interim Additions for NOX Compliance

	Depreciable Balance 09/30/03		KIUC Rates W/Adjust. Gross Salv/COR	Proposed Rates KIUC	Depreciation Under KIUC Rates W/Adjust. Gross Salv/COR	Depreciation Under KIUC Rates	Net Difference KIUC Rates W/Adjust. Gross Salv/COR/ KIUC Rates
361 Structures and Improvements	4,126,448		1.89%	1.84%	77,990	75,927	(2,063)
362 Station Equipment	96,700,056		2.24%	0.89%	2,166,081	860,630	(1,305,451)
364 Poles Towers & Fixtures	176,881,754		3.52%	1.46%	6,226,238	2,582,474	(3,643,764)
365 Overhead Conductors & Devices	165,135,703		3.02%	1.70%	4,987,098	2,807,307	(2,179,791)
366 Underground Conduit	1,664,173		1.75%	1.93%	29,123	32,119	2,996
367 Underground Conductors & Devices	56,772,724		3.29%	0.50%	1,867,823	283,864	(1,583,959)
368 Line Transformers	219,930,197		2.41%	2.27%	5,300,318	4,992,415	(307,902)
369 Services	82,837,019		3.75%	3.75%	3,106,388	3,106,388	-
370 Meters	62,508,577		2.79%	2.13%	1,743,989	1,331,433	(412,557)
371 Installations on Customer Premises	18,268,926		6.27%	6.41%	1,145,462	1,171,038	25,576
373 Street Lighting & Signal Systems	50,814,837		3.85%	2.39%	1,956,371	1,214,475	(741,897)
Total Distribution Plant	**938,776,962**				**28,623,105**	**18,466,893**	**(10,156,212)**
General Plant							
389.2 Land	2,825,417	ND	0.00%	0.00%	-	-	-
390.1 Structures & Improvements	30,511,481		1.76%	0.24%	537,002	73,228	(463,775)
390.2 Improvements to Leased Property	756,079		0.00%	2.40%	-	18,146	18,146
391.1 Office Furniture & Equipment	6,631,398		5.82%	5.50%	385,947	364,727	(21,220)
391.2 Non PC Computer Equipment	13,732,616		20.00%	20.00%	2,746,523	2,746,523	-
391.3 Cash Processing Equipment	817,575		10.00%	4.88%	81,758	39,898	(41,860)
391.4 Personal Computer Equipment	11,716,009		33.33%	33.33%	3,904,946	3,904,946	-
392 Transportation Equipment	23,749,239		20.00%	20.00%	4,749,848	4,749,848	-
393 Stores Equipment	674,815		2.87%	2.14%	19,367	14,441	(4,926)
394 Tool, Shop, and Garage Equipment	4,637,322		2.74%	1.46%	127,063	67,705	(59,358)
395 Laboratory Equipment	3,307,714		3.16%	1.96%	104,524	64,831	(39,693)
396 Power Operated Equipment	225,500		3.56%	4.02%	8,028	9,065	1,037
397 Communication Equipment	13,113,712		3.55%	4.40%	465,537	577,003	111,467
398 Misc Equipment	463,335		5.19%	0.00%	24,047	-	(24,047)
Total General Plant	**113,162,212**				**13,154,589**	**12,630,360**	**(524,229)**
TOTAL PLANT excluding ARO Assets	**3,178,796,889**						
ARO Assets excluded from Plant in service	**8,608,030**						
Total Plant in Service	**3,187,404,919**						
Total Annual Depreciation					**107,112,508**	**79,768,777**	**(27,343,730)**
Less Amounts not included in Income Statement Depreciation							
Coal Cars					351,008	152,180	**(198,828)**
Brown Gas Pipeline					283,543	376,385	**92,842**
TC Gas Pipeline					153,487	192,419	**38,932**
Account 139200 Transportation Equipment					4,749,848	4,749,848	**-**
Subtotal					**5,537,886**	**5,470,832**	**(67,054)**
Less ECR Depreciation					**194,434**	**223,677**	**29,243**
Total Annualized Depreciation					**101,380,187**	**74,074,268**	**(27,305,918)**

Kentucky Utilities Company
Annualized Depreciation
at September 30, 2003
Using Historical Gross Salvage and Cost of Removal and Removing Interim Additions for NOX Compliance

	Depreciable Balance 09/30/03	KIUC Rates W/Adjust. Gross Salv/COR	Proposed Rates KIUC	Depreciation Under KIUC Rates W/Adjust. Gross Salv/COR	Depreciation Under KIUC Rates	Net Difference KIUC Rates W/Adjust. Gross Salv/COR/ KIUC Rates
Pro Forma Depreciation Adjustment						
Twelve months ended 9/30/03 per books						
Depreciation						96,724,719
Amortization						4,509,128
Less:Depreciation SFAS 143 Assets						(131,239)
Less:Depreciation of ECR Assets						(194,436)
						100,908,171
Annualized Depreciation under current rates						101,380,187
(1) Adjustment due to annualizing current rates						472,016
12 months depreciation under KIUC rates ADJUSTED FOR Gross Salv/COR						80,604,017
Less:Annualized Depreciation under current rates						(101,380,187)
(2) Adjustment due to proposed rates						(20,776,170)
Total Adjustment (1) + (2)						(20,304,154)
KU Proposed Adjustment						2,395,535
(3) Total Net Difference Between KIUC Adjustment for Gross Salv/COR						**(22,699,689)**
Total Annualized Depreciation Adjusted by KIUC for Removal of NOX Compliance Interim Additions						**74,074,268**
Total Annualized Depreciation Adjusted by KIUC for Gross Salv/COR Adjustment						**(80,604,017)**
(4) Total Net Difference Between KIUC Adj. For Gross Salv/COR & Removal of NOX Compliance Interim Additions						**(6,529,749)**
Total Net Difference Between KIUC Adj for Gross Salv/COR with Removal of NOX Compliance & KU Proposed Adjustment (3) + (4)						**(29,229,438)**
Kentucky Jurisdiction Percentage						**87.299%**
Kentucky Jurisdiction Amount						**(25,517,007)**

Exhibit___(LK-7)

Kentucky Utilities Company
Capitalization and Return Requirements
At September 30, 2003

Rate of Return as Filed by KU

	Capital Amounts	Capital Ratios	Component Costs	Wtd Avg Cost	Convers Factor	Grossed Up Wtd Avg Cost
Short Term Debt	77,825,772	5.90%	1.06%	0.06%	1.006769	0.06%
A/R Securitization	38,856,247	2.95%	1.39%	0.04%	1.006769	0.04%
Long Term Debt	483,733,595	36.70%	3.12%	1.14%	1.006769	1.15%
Preferred Stock	31,531,735	2.39%	5.68%	0.14%	1.688147	0.23%
Common Equity	686,177,634	52.06%	11.25%	5.86%	1.688147	9.89%
Total	1,318,124,983	100.00%		7.24%		11.27%
Return Requirement before Gross-Up				95,443,530		
Return Requirement after Gross-Up						148,534,579

Rate of Return with KIUC Return on Common Equity

	Capital Amounts	Capital Ratios	Component Costs	Wtd Avg Cost	Convers Factor	Grossed Up Wtd Avg Cost
Short Term Debt	77,825,772	5.90%	1.06%	0.06%	1.006769	0.06%
A/R Securitization	38,856,247	2.95%	1.39%	0.04%	1.006769	0.04%
Long Term Debt	483,733,595	36.70%	3.12%	1.14%	1.006769	1.15%
Preferred Stock	31,531,735	2.39%	5.68%	0.14%	1.688147	0.23%
Common Equity	686,177,634	52.06%	8.70%	4.53%	1.688147	7.65%
Total	1,318,124,983	100.00%		5.91%		9.03%
Return Requirement before Gross-Up				77,946,000		
Return Requirement after Gross-Up						118,996,181
Reduction in Revenue Requirement						29,538,398
Effect of Each 1% ROE						11,583,685

AMERICAN ELECTRIC POWER

CANCELLING ORIGINAL SHEET NO. 19-1
SHEET NO.

P.S.C. ELECTRIC NO. 7

TARIFF S. S. C.
(System Sales Clause)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., Experimental R.S.-T.O.D., S.G.S., M.G.S., Experimental M.G.S.-T.O.D., L.G.S., Q.P., C.I.P.-T.O.D., I.R.P., M.W., O.L., and S.L.

RATE.

1. When the monthly net revenues from system sales are above or below the monthly base net revenues from system sales, as provided in paragraph 3 below, an additional credit or charge equal to the product of the Kwhrs and a system sales adjustment factor (A) shall be made, where "A", calculated to the nearest 0.0001 mill per kilowatthour, is defined as set forth below.

System Sales Adjustment Factor (A) = [.5(Tm - Tb)]/Sm

In the above formula "T" is Kentucky Power Company's (KPCo) monthly net revenues from system sales in the current (m) and base (b) periods and "S" is the Kwh sales in the current (m) period, all defined below.

2. The net revenue from American Electric Power (AEP) System deliveries to non-associated companies that are shared by AEP Member Companies, including KPCo, in proportion to their Member Load Ratio and as reported in the Federal Energy Regulatory Commission's Uniform System of Accounts under Account 447, Sales for Resale, shall consist of and be derived as follows:

a. KPCo's Member Load Ratio share of total revenues from System sales as recorded in Account 447, less

b. KPCo's Member Load Ratio share of total out-of-pocket costs incurred in supplying the power and energy for the deliveries in (a) above.

The out-of-pocket costs include all operating, maintenance, tax, transmission losses and other expenses that would not have been incurred if the power and energy had not been supplied for such deliveries, including demand and energy charges for power and energy supplied by Third Parties.

3. The base monthly net revenues from system sales are as follows:

Billing Month	Base Net Revenues from System Sales (Total Company Basis)
January	$ 895,960
February	767,802
March	893,126
April	1,036,738
May	1,085,852
June	1,324,166
July	1,027,403
August	1,154,184
September	912,736
October	731,014
November	624,320
December	862,035

PUBLIC SERVICE COMMISSION OF KENTUCKY EFFECTIVE
MAR 01 1996
PURSUANT TO 807 KAR 5:011, SECTION 9 (1)
BY: [signature]
FOR THE PUBLIC SERVICE COMMISSION

4. Sales (S) shall be equated to the sum of (a) generation (including energy produced by generating plants during the construction period), (b) purchase, and (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) inter-system sales and less (f) total system losses.

5. The system sales adjustment factor shall be based upon estimated monthly revenues and costs for system sales, subject to subsequent adjustment upon final determination of actual revenues and costs.

(Cont'd. on Sheet No. 19-2)

DATE OF ISSUE January 30, 1996 DATE EFFECTIVE August 2, 1995

ISSUED BY E. K. WAGNER — DIRECTOR OF RATES — ASHLAND, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 91-066 dated April 1, 1991

AMERICAN ELECTRIC POWER

CANCELLING ORIGINAL SHEET NO. 19-2
SHEET NO. ______

T

P.S.C. ELECTRIC NO. 7

TARIFF S. S. C. (Cont'd.)
(System Sales Clause)

6. The monthly System Sales Clause shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments which shall include data and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

MAR 2 1 1996

PURSUANT TO 807 KAR 5:011,
SECTION 9 (1)
BY: Gordon C. Neel
FOR THE PUBLIC SERVICE COMMISSION

DATE OF ISSUE January 30, 1996 DATE EFFECTIVE Service rendered on and after April 1, 1991

ISSUED BY E. K. WAGNER DIRECTOR OF RATES ASHLAND, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 91-066 dated April 1, 1991

AMERICAN ELECTRIC POWER

CANCELLING ORIGINAL SHEET NO. 19-1
SHEET NO.

T

P.S.C. ELECTRIC NO. 7

TARIFF S. S. C.
(System Sales Clause)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., Experimental R.S.-T.O.D., S.G.S., M.G.S., Experimental M.G.S.-T.O.D., L.G.S., Q.P., C.I.P.-T.O.D., I.R.P., M.W., O.L., and S.L.

RATE.

1. When the monthly net revenues from system sales are above or below the monthly base net revenues from system sales, as provided in paragraph 3 below, an additional credit or charge equal to the product of the Kwhrs and a system sales adjustment factor (A) shall be made, where "A", calculated to the nearest 0.0001 mill per kilowatthour, is defined as set forth below.

System Sales Adjustment Factor (A) = (.5[Tm - Tb])/Sm

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August	1,154,184
September	912,736
October	731,014
November	624,320
December	862,035

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

MAR 07 1996

PURSUANT TO 807 KAR 5:011,
SECTION 9 (1)
BY: Cordelia C. Neal
FOR THE PUBLIC SERVICE COMMISSION

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(Cont'd. on Sheet No. 19-2)

DATE OF ISSUE January 30, 1996 DATE EFFECTIVE August 2, 1995

ISSUED BY E. K. WAGNER — DIRECTOR OF RATES — ASHLAND, KENTUCKY
NAME — TITLE — ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 91-066 dated April 1, 1991

AMERICAN ELECTRIC POWER

CANCELLING ORIGINAL SHEET NO. 19-2
SHEET NO.

T

P.S.C. ELECTRIC NO. 7

TARIFF S. S. C. (Cont'd.)
(System Sales Clause)

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PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

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PURSUANT TO 807 KAR 5:011,
SECTION 9 (1)
BY: Jordan C. Neel
FOR THE PUBLIC SERVICE COMMISSION

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