COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO. 2003-00433

DIRECT TESTIMONY

AND EXHIBITS

OF

ROBERT J. HENKES

PERTAINING TO THE ELECTRIC CASE

On Behalf of the Office Of Rate Intervention Of The Attorney General Of The Commonwealth Of Kentucky

March 23, 2004

Louisville Gas and Electric Company
Case No. 2003-00433 Electric Rate Case
Direct Testimony of Robert J. Henkes

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I. STATEMENT OF QUALIFICATIONS

Q. WOULD YOU STATE YOUR NAME AND ADDRESS?

A. My name is Robert J. Henkes and my business address is 7 Sunset Road, Old Greenwich, Connecticut 06870.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am Principal and founder of Henkes Consulting, a financial consulting firm that specializes in utility regulation.

Q. WHAT IS YOUR REGULATORY EXPERIENCE?

A. I have prepared and presented numerous testimonies in rate proceedings involving electric, gas, telephone, water and wastewater companies in jurisdictions nationwide including Arkansas, Delaware, District of Columbia, Georgia, Kentucky, Maryland, New Jersey, New Mexico, Pennsylvania, Vermont, the U.S. Virgin Islands and before the Federal Energy Regulatory Commission. A complete listing of jurisdictions and rate proceedings in which I have been involved is provided in Appendix I attached to this testimony.

Q. WHAT OTHER PROFESSIONAL EXPERIENCE HAVE YOU HAD?

A. Prior to founding Henkes Consulting in 1999, I was a Principal of The Georgetown Consulting Group, Inc. for over 20 years. At Georgetown Consulting I performed the same type of consulting services as I am currently rendering through Henkes Consulting. Prior to my association with Georgetown Consulting, I was employed by the American Can Company as Manager of Financial Controls. Before joining the American Can Company, I was employed by the management consulting division of Touche Ross & Company (now Deloitte & Touche) for over six years. At Touche Ross, my experience, in addition to regulatory work, included numerous projects in a wide variety of industries and financial disciplines such as cash flow projections, bonding feasibility, capital and profit forecasting, and the design and implementation of accounting and budgetary reporting and control systems.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor degree in Management Science received from the Netherlands School of Business, The Netherlands in 1966; a Bachelor of Arts degree received from the University of Puget Sound, Tacoma, Washington in 1971; and an MBA degree in Finance received from Michigan State University, East Lansing, Michigan in 1973. I have also completed the CPA program of the New York University Graduate School of Business.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF THIS TESTIMONY?

A. I was engaged by the Office of Rate Intervention of the Attorney General of Kentucky ("AG") to conduct a review and analysis and present testimony in the matter of the petition of Louisville Gas and Electric Company ("LG&E" or the "Company") for an increase in its base rates for electric service.

The purpose of this testimony is to present to the Kentucky Public Service Commission ("KPSC" or the "Commission") the appropriate electric capital structure and overall rate of return, rate base and pro forma test period operating income, as well as the appropriate electric revenue requirement for the Company in this proceeding.

In the determination of the AG's recommended capital structure and overall rate of return, rate base, operating income and revenue requirement, I have relied on and incorporated the recommendations of the following other expert witnesses engaged by the AG in this proceeding:

1. Dr. <u>Carl Weaver</u>, concerning the appropriate capital structure ratios, cost rates for debt, preferred stock, the return on common equity, and the resulting overall rate of return for the Company in this proceeding;
2. Mr. <u>Michael Majoros,</u> concerning the FASB 143 Asset Retirement Obligation issue and the appropriate depreciation rates to be adopted by the Commission in this case; and

3. Mr. David Brown Kinloch, concerning LG&E's proposal in this case to increase certain Miscellaneous Service charges.

In developing this testimony, I have reviewed and analyzed the Company's December 29, 2003 filing; supporting testimonies, exhibits, filing requirements and workpapers; the Company's responses to initial and follow-up data requests by the KPSC Staff, AG and other intervenors; and other relevant financial documents and data.

III. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE.

A. I have reached the following findings and conclusions in this case:

1. The electric revenue requirement determination in this case should be based on LG&E's capitalization. This revenue requirement determination base has also been proposed by the Company in this rate proceeding and has been consistently applied by the Commission in LG&E's previous electric base rate proceedings (schedule RJH-1, line 1).

2. The appropriate adjusted electric capitalization as of September 30, 2003, the end of the test period in this case, amounts to $1,460.257 million which is $25.444 million lower than the adjusted electric capitalization of $1,485.701 million proposed by LG&E (schedule RJH-1, line 1 and schedule RJH-2).

3. The appropriate pro forma adjusted electric rate base measured as of September 30, 2003, the end of the test period in this case, amounts to $1.479 million. (schedule RJH-3). The Company has not presented a proposed adjusted electric rate base in this case.

4. The AG's expert rate of return witness, Dr. Carl Weaver, has recommended a short term debt cost rate of 1.06%, A/R securitization rate of 1.39%, long term debt rate of 3.77%, preferred stock cost rate of 2.51% and a return on equity range of 9.75%

to 10.25%, with a mid-point of 10.00%. These recommended capital cost rates, together with Dr. Weaver's recommended capital structure ratios produce the AG's recommended overall rate of return for LG&E's electric operations of 6.46% (Schedule RJH-2). This is equivalent to a rate of return of 6.38% on the Company's adjusted electric rate base (schedule RJH-3, line 15).

By comparison, the Company has proposed an overall rate of return on capital structure of 7.12% for its electric operations. Since the Company has not presented a proposed adjusted electric rate base, it has not provided an equivalent proposed overall return on rate base number for its electric operations.

5. The appropriate pro forma test period electric operating income amounts to $87.108 million, which is $19.098 million higher than LG&E's proposed test period electric operating income of $68.010 million (schedule RJH-1, line 4 and schedule RJH-4).

6. The appropriate revenue conversion factor to be used for rate making purposes in this case is approximately .5948. This is higher than the Company's proposed revenue conversion factor of approximately .5924 (schedule RJH-1, line 6 and footnote 4).

7. The application of the recommended overall rate of return of 6.46% to the recommended capital structure of $1,460.257 million, combined with the recommended pro forma test period operating income of $87.108 million and the revenue conversion factor of approximately .5948 indicates that the Company has an overall annual revenue deficiency for its electric operations of $12.141 million.

This is $51.623 million (81%) lower than the Company's proposed annual electric revenue deficiency of $63.764 million (schedule RJH-1, lines 1-7).

8. The recommended annual electric revenue deficiency of $12.141 million should be achieved by increasing LG&E's annual electric revenues by $12.140 million and LG&E's annual miscellaneous electric service charges by approximately $1,000 (schedule RJH-1, lines 8-10).

9. The recommended annual electric revenue deficiency and associated electric rate increases identified in recommendation nos. 7 and 8 do not yet reflect the increase in the recommended pro forma electric test year operating income for the restatement of all Kentucky income taxes included in LG&E's proposed pro forma test year operating income from a rate of 8.25% to an effective rate of 7.87% (schedule RJH-4, line 1, * notation). This AG recommendation could not be quantified when this testimony was being prepared. Once LG&E has provided the necessary information to quantify this additional AG recommendation, the AG's recommended electric revenue deficiency and rate increase recommendations as currently presented in this testimony must be updated to reflect the impact of this additional recommendation.

IV. REVENUE REQUIREMENT ISSUES

A. CAPITALIZATION AND OVERALL RATE OF RETURN

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED TEST YEAR-END ADJUSTED CAPITALIZATION AND CAPITAL STRUCTURE RATIOS FOR ITS ELECTRIC OPERATIONS IN THIS CASE.

A. As shown on Rives Exhibit 2, page 1, the starting point of the Company's proposed pro forma adjusted electric capitalization is the actual per books total company capitalization as of 9/30/2003 of approximately $1,924.559 million, consisting of short term debt, A/R securitization, long term debt, preferred stock and common equity. The Company then allocated this total company test year-end capitalization between its electric and gas operations based on a rate base allocation percentage. This results in an allocated electric capitalization balance of $1,619.131 million. Next, the Company made 6 pro forma electric capitalization adjustments in order to arrive at its proposed adjusted electric capitalization of $1,485.701 million. These 6 proposed electric capitalization adjustments concern (1) the removal of certain Trimble County inventories; (2) the removal of LG&E's investment in the Ohio Valley Electric Corporation; (3) the addition of the Job Development Tax Credit balance allocated to electric operations; (4) the removal of reimbursed capital to repair the E.W. Brown combustion turbines; (5) the removal of the Environmental Surcharge rate base associated with the Company's post-1995 ECR Plan; and (6) the reversal of the impact of the Company's Minimum Pension Liability ("MPL") adjustment to common equity. The first 5 of these capitalization adjustments only impact the dollar amount of the electric capitalization without changing the ratios of the capitalization components. The last capitalization adjustment concerning the MPL issue is an adjustment that not only impacts the capitalization dollar balance, but also changes the capital structure ratios because it involves an adjustment that is made to the common equity balance only.

The so-derived adjusted electric capitalization and capital structure ratios proposed by LG&E are summarized in the first two columns on the top part of schedule RJH-2.

Q. DOES THE AG AGREE WITH THE COMPANY'S PROPOSED TEST YEAR-END ADJUSTED ELECTRIC CAPITALIZATION AND CAPITAL STRUCTURE RATIOS THAT YOU JUST DESCRIBED?

A. Dr. Weaver has informed me that, based on his review and analysis, he has found reasonable the Company's proposed total company test year-end capitalization consisting of short term debt, A/R securitization, long term debt, preferred stock and common equity, and he recommends that this capitalization be used as the appropriate starting point for the determination of the Company's overall rate of return determination. In this case, I am responsible for addressing the appropriateness of (a) the Company's proposed total company capitalization allocation to electric operations, and (b) each of the Company's 6 proposed electric capitalization adjustments. Based on my review of these issues, I agree with all of the Company's proposed electric capitalization proposals with the exception of the Company's proposed MPL adjustment to its common equity balance. I recommend that the Company's proposed MPL related equity adjustment be rejected by the

Commission.

The resulting AG-recommended adjusted electric capitalization and capital structure ratios are summarized in the first two columns on the bottom part of schedule RJH-2.

Q. BRIEFLY SUMMARIZE THE COMPANY'S PROPOSAL WITH REGARD TO THE MPL ISSUE IN THIS CASE.

A. The Company is proposing to reverse actual write-downs to its common equity balance that were previously recorded by LG&E in accordance with SFAS 130, *Reporting Comprehensive Income*, in order to reflect the Company's Minimum Pension Liability ("MPL"). As shown on Rives Exhibit 2, page 2, column (7), this proposal has the effect of increasing the Company's proposed adjusted electric capital structure by $25.443 million. I understand that this proposed common equity adjustment would only be possible if the Company is allowed to establish a regulatory asset for the amount of the MPL equity write-down. Therefore, the Company in this case is also requesting approval from the KPSC to record such a regulatory asset. The Company claims that the establishment of the MPL regulatory asset is consistent with and allowed by SFAS 71.

Q. PLEASE EXPLAIN YOUR RECOMMENDATION THAT THE COMMISSION REJECT THE COMPANY'S PROPOSED MPL RELATED COMMON EQUITY ADJUSTMENT FOR RATEMAKING PURPOSES IN THIS CASE.

A. There are several reasons why I believe the Company's proposals to reverse the MPL related equity write-down and establish a regulatory asset for the MPL are inappropriate and should be rejected by the KPSC.

First, the equity write-down was actually made on the Company's books in accordance with generally accepted accounting rules and, therefore, represents an actual, known and measurable capitalization element at September 30, 2003, the end of the test year in this case. In this regard, it should be noted that in LG&E's prior electric rate case, Case No. 98-426, the Commission similarly rejected a proposal on the part of the Company to reverse for ratemaking purposes certain common equity write-downs that were actually booked by the Company during the test year in that case.[1] On page 65 of its Order in Case No. 98-426, the Commission stated in this regard:

> The Commission cannot simply ignore the fact that the write-off has occurred and will continue to affect LG&E's capitalization in the future.

Thus, my recommendation to reject the Company's proposed equity write-down reversal in the current case is consistent with previously established Commission ratemaking policy.

Second, I am not convinced that the establishment of a regulatory MPL asset is consistent with and allowed by SFAS 71. In its testimony and responses to data requests, LG&E states that the regulatory MPL asset would only be extinguished through *balance sheet* accounting (i.e., changes in asset values). SFAS 71 on the other hand envisions the recovery of deferred expenses through rates, which implies an *income statement* orientation. Moreover, under SFAS 71, it is the action of the regulator, not exogenous

[1] Case No. 98-426, KPSC Order at 64-65.

economic forces, that makes the recovery of the regulatory asset possible. All of this raises a question in my mind as to whether the proposed regulatory asset meets the definition of the type of cost to which SFAS 71 is intended to apply.

Finally, I am concerned that the establishment of a regulatory asset pursuant to SFAS 71 may give rise to a presumption that the underlying costs are recoverable from ratepayers and preclude a prudence review of these costs in the future. For example, if the regulatory MPL asset balance is not eventually eliminated through the normal operation of SFAS 87 accounting, that in turn could lead to a claim for amortization through rates in a future LG&E rate proceeding, as has been the treatment afforded all previous and existing regulatory assets by the KPSC for LG&E.

Q. NOW THAT YOU HAVE DISCUSSED THE AG'S RECOMMENDED ADJUSTED ELECTRIC CAPITALIZATION AND ASSOCIATED CAPITAL STRUCTURE RATIOS, WHAT ARE THE AG'S RECOMMENDED CAPITAL COST RATES AND OVERALL RATE OF RETURN?

A. The AG's expert rate of return witness, Dr. Carl Weaver, has recommended the same cost rates as LG&E for the adjusted test year-end capitalization components of short term debt, A/R securitization, long term debt, and preferred stock. With regard to the return on common equity for LG&E's electric operations, Dr. Weaver has recommended a return range of 9.75% to 10.25%, with a mid-point return rate of 10.00%. Schedule RJH-2 shows that the AG's recommended overall rate of return for its electric operations based on these capital costs rates is 6.46%.

Q. WHAT IS YOUR OPINION REGARDING THE METHOD IN WHICH A UTILITY'S RETURN REQUIREMENT SHOULD BE DETERMINED FOR RATE MAKING PURPOSES?

A. I believe a utility's return requirement for rate making purposes should be determined by applying the calculated overall rate of return to the lower of the utility's capitalization or original cost rate base. When a utility's capitalization dollar balance is higher than the used and useful rate base investment balance, this generally indicates that a portion of this utility's capitalization has been used to finance investments that are not used and useful to the ratepayers and are therefore not included in the utility's rate base, e.g., non-regulated/non-utility assets, "below-the-line" assets, *etc.* When a utility's rate base is higher than the capitalization balance, this could mean that portions of the rate base investments have been financed with funds other than investor-supplied debt, preferred stock and common equity; or it could mean that rate base investments that have been assumed to exist by way of hypothetical formulas (e.g., the "1/8th method" used to estimate assumed cash working capital) do not actually exist.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL IN THIS CASE THAT THE COMPANY'S RETURN REQUIREMENT BE DETERMINED BY APPLYING THE APPROPRIATE ELECTRIC OVERALL RATE OF RETURN TO THE ADJUSTED ELECTRIC CAPITALIZATION AT THE END OF THE TEST YEAR?

A. Yes. The Company's proposed return requirement approach in this case is consistent with the principles I just discussed and is also consistent with the return requirement rate making policy adopted by the KPSC in all of LG&E's prior base rate proceedings.

B. RATE BASE

Q. HAS THE COMPANY PRESENTED AN ADJUSTED ORIGINAL COST RATE BASE FOR ITS ELECTRIC OPERATIONS IN ITS FILING SCHEDULES IN THIS PROCEEDING?

A. No. While the Company has presented an unadjusted electric original cost rate base for purposes of developing the electric rate base allocation percentage,[2] the Company did not present an adjusted electric original cost rate base for purposes of determining the appropriate return on rate base as compared to the appropriate return on capitalization. This is contrary to KPSC ratemaking policy and practice. For example, in both LG&E's most recent electric and gas base rate proceedings, Case Nos. 98-426 and 2000-080, the Commission's Orders[3] presented the Company's adjusted electric and gas original cost rate bases.

Q. HAVE YOU DETERMINED THE APPROPRIATE ADJUSTED ORIGINAL COST RATE BASE FOR LG&E'S ELECTRIC OPERATIONS IN THIS CASE?

A. Yes, this recommended adjusted electric original cost rate base has been developed on

[2] This is presented on Rives Exhibit 3, page 1.
[3] See page 63 of the KPSC Order in Case No. 98-426 and page 23 of the KPSC Order in Case No. 2000-080.

schedule RJH-3. The starting point is LG&E's proposed unadjusted electric original cost rate base measured as of the end of the test year, September 30, 2003. I then made various adjustments in order to arrive at the AG's recommended adjusted electric original cost rate base to be used for ratemaking purposes in this case. Each of these recommended rate base adjustments are shown on schedule RJH-3 and will be discussed in detail in the subsequent sections of this testimony.

- **Post-1995 ECR Plan Rate Base**

Q. PLEASE EXPLAIN THE NET RATE BASE ADJUSTMENT OF $200.962 MILLION FOR THE POST-1995 ECR PLAN RATE BASE THAT IS SHOWN IN THE SECOND COLUMN OF SCHEDULE RJH-3.

A. As discussed on page 26 of Mr. Rives' testimony and shown on Rives Exhibit 2, page 2, LG&E has removed from its electric capitalization the environmental surcharge rate base associated with the Company's post-1995 ECR Plan. The Company has properly done this because LG&E is separately recovering a return on its environmental rate base through the environmental surcharge. Consistent with this position, it is also necessary to remove this post-1995 ECR Plan environmental rate base investment from the Company's unadjusted electric original cost rate base. Based on information contained in the response to AG-1-8, I have therefore removed a total net environmental surcharge rate base amount of $200.962 million that is associated with the post-1995 ECR plan. This net rate base adjustment amount of $200.962 million consists of (1) $203.504 million for environmental plant in service and CWIP, (2) offset by approximately $2.570 million for associated accumulated depreciation and deferred income taxes, and (3) $28,000 for cash working capital.[4]

- **Other Plant In Service Adjustments**

Q. SHOULD ADDITIONAL ADJUSTMENS TO THE COMPANY'S TEST YEAR PLANT IN SERVICE BALANCE BE MADE TO ARRIVE AT THE PROPERLY ADJUSTED ELECTRIC ORIGINAL COST RATE BASE?

A. Yes. Consistent with LG&E's proposed capitalization adjustment for the approximate $3.3 million capitalized E.W. Brown rate base investment, this same balance should also be removed from the unadjusted test year electric rate base. In addition, I believe that the plant in service balance should be adjusted for the removal of approximately $4.6 million of ARO assets. I have shown the total of these two plant in service adjustments on line 1 of the Other Adjustments column of schedule RJH-3.

- **Accumulated Depreciation Reserve**

Q. PLEASE EXPLAIN THE RECOMMENDED DEPRECIATION RESERVE ADJUSTMENT SHOWN ON LINE 2 OF THE OTHER ADJUSTMENTS COLUMN ON SCHEDULE RJH-3.

A. This adjustment is a direct result of the annualized depreciation expense adjustment discussed later in this testimony. As shown in footnote (5) of schedule RJH-3, the

[4] The $28,000 for cash working capital was calculated by taking 1/8th of the test year post-1995 ECR plan O&M expenses of $269,762.

adjustment reflects the pro forma annualized impact on the Company's adjusted test year depreciation reserve balance of the AG's recommended annualized depreciation expense adjustment detailed on schedule RJH-8. As confirmed by the Company in its responses to AG-1-11 and AG-1-12, this recommended depreciation reserve adjustment is entirely consistent with a similar depreciation reserve adjustment proposed by LG&E and adopted by the Commission in LG&E's most recent gas rate case in Case No. 2000-080.

- **Materials and Supplies**

Q. PLEASE EXPLAIN THE RECOMMENDED MATERIALS AND SUPPLIES ADJUSTMENT SHOWN ON LINE 9 OF THE OTHER ADJUSTMENTS COLUMN ON SCHEDULE RJH-3.

A. As confirmed in the response to AG-2-39, the Company's proposed test year 13-month average materials and supplies balance of $55.832 million includes a balance of approximately $333,000 associated with Carbide Lime inventory which was written off the Company's books in November 2002, the second month of the test year. For that reason, the AG recommends that this Carbide Lime inventory be removed from the calculation of the 13-month average test year materials and supplies balance.

- **Cash Working Capital**

Q. PLEASE DESCRIBE THE DERIVATION OF THE COMPANY'S CASH WORKING CAPITAL AMOUNT CLAIMED IN THIS CASE.

A. The Company has proposed to calculate the cash working capital in this case based on the so-called "modified 1/8th formula" method. This method assumes that 1/8th of the pro forma test year electric operation and maintenance expenses (net of purchased power expenses) represents a reasonable cash working capital approximation. As shown on Rives Exhibit 3, page 2, based on this methodology the Company has calculated a proposed electric cash working capital of approximately $52.801 million.

Q. DO YOU AGREE WITH THE USE OF THE MODIFIED 1/8TH METHOD TO DETERMINE THE COMPANY'S CASH WORKING CAPITAL REQUIREMENT?

A. No. I believe that only a properly performed detailed lead/lag study would generate an accurate approximation of a utility's cash working capital. However, based on my review of the Company's prior base rate proceedings, it is my understanding that the Commission has consistently allowed this Company's cash working capital to be determined based on this modified 1/8th method. I have therefore chosen not to challenge this method in this case.

Q. DO YOU RECOMMEND THAT ADJUSTMENTS BE MADE TO THE COMPANY'S PROPOSED CASH WORKING CAPITAL REQUIREMENT?

A. Yes. First, the Company's proposed cash working capital should be reduced to reflect the removal of all post-1995 ECR Plan revenue requirements from electric base rates. The post-1995 ECR Plan revenue requirement elimination includes the removal of $224,576[5] worth of post-1995 ECR Plan operation and maintenance expenses from the Company's

[5] See the response to AG-1-8.

overall test year electric operation and maintenance expenses. Therefore, the Company's proposed electric cash working capital should be reduced by 1/8th of \$224,576, or approximately \$28,000. This rate base adjustment is shown on line 11 of the second column of schedule RJH-3.

Second, the Company's proposed cash working capital should be reduced to reflect the removal of all DSM revenue requirements from electric base rates. The Company's electric DSM expenses are completely recovered through a DSM surcharge rate recovery mechanism that is completely separate from electric base rate recovery. For this reason, the Company has made a specific adjustment to remove all test year electric DSM operation and maintenance expenses of \$3.280 million as an adjustment to the electric revenue requirement in this case.[6] Consequently, the Company's proposed electric cash working capital should be reduced by 1/8th of \$3.280 million, or approximately \$410,000. This recommended cash working capital adjustment is reflected on line 11 of the Other Adjustments column of schedule RJH-3.

Q. ARE THE AFOREMENTIONED CASH WORKING CAPITAL ADJUSTMENTS CONSISTENT WITH THE APPROACH USED BY THE COMPANY FOR PURPOSES OF CALCULATING THE COMPANY'S GAS CASH WORKING CAPITAL REQUIREMENT?

A. Yes. The Company's proposed gas cash working capital requirement is calculated by taking 1/8th of the test year gas operation and maintenance expenses, net of all gas supply

[6] See Rives Exhibit 1, Schedule 1.09.

costs. In its response to AG-1-24, LG&E explained that the rationale for excluding gas supply costs from its gas cash working capital requirement determination is that (1) the "gas supply costs are completely recovered through a separate rate from the base rates", and (2) "The gas supply costs are also removed as an adjustment to gas revenue requirements, thus an adjustment is appropriate for the cash working capital requirement." Since the same circumstances exist for the Company's electric ECR and DSM costs, the same cash working capital adjustments for removed electric ECR and DSM operation and maintenance expenses would be in order.

Q. SHOULD THERE BE A FINAL CASH WORKING CAPITAL ADJUSTMENT THAT WILL NOT BE KNOWN AND MEASURABLE UNTIL THE COMMISSION DECIDES THE APPROPRIATE PRO FORMA TEST YEAR ELECTRIC OPERATION AND MAINTENANCE EXPENSE LEVEL?

A. Yes. Based on my review of prior Commission Orders, it is my understanding that the Commission calculates this Company's cash working capital based on taking 1/8th of the pro forma adjusted test year operation and maintenance expenses. Thus, the AG-recommended electric cash working capital currently shown on line 11 of schedule RJH-3 must ultimately be further adjusted to reflect all KPSC-ordered pro forma test year electric operation and maintenance expenses.

C. OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AS COMPARED TO

YOUR RECOMMENDED PRO FORMA ELECTRIC OPERATING INCOME FOR THE TEST PERIOD IN THIS CASE.

A. The Company's proposed and my recommended pro forma test year electric operating income positions are summarized on schedule RJH-4. The Company has proposed total pro forma test period electric operating income of $68.010 million. As summarized on schedule RJH-4, I have made a large number of pro forma electric operating income adjustments which, in total, have the effect of increasing the Company's proposed test year electric operating income by $19.098 million to total recommended pro forma test period electric operating income of $87.108 million. Each of the recommended electric operating income adjustments will be discussed in detail in the subsequent sections of this testimony.

- <u>**Kentucky State Income Tax Rate**</u>

Q. **WHAT IS THE KENTUCKY STATE INCOME TAX RATE THAT HAS BEEN USED BY LG&E FOR RATEMAKING PURPOSES IN THIS PROCEEDING?**

A. The Company has used a Kentucky state income tax rate of 8.25%. It used this state income tax rate in all income tax components of the ratemaking formula to derive the Company's claimed overall electric revenue deficiency of $63.764 million. In other words, it used a state income tax rate of 8.25% in the determination of (1) the unadjusted test year electric income tax starting point,[7] (2) the income tax impact of all of LG&E's proposed pro forma operating income adjustments[8], and (3) the revenue conversion factor to translate

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[7] This is the income tax amount of $50.987 million on line 14 of filing requirement Tab 42.
[8] This is the total income tax adjustment amount of $27.559 million shown on line 14 of filing requirement Tab 42, making up the income tax adjustments on Rives Exhibit 1, Schedules 1.36, 1.37 and 1.38.

the electric operating income deficiency into a tax-grossed up electric revenue deficiency.[9]

Q. DOES LG&E PAY AN EFFECTIVE STATE INCOME TAX RATE DIFFERENT FROM THE 8.25% RATE AS A RESULT OF ITS PARTICIPATION IN A CONSOLIDATED KENTUCKY INCOME TAX FILING?

A. Yes. As confirmed in the response to PSC-2-15 (c), LG&E has been filing consolidated Kentucky corporation income tax returns generating the following effective Kentucky income tax rates during the last 4 years:

	Effective State Income Tax Rates (excluding credits)
1999	7.41%
2000	7.69%
2001	7.73%
2002	7.87%

Q. HAS THE COMMISSION RECENTLY ESTABLISHED A NEW POLICY OF RECOGNIZING THE USE OF AN EFFECTIVE KENTUCKY STATE INCOME TAX RATE FOR RATEMAKING PURPOSES IN CASES INVOLVING KENTUCKY UTILITIES THAT PARTICIPATE IN CONSOLIDATED KENTUCKY CORPORATION INCOME TAX RETURNS?

A. Yes. The Commission established this new ratemaking policy on a trial basis in the most recent Union Light, Heat and Power Company ("ULH&P") base rate proceeding, Case No. 2001-00092.

[9] This is shown on Rives Exhibit 1, Schedule 1.39.

Q. DID THE COMMISSION EXPRESS A CONCERN IN THIS RECENT ULH&P RATE PROCEEDING WITH REGARD TO THE USE OF THE EFFECTIVE KENTUCKY STATE INCOME TAX RATE?

A. Yes. The Commission appeared to be somewhat concerned by the significant fluctuation experienced in ULH&P's effective state income tax rate from 5.15% in one tax year to 3.03% in the next tax year.[10]

Q. IS THERE REASON FOR A SIMILAR CONCERN IN THIS CASE?

A. No. As can be seen from the above table, LG&E's effective Kentucky state income tax rate has ranged from 7.41% to 7.87% with an average rate of 7.68% during the most recent 4 years. Thus, there is hardly any fluctuation in this effective tax rate from year to year. I believe that this should remove any concern in this case that LG&E's most recent 2002 effective state income tax rate of 7.87%, for example, would not be representative of the effective state income tax rate that can be expected to be in effect during the rate effective period of this rate case.

Q. WHAT IS YOUR RECOMMENDATION BASED ON THE FOREGOING FINDINGS AND CONCLUSIONS?

A. Since I see no reason why the trial use of the effective state income tax rate established by the Commission in the 2001 ULH&P rate case should not be extended to LG&E, I recommend that LG&E's proposed state income tax rate of 8.25% be replaced with the effective state income tax rate of 7.87% from the Company's most recent 2002

[10] See ULH&P Case No. 2001-00092, final Order dated January 31, 2002 at 59.

consolidated Kentucky corporation income tax return.

Q. WHAT INCOME TAX ADJUSTMENTS ARE REQUIRED IN ORDER TO RESTATE THE COMPANY'S TEST YEAR STATE INCOME TAX RATE FROM 8.25% TO 7.87%?

A. First, the unadjusted test year electric income taxes of $50.987 million[11] -- which form the starting point of the Company's proposed pro forma adjusted test year electric income taxes -- must be restated to reflect the reduction of the 8.25% state income tax rate to 7.87%.

Second, the income tax impact of all of the Company's proposed pro forma operating income adjustments[12] must be restated to reflect a state income tax rate of 7.87% rather than 8.25%.

Third, all of the AG-recommended adjustments to the Company's proposed pro forma test year electric after-tax operating income that are summarized on schedule RJH-4 must reflect the effective state income tax rate of 7.87%

Finally, the state income tax rate in the development of the Revenue Conversion Factor must be restated at 7.87%.

[11] See line 14 of filing requirement Tab 42.
[12] This is the total income tax adjustment amount of $27.559 million shown on line 14 of filing requirement Tab 42, making up the income tax adjustments on Rives Exhibit 1, Schedules 1.36, 1.37 and 1.38.

Q. ARE ALL OF THE AFOREMENTIONED STATE INCOME TAX ADJUSTMENTS REFLECTED IN THIS TESTIMONY?

A. No. The AG's recommended Revenue Conversion Factor on schedule RJH-1 has been properly determined based on an effective state income tax rate of 7.87%. Similarly, all of the AG's recommended adjustments to the Company's proposed pro forma test year electric after-tax operating income summarized on schedule RJH-4 have been appropriately calculated using a state income tax rate of 7.87%. However, the restatement of all state income taxes from 8.25% to 7.87% in the determination of the Company's proposed pro forma test year electric after-tax operating income of $68.010[13] million has not currently been reflected for the simple reason that the AG did not have the necessary per books income tax data available to make this computation. Since the Company has all of this tax information available, I recommend that the Company make these state income tax restatement calculations and present them to the Commission and the AG. Once this information has been received and reviewed by the AG, the recommended pro forma test year electric after-tax operating income number on schedule RJH-4, line 15 should be updated to reflect this information.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS ISSUE?

A. Yes. In data request PSC-2-15 (c) (3), the Commission suggests that if an effective Kentucky state income tax were to be used for ratemaking purposes in this case, this rate should only be used in the determination of the Revenue Conversion Factor and in the

[13] The $68.010 million is shown on line 15 of filing requirement Tab 42 and includes LG&E's proposed pro forma adjusted test year income taxes of $23.428 million. This latter pro forma income tax amount must be restated based on the use of a 7.87% state income tax rate rather than the 8.25% rate.

calculation of the income tax impact of all pro forma operating income adjustments. I do not agree with the suggestion that the use of the effective state income tax be limited only to the determination of the pro forma test year operating income adjustments. The only appropriate approach would be to apply the effective state income tax rate *both* in the determination of the pro forma test year operating income adjustments, *and* in the determination of the unadjusted test year operating income that was used as the starting point of the proposed overall pro forma test year operating income in this case. The approach suggested in PSC-2-15 (c) (3) would produce the wrong end result. In fact, it would result in an electric revenue requirement *increase*, which makes no sense in light of the fact that we are dealing with a state income tax rate *decrease* from 8.25% to 7.87%. The electric revenue requirement increase would result from the fact that the total of the Company's proposed test year electric operating income adjustments amount to a taxable income reduction of approximately $68.233 million.[14] Applying a state income tax rate of 7.87% to this taxable income reduction would produce a lower state income tax savings than applying a state income tax rate of 8.25%. This, in turn, would increase the electric revenue requirement in this case.

- **Interest Synchronization**

Q. DOES THE KPSC HAVE A RATEMAKING POLICY REGARDING INTEREST SYNCHRONIZATION?

A. Yes. The KPSC has a well-established ratemaking policy that the interest expenses to be

[14] See Rives Exhibit 1, page 3, line 39.

used as a deduction from pro forma test year taxable income be determined by the application of the weighted cost of debt to the adjusted capitalization allowed by the Commission for ratemaking purposes. This so-called pro forma "synchronized" interest expense level should then replace the per books test year interest expense level that was used as a tax deduction in the determination of the test year income taxes. Mr. Rives also acknowledges this Commission ratemaking policy on page 17 of his testimony where he states that, "The Commission has traditionally recognized the income tax effects of adjustments to interest expense through an interest synchronization adjustment."

Q. IS THERE AN ISSUE IN THE MANNER IN WHICH LG&E AND THE AG HAVE CALCULATED THEIR RESPECTIVE PRO FORMA SYNCHRONIZED INTEREST EXPENSE LEVELS?

A. No. As shown on schedule RJH-5, both LG&E and the AG have properly calculated their respective pro forma synchronized interest expense amounts by multiplying their recommended weighted cost of debt percentages included in their overall rate of return numbers times their recommended adjusted capitalization levels.

Q. IS THERE AN ISSUE IN THE DATA USED BY LG&E TO CALCULATE ITS PROPOSED PRO FORMA INTEREST SYNCHRONIZATION ADJUSTMENT?

A. Yes. The pro forma synchronized interest expense should replace the test year interest expense that has actually been used as a taxable income deduction in the determination of the Company's per books test year income taxes. The difference between these two interest expense levels represents the interest synchronization adjustment. As shown on line 4 of schedule RJH-5, for purposes of the interest synchronization adjustment, LG&E has assumed that the test year per books interest expenses amount to $24.315 million. However, in the responses to AG-1-25 (c) and AG-2-42, LG&E has confirmed that the total interest expense used as a taxable income deduction in the determination of the test year per books electric operating income taxes of $50.987 million[15] amounts to $23.209 million. Thus, since LG&E has used the test year per books electric operating income taxes of $50.987 million as the starting point for the total pro forma adjusted income taxes in this case, the test year per books interest expense of $23.209 million that was used as a tax deduction in the determination of the per books test year income taxes of $50.987 million must be compared to the pro forma synchronized interest expense level in the determination of the appropriate interest synchronization adjustment. The AG has done so, as shown in the last column of schedule RJH-5.

Q. WHAT IS THE IMPACT ON THE COMPANY'S PROPOSED TEST YEAR AFTER-TAX OPERATING INCOME OF A PROPERLY CALCULATED INTEREST SYNCHRONIZATION ADJUSTMENT SUCH AS HAS BEEN DONE BY THE AG?

A. As shown on schedule RJH-5, the difference between the properly calculated AG-recommended interest synchronization adjustment and LG&E's proposed interest synchronization adjustment increases the Company's pro forma electric test year after-tax operating income by $442,000.

[15] See Volume 3 – Tab 42, line 14.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THIS INTEREST ISSUE?

A. Yes. In it response to AG-2-42, LG&E states that while the correct test year per books electric interest expenses amount to $24.315 million (the amount used in the Company's proposed interest synchronization adjustment calculations), it inadvertently used a per books electric interest expense amount of $23.209 million as taxable income deduction in the determination of the unadjusted test year electric income taxes of $50.987 million that is being used as the starting point for the total pro forma electric income taxes in this case. While the $23.209 million interest expense may have been an incorrect number, it should still be used as the test year per books interest number to be compared to the pro forma synchronized interest number in the interest synchronization adjustment. This is because the $23.209 interest number was used in the calculation of the unadjusted test year electric income taxes of $50.987 million. If the "correct" interest amount of $24.315 million had been used as tax deductible interest in the determination of the per books test year electric income taxes, this per books income tax number would have been approximately $446,000[16] lower than the $50.987 million test year per books income tax number. Thus, if one wants to accept the Company's proposed interest synchronization approach, one would first have to reduce the test year per books electric income taxes by $446,000.

[16] Difference between $24.315 million and 23.209 million = $1.106 million x combined income tax rate of 40.3625%, or $446,000.

- **Unbilled Revenue Adjustment**

Q. IS THERE AN ISSUE WITH REGARD TO THE COMPANY'S PROPOSAL TO REMOVE UNBILLED ELECTRIC REVENUES FROM THE TEST YEAR?

A. Yes. The issue is that the Company should also have removed certain electric operating expenses associated with the unbilled revenue adjustment in order to achieve a proper matching of the test year expenses and all billed revenues.

Q. PLEASE EXPLAIN WHY THIS IS SO.

A. Rives Exhibit 1, Schedule 1.00 shows that the Company has removed the unbilled electric revenues at the end of the test year, 9/30/3003, from the test year and has replaced these test year-end unbilled revenues with the unbilled electric revenues that were on the Company's books at the beginning of the test year, 9/30/2002. As shown in filing workpaper page 98 of the attachment to KIUC-1-78, the unbilled electric revenues of $22.895 million at the end of the test year represent revenues that are associated with 414,294,000 KWHs worth of electric services that were rendered *during* the test year ending 9/30/2003, but for which the Company's customers were not yet billed as of 9/30/2003. Conversely, the unbilled electric revenues of $21.028 million at the beginning of the test year represent revenues that are associated with 410,199,000 KWHs worth of electric services that were rendered *prior to* the test year ending 9/30/2003, but for which the Company's customers were not yet billed as of 9/30/2002. Thus, by virtue of its proposed unbilled revenue adjustment, the Company has removed from the test year net electric revenues of $1.867 million, representing 4,095,000 KWHs worth of electric services that were rendered during the test year. The problem is that the operating expenses associated with these 4,095,000 KWHs of test year electric services are still included in the test year because the Company has not proposed an adjustment to remove these expenses. Therefore, an adjustment is required to remove the operating expenses associated with the test year electric services that have been removed in the Company's unbilled revenue adjustment. Only that way is there a proper matching of the revenues and expenses associated with electric services rendered in the test year.

Q. WHAT METHOD DO YOU RECOMMEND BE USED TO ESTIMATE THE REMOVAL OF THE TEST YEAR OPERATING EXPENSES ASSOCIATED WITH THE COMPANY'S UNBILLED ELECTRIC REVENUE ADJUSTMENT?

A. I recommend that the same method be used as has been used by LG&E and accepted by the Commission in the estimated quantification of test year expenses associated with the test-year end customer revenue annualization adjustment, i.e., through the application of an appropriate Operating Expense Ratio to the revenue adjustment amount at issue. As can be seen from Seelye Exhibit 25, the Company's proposed test year-end customer revenue annualization adjustment in this case results in an increase in test year KWH electric services with an associated revenue increase impact of approximately $2.6 million. The Company then applied an Operating Expense Ratio of approximately 56% to this revenue increase in order to estimate an associated test year operating expense amount of approximately $1.46 million. Thus, I recommend that the same Operating Expense Ratio of approximately 56% be applied to LG&E's proposed unbilled electric revenue adjustment in order to reflect the estimated test year operating expense reduction associated with the unbilled electric revenue adjustment.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PRO FORMA TEST YEAR ELECTRIC AFTER-TAX OPERATING INCOME?

A. As shown on schedule RJH-6, my recommendation to remove the test year operating expenses associated with the Company's unbilled revenue adjustment increases the Company's proposed pro forma test year electric after-tax operating income by $624,000.

- **Customer Growth Revenue Annualization**

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT SHOWN ON SEELYE EXHIBIT 25.

A. The Company has proposed to reflect for ratemaking purposes the annualized impact on test year net[17] operating revenues of customer growth experienced during the test year. To accomplish this, the Company, first, has compared the actual numbers of customers at September 30, 2003 to the corresponding 12-month average test year number of customers. The so-determined test year customer growth was then multiplied by the test year average KWH consumption per customer and the test year average revenue per KWH in order to arrive at its proposed revenue annualization adjustment for customer growth during the test year. As shown on Seelye Exhibit 25, the Company's proposed adjustment results in a pro

[17] Operating revenues net of associated operating expenses.

forma net electric revenue increase of approximately $1.156 million.

Q. SHOULD THE COMPANY'S PROPOSED CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT FIRST BE CORRECTED TO REFLECT 13-MONTH RATHER THAN 12-MONTH AVERAGE TEST YEAR CUSTOMER LEVELS?

A. Yes. In AG-2-46, I requested the Company to re-calculate its proposed revenue annualization adjustment by comparing the actual number of customers at the end of the test year to the 13-month average test year number of customers. The Company provided this information in its response to PSC-3-28. As can be gleaned from this response, this correction would increase the Company's originally proposed net revenue increase of $1.156 million to $1.305 million.

Q. DO YOU BELIEVE THAT THE COMPANY'S PROPOSED CUSTOMER GROWTH REVENUE ANNUALIZATION CALCULATION METHODOLOGY IS APPROPRIATE?

A. No. While I am aware that the methodology used by LG&E has previously been accepted by the Commission, unfortunately this method has the potential of producing the wrong end result which fails to accurately reflect the actual customer growth trend experienced by the Company.

Q. COULD YOU EXPLAIN THIS IN MORE DETAIL?

A. Yes. The problem lies in the fact that the Company's employed calculation method compares the test year average number of customers to a corresponding customer level the Company has on line at a single point in time. In this particular case, this single point in time is September 30, 2003 because that happens to be the end of the test year chosen by LG&E. If customer growth were to occur gradually and consistently over the course of the year, there wouldn't be a problem with the Company's employed calculation method. However, that is not always the case. For example, the response to AG-1-324, page 1 of 6 shows that, while the growth trend for the Company's residential electric customers is clearly upward during the year, for a variety of reasons (e.g., seasonality), the Company's residential electric customers experience upward and downward monthly fluctuations within the year. Specifically, AG-1-324, page 1 indicates that while the actual number of residential customers at the end of the test year, September 2003, amounts to 338,772, this customer level increased to 340,203 in November and then decreased to 337,102 in the next month, December 2003. In AG-2-67 (b), the AG gave some specific illustrations as to why the Company's employed calculation method has the potential of producing the wrong end result which fails to accurately reflect the actual customer growth trend experienced by the Company:

> 67 b. As shown on Seelye Exhibit 25, under the Company's proposed customer annualization adjustment method, it compared the 9/30/03 number of customers to the average test year number of customers, resulting, for example, in a calculated residential customer increase of 1,883.
>
> i. If the test year had been the 12-month period ended November 2003, the Company's customer annualization method would have produced residential customer increase of 2,639 (November 2003 number of customers of 340,203 compared to average number of customers during the 12-month period ended November 30, 2003 of 337,564). Please confirm this. If you do not agree, explain your disagreement.
>
> ii. On the other hand, if the test year had been the 12-month period ended

> December 2003, the Company's customer annualization method would have produced a residential customer number decrease of 666 (December 2003 number of customers of 337,102 compared to average number of customers during the 12-month period ended December 31, 2003 of 337,768). Please confirm this. If you do not agree, explain your disagreement.

In its response to this data request, the Company confirmed all of the above referenced information.

Q. IS THERE A BETTER METHOD TO CALCULATE THE COMPANY'S AVERAGE TEST YEAR CUSTOMER GROWTH THAT PRODUCES AN END RESULT THAT IS TRULY REFLECTIVE OF THE ACTUAL CUSTOMER GROWTH TREND RECENTLY EXPERIENCED BY THE COMPANY AND THAT AVOIDS THE POTENTIAL INACCURACIES CAUSED BY MONTH-TO-MONTH CUSTOMER FLUCTUATIONS?

A. Yes. This customer growth method was introduced by me in a prior Delta Natural Gas rate proceeding, Case No. 97-066, and was accepted by the Commission in setting the rates for Delta in that case. This customer growth method first calculates an appropriate average annual compound growth rate for each of the Company's customer classes during a recent historic period, including the test year. One half of this average annual compound growth rate would represent the appropriate customer growth rate within the test year. This is so because the comparison of the test year-end level of customers to the average test year number of customers is supposed to represent, on average, a half-year's worth of customer growth. This half-year growth rate should then be applied to the average test year number of customers for the particular customer class in order to arrive at the appropriate test year-end customer growth adjustment number.

Q. COULD YOU GIVE AN EXAMPLE OF THIS RECOMMENDED CALCULATION METHOD FOR THE COMPANY'S TEST YEAR RESIDENTIAL ELECTRIC CUSTOMERS?

A. Yes. The response to AG-1-324, page 1, shows that the Company's actual average number of residential electric customers for the years 1999 through 2003 were as follows:

1999	320,874
2000	324,374
2001	330,031
2002	334,329
2003	337,768

This available data indicates that the Company's most recent historic average annual compound growth rate is 1.30%. Taking one-half of this average annual compound growth rate indicates an average half-year customer growth rate of 0.65%. Applying this half-year average customer growth rate to the 13-month average test year electric residential customers of 337,034 shown in column (1) of PSC-3-28, produces a test year-end customer growth adjustment of 2,191 residential electric customers as compared to the 1,738 electric residential customer growth number produced by LG&E's test year-end customer growth calculation method shown in the response to PSC-3-28. As shown on the first line of schedule RJH-7, page 2, this produces a recommended revenue adjustment amount of $1.433 million, which is significantly higher than the corresponding residential customer growth revenue adjustment of $1.137 million shown on PSC-3-28, page 1.

Q. HAVE YOU MADE SIMILAR CUSTOMER GROWTH CALCULATIONS BASED ON THIS RECOMMENDED CALCULATION METHODOLOGY FOR THE

OTHER CUSTOMER CLASSES SHOWN ON SEELYE EXHIBIT 25 AND PSC-3-28?

A. While it certainly was my intent to do so, the Company could not provide me with the necessary information. Both in AG-1-35 and again in follow-up request AG-2-47, I requested monthly customer numbers from 1999 through to date for the exact same customer classes shown on Seelye Exhibit 25. However, the Company did not provide this information for the reason that "the information is not available in the format requested." The only customer class for which all of the required calculation data for my recommended methodology is available is the residential customer class.

Q. HAVE YOU PREPARED A CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT THAT REFLECTS YOUR RECOMMENDED CALCULATION METHODOLOGY FOR THE ELECTRIC RESIDENTIAL CUSTOMERS?

A. Yes. This customer growth revenue annualization adjustment is shown on schedule RJH-7, page 2. As I discussed before, the first line on this schedule shows that the residential customer growth revenue annualization adjustment produces a revenue increase adjustment of $1.433 million. Since I could not use the same recommended customer growth calculation method for all of the other electric customer classes, I have simply adopted the revenue adjustments for these customer classes that were calculated through LG&E's proposed method. I have also offset the recommended revenue annualization adjustment amount with associated operating expenses by applying LG&E's proposed Operating Expense Ratio of 0.5579 to the revenue adjustment amount.

In summary, the recommended electric customer growth revenue annualization adjustment produces a net test year operating revenue adjustment of $1.436 million.

Q. HOW DOES THE USE OF YOUR RECOMMENDED CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT IMPACT THE COMPANY'S PROPOSED TEST YEAR AFTER-TAX OPERATING INCOME FOR ITS GAS OPERATIONS?

A. As shown on schedule RJH-7, page 1, the use of my recommended customer growth revenue annualization adjustment increases the Company's proposed after-tax electric operating income by $167,000.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING THIS ISSUE?

A. Yes. I recommend that the Commission order the Company to follow the recommended customer growth revenue annualization calculation approach for all electric customer classes in its next base rate case.

- **<u>Annualized Depreciation Expense</u>**

Q. PLEASE EXPLAIN THE REASON FOR THE RECOMMENDED ANNUALIZED DEPRECIATION EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-8.

A. The annualized depreciation expense adjustment shown on Schedule RJH-8 is a direct result of the difference between the new depreciation rates proposed in this case by LG&E and those recommended by Michael Majoros, the AG's depreciation expert. The depreciation rates recommended by Mr. Majoros, as applied to the depreciable plant in service balances at the end of the test year, produce $22.335 million lower annualized depreciation expenses than proposed by LG&E in this case. This has the result of increasing the Company's proposed pro forma test year after-tax electric operating income by $13.375 million.

- **<u>Promotional Expenses</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENTS FOR PROMOTIONAL EXPENSES SHOWN ON SCHEDULE RJH-9.

A. With regard to the treatment of promotional expenses for rate making purposes, 807 KAR 5:016, Section 4, states:

> Advertising Disallowed. (1) Advertising expenditures for political, promotional, and institutional advertising by electric or gas utilities shall not be considered as producing a material benefit to the ratepayers and, as such, those expenditures are expressly disallowed for rate-making purposes.

In accordance with this regulation, the Company removed from rate consideration in this case all of the advertising expenses in accounts 913002 and 930101 because these expenses were deemed to be of a promotional and/or institutional nature.[18] However, the Company did not similarly remove from its filing a number of additional expenses for which the clear purpose is the promotion of the sales of electricity. I recommend that these additional

[18] See Rives Exhibit 1, Schedule 1.15.

promotional expenses also be removed for rate making purposes in this case.

Q. COULD YOU DESCRIBE EACH OF THE PROMOTIONAL EXPENSE ITEMS THAT YOU RECOMMEND BE DISALLOWED IN THIS CASE?

A. Yes. First, the test year electric expenses of $22,699 included in account 909001 – Public Information expenses should be disallowed. It is my understanding that the expenses included in this account are for advertising of a promotional nature, as well as for contributions and community relations activities. It should also be noted that the Commission disallowed similar account 909001 Public Information expenses in the Company's prior gas base rate case in Case No. 2000-080.

Second, the electric account 909002 test year expenses include $3,119 worth of expenses of a promotional nature that should have been removed for ratemaking purposes in this case. This was confirmed by the Company in its response to AG-1-229.

Third, the test year expenses include $64,632[19] for electric expenses in accounts 912001 and 912005 which the Company has classified as Economic Development Research and Marketing Management expenses. In response to AG 1-48 (a), the Company clearly states that,

> Accounts 912001 and 912005 include the cost of labor, materials, and other expenses incurred in <u>promotional</u>, demonstration, and selling activities, except by merchandising, the object of which is to <u>promote or retain the use of utility services by present and prospective customers</u>." (Emphasis supplied).

[19] $13,177 for expenses in account 912001 and $51,455 for expenses in account 912005.

I have removed these expenses for rate making purposes in this case because they do not produce a "material benefit" for the ratepayers and are mostly related to activities promoting the sales of electric utility services. It should be noted that the Commission disallowed similar account 912001 expenses in the Company's prior gas base rate case in Case No. 2000-080 and also stated on page 36 of its Order in that case that "the FERC definition of Account 912001 matches the Administrative Regulation definition of advertising that is to be excluded from ratemaking."

Q. WHAT IS THE IMPACT OF YOUR PROMOTIONAL EXPENSE RECOMMENDATIONS ON THE COMPANY'S PROPOSED TEST YEAR ELECTRIC AFTER-TAX OPERATING INCOME ?

A. As shown on schedule RJH-9, the recommended disallowances for the additional promotional expenses increase the Company's proposed test year electric after-tax operating income by approximately $54,000.

- **Rate Case Expense**

Q. PLEASE SUMMARIZE LG&E'S PROPOSED RATE CASE EXPENSES FOR ITS CONSOLIDATED ELECTRIC AND GAS RATE CASES.

A. As shown on Rives Exhibit 1, Schedule 1.16, the Company has proposed total estimated electric rate case expenses of approximately $1 million and estimated gas rate case expenses of approximately $651,000. In its response to AG-1-47, the Company has updated these original rate case expense estimates and is now projecting total electric rate case expenses of $1.170 million and total gas rate case expenses of approximately $821,000. Thus, the Company now estimates that these two consolidated electric and gas rate cases will have associated rate case expenses of almost $2 million.

Q. DO YOU BELIEVE THAT THE COMPANY'S RATE CASE EXPENSES FOR THE CURRENT ELECTRIC AND GAS CASES ARE REASONABLE AND ACCURATE?

A. No. I believe that these estimated rate case expenses are too high particularly in light of the fact that, due to the consolidated nature of these two cases, many of the rate case activities can be shared between the two cases. For example, the response to AG-1-47 indicates that the Company has estimated that for both the electric and gas rate case it will incur almost $170,000 for "newspaper, media, etc.," i.e., a total of almost $340,000 for such miscellaneous rate case expenses. Given that most newspaper and other media communications can be shared for these two consolidated rate cases, these separate $170,000 cost estimates for both the electric and gas case seem unreasonably high.

The Company's rate case expense estimates for the current electric and gas rate cases also seem unreasonably high when compared to the rate case expenses in the Company's last gas rate case, Case No. 2000-080, which was concluded in late 2000. In that case, LG&E had proposed estimated total gas rate case expenses of $420,000. The actual rate case expenses turned out to be approximately $296,000, which amount was allowed for ratemaking purposes by the Commission. Thus, while the actual rate case expenses for LG&E's last fully litigated gas case, completed less than 3 ½ years ago, amounted to less than $300,000, the Company is now estimating gas rate case expenses of $651,000 (currently updated to $821,000) in a consolidated case where it can share many of the rate case activities with the electric rate case budget.

Q. WHAT ARE YOUR CONCLUSIONS BASED ON THE AFOREMENTIONED INFORMATION?

A. I conclude that the Company's rate case expense estimates for the current electric and gas cases are unreasonably high and potentially quite inaccurate, and that, therefore, the Commission should not rely on the rate case expense estimates that have been presented by LG&E in its electric and gas rate cases.

Q. WHAT LEVEL OF RATE CASE EXPENSES ARE YOU RECOMMENDING FOR RATE RECOGNITION IN BOTH THE CURRENT ELECTRIC AND GAS RATE CASES?

A. Following Commission ratemaking policy, I recommend that rate recognition be given to all actual rate case expenses prudently incurred by LG&E to process its electric and gas rate cases. At the time this testimony is being prepared, the actual expenses incurred to date for the electric rate case amount to approximately $324,000.[20] Based on a 3-year amortization period, this would result in an annual rate case expense rate allowance of $108,000. This recommended rate case expense allowance should be updated to include additional prudently incurred electric rate case expenses that may be provided by LG&E during the course of this proceeding.

[20] Per the response to PSC-2-57 – Updated 2/27/2004.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PRO FORMA TEST YEAR ELECTRIC AFTER-TAX OPERATING INCOME?

A. As shown on schedule RJH-10, my electric rate case expense recommendation increases the Company's proposed pro forma test year electric after-tax operating income by $135,000.

- **<u>Injury and Damage Expense Normalization</u>**

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED INJURY AND DAMAGE ("I&D") EXPENSE NORMALIZATION ADJUSTMENT.

A. As shown on Rives Exhibit 1, Schedule 1.19, the Company has proposed to adjust the test year I&D expenses by replacing them with a normalized I&D expense level. The proposed normalized I&D expense level represents the 5-year average of the CPI-adjusted I&D expenses incurred by LG&E during the 5-year period 1998 through 2002.

Q. DO YOU AGREE WITH THIS PROPOSED EXPENSE NORMALIZATION ADJUSTMENT?

A. With one exception, I find the Company's proposal to be reasonable. The one exception is that the 5-year CPI-adjusted average should shift forward by approximately one year, i.e., it should start with 1999 and end with the test year. In this way, the normalized average expense is based on the most recent actual data through the end of the test year.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PRO FORMA TEST YEAR ELECTRIC AFTER-TAX OPERATING INCOME?

A. As shown on schedule RJH-11, my normalized I&D expense recommendation increases the Company's proposed pro forma test year electric after-tax operating income by $43,000.

- **IT Staff Reduction Cost Savings**

Q. HAS THE COMPANY PROPOSED AN ADJUSTMENT IN THIS CASE TO REFLECT COST SAVINGS RESULTING FROM STAFF REDUCTIONS IN ITS INFORMATION TECHNOLOGY ("IT") DEPARTMENT?

A. Yes, as described on pages 12-13 of Ms. Scott's testimony, the Company has reduced its test year operating expenses to reflect the October 2003 reduction of 27 staff people in its IT department. The Company has partially offset this cost savings adjustment by the 3-year amortization of the associated Cost to Achieve the savings.

Q. IS THERE AN ISSUE ASSOCIATED WITH THIS LG&E-PROPOSED NET COST SAVINGS ADJUSTMENT?

A. Yes. As shown on Rives Exhibit 1, Schedule 1.26, the Company has only reflected the payroll, payroll tax and 401(k) cost savings associated with the IT staff reduction. It has not reflected additional cost savings such as the Team Incentive Awards ("TIA") and other employee benefits (pension; FAS-106; medical, dental and life insurance; long term disability) that the Company no longer has to pay as a result of the IT staff reduction. In the responses to AG-1-62 (c) and AG-2-57, the Company has confirmed that it will experience additional total cost savings of $306,990 for the above-referenced TIA awards and other employee benefits. The portion of these additional cost savings allocable to LG&E's electric operations is 79%.

Q. HOW DOES THE RECOGNITION OF SUCH ADDITIONAL COST SAVINGS IMPACT THE COMPANY'S PROPOSED TEST YEAR AFTER-TAX OPERATING INCOME FOR ITS ELECTRIC OPERATIONS?

A. As shown on schedule RJH-12, the recognition of such additional IT staff reduction related cost savings increases LG&E's proposed test year electric after-tax operating income by $146,000.

- **Obsolete Inventory Write-off**

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL REGARDING THE OBSOLETE INVENTORY WRITE-OFF.

A. During the test year, the Company wrote off $2.061 million worth of inventory for its steam plants that was acquired prior to the test year and had become obsolete. In this case, the Company is proposing to charge this write-off to its ratepayers on a going forward basis based on a three-year amortization period.

Q. DO YOU AGREE WITH THIS PROPOSAL?

A. No. The test year write-off represents a non-recurring event that should be fully removed from the test year as it is not representative of what can be expected on an annual recurring basis during the rate effective period of this case. Moreover, since the obsolete inventory has actually been written off the Company's books, it is inappropriate to put this item back on the Company's books in a deferral account in order to enable future amortization of this deferral to the ratepayers. Therefore, the Commission should disallow LG&E's proposed 3-year amortization of this write-off.

This non-recurring event should be treated for ratemaking purposes in the same way as the Company has proposed for the Cane Run Repair refund that is discussed on page 14 of Ms. Scott's testimony and shown on Rives Exhibit 1, Schedule 1.30. This refund of almost $3.6 million was for repairs to the Cane Run Station and was received and credited to operating expense during the test year. With regard to this item, Ms. Scott properly concluded that "The insurance reimbursement is a non-recurring item and therefore must be removed from the test year." In response to KIUC-1-102 Ms. Scott further clarified regarding this matter that the refund …"should be removed in full to better reflect the representative level of annual expenses for ratemaking purposes." Thus, the recommended removal of the non-recurring obsolete inventory write-off is entirely consistent with LG&E's proposed removal from the test year of the non-recurring Cane Run Repair refund.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PRO FORMA TEST YEAR ELECTRIC AFTER-TAX OPERATING

INCOME?

A. As shown on schedule RJH-13, the previously discussed recommendation increases the Company's proposed pro forma test year electric after-tax operating income by $411,000.

- **Carbide Lime Write-Off**

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL REGARDING THE CARBIDE LIME WRITE-OFF.

A. During the test year, the Company wrote off $2.125 million worth of Carbide Lime inventory that was paid for, but never received by, LG&E due to bankruptcy of the supplier. Similar to what it has proposed for the previously discussed obsolete inventory write-off, the Company is proposing to charge this Carbide Lime write-off to its ratepayers on a going forward basis based on a three-year amortization period

Q. DO YOU AGREE WITH THIS PROPOSAL?

A. No. I disagree with LG&E's proposal regarding this issue for the same reasons I disagree with LG&E's proposal regarding the obsolete inventory write-off that was discussed in the prior section of this testimony. The Commission should therefore also disallow LG&E's proposed 3-year amortization of this Carbide Lime write-off.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PRO FORMA TEST YEAR ELECTRIC AFTER-TAX OPERATING INCOME?

A. As shown on schedule RJH-14, the previously discussed recommendation increases the Company's proposed pro forma test year electric after-tax operating income by $424,000.

- **Miscellaneous Adjustments**

Q. PLEASE DESCRIBE THE MISCELLANEOUS ADJUSTMENTS SHOWN ON SCHEDULE RJH-15.

A. First, I recommend the removal of $17,957 worth of allocated electric donation expenses that the Company erroneously failed to remove from the test year electric operating expenses. The derivation of this electric donation amount is shown in footnote (1) of schedule RJH-15.

Second, I recommend the removal from test year electric operating expenses of $59,403 for expenses associated with employee gifts, award banquets, parties and other social events (e.g., company picnics). Based on my review of prior Commission Orders,[21] it is my understanding that the Commission has a ratemaking policy of removing the previously referenced expense types from rate consideration. I would agree that these types of expenses have nothing to do with the provision of safe and reliable electric service and, therefore, should not be charged to the ratepayers. In AG-1-77, the AG requested the Company to provide the test year expense amount for each of the previously referenced expense types. In response to this request, the Company stated that while the total test year

[21] Particularly KPSC Orders involving Kentucky-American Water Company, such as the KPSC's Orders in Case Nos. 97-034, 95-554, 90-321, 89-348 and 10481.

electric expenses for employee gifts, award banquets, social events and parties, and other employee related social expenses amount to $118,805, it could not provide those expenses broken out by the specific expense types that were requested in AG-1-77. Since there is no further breakout of the total $118,805 expense amount, and in order to be conservative, I have assumed that 50% of the $118,805, or $59,403, is associated with employee gifts, award banquets, parties and other social events that should be removed for ratemaking purposes in this case.

Third, I recommend the removal from test year electric operating expenses of approximately $140,000 for EEI expenses that should not be charged to the ratepayers. As shown in the response to AG-1-85, in excess of 72% of EEI's annual activities are dedicated to legislative advocacy (23.6%), regulatory advocacy (13.8%), legislative and regulatory policy research (18.4%), institutional advertising and marketing (8.5%), and public relations (8.0%). These types of EEI activities should be the responsibility of LG&E's stockholders as they produce no benefits to the Company's ratepayers. The total EEI dues included in LG&E's test year electric operating expenses amount to $195,401. Applying the 72% disallowance rate to these EEI dues of $195,401 results in the recommended EEI expense disallowance of approximately $140,000.

Finally, I have updated the Company's originally proposed ECR Roll-In adjustment shown in Rives Exhibit 1, Schedule 1.03 to reflect the additional ECR Roll-In that took place on December 11, 2003. The response to PSC-3-35 indicates that this reduces the Company's proposed base revenue adjustment in Rives Schedule 1.03 by $5,472. This recommended revenue reduction adjustment is shown on line 4 of schedule RJH-15.

Q. WHAT IS THE IMPACT OF YOUR MISCELLANEOUS ADJUSTMENT RECOMMENDATIONS ON THE COMPANY'S PROPOSED TEST YEAR ELECTRIC AFTER-TAX OPERATING INCOME ?

A. As shown on schedule RJH-15, the recommended miscellaneous expense adjustments increase the Company's proposed test year electric after-tax operating income by approximately $127,500.

- **FASB 143 Asset Retirement Obligation Adjustment**

Q. PLEASE EXPLAIN THE REASON FOR THE RECOMMENDED FASB 143 ASSET RETIREMENT OBLIGATION ("ARO") ADJUSTMENT SHOWN ON SCHEDULE RJH-16.

A. The FASB 143 ARO adjustment shown on Schedule RJH-16 reflects the recommendations regarding this issue contained in the testimony of Michael Majoros, the AG's depreciation expert. As shown on Schedule RJH-16, Mr. Majoros' FASB 143 ARO recommendations have the result of increasing the Company's proposed pro forma test year after-tax operating income by $3.149 million.

- **MISO Issues**

Q. WHAT IS YOUR UNDERSTANDING REGARDING THE MISO ISSUES THAT

HAVE BEEN RAISED BY LG&E IN THIS PROCEEDING IN THE TESTIMONY OF MR. BEER?

A. First, I understand that LG&E is requesting a pro forma expense level of approximately $3.3 million for expected ongoing MISO Schedule 10 administrative costs in this case. This proposed pro forma base rate expense level assumes that LG&E will continue to be a member of MISO in the future.

I also understand that, in a separate proceeding in Case No. 2003-00266, the Commission is investigating whether or not LG&E's continued membership in MISO is in the public interest. If the Commission ultimately decides in Case No. 2003-00266 that LG&E's continued membership in MISO is not in the public interest and orders the Company to withdraw from MISO, then LG&E will be subject to a substantial exit fee. In its responses to AG-1-53 (d) and 1-235, the Company states that, assuming a final exit date of 12/31/2004, the estimated exit fee for both LG&E and KU would be in the range of $24 million. I have been informed by my counsel, however, that during the ongoing proceeding in Case No. 2003-00266, this total estimated exit fee may be as high as $38 million.

If, after the conclusion of the instant base rate proceeding, the Company is subsequently ordered by the Commission in Case No. 2003-00266 to exit MISO, it is proposing the following ratemaking treatment:

(1) Continued base rate recovery in the base rates established in the current rate case for all costs incurred in connection with its ongoing MISO membership obligations up

until the point in time that the Company is authorized by FERC to withdraw from MISO (this would involve the annual MISO Schedule 10 cost of $3.3 million proposed for base rate recovery by LG&E in this proceeding).

(2) A rate filing with the Commission for (a) removal of the $3.3 million ongoing MISO Schedule 10 costs from the then-current base rates, and (b) inclusion in base rates of the amortization of the exit fee over a specified amortization period.

Q. DOES THE COMPANY'S PROPOSAL TO RECEIVE BASE RATE RECOVERY FOR ANY MISO EXIT FEES REQUIRE THE ESTABLISHMENT OF A REGULATORY ASSET FOR THE MISO EXIT FEE OBLIGATION?

A. Yes. While Mr. Beer's testimony in this case does not make mention of this, it is my understanding that LG&E in this proceeding is essentially seeking approval to establish a regulatory asset for any potential MISO exit fees that may result from a Commission ruling in Case No. 2003-00266

Q. WHAT IS YOUR POSITION REGARDING THE AFOREMENTIONED MISO ISSUES?

A. I take no exception to the Company's proposal to include an estimated ongoing annual level of $3.3 million for MISO Schedule 10 administrative costs for base rate recovery in this case pending the Commissions decision in Case No. 2002-00266. However, I do not agree with the Company's proposal for another rate filing subsequent to the current rate proceeding in case the Commission were to order LG&E in Case No. 2002-00266 to withdraw from MISO. An important principle of proper ratemaking is rate stability and the

Company's proposal unnecessarily uproots that principle. Instead, I recommend that, if LG&E is ordered to exit MISO, the base rates to be established in the current case continue to remain in effect without any change for the net impact of the removal of the $3.3 million Schedule 10 base rate recovery and the addition of the amortization of the MISO exit fee in the regulatory asset account. The Company should be ordered by the Commission to establish a regulatory liability account for the continued annual $3.3 million base rate recovery for the MISO Schedule 10 costs it would no longer incur. The balance in this regulatory liability account should serve to offset the MISO exit fee in the regulatory asset account in LG&E's next electric base rate proceeding. If the balance in this regulatory liability account exceeds the balance in the regulatory asset account, this excess should be returned to LG&E's ratepayers in an appropriate manner.

- **<u>Other Expense Issues</u>**

Q. IN THE PARALLEL KENTUCKY UTILITIES ("KU") RATE CASE, AG WITNESS MAJOROS HAS IDENTIFIED CERTAIN ISSUES THAT HAVE NOT BEEN ADDRESSED BY YOU IN THIS LG&E RATE CASE. WHAT IS YOUR RECOMMENDED POSITION ON THIS?

A. Consistency would dictate that the two companies be treated for ratemaking purposes in like fashion and I would encourage the Commission to do so. For example, for reasons discussed in his testimony, Mr. Majoros has recommended that the Commission only recognize for ratemaking purposes the actual test year pension and Other Post-Employment Benefit expenses booked by KU, consistent with the Commission's finding in LG&E's

prior gas rate case, Case No. 2000-080. The value of this recommendation in the current electric LG&E rate case is a reduction in LG&E's proposed pro forma test year electric operating expenses of $2.755 million (see Rives Exhibit 1, Schedule 1.13).

D. REVENUE CONVERSION FACTOR

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AS COMPARED TO YOUR RECOMMENDED REVENUE CONVERSION FACTOR TO BE USED FOR RATEMAKING PURPOSES IN THIS CASE.

A. As shown on schedule RJH-1, line 6, the Company's proposed Revenue Conversion Factor is approximately 0.5924 whereas the AG's recommended Revenue Conversion Factor is approximately 0.5948. As can be seen from the Revenue Conversion Factor calculations in footnote (4) of schedule RJH-1, the only reason why these two factors are different is that LG&E's proposed factor incorporates a Kentucky state income tax rate of 8.25%, while the AG's recommended factor incorporates a Kentucky state income tax rate of 7.87%. The reasons for this have been discussed previously in this testimony.

Q. MR. HENKES, DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

In Re the Matter of:

MAR 1 6 2004

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY))) **CASE NO: 2003-00433**

AFFIDAVIT

Comes the affiant, Robert J. Henkes, and being duly sworn states that the foregoing testimony and attached schedules were prepared by him are, to the best of his information and belief, true and correct.

State/Commonwealth of Connecticut
County of Fairfield

Subscribed and sworn to before me by the Affiant Robert J. Henkes this the 16th day of March, 2004.

Notary Public, State at Large

OFFICIAL SEAL
Notary Public, Connecticut
Fairfield County
BRIAN R. FALKOWSKI
My Commission Expires Jan. 31, 2007

LOUSIVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
SUMMARY OF REVENUE REQUIREMENT POSITIONS
($000)

	LG&E Electric (1)		Adjustments		AG	
1. Capital Structure	$ 1,485,701		$ (25,444)		$ 1,460,257	Sch. RJH-2
2. Rate of Return	7.12%				6.46%	Sch. RJH-2
3. Income Requirement	105,782				94,330	
4. Pro Forma Income	68,010		19,098		87,108	Sch. RJH-4
5. Income Deficiency	37,772				7,221	
6. Revenue Conversion Factor	0.59236556				0.59481897	(4)
7. Overall Revenue Deficiency	$ 63,764		$ (51,623)		$ 12,141	
8. Increase in Misc. Charges	$ 133	(2)	$ (132)		1	(5)
9. Increase in Revenues	63,632	(3)	(51,492)		12,140	
10. Total Rate Increase	$ 63,764		$ (51,623)		$ 12,141	

(1) Rives Exhibits 1, 2 and 7

(2) Response to AG-1-4

(3) Tab 23 and response to AG-1-4

(4)

	LG&E	AG	
Revenues	100.000000	100.000000	
Less: Bad Debt and PSC Fees	(0.672300)	(0.672300)	
	99.327700	99.327700	
Less: State Income Tax @ 8.25%	(8.194535)	(7.817090)	State Income Tax @ 7.87%
	91.133165	91.510610	
Less: Federal Income Tax @ 35%	(31.896609)	(32.028714)	
Revenue Conversion Factor	59.236556	59.481897	

(5) Testimony of David Brown Kinloch

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
ADJUSTED CAPITALIZATION AT 9/30/03
($000)

LG&E PROPOSED:	Adjusted Electric Capitalization (1)	Capitalization Ratios	Cost Rates	Weighted Cost Rates
1. Short Term Debt	$ 57,012	3.84%	1.06%	0.04%
2. A/R Securitization	56,749	3.82%	1.39%	0.05%
3. Long Term Debt	605,311	40.74%	3.77%	1.54%
4. Preferred Stock	53,433	3.60%	2.51%	0.09%
5. Common Equity	713,196	48.00%	11.25%	5.40%
6. Total	$ 1,485,701	100.00%		7.12%

AG RECOMMENDED:	Adjusted Electric Capitalization	Capitalization Ratios	Cost Rates	Weighted Cost Rates
1. Short Term Debt	$ 57,012	3.90%	1.06%	0.04%
2. A/R Securitization	56,749	3.89%	1.39%	0.05%
3. Long Term Debt	605,311	41.45%	3.77%	1.56%
4. Preferred Stock	53,433	3.66%	2.51%	0.09%
5. Common Equity	687,752 (2)	47.10%	10.00% (3)	4.71%
6. Total	$ 1,460,257	100.00%		6.46%

(1) Rives Exhibit 2, page 1, column (6)

(2)

LG&E's proposed adjusted common equity balance:	$ 713,196	
Remove LG&E's proposed Minimum Pension Liability add-back:	(25,443)	Rives Exh. 2, page 2, col. (7)
AG-Recommended adjusted common equity balance:	$ 687,753	

(3) Testimony of Dr. Carl Weaver: midpoint of range of 9.75% - 10.25%

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
SUMMARY OF ORIGINAL COST RATE BASE POSITIONS
($000)

	LG&E Electric (1)	Remove Post'95 ECR Components (2)	Other Adjustments	AG	
1. Utility Plant at Original Cost	$ 3,232,386	$ (203,504)	$ (7,937) (4)	$ 3,020,945	
2. Reserve for Depreciation	(1,339,452)	1,973	13,375 (5)	(1,324,104)	
3. Net Utility Plant	1,892,934	(201,531)	5,438	1,696,841	
Deduct:					
4. Customer Advances	(507)			(507)	
5. Deferred Income Taxes	(291,451)	597		(290,854)	
6. FAS 109 Deferred Inc. Tax	(37,113)			(37,113)	
7. Investment Tax Credit	(4)			(4)	
8. Total Deductions	(329,075)	597		(328,478)	
Add:					
9. Materials and Supplies	55,832		(333) (6)	55,499	
10. Prepayments	2,883			2,883	
11. Cash Working Capital	52,801	(28) (3)	(410) (7)	52,363	
12. Total Additions	111,516	(28)	(743)	110,745	
13. Total Net Original Rate Base	$ 1,675,375	$ (200,962)	$ 4,695	$ 1,479,108	
14. Income Requirement				$ 94,330	Sch. RJH-1, L3
15. Return on Rate Base [L14 / L13]				6.38%	

(1) Rives Exhibit 3, page 1

(2) Response to AG-1-8

(3) Per response to AG-1-8: Post-1995 ECR Plan related O&M expense removal of $224,576 / 8 = $28,072.

(4) Remove capitalized E.W. Brown repairs per Rives Exhibit 2, p.2	$ 3,351,980
Remove ARO assets	4,585,010
	$ 7,936,990

(5) Annualized impact on depreciation reserve of AG's recommended depreciation expense adjustment - see sch. RJH-8, line 3

(6) Per response to AG-2-39. Remove written-off carbide lime inventory.

(7) DSM expenses removed from test year O&M expenses: $3,280,013 / 8 = $ 410,000

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
SUMMARY OF PRO FORMA OPERATING INCOME POSITIONS
($000)

	LG&E Electric	
1. LG&E's Proposed Pro Forma After-Tax Operating Income:	$ 68,010 *	Rives Exh. 1, p.3
AG-RECOMMENDED ADJUSTMENTS:		
2. Impact of Re-Stating KY Income Taxes Included in Line 1 From Rate of 8.25% to Effective Rate of 7.87%	To be Calculated by LG&E	
3. Interest Synchonization	442	Sch. RJH-5
4. Unbilled Revenue Adjustment	624	Sch. RJH-6
5. Customer Growth Revenue Annualization	167	Sch. RJH-7
6. Annualized Depreciation Expense	13,375	Sch. RJH-8
7. Additional Promotional Expenses	54	Sch. RJH-9
8. Rate Case Expense	135	Sch. RJH-10
9. I&D Expense Normalization	43	Sch. RJH-11
10. IT Staff Reduction Cost Savings	146	Sch. RJH-12
11. Obsolete Inventory Write-Off	411	Sch. RJH-13
12. Carbide Lime Write-Off	424	Sch. RJH-14
13. Miscellaneous Adjustments	127	Sch. RJH-15
14. FAS-143 ARO Adjustment	3,149	Sch. RJH-16
15. AG-Recommended Pro Forma After-Tax Operating Income:	$ 87,108	

* This after-tax operating income amount is calculated based on KY state income taxes of 8.25%. These KY income taxes must be re-stated at a rate of 7.87%

LOUSIVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
INTEREST SYNCHRONIZATION ADJUSTMENT
($000)

	LG&E Electric (1)	Adjustments	AG	
1. Adjusted Capitalization	$ 1,485,701		$ 1,460,257	Sch. RJH-2
2. Weighted Cost of Debt	1.63%		1.66%	Sch. RJH-2
3. Pro Forma Interest Expense	$ 24,217		$ 24,213	
4. Test Year Per Books Interest Deduction	24,315		23,209	(2)
5. Interest Synchronization Adjustment	(98)		1,004	
6. Composite Income Tax Rate	40.3625%		40.1155%	(3)
7. Impact on After-Tax Income	$ (40)	$ 442	$ 403	

(1) Rives Exhibit 1, Schedule 1.37
(2) Responses to AG-1-25 and 2-42
(3) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%.

LOUSIVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
APPLICATION OF OPERATING RATIO TO UNBILLED REVENUE ADJUSTMENT
($000)

LG&E Electric Unbilled Revenue Adjustment:	$000s (1)		Associated KWHs (2)
1. Remove Unbilled Revenues at 9/30/03	$ (22,895)		(414,294,000)
2. Add Unbilled Revenues at 9/30/02	21,028		410,199,000
3. Net Impact on Test Year	$ (1,867)		(4,095,000)
4. Operating Ratio	0.5579	(3)	
5. Test Year Operating Expense Reduction Associated with Unbilled Revenue Adj.	$ (1,042)		
6. Composite After-Tax Income Factor	0.598845	(4)	
7. Impact on After-Tax Operating Income	$ 624		

(1) Rives Exhibit 1, Schedule 1.00

(2) Attachment to response to KIUC-1-78, p.98 of 441

(3) Seelye Exhibit 25

(4) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUSIVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT
($000)

	LG&E Electric (1)	Adjustments	AG	
1. Net Revenue Adjustment	$ 1,156	280	1,436	Sch. RJH-7, p.2
2. Composite After-Tax Income Factor		0.598845 (2)		
3. Impact on After-Tax Operating Income		$ 167		

(1) Seelye Exhibit 25, page 1

(2) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUSIVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT
($000)

	(1) Test Year 13-mos Avg Customers	(2) Avg 1/2 Year Customer Growth Rate	(3) Test Year Customer Growth Adj [1 x2]	(4) Actual KWHs	(5) Avg KWH Per Customer [4 / 1]	(6) Test Year KWH Growth Adj [3 x 5]	(7) Avg Revenue per KWH	(8) Recommended Revenue Adjustment [6 x 7]
Residential Rate R	337,034	0.65% *	2,191	3,847,709,782	11,416	25,010,114	$ 0.0573	$ 1,433,080
Water Heating Rate WH		[calculated per LG&E's methodology as shown in response to PSC-3-28]						(9,271)
General Service Rate GS		[calculated per LG&E's methodology as shown in response to PSC-3-28]						(258,741)
Large Commercial LC (Sec)		[calculated per LG&E's methodology as shown in response to PSC-3-28]						854,454
Large Commercial LCTOD (Sec)		[calculated per LG&E's methodology as shown in response to PSC-3-28]						566,077
Industrial Power LP (sec)		[calculated per LG&E's methodology as shown in response to PSC-3-28]						147,900
Traffic Lighting TLE		[calculated per LG&E's methodology as shown in response to PSC-3-28]						5,157
Public Street Lighting PSL		[calculated per LG&E's methodology as shown in response to PSC-3-28]						317,308
Outdoor Lighting OL		[calculated per LG&E's methodology as shown in response to PSC-3-28]						191,264
TOTAL								$ 3,247,228
				Less: Associated Operating Expenses @ 0.5579:				(1,811,628)
				Recommended Net Revenue Adjustment:				$ 1,435,599

* Source: AG-1-324, p.1:

	Residential
1999	320,874
2000	324,374
2001	330,031
2002	334,329
2003	337,768
Avg Annual Compound Growth Rate	1.30%
Avg 1/2 Year Compound Growth Rate	0.65%

LOUSIVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
ANNUALIZED DEPRECIATION EXPENSE ADJUSTMENT
($000)

	LG&E Electric (1)	Adjustments	AG	
1. Annualized Depreciation Expense With New Rates	$ 103,382		$ 81,047	(2)
2. Test Year Per Books Depr. Exp. Excluding ARO and Post-1995 ECR	94,422		94,422	
3. Depreciation Expense Change	$ 8,960	$ (22,335)	$ (13,375)	
4. Composite After-Tax Income Factor		0.598845 (3)		
5. Impact on After-Tax Operating Income		$ 13,375		

(1) Rives Exhibit 1, Schedule 1.11
(2) Testimony of Michael Majoros
(3) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

Case No. 2003-00433

Sch. RJH-9

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
ADDITIONAL PROMOTIONAL EXPENSE ADJUSTMENTS

Additional Promotional Expenses Not Removed by LG&E:		LG&E Electric	
1. Promotional Expenses in Account 909001	$	22,699	(1)
2. Promotional Expenses in Account 909002		3,119	(2)
3. Promotional Expenses in Account 912001		13,177	(3)
4. Promotional Expenses in Account 912005		51,455	(3)
5. Total Additional Promotional Expense Removal	$	90,450	
6. Composite After-Tax Income Factor		0.598845	(4)
7. Impact on After-Tax Operating Income	$	54,166	

(1) Response to AG-1-49 (b)

(2) Response to AG-1-229

(3) Response to AG-1-48

(4) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

Case No. 2003-00433

Sch. RJH-10

LOUSIVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
RATE CASE EXPENSE ADJUSTMENT
($000)

	LG&E Electric (1)	Adjustments	AG	
1. Total Estimated Rate Case Expense	$ 1,001	$ 324,074	$ 324	(2)
2. Amortization Period (Yrs)	3		3	
3. Annual Amortization Expense	$ 334	$ (226)	$ 108	
4. Composite After-Tax Income Factor		0.598845 (3)		
5. Impact on After-Tax Operating Income		$ 135		

(1) Rives Exhibit 1, Schedule 1.16

(2) Response to PSC-2-57 - Updated 2/27/2004

(3) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

Case No. 2003-00433

Sch. RJH-11

LOUSIVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
INJURY AND DAMAGE EXPENSE NORMALIZATION ADJUSTMENT
($000)

	LG&E Electric (1)	Adjustments	AG	
1. Normalized I&D Expenses	$ 2,006		$ 1,935	(2)
2. Actual Test Year I&D Expenses	1,505		1,505	
3. Expense Adjustment	$ 501	$ (71)	$ 430	
4. Composite After-Tax Income Factor		0.598845 (3)		
5. Impact on After-Tax Operating Income		$ 43		

(1) Rives Exhibit 1, Schedule 1.19

(2) Per Rives Exhibit 1, Schedule 1.19:

	CPI-U Adjusted Electric I&D Expenses	
	LG&E	AG
1998	$ 1,860	$ -
1999	2,103	2,103
2000	1,887	1,887
2001	758	758
2002	3,423	3,423
Test Year	-	1,505
5-Year Average	$ 2,006	$ 1,935

(3) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
ADDITIONAL IT STAFF REDUCTION COST SAVINGS
($000)

Additional IT Staff Reduction Cost Savings Not Reflected by LG&E:	LG&E Electric	
1. Reduction in Pension, FAS-106, Medical, Dental, Life Insurance, Long Term Disability and TIA Expenses	$ 243	(1)
2. Composite After-Tax Income Factor	0.598845	(3)
3. Impact on After-Tax Operating Income	$ 146	

(1) Responses to AG-1-62 (c) and AG-2-57: total expense reduction of $306,990 x 79% electric portion = $242,522
(2) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

Case No. 2003-00433

Sch. RJH-13

LOUSIVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
OBSOLETE INVENTORY WRITE-OFF ADJUSTMENT
($000)

	LG&E Electric (1)	Adjustments	AG
1. Write-Off of Obsolete Inventory	$ 2,061		$ -
2. Amortization Period (Yrs)	3		
3. Annual Amortization Expense	687	$ (687)	-
4. Amount Included in Test Year	2,061		2,061
5. Adjustment to Remove Expense from Test Year	$ (1,374)	$ (687)	$ (2,061)
6. Composite After-Tax Income Factor		0.598845 (2)	
7. Impact on After-Tax Operating Income		$ 411	

(1) Rives Exhibit 1, Schedule 1.31

(2) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUSIVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
CARBIDE LIME WRITE-OFF ADJUSTMENT
($000)

	LG&E Electric (1)	Adjustments	AG
1. Carbide Lime Write-Off	$ 2,125		$ -
2. Amortization Period (Yrs)	3		
3. Annual Amortization Expense	708	$ (708)	-
4. Amount Included in Test Year	2,125		2,125
5. Adjustment to Remove Expense from Test Year	$ (1,417)	$ (708)	$ (2,125)
6. Composite After-Tax Income Factor		0.598845 (2)	
7. Impact on After-Tax Operating Income		$ 424	

(1) Rives Exhibit 1, Schedule 1.32

(2) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
MISCELLANEOUS ADJUSTMENTS

Miscellaeous Test Year Expense and Revenue Adjustments:	LG&E Electric	
1. Remove Donation Expenses	$ 17,957	(1)
2. Remove Expenses for Employee Gifts, Award Banquets, Parties and Social Events	59,403	(2)
3. Remove 72.16% of EEI Dues	141,001	(3)
4. ECR Roll-In Revenue Adjustment	(5,472)	(4)
5. Total Impact on Pre-Tax Operating Income	$ 212,889	
6. Composite After-Tax Income Factor	0.598845	(5)
7. Impact on After-Tax Operating Income	$ 127,488	

(1) Since LG&E did not provide the electric/gas allocators in response to AG-2-63, the AG has assumed that 80% of donation expenses are allocable to electric operations. Response to PSC-1-32: $22,426 x 80% = $17,957.

(2) Per response to AG-1-77: 50% x $118,805 = $59,403

(3)

- Per response to AG-1-313: Electric EEI dues in test year:	$ 195,401
- Per response to AG-85: Portion of EEI activities devoted to legislative and regulatory advocacy; legislative and regulatory policy research; advertising, marketing and public relations:	72.16%
- EEI dues to be removed from test year	$ 141,001

(4)

LG&E's originally proposed ECR roll-in revenue adjustment per Rives Sch. 1.03	$ 723,260
Updated ECR roll-in revenue adjustment per response to PSC-3-35	717,788
Reduction in test year base revenues	$ (5,472)

(5) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUSIVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
FAS-143 ASSET RETIREMENT OBLIGATION ADJUSTMENT
($000)

	LG&E Electric (1)	Adjustments	AG	
1. Impact on After-Tax Operating Income of FAS-143 ARO Adjustment	$ (3,149)	$ 3,149	$ -	(2)

(1) Rives Exhibit 1, Schedule 1.25
(2) Testimony of Michael Majoros

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BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO. 2003-00433

DIRECT TESTIMONY AND EXHIBITS OF ROBERT J. HENKES PERTAINING TO THE GAS RATE CASE

On Behalf of the Office Of Rate Intervention Of The Attorney General Of The Commonwealth Of Kentucky

March 23, 2004

I. STATEMENT OF QUALIFICATIONS

Q. WOULD YOU STATE YOUR NAME AND ADDRESS?

A. My name is Robert J. Henkes and my business address is 7 Sunset Road, Old Greenwich, Connecticut 06870.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am Principal and founder of Henkes Consulting, a financial consulting firm that specializes in utility regulation.

Q. WHAT IS YOUR REGULATORY EXPERIENCE?

A. I have prepared and presented numerous testimonies in rate proceedings involving electric, gas, telephone, water and wastewater companies in jurisdictions nationwide including Arkansas, Delaware, District of Columbia, Georgia, Kentucky, Maryland, New Jersey, New Mexico, Pennsylvania, Vermont, the U.S. Virgin Islands and before the Federal Energy Regulatory Commission. A complete listing of jurisdictions and rate proceedings in which I have been involved is provided in Appendix I attached to this testimony.

Q. WHAT OTHER PROFESSIONAL EXPERIENCE HAVE YOU HAD?

A. Prior to founding Henkes Consulting in 1999, I was a Principal of The Georgetown Consulting Group, Inc. for over 20 years. At Georgetown Consulting I performed the same type of consulting services as I am currently rendering through Henkes Consulting. Prior to my association with Georgetown Consulting, I was employed by the American Can Company as Manager of Financial Controls. Before joining the American Can Company, I was employed by the management consulting division of Touche Ross & Company (now Deloitte & Touche) for over six years. At Touche Ross, my experience, in addition to regulatory work, included numerous projects in a wide variety of industries and financial disciplines such as cash flow projections, bonding feasibility, capital and profit forecasting, and the design and implementation of accounting and budgetary reporting and control systems.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor degree in Management Science received from the Netherlands School of Business, The Netherlands in 1966; a Bachelor of Arts degree received from the University of Puget Sound, Tacoma, Washington in 1971; and an MBA degree in Finance received from Michigan State University, East Lansing, Michigan in 1973. I have also completed the CPA program of the New York University Graduate School of Business.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF THIS TESTIMONY?

A. I was engaged by the Office of Rate Intervention of the Attorney General of Kentucky ("AG") to conduct a review and analysis and present testimony in the matter of the petition of Louisville Gas and Electric Company ("LG&E" or the "Company") for an increase in its base rates for gas service.

The purpose of this testimony is to present to the Kentucky Public Service Commission ("KPSC" or the "Commission") the appropriate gas capital structure and overall rate of return, rate base and pro forma test period operating income, as well as the appropriate gas revenue requirement for the Company in this proceeding.

In the determination of the AG's recommended capital structure and overall rate of return, rate base, operating income and revenue requirement, I have relied on and incorporated the recommendations of the following other expert witnesses engaged by the AG in this proceeding:

1. Dr. <u>Carl Weaver</u>, concerning the appropriate capital structure ratios, cost rates for debt, preferred stock, the return on common equity, and the resulting overall rate of return for the Company in this proceeding;
2. Mr. <u>Michael Majoros,</u> concerning the appropriate depreciation rates to be adopted by the Commission in this case; and
3. Mr. David Brown Kinloch, concerning LG&E's proposal in this case to increase

certain Miscellaneous Service charges.

In developing this testimony, I have reviewed and analyzed the Company's December 29, 2003 filing; supporting testimonies, exhibits, filing requirements and workpapers; the Company's responses to initial and follow-up data requests by the KPSC Staff, AG and other intervenors; and other relevant financial documents and data.

III. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE.

A. I have reached the following findings and conclusions in this case:

1. The gas revenue requirement determination in this case should be based on LG&E's capitalization. This revenue requirement determination base has been proposed by the Company in this rate proceeding and has been consistently applied by the Commission in LG&E's previous gas base rate proceedings (schedule RJH-1, line 1).

2. The appropriate adjusted gas capitaliation as of September 30, 2003, the end of the test period in this case, amounts to $307.343 million which is $4.8 million lower than the adjusted electric capitalization amount of $312.143 million proposed by LG&E (schedule RJH-1, line 1 and schedule RJH-2).

3. The appropriate pro forma adjusted gas rate base measured as of September 30, 2003, the end of the test period in this case, amounts to approximately $320 million. (schedule RJH-3). The Company has not presented a proposed adjusted gas rate base in this case.

4. The AG's expert rate of return witness, Dr. Carl Weaver, has recommended a short term debt cost rate of 1.06%, A/R securitization rate of 1.39%, long term debt rate of 3.77%, preferred stock cost rate of 2.51% and a return on equity range of 10.10%

to 10.60%, with a mid-point of 10.35%. These recommended capital cost rates, together with Dr. Weaver's recommended capital structure ratios produce the AG's recommended overall rate of return for LG&E's gas operations of 6.62% (Schedule RJH-2). This is equivalent to a rate of return of 6.36% on the Company's adjusted gas rate base (schedule RJH-3, line 16).

By comparison, the Company has proposed an overall rate of return on capital structure of 7.23% for its gas operations. Since the Company has not presented a proposed adjusted gas rate base, it has not provided an equivalent proposed overall return on rate base number for its gas operations.

5. The appropriate pro forma test period gas operating income amounts to $16.702 million, which is $5.452 million higher than LG&E's proposed test period electric operating income of $11.250 million (schedule RJH-1, line 4 and schedule RJH-4).

6. The appropriate revenue conversion factor to be used for rate making purposes in this case is approximately .5948. This is higher than the Company's proposed revenue conversion factor of approximately .5924 (schedule RJH-1, line 6 and footnote 4).

7. The application of the recommended overall rate of return of 6.62% to the recommended capital structure of $307.343 million, combined with the recommended pro forma test period operating income of $16.702 million and the revenue conversion factor of approximately .5948 indicates that the Company has an overall annual revenue deficiency for its gas rate operations of $6.151 million.

This is $12.956 million (67.8%) lower than the Company's proposed annual gas revenue deficiency of $19.106 million (schedule RJH-1, lines 1-7).

8. The recommended annual gas revenue deficiency of $6.151 million should be achieved by increasing LG&E's annual gas revenues by $6.096 million and LG&E's annual miscellaneous gas service charges by approximately $55,000 (schedule RJH-1, lines 8-10)

9. The recommended annual gas revenue deficiency and associated gas rate increases identified in recommendation nos. 7 and 8 do not yet reflect the increase in the recommended pro forma gas test year operating income for the restatement of all Kentucky income taxes included in LG&E's proposed pro forma test year operating income from a rate of 8.25% to an effective rate of 7.87% (schedule RJH-4, line 1, * notation). This AG recommendation could not be quantified when this testimony was being prepared. Once LG&E has provided the necessary information to quantify this additional AG recommendation, the AG's recommended gas revenue deficiency and rate increase recommendations as currently presented in this testimony must be updated to reflect the impact of this additional recommendation.

IV. REVENUE REQUIREMENT ISSUES

A. CAPITALIZATION AND OVERALL RATE OF RETURN

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED TEST YEAR-END ADJUSTED CAPITALIZATION AND CAPITAL STRUCTURE RATIOS FOR ITS GAS OPERATIONS IN THIS CASE.

A. As shown on Rives Exhibit 2, page 1, the starting point of the Company's proposed pro forma adjusted gas capitalization is the actual per books total company capitalization as of 9/30/2003 of approximately $1,924.559 million, consisting of short term debt, A/R securitization, long term debt, preferred stock and common equity. The Company then allocated this total company test year-end capitalization between its electric and gas operations based on a rate base allocation percentage. This results in an allocated gas capitalization balance of $305.428 million. Next, the Company made 2 pro forma gas capitalization adjustments in order to arrive at its proposed adjusted gas capitalization of $312.143 million. These 2 proposed gas capitalization adjustments concern (1) the addition of the Job Development Tax Credit balance allocated to gas operations; and (2) the reversal of the impact of the Company's Minimum Pension Liability ("MPL") adjustment to common equity. The first capitalization adjustment only impacts the dollar amount of the gas capitalization without changing the ratios of the capitalization components. The second capitalization adjustment concerning the MPL issue is an adjustment that not only impacts the capitalization dollar balance, but also changes the capital structure ratios because it involves an adjustment that is made to the common equity balance only.

The so-derived adjusted gas capitalization and capital structure ratios proposed by LG&E are summarized in the first two columns on the top part of schedule RJH-2.

Q. DOES THE AG AGREE WITH THE COMPANY'S PROPOSED TEST YEAR-END ADJUSTED GAS CAPITALIZATION AND CAPITAL STRUCTURE RATIOS THAT YOU JUST DESCRIBED?

A. Dr. Weaver has informed me that, based on his review and analysis, he has found reasonable the Company's proposed total company test year-end capitalization consisting of short term debt, A/R securitization, long term debt, preferred stock and common equity, and he recommends that this capitalization be used as the appropriate starting point for the determination of the Company's overall rate of return determination. In this case, I am responsible for addressing the appropriateness of (a) the Company's proposed total company capitalization allocation to gas operations, and (b) the Company's proposed two gas capitalization adjustments. Based on my review of these issues, I agree with all of the Company's proposed gas capitalization proposals with the exception of the Company's proposed MPL adjustment to its common equity balance. I recommend that the Company's proposed MPL related equity adjustment be rejected by the Commission.

The resulting AG-recommended adjusted gas capitalization and capital structure ratios are summarized in the first two columns on the bottom part of schedule RJH-2.

Q. BRIEFLY SUMMARIZE THE COMPANY'S PROPOSAL WITH REGARD TO

THE MPL ISSUE IN THIS CASE.

A. The Company is proposing to reverse actual write-downs to its common equity balance that were previously recorded by LG&E in accordance with SFAS 130, *Reporting Comprehensive Income*, in order to reflect the Company's Minimum Pension Liability ("MPL"). As shown on Rives Exhibit 2, page 2, column (7), this proposal has the effect of increasing the Company's proposed adjusted gas capital structure by $4.8 million. I understand that this proposed common equity adjustment would only be possible if the Company is allowed to establish a regulatory asset for the amount of the MPL equity write-down. Therefore, the Company in this case is also requesting approval from the KPSC to record such a regulatory asset. The Company claims that the establishment of the MPL regulatory asset is consistent with and allowed by SFAS 71.

Q. PLEASE EXPLAIN YOUR RECOMMENDATION THAT THE COMMISSION REJECT THE COMPANY'S PROPOSED MPL RELATED COMMON EQUITY ADJUSTMENT FOR RATEMAKING PURPOSES IN THIS CASE.

A. There are several reasons why I believe the Company's proposals to reverse the MPL related equity write-down and establish a regulatory asset for the MPL are inappropriate and should be rejected by the KPSC.

First, the equity write-down was actually made on the Company's books in accordance with generally accepted accounting rules and, therefore, represents an actual, known and measurable capitalization element at September 30, 2003, the end of the test year in this case. In this regard, it should be noted that in LG&E's prior electric rate case, Case No.

98-426, the Commission similarly rejected a proposal on the part of the Company to reverse for ratemaking purposes certain common equity write-downs that were actually booked by the Company during the test year in that case.[1] On page 65 of its Order in Case No. 98-426, the Commission stated in this regard:

> The Commission cannot simply ignore the fact that the write-off has occurred and will continue to affect LG&E's capitalization in the future.

Thus, my recommendation to reject the Company's proposed equity write-down reversal in the current case is consistent with previously established Commission ratemaking policy.

Second, I am not convinced that the establishment of a regulatory MPL asset is consistent with and allowed by SFAS 71. In its testimony and responses to data requests, LG&E states that the regulatory MPL asset would only be extinguished through *balance sheet* accounting (i.e., changes in asset values). SFAS 71 on the other hand envisions the recovery of deferred expenses through rates, which implies an *income statement* orientation. Moreover, under SFAS 71, it is the action of the regulator, not exogenous economic forces, that makes the recovery of the regulatory asset possible. All of this raises a question in my mind as to whether the proposed regulatory asset meets the definition of the type of cost to which SFAS 71 is intended to apply.

Finally, I am concerned that the establishment of a regulatory asset pursuant to SFAS 71 may give rise to a presumption that the underlying costs are recoverable from ratepayers and preclude a prudence review of these costs in the future. For example, if the regulatory MPL asset balance is not eventually eliminated through the normal operation of SFAS 87

[1] Case No. 98-426, KPSC Order at 64-65.

accounting, that in turn could lead to a claim for amortization through rates in a future LG&E rate proceeding, as has been the treatment afforded all previous and existing regulatory assets by the KPSC for LG&E.

Q. NOW THAT YOU HAVE DISCUSSED THE AG'S RECOMMENDED ADJUSTED GAS CAPITALIZATION AND ASSOCIATED CAPITAL STRUCTURE RATIOS, WHAT ARE THE AG'S RECOMMENDED CAPITAL COST RATES AND OVERALL RATE OF RETURN?

A. The AG's expert rate of return witness, Dr. Carl Weaver, has recommended the same cost rates as LG&E for the adjusted test year-end capitalization components of short term debt, A/R securitization, long term debt, and preferred stock. With regard to the return on common equity for LG&E's gas operations, Dr. Weaver has recommended a return range of 10.10% to 10.60%, with a mid-point return rate of 10.35%. Schedule RJH-2 shows that the AG's recommended overall rate of return for its gas operations based on these capital costs rates is 6.62%.

Q. WHAT IS YOUR OPINION REGARDING THE METHOD IN WHICH A UTILITY'S RETURN REQUIREMENT SHOULD BE DETERMINED FOR RATE MAKING PURPOSES?

A. I believe a utility's return requirement for rate making purposes should be determined by applying the calculated overall rate of return to the lower of the utility's capitalization or original cost rate base. When a utility's capitalization dollar balance is higher than the used and useful rate base investment balance, this generally indicates that a portion of this utility's capitalization has been used to finance investments that are not used and useful to the ratepayers and are therefore not included in the utility's rate base, e.g., non-regulated/non-utility assets, "below-the-line" assets, *etc.* When a utility's rate base is higher than the capitalization balance, this could mean that portions of the rate base investments have been financed with funds other than investor-supplied debt, preferred stock and common equity; or it could mean that rate base investments that have been assumed to exist by way of hypothetical formulas (e.g., the "1/8th method" used to estimate assumed cash working capital) do not actually exist.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL IN THIS CASE THAT THE COMPANY'S RETURN REQUIREMENT BE DETERMINED BY APPLYING THE APPROPRIATE GAS OVERALL RATE OF RETURN TO THE ADJUSTED GAS CAPITALIZATION AT THE END OF THE TEST YEAR?

A. Yes. The Company's proposed return requirement approach in this case is consistent with the principles I just discussed and is also consistent with the return requirement rate making policy adopted by the KPSC in all of LG&E's prior base rate proceedings.

B. RATE BASE

Q. HAS THE COMPANY PRESENTED AN ADJUSTED ORIGINAL COST RATE BASE FOR ITS GAS OPERATIONS IN ITS FILING SCHEDULES IN THIS PROCEEDING?

A. No. While the Company has presented an unadjusted gas original cost rate base for purposes of developing the gas rate base allocation percentage,[2] the Company did not present an adjusted gas original cost rate base for purposes of determining the appropriate return on rate base as compared to the appropriate return on capitalization. This is contrary to KPSC ratemaking policy and practice. For example, in both LG&E's most recent electric and gas base rate proceedings, Case Nos. 98-426 and 2000-080, the Commission's Orders[3] presented the Company's adjusted electric and gas original cost rate bases.

Q. HAVE YOU DETERMINED THE APPROPRIATE ADJUSTED ORIGINAL COST RATE BASE FOR LG&E'S GAS OPERATIONS IN THIS CASE?

A. Yes, this recommended adjusted gas original cost rate base has been developed on schedule RJH-3. The starting point is LG&E's proposed unadjusted gas original cost rate base measured as of the end of the test year, September 30, 2003. I then made two adjustments in order to arrive at the AG's recommended adjusted gas original cost rate base to be used for ratemaking purposes in this case. These two recommended rate base adjustments are shown on schedule RJH-3 and will be discussed in detail in the subsequent sections of this testimony.

- **<u>Accumulated Depreciation Reserve</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED DEPRECIATION RESERVE ADJUSTMENT SHOWN ON LINE 2 OF SCHEDULE RJH-3.

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[2] This is presented on Rives Exhibit 3, page 1.
[3] See page 63 of the KPSC Order in Case No. 98-426 and page 23 of the KPSC Order in Case No. 2000-080.

A. This adjustment is a direct result of the annualized depreciation expense adjustment discussed later in this testimony. As shown in footnote (2) of schedule RJH-3, the adjustment reflects the pro forma annualized impact on the Company's adjusted test year depreciation reserve balance of the AG's recommended annualized depreciation expense adjustment detailed on schedule RJH-8. As confirmed by the Company in its responses to AG-1-11 and AG-1-12, this recommended depreciation reserve adjustment is entirely consistent with a similar depreciation reserve adjustment proposed by LG&E and adopted by the Commission in LG&E's most recent gas rate case in Case No. 2000-080.

- **Cash Working Capital**

Q. PLEASE DESCRIBE THE DERIVATION OF THE COMPANY'S CASH WORKING CAPITAL AMOUNT CLAIMED IN THIS CASE.

A. The Company has proposed to calculate the cash working capital in this case based on the so-called "modified 1/8th formula" method. This method assumes that 1/8th of the pro forma test year gas operation and maintenance expenses (net of gas supply expenses) represents a reasonable cash working capital approximation. As shown on Rives Exhibit 3, page 2, based on this methodology the Company has calculated a proposed electric cash working capital of approximately $5.641 million.

Q. DO YOU AGREE WITH THE USE OF THE MODIFIED 1/8TH METHOD TO DETERMINE THE COMPANY'S CASH WORKING CAPITAL REQUIREMENT?

A. No. I believe that only a properly performed detailed lead/lag study would generate an accurate approximation of a utility's cash working capital. However, based on my review of the Company's prior base rate proceedings, it is my understanding that the Commission has consistently allowed this Company's cash working capital to be determined based on this modified 1/8th method. I have therefore chosen not to challenge this method in this case.

Q. DO YOU RECOMMEND THAT ADJUSTMENTS BE MADE TO THE COMPANY'S PROPOSED CASH WORKING CAPITAL REQUIREMENT?

A. Yes. The Company's proposed cash working capital should be reduced to reflect the removal of all DSM revenue requirements from gas base rates. The Company's gas DSM expenses are completely recovered through a DSM surcharge rate recovery mechanism that is completely separate from gas base rate recovery. For this reason, the Company has made a specific adjustment to remove all test year gas DSM operation and maintenance expenses of $1.527 million as an adjustment to the gas revenue requirement in this case.[4] Therefore, the Company's proposed gas cash working capital should be reduced by 1/8th of $1.527 million, or approximately $191,000. This recommended cash working capital adjustment is reflected on line 12 of schedule RJH-3.

Q. ARE THE AFOREMENTIONED CASH WORKING CAPITAL ADJUSTMENTS CONSISTENT WITH THE APPROACH USED BY THE COMPANY FOR PURPOSES OF CALCULATING THE COMPANY'S GAS CASH WORKING CAPITAL REQUIREMENT?

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[4] See Rives Exhibit 1, Schedule 1.09.

A. Yes. The Company's proposed gas cash working capital requirement is calculated by taking 1/8th of the test year gas operation and maintenance expenses, net of all gas supply costs. In its response to AG-1-24, LG&E explained that the rationale for excluding gas supply costs from its gas cash working capital requirement determination is that (1) the "gas supply costs are completely recovered through a separate rate from the base rates", and (2) "The gas supply costs are also removed as an adjustment to gas revenue requirements, thus an adjustment is appropriate for the cash working capital requirement." Since the same circumstances exist for the Company's gas DSM costs, the same cash working capital adjustments for removed gas DSM operation and maintenance expenses would be in order.

Q. WILL THERE BE A FINAL CASH WORKING CAPITAL ADJUSTMENT THAT WILL NOT BE KNOWN AND MEASURABLE UNTIL THE COMMISSION DECIDES THE APPROPRIATE PRO FORMA TEST YEAR GAS OPERATION AND MAINTENANCE EXPENSE LEVEL?

A. Yes. Based on my review of prior Commission Orders, it is my understanding that the Commission calculates this Company's cash working capital based on taking 1/8th of the pro forma adjusted test year operation and maintenance expenses. Thus, the AG-recommended gas cash working capital currently shown on line 12 of schedule RJH-3 must ultimately be further adjusted to reflect all KPSC-ordered pro forma test year gas operation and maintenance expenses.

C. OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AS COMPARED TO YOUR RECOMMENDED PRO FORMA GAS OPERATING INCOME FOR THE TEST PERIOD IN THIS CASE.

A. The Company's proposed and my recommended pro forma test year gas operating income positions are summarized on schedule RJH-4. The Company has proposed total pro forma test period gas operating income of $11.250 million. As summarized on schedule RJH-4, I have made a large number of pro forma gas operating income adjustments which, in total, have the effect of increasing the Company's proposed test year gas operating income by $5.452 million to total recommended pro forma test period gas operating income of $16.702 million. Each of the recommended gas operating income adjustments will be discussed in detail in the subsequent sections of this testimony.

- **Kentucky State Income Tax Rate**

Q. WHAT IS THE KENTUCKY STATE INCOME TAX RATE THAT HAS BEEN USED BY LG&E FOR RATEMAKING PURPOSES IN THIS PROCEEDING?

A. The Company has used a Kentucky state income tax rate of 8.25%. It used this state income tax rate in all income tax components of the ratemaking formula to derive the Company's claimed overall gas revenue deficiency of $19.106 million. In other words, it used a state income tax rate of 8.25% in the determination of (1) the unadjusted test year gas income tax starting point,[5] (2) the income tax impact of all of LG&E's proposed pro

[5] This is the income tax amount of $7,592,206 million on line 13 of filing requirement Tab 42.

forma operating income adjustments[6], and (3) the revenue conversion factor to translate the gas operating income deficiency into a tax-grossed up gas revenue deficiency.[7]

Q. DOES LG&E PAY AN EFFECTIVE STATE INCOME TAX RATE DIFFERENT FROM THE 8.25% RATE AS A RESULT OF ITS PARTICIPATION IN A CONSOLIDATED KENTUCKY INCOME TAX FILING?

A. Yes. As confirmed in the response to PSC-2-15 (c), LG&E has been filing consolidated Kentucky corporation income tax returns generating the following effective Kentucky income tax rates during the last 4 years:

	Effective State Income Tax Rates (excluding credits)
1999	7.41%
2000	7.69%
2001	7.73%
2002	7.87%

Q. HAS THE COMMISSION RECENTLY ESTABLISHED A NEW POLICY OF RECOGNIZING THE USE OF AN EFFECTIVE KENTUCKY STATE INCOME TAX RATE FOR RATEMAKING PURPOSES IN CASES INVOLVING KENTUCKY UTILITIES THAT PARTICIPATE IN CONSOLIDATED KENTUCKY CORPORATION INCOME TAX RETURNS?

A. Yes. The Commission established this new ratemaking policy on a trial basis in the most recent Union Light, Heat and Power Company ("ULH&P") base rate proceeding, Case No.

[6] This is the total income tax adjustment amount of $3.3 million shown on line 13 of filing requirement Tab 42, making up the income tax adjustments on Rives Exhibit 1, Schedules 1.36, 1.37 and 1.38.
[7] This is shown on Rives Exhibit 1, Schedule 1.39.

2001-00092.

Q. DID THE COMMISSION EXPRESS A CONCERN IN THIS RECENT ULH&P RATE PROCEEDING WITH REGARD TO THE USE OF THE EFFECTIVE KENTUCKY STATE INCOME TAX RATE?

A. Yes. The Commission appeared to be somewhat concerned by the significant fluctuation experienced in ULH&P's effective state income tax rate from 5.15% in one tax year to 3.03% in the next tax year.[8]

Q. IS THERE REASON FOR A SIMILAR CONCERN IN THE ELECTRIC LG&E CASE AT HAND?

A. No. As can be seen from the above table, LG&E's effective Kentucky state income tax rate has ranged from 7.41% to 7.87% with an average rate of 7.68% during the most recent 4 years. Thus, there is hardly any fluctuation in this effective tax rate from year to year. I believe that this should remove any concern in this case that LG&E's most recent 2002 effective state income tax rate of 7.87%, for example, would not be representative of the effective state income tax rate that can be expected to be in effect during the rate effective period of this rate case.

Q. WHAT IS YOUR RECOMMENDATION BASED ON THE FOREGOING FINDINGS AND CONCLUSIONS?

A. Since I see no reason why the trial use of the effective state income tax rate established by

[8] See ULH&P Case No. 2001-00092, final Order dated January 31, 2002 at 59.

the Commission in the 2001 ULH&P rate case should not be extended to LG&E, I recommend that LG&E's proposed state income tax rate of 8.25% be replaced with the effective state income tax rate of 7.87% from the Company's most recent 2002 consolidated Kentucky corporation income tax return.

Q. WHAT INCOME TAX ADJUSTMENTS ARE REQUIRED IN ORDER TO RE-STATE THE COMPANY'S TEST YEAR STATE INCOME TAX RATE FROM 8.25% TO 7.87%?

A. First, the unadjusted test year gas income taxes of $7.592 million[9] - which form the starting point of the Company's proposed pro forma adjusted test year gas income taxes - must be restated to reflect the reduction of the 8.25% state income tax rate to 7.87%.

Second, the income tax impact of all of the Company's proposed pro forma operating income adjustments[10] must be restated to reflect a state income tax rate of 7.87% rather than 8.25%.

Third, all of the AG-recommended adjustments to the Company's proposed pro forma test year gas after-tax operating income that are summarized on schedule RJH-4 must reflect the effective state income tax rate of 7.87%

Finally, the state income tax rate in the development of the Revenue Conversion Factor

[9] See line 13 of filing requirement Tab 42.
[10] This is the total income tax adjustment amount of $3.3 million shown on line 13 of filing requirement Tab 42, making up the income tax adjustments on Rives Exhibit 1, Schedules 1.36, 1.37 and 1.38.

must be restated at 7.87%.

Q. ARE ALL OF THE AFOREMENTIONED STATE INCOME TAX ADJUSTMENTS REFLECTED IN THIS TESTIMONY?

A. No. The AG's recommended Revenue Conversion Factor on schedule RJH-1 has been properly determined based on an effective state income tax rate of 7.87%. Similarly, all of the AG's recommended adjustments to the Company's proposed pro forma test year gas after-tax operating income summarized on schedule RJH-4 have been appropriately calculated using a state income tax rate of 7.87%. However, the restatement of all state income taxes from 8.25% to 7.87% in the determination of the Company's proposed pro forma adjusted test year gas after-tax operating income of $11.250[11] million has not currently been reflected for the simple reason that the AG did not have the necessary per books income tax data available to make this computation. Since the Company has all of this tax information available, I recommend that the Company make these state income tax restatement calculations and present them to the Commission and the AG. Once this information has been received and reviewed by the AG, the recommended pro forma test year gas after-tax operating income number on schedule RJH-4, line 14 should be updated to reflect this information.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS ISSUE?

A. Yes. In data request PSC-2-15 (c) (3), the Commission suggests that if an effective

[11] The $11.250 million is shown on line 14 of filing requirement Tab 42 and includes LG&E's proposed pro forma adjusted test year income taxes of $4.292 million. This latter pro forma income tax amount must be restated based on the use of a 7.87% state income tax rate rather than the 8.25% rate.

Kentucky state income tax were to be used for ratemaking purposes in this case, this rate should only be used in the determination of the Revenue Conversion Factor and in the calculation of the income tax impact of all pro forma operating income adjustments. I do not agree with the suggestion that the use of the effective state income tax be limited only to the determination of the pro forma test year operating income adjustments. The only appropriate approach would be to apply the effective state income tax rate *both* in the determination of the pro forma test year operating income adjustments, *and* in the determination of the unadjusted test year operating income that was used as the starting point of the proposed overall pro forma test year operating income in this case. The approach suggested in PSC-2-15 (c) (3) would produce the wrong end result. In fact, it would result in a gas revenue requirement *increase*, which makes no sense in light of the fact that we are dealing with a state income tax rate *decrease* from 8.25% to 7.87%. The gas revenue requirement increase would result from the fact that the total of the Company's proposed test year gas operating income adjustments amounts to a taxable income reduction of approximately $8.774 million.[12] Applying a state income tax rate of 7.87% to this taxable income reduction would produce a lower state income tax savings than applying a state income tax rate of 8.25%. This, in turn, would increase the gas revenue requirement in this case.

- **<u>Interest Synchronization</u>**

Q. DOES THE KPSC HAVE A RATEMAKING POLICY REGARDING INTEREST

[12] See Rives Exhibit 1, page 3, line 39.

SYNCHRONIZATION?

A. Yes. The KPSC has a well-established ratemaking policy that the interest expenses to be used as a deduction from pro forma test year taxable income be determined by the application of the weighted cost of debt to the adjusted capitalization allowed by the Commission for ratemaking purposes. This so-called pro forma "synchronized" interest expense level should then replace the per books test year interest expense level that was used as a tax deduction in the determination of the test year income taxes. Mr. Rives also acknowledges this Commission ratemaking policy on page 17 of his testimony where he states that, "The Commission has traditionally recognized the income tax effects of adjustments to interest expense through an interest synchronization adjustment."

Q. IS THERE AN ISSUE IN THE MANNER IN WHICH LG&E AND THE AG HAVE CALCULATED THEIR RESPECTIVE PRO FORMA SYNCHRONIZED INTEREST EXPENSE LEVELS?

A. No. As shown on schedule RJH-5, both LG&E and the AG have properly calculated their respective pro forma synchronized interest expense amounts by multiplying their recommended weighted cost of debt percentages included in their overall rate of return numbers times their recommended adjusted gas capitalization levels.

Q. IS THERE AN ISSUE IN THE DATA USED BY LG&E TO CALCULATE ITS PROPOSED PRO FORMA INTEREST SYNCHRONIZATION ADJUSTMENT?

A. Yes. The pro forma synchronized interest expense should replace the test year interest expense that has actually been used as a taxable income deduction in the determination of the Company's per books test year income taxes. The difference between these two interest expense levels represents the interest synchronization adjustment. As shown on line 4 of schedule RJH-5, for purposes of the interest synchronization adjustment, LG&E has assumed that the test year per books interest expenses amount to $4.713 million. However, in the responses to AG-1-25 (c) and AG-2-42, LG&E has confirmed that the total interest expense used as a taxable income deduction in the determination of the test year per books gas operating income taxes of $7.592 million[13] amounts to $2.542 million. Thus, since LG&E has used the test year per books gas operating income taxes of $7.592 million as the starting point for the total pro forma adjusted income taxes in this case, the test year per books interest expense of $2.542 million that was used as a tax deduction in the determination of the per books test year income taxes of $7.592 million must be compared to the pro forma synchronized interest expense level in the determination of the appropriate interest synchronization adjustment. The AG has done so, as shown in the last column of schedule RJH-5.

Q. WHAT IS THE IMPACT ON THE COMPANY'S PROPOSED TEST YEAR AFTER-TAX OPERATING INCOME OF A PROPERLY CALCULATED INTEREST SYNCHRONIZATION ADJUSTMENT SUCH AS HAS BEEN DONE BY THE AG?

A. As shown on schedule RJH-5, the difference between the properly calculated AG-recommended interest synchronization adjustment and LG&E's proposed interest synchronization adjustment increases the Company's pro forma gas test year after-tax

[13] See Volume 3 – Tab 42, line 13.

operating income by $873,000.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THIS INTEREST ISSUE?

A. Yes. In it response to AG-2-42, LG&E states that while the correct test year per books gas interest expenses amount to $4.713 million (the amount used in the Company's proposed interest synchronization adjustment calculations), it inadvertently used a per books gas interest expense amount of $2.542 million as taxable income deduction in the determination of the unadjusted test year gas income taxes of $7.592 million that is being used as the starting point for the total pro forma gas income taxes in this case. While the $2.542 million interest expense may have been an incorrect interest expense number, it should still be used as the test year per books interest number to be compared to the pro forma synchronized interest number in the interest synchronization adjustment. This is because the $2.542 million interest number was used in the calculation of the unadjusted test year electric income taxes of $7.592 million. If the "correct" interest amount of $4.713 million had been used as tax deductible interest in the determination of the per books test year electric income taxes, this per books income tax number would have been approximately $876,000[14] lower than the $7.592 million test year per books income tax number. Thus, if one wants to accept the Company's proposed interest synchronization approach, one would first have to reduce the test year per books electric income taxes by

[14] Difference between $4.713 million and 2.542 million = $2.171 million x combined income tax rate of 40.3625%, or $876,000.

$876,000.

- **Unbilled Revenue Adjustment**

Q. IS THERE AN ISSUE WITH REGARD TO THE COMPANY'S PROPOSAL TO REMOVE UNBILLED ELECTRIC REVENUES FROM THE TEST YEAR?

A. Yes. The issue is that the Company should also have removed certain gas operating expenses associated with the unbilled revenue adjustment in order to achieve a proper matching of the test year expenses and all billed revenues.

Q. PLEASE EXPLAIN WHY THIS IS SO.

A. Rives Exhibit 1, Schedule 1.00 shows that the Company has removed the unbilled gas revenues at the end of the test year, 9/30/3003, from the test year and has replaced these test year-end unbilled revenues with the unbilled gas revenues that were on the Company's books at the beginning of the test year, 9/30/2002. As shown in filing workpaper page 98 of the attachment to KIUC-1-78, the unbilled gas revenues of $6.326 million at the end of the test year represent revenues that are associated with 517,000 MCFs worth of gas services that were rendered *during* the test year ending 9/30/2003, but for which the Company's customers were not yet billed as of 9/30/2003. Conversely, the unbilled gas revenues of $3.546 million at the beginning of the test year represent revenues that are associated with 450,000 MCFs worth of gas services that were rendered *prior to* the test year ending 9/30/2003, but for which the Company's customers were not yet billed as of 9/30/2002. Thus, by virtue of its proposed unbilled revenue adjustment, the Company has removed from the test year net gas revenues of $2.780 million, representing 67,000 MCFs worth of gas services that were rendered during the test year. The problem is that the operating expenses associated with these 67,000 MCFs of test year gas services are still included in the test year because the Company has not proposed an adjustment to remove these expenses. Therefore, an adjustment is required to remove the operating expenses associated with the test year gas services that have been removed in the Company's unbilled revenue adjustment. Only that way is there a proper matching of the revenues and expenses associated with gas services rendered in the test year.

Q. WHAT METHOD DO YOU RECOMMEND BE USED TO ESTIMATE THE REMOVAL OF THE TEST YEAR OPERATING EXPENSES ASSOCIATED WITH THE COMPANY'S UNBILLED REVENUE ADJUSTMENT?

A. I recommend that the same method be used as has been used by LG&E and accepted by the Commission in the estimated quantification of test year expenses associated with the test-year end customer revenue annualization adjustment, i.e., through the application of an appropriate Operating Expense Ratio to the revenue adjustment amount at issue. As can be seen from Seelye Exhibit 9, this Operating Expense Ratio is approximately 30%. Thus, I recommend that the same Operating Expense Ratio of approximately 30% be applied to LG&E's proposed unbilled gas revenue adjustment in order to reflect the estimated test year operating expense reduction associated with the unbilled gas revenue adjustment.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PRO FORMA TEST YEAR GAS AFTER-TAX OPERATING

INCOME?

A. As shown on schedule RJH-6, my recommendation to remove the test year operating expenses associated with the Company's unbilled gas revenue adjustment increases the Company's proposed pro forma test year gas after-tax operating income by $497,000.

- **Customer Growth Revenue Annualization**

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED GAS CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT SHOWN ON SEELYE EXHIBIT 9.

A. The Company has proposed to reflect for ratemaking purposes the annualized impact on test year net[15] operating revenues of customer growth experienced during the test year. To accomplish this, the Company, first, has compared the actual numbers of customers at September 30, 2003 to the corresponding 12-month average test year number of customers. The so-determined test year customer growth was then multiplied to the test year average MCF consumption per customer and the test year average revenue per MCF in order to arrive at its proposed revenue annualization adjustment for customer growth during the test year. As shown on Seelye Exhibit 9, the Company's proposed adjustment results in a pro forma net gas revenue decrease of approximately $40,000.

Q. SHOULD THE COMPANY'S PROPOSED CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT FIRST BE CORRECTED TO REFLECT 13-

[15] Operating revenues net of associated operating expenses.

MONTH RATHER THAN 12-MONTH AVERAGE TEST YEAR CUSTOMER LEVELS?

A. Yes. In AG-2-44, I requested the Company to re-calculate its proposed gas revenue annualization adjustment by comparing the actual number of customers at the end of the test year to the 13-month average test year number of customers. The Company provided this information in its response to PSC-3-24. As can be gleaned from this response, this correction would change the Company's originally proposed net gas revenue decrease of $40,000 to a net revenue decrease of approximately $4,000.

Q. DO YOU BELIEVE THAT THE COMPANY'S PROPOSED CUSTOMER GROWTH REVENUE ANNUALIZATION CALCULATION METHODOLOGY IS APPROPRIATE?

A. No. While I am aware that the methodology used by LG&E has previously been accepted by the Commission, unfortunately this method has the potential of producing the wrong end result that does not accurately reflect the actual customer growth trend experienced by the Company.

Q. COULD YOU EXPLAIN THIS IN MORE DETAIL?

Yes. The problem lies in the fact that the Company's calculation method compares the test year average number of customers to a corresponding customer level the Company has on line at a single point in time. In this particular case, this single point in time is September 30, 2003 because that happens to be the end of the test year chosen by LG&E. If customer growth were to occur gradually and consistently over the course of the year, there wouldn't be a problem with the Company's employed calculation method. However, that is not the case. If we consider, for example, the Company's residential customers, the response to AG-1-324, page 4 of 6 shows the following actual monthly gas residential customer levels for the year 2003:

Jan	285,464
Feb	287,276
Mar	286,742
Apr	286,742
May	287,849
Jun	287,882
Jul	287,465
Aug	287,183
Sep	287,183
Oct	287,115
Nov	289,046
Dec	286,868

Thus, while the growth trend for the Company's residential gas customers is clearly upward during the year, for a variety of reasons (e.g., seasonality), the Company's residential gas customers experience significant upward and downward monthly fluctuations within the year. As can be seen from the above table, while the actual number of customers at the end of the test year, September 2003, amounted to 287,183, this customer level increased to 289,046 in November and then decreased to 286,868 in the next month, December 2003. The same type of upward and downward monthly customer fluctuations was experienced in the first 5 months of 2003. In AG-2-66 (b), the AG gave some specific illustrations as to why the Company's employed calculation method has the potential of producing the wrong end result that is not reflective of the actual customer growth trend experienced by the Company:

> 66 b. As shown on Seelye Exhibit 9, under the Company's proposed customer annualization adjustment method, it compared the 9/30/03 number of

customers to the average test year number of customers, resulting, for example, in a calculated residential customer increase of 593.

i. If the test year had been the 12-month period ended November 2003, the Company's customer annualization method would have produced residential customer increase of 1,930 (November 2003 number of customers of 289,046 compared to average number of customers during the 12-month period ended November 30, 2003 of 287,116). Please confirm this. If you do not agree, explain your disagreement.

ii. On the other hand, if the test year had been the 12-month period ended December 2003, the Company's customer annualization method would have produced a residential customer number decrease of 388 (December 2003 number of customers of 286,868 compared to average number of customers during the 12-month period ended December 31, 2003 of 287,252). Please confirm this. If you do not agree, explain your disagreement.

In its response to this data request, the Company confirmed all of the above referenced information.

With regard to the Company's commercial gas customers, the response to AG-1-324, page 4 of 6 shows the following average annual commercial customer levels for LG&E in the last 5 years:

	Average Commercial Customers
1999	21,274
2000	21,824
2001	22,175
2002	22,817
2003	23,459

The above table clearly indicates that there is a consistent and continuous growth trend for the average annual commercial gas customers of LG&E. In fact, the commercial customer growth numbers in the above table are equivalent to an average annual compound growth rate of 2.5% from 1999 through 2003. Yet, despite this consistent and continuous growth trend, the Company's customer growth calculation method on Seelye Exhibit 9 calculates a pro forma *decrease* in the average test year gas commercial customers because the commercial customer number on September 30, 2003 happened to be lower than the test year's average commercial customer number. Again, this illustrates that the Company's employed calculation method produces incorrect end results that are inconsistent with the true customer growth trend.

Q. IS THERE A BETTER METHOD TO CALCULATE THE COMPANY'S AVERAGE TEST YEAR CUSTOMER GROWTH THAT PRODUCES AN END RESULT THAT IS TRULY REFLECTIVE OF THE ACTUAL CUSTOMER GROWTH TREND RECENTLY EXPERIENCED BY THE COMPANY AND THAT AVOIDS THE POTENTIAL INACCURACIES CAUSED BY MONTH-TO-MONTH CUSTOMER FLUCTUATIONS?

A. Yes. This customer growth method was introduced by me in a prior Delta Natural Gas rate proceeding, Case No. 97-066, and was accepted by the Commission in setting the rates for Delta in that case. This customer growth method first calculates an appropriate average annual compound growth rate for each of the Company's customer classes during a recent historic period, including the test year. One half of this average annual compound growth rate would represent the appropriate customer growth rate within the test year. This is so because the comparison of the test year-end level of customers to the average test year number of customers is supposed to represent, on average, a half-year's worth of customer growth. This half-year growth rate should then be applied to the average test year number of customers for the particular customer class in order to arrive at the appropriate test year-end customer growth adjustment number.

Q. COULD YOU GIVE AN EXAMPLE OF THIS RECOMMENDED CALCULATION METHOD FOR THE COMPANY'S TEST YEAR RESIDENTIAL GAS CUSTOMERS?

A. Yes. The response to AG-1-324, page 4 shows that the Company's actual average number of residential gas customers for the years 1999 through 2003 were as follows:

1999	270,471
2000	274,541
2001	279,520
2002	283,980
2003	287,256

This available data indicates that the Company's most recent historic average annual compound growth rate is 1.52%. Taking one-half of this average annual compound growth rate indicates an average half-year customer growth rate of 0.76%. Applying this half-year average customer growth rate to the 13-month average test year gas residential customers of 286,424 shown in column (1) of PSC-3-24 produces a test year-end customer growth adjustment of 2,177 residential gas customers as compared to the 759 gas residential customer growth number produced by LG&E's test year-end customer growth calculation method shown in the response to PSC-3-24. As shown on the first line of schedule RJH-7, page 2, this produces a recommended revenue adjustment amount of $419,231, or significantly higher than the corresponding residential customer growth revenue adjustment of $146,234 shown on PSC-3-28, page 1.

Q. HAVE YOU MADE SIMILAR CUSTOMER GROWTH CALCULATIONS BASED ON THIS RECOMMENDED CALCULATION METHODOLOGY FOR THE

OTHER CUSTOMER CLASSES SHOWN ON SEELYE EXHIBIT 9 AND PSC-3-24?

A. While it certainly was my intent to do so, the Company could not provide me with the necessary information. Both in AG-1-30 and again in follow-up request AG-2-45, I requested monthly customer numbers from 1999 through to date for the same customer classes shown on Seelye Exhibit 9. However, the Company did not provide this information for the reason that "the information is not available in the format requested." The only customer class for which all of the required calculation data for my recommended methodology is available is the residential customer class.

Q. HAVE YOU PREPARED A GAS CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT THAT REFLECTS YOUR RECOMMENDED CALCULATION METHODOLOGY FOR THE GAS RESIDENTIAL CUSTOMERS?

A. Yes. This customer growth revenue annualization adjustment is shown on schedule RJH-7, page 2. As I discussed before, the first line on this schedule shows that the residential customer growth revenue annualization adjustment produces a revenue increase adjustment of $419,231. Since I could not use the same recommended customer growth calculation method for all of the other gas customer classes, I have simply adopted the revenue adjustments for these customer classes that were calculated through LG&E's proposed method. I have also offset the recommended revenue annualization adjustment amount with associated operating expenses by applying LG&E's proposed Operating Expense Ratio of 0.2987 to the revenue adjustment amount.

In summary, the recommended gas customer growth revenue annualization adjustment produces a net test year gas operating revenue increase adjustment of $187,236.

Q. HOW DOES THE USE OF YOUR RECOMMENDED CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT IMPACT THE COMPANY'S PROPOSED TEST YEAR AFTER-TAX OPERATING INCOME FOR ITS GAS OPERATIONS?

A. As shown on schedule RJH-7, page 1, the use of my recommended customer growth revenue annualization adjustment increases the Company's proposed after-tax gas operating income by $136,000.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING THIS ISSUE?

A. Yes. I recommend that the Commission order the Company to follow the recommended customer growth revenue annualization calculation approach for all gas customer classes in its next base rate case.

- **<u>Annualized Depreciation Expense</u>**

Q. PLEASE EXPLAIN THE REASON FOR THE RECOMMENDED ANNUALIZED DEPRECIATION EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-8.

A. The annualized depreciation expense adjustment shown on Schedule RJH-8 is a direct result of the difference between the new depreciation rates proposed in this case by LG&E and those recommended by Michael Majoros, the AG's depreciation expert. The depreciation rates recommended by Mr. Majoros, as applied to the depreciable plant in service balances at the end of the test year, produce $5.775 million lower annualized depreciation expenses than proposed by LG&E in this case. This has the result of increasing the Company's proposed pro forma test year after-tax gas operating income by $3.458 million.

- **Promotional Expenses**

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENTS FOR PROMOTIONAL EXPENSES SHOWN ON SCHEDULE RJH-9.

A. With regard to the treatment of promotional expenses for rate making purposes, 807 KAR 5:016, Section 4, states:

> Advertising Disallowed. (1) Advertising expenditures for political, promotional, and institutional advertising by electric or gas utilities shall not be considered as producing a material benefit to the ratepayers and, as such, those expenditures are expressly disallowed for rate-making purposes.

In accordance with this regulation, the Company removed from rate consideration in this case all of the advertising expenses in accounts 913002 and 930101 because these expenses were deemed to be of a promotional and/or institutional nature.[16] However, the Company did not similarly remove from its filing a number of additional expenses for which the clear purpose is the promotion of the sales of gas. I recommend that these additional

[16] See Rives Exhibit 1, Schedule 1.15.

promotional expenses also be removed for rate making purposes in this case.

Q. COULD YOU DESCRIBE EACH OF THESE PROMOTIONAL EXPENSE ITEMS WHICH YOU RECOMMEND BE DISALLOWED IN THIS CASE?

A. Yes. First, the test year gas expenses of $9,272 included in account 909001 – Public Information expenses should be disallowed. It is my understanding that the expenses included in this account are for advertising of a promotional nature, as well as for contributions and community relations activities. It should also be noted that the Commission disallowed similar account 909001 Public Information expenses in the Company's prior gas base rate case in Case No. 2000-080.

Second, the gas account 909002 test year expenses include $1,274 worth of expenses of a promotional nature that should have been removed for ratemaking purposes in this case. This was confirmed by the Company in its response to AG-1-229.

Third, the test year expenses include $26,399[17] for gas expenses in accounts 912001 and 912005 which the Company has classified as Economic Development Research and Marketing Management expenses. In response to AG 1-48 (a), the Company clearly states that,

> Accounts 912001 and 912005 include the cost of labor, materials, and other expenses incurred in <u>promotional</u>, demonstration, and selling activities, except by merchandising, the object of which is to <u>promote or retain the use of utility services by present and prospective customers</u>." (Emphasis supplied).

[17] $5,382 for expenses in account 912001 and $21,017 for expenses in account 912005.

I have removed these expenses for rate making purposes in this case because they do not produce a "material benefit" for the ratepayers and are mostly related to activities promoting the sales of gas utility services. It should be noted that the Commission disallowed similar account 912001 expenses in the Company's prior gas base rate case in Case No. 2000-080 and also stated on page 36 of its Order in that case that "the FERC definition of Account 912001 matches the Administrative Regulation definition of advertising that is to be excluded from ratemaking."

Q. WHAT IS THE IMPACT OF YOUR PROMOTIONAL EXPENSE RECOMMENDATIONS ON THE COMPANY'S PROPOSED TEST YEAR GAS AFTER-TAX OPERATING INCOME ?

A. As shown on schedule RJH-9, the recommended disallowances for the additional promotional expenses increase the Company's proposed test year gas after-tax operating income by approximately $22,000.

- Rate Case Expense

Q. PLEASE SUMMARIZE LG&E'S PROPOSED RATE CASE EXPENSES FOR ITS CONSOLIDATED ELECTRIC AND GAS RATE CASES.

A. As shown on Rives Exhibit 1, Schedule 1.16, the Company has proposed total estimated electric rate case expenses of approximately $1 million and estimated gas rate case expenses of approximately $651,000. In its response to AG-1-47, the Company has updated these original rate case expense estimates and is now projecting total electric rate case expenses of \$1.170 million and total gas rate case expenses of approximately \$821,000. Thus, the Company now estimates that these two consolidated electric and gas rate cases will have associated rate case expenses of almost \$2 million.

Q. DO YOU BELIEVE THAT THE COMPANY'S RATE CASE EXPENSES FOR THE CURRENT ELECTRIC AND GAS CASES ARE REASONABLE AND ACCURATE?

A. No. I believe that these estimated rate case expenses are too high particularly in light of the fact that, due to the consolidated nature of these two cases, many of the rate case activities can be shared between the two cases. For example, the response to AG-1-47 indicates that the Company has estimated that for both the electric and gas rate case it will incur almost \$170,000 for "newspaper, media, etc.," i.e., a total of almost \$340,000 for such miscellaneous rate case expenses. Given that most newspaper and other media communications can be shared for these two consolidated rate cases, these separate \$170,000 cost estimates for both the electric and gas case seem unreasonably high.

The Company's rate case expense estimates for the current electric and gas rate cases also seem unreasonably high when compared to the rate case expenses in the Company's last gas rate case, Case No. 2000-080, which was concluded in late 2000. In that case, LG&E had proposed estimated total gas rate case expenses of \$420,000. The actual rate case expenses turned out to be approximately \$296,000, which amount was allowed for ratemaking purposes by the Commission. Thus, while the actual rate case expenses for LG&E's last fully litigated gas case, completed less than 3 ½ years ago, amounted to less than $300,000, the Company is now estimating gas rate case expenses of $651,000 (currently updated to $821,000) in a consolidated case where it can share many of the rate case activities with the electric rate case budget.

Q. WHAT ARE YOUR CONCLUSIONS BASED ON THE AFOREMENTIONED INFORMATION?

A. I conclude that the Company's rate case expense estimates for the current electric and gas cases are unreasonably high and potentially quite inaccurate, and that, therefore, the Commission should not rely on the rate case expense estimates that have been presented by LG&E in its electric and gas rate cases.

Q. WHAT LEVEL OF RATE CASE EXPENSES ARE YOU RECOMMENDING FOR RATE RECOGNITION IN BOTH THE CURRENT ELECTRIC AND GAS RATE CASES?

A. Following Commission ratemaking policy, I recommend that rate recognition be given to all actual rate case expenses prudently incurred by LG&E to process its electric and gas rate cases. At the time this testimony is being prepared, the actual expenses incurred to date for the gas rate case amount to approximately $207,000.[18] Based on a 3-year amortization period, this would result in an annual rate case expense rate allowance of $69,000. This recommended rate case expense allowance should be updated to include additional prudently incurred gas rate case expenses that may be provided by LG&E during the course of this proceeding.

[18] Per the response to PSC-2-57 – Updated 2/27/2004.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PRO FORMA TEST YEAR GAS AFTER-TAX OPERATING INCOME?

A. As shown on schedule RJH-10, my electric rate case expense recommendation increases the Company's proposed pro forma test year gas after-tax operating income by $89,000.

- **Injury and Damage Expense Normalization**

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED INJURY AND DAMAGE ("I&D") EXPENSE NORMALIZATION ADJUSTMENT.

A. As shown on Rives Exhibit 1, Schedule 1.19, the Company has proposed to adjust the test year I&D expenses by replacing them with a normalized I&D expense level. The proposed normalized I&D expense level represents the 5-year average of the CPI-adjusted I&D expenses incurred by LG&E during the 5-year period 1998 through 2002.

Q. DO YOU AGREE WITH THIS PROPOSED EXPENSE NORMALIZATION ADJUSTMENT?

A. With one exception, I find the Company's proposal to be reasonable. The one exception is that the 5-year CPI-adjusted average should shift forward by approximately one year, i.e., it should start with 1999 and end with the test year. In this way, the normalized average expense is based on the most recent actual data through the end of the test year.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PRO FORMA TEST YEAR GAS AFTER-TAX OPERATING INCOME?

A. As shown on schedule RJH-11, my normalized I&D expense recommendation increases the Company's proposed pro forma test year gas after-tax operating income by $52,000.

- IT Staff Reduction Cost Savings

Q. HAS THE COMPANY PROPOSED AN ADJUSTMENT IN THIS CASE TO REFLECT COST SAVINGS RESULTING FROM STAFF REDUCTIONS IN ITS INFORMATION TECHNOLOGY ("IT") DEPARTMENT?

A. Yes, as described on pages 12-13 of Ms. Scott's testimony, the Company has reduced its test year operating expenses to reflect the October 2003 reduction of 27 staff people in its IT department. The Company has partially offset this cost savings adjustment by the 3-year amortization of the associated Cost to Achieve the savings.

Q. IS THERE AN ISSUE ASSOCIATED WITH THIS LG&E-PROPOSED NET COST SAVINGS ADJUSTMENT?

A. Yes. As shown on Rives Exhibit 1, Schedule 1.26, the Company has only reflected the payroll, payroll tax and 401(k) cost savings associated with the IT staff reduction. It has not reflected additional cost savings such as the Team Incentive Awards ("TIA") and other employee benefits (pension; FAS-106; medical, dental and life insurance; long term disability) that the Company no longer has to pay for the IT staff reduction. In the responses to AG-1-62 (c) and AG-2-57, the Company has confirmed that it will experience additional total cost savings of $306,990 for the above-referenced TIA awards and other employee benefits. The portion of these additional cost savings allocable to LG&E's gas operations is 21%.

Q. HOW DOES THE RECOGNITION OF SUCH ADDITIONAL COST SAVINGS IMPACT THE COMPANY'S PROPOSED TEST YEAR AFTER-TAX OPERATING INCOME FOR ITS GAS OPERATIONS?

A. As shown on schedule RJH-12, the recognition of such additional IT staff reduction related cost savings increases LG&E's proposed test year gas after-tax operating income by $38,000.

- **Operating Ratio Adjustments**

Q. IS THERE AN ISSUE WITH REGARD TO THE COMPANY'S PROPOSED TEMPERATURE NORMALIZATION ADJUSTMENT SHOWN ON SEELYE EXHIBIT 8 AND CUSTOMER LOSS ADJUSTMENT SHOWN ON SEELYE EXHIBIT 10?

A. Yes. The issue is that the Company should also have removed certain gas operating expenses associated with these two revenue adjustments in order to achieve a proper matching of the test year revenues and expenses.

Q. PLEASE EXPLAIN WHY THIS IS SO.

A. Seelye Exhibit 8 shows that, as a result of its proposed temperature normalization adjustment, the Company has removed 1,201,571 MCFs worth of gas services that were actually rendered during the test year. Seelye Exhibit 19 shows that the Company has also removed 46,447 MCFs worth of gas services from the test year to reflect the loss of a customer at the end of the test year due to a plant closing. While the Company has removed the test year revenues associated with these two gas service adjustments, it has not removed the operating expenses associated with these gas service reductions. In order to achieve a proper matching of the revenues and expenses associated with gas services reflected in the pro forma test year results, such an operating expense adjustment should be made.

Q. WHAT METHOD DO YOU RECOMMEND BE USED TO ESTIMATE THE REMOVAL OF THE TEST YEAR OPERATING EXPENSES ASSOCIATED WITH THESE TWO PROPOSED GAS SERVICE REDUCTION ADJUSTMENTS?

A. I recommend that the same method be used as has been used by LG&E and accepted by the Commission in the estimated quantification of test year expenses associated with the test-year end customer revenue annualization adjustment, i.e., through the application of an appropriate Operating Expense Ratio to the revenue adjustment amount at issue. As can be seen from Seelye Exhibit 9, the Company's proposed test year-end customer revenue annualization adjustment in this case results in a decrease in test year gas services of 167,722 MCFs with an associated revenue decrease impact of approximately $40,000. The Company then applied an Operating Expense Ratio of approximately 30% to this revenue decrease in order to estimate the associated test year operating expense decrease. Thus, I recommend that the same Operating Expense Ratio of approximately 30% be applied to LG&E's proposed temperature normalization and customer loss revenue reduction adjustments in order to reflect the estimated test year operating expense reductions associated with these two adjustments.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PRO FORMA TEST YEAR GAS AFTER-TAX OPERATING INCOME?

A. As shown on schedule RJH-13, the previously discussed recommendation increases the Company's proposed pro forma test year gas after-tax operating income by approximately $9,000.

- **Purification Expenses and Storage Field Losses**

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED PURIFICATION EXPENSE AND STORAGE FIELD LOSSES ADJUSTMENTS SHOWN ON RIVES EXHIBIT 1, SCHEDULE 1.34.

A. In short, the Company is proposing to "reprice" the actual average test year cost per MCF for its purification expenses and storage field losses based on the actual Gas Stored Underground cost per MCF at the end of the test year, September 30, 2003. As shown on schedule RJH-14, lines 1-6, the actual average test year cost per MCF for the Company's purification MCF volume in the test year is $3.80. The Company is proposing to reprice its test year purification volume based on the actual Gas Stored Underground cost per MCF at

9/30/03 of $5.38. As shown on line 7 of schedule RJH-14, this proposed repricing results in a pro forma test year purification expense increase of approximately $163,000. Similarly, schedule RJH-14, lines 8-13 show that the actual average test year cost per MCF for the Company's storage field losses in the test year is $4.36. The Company is also proposing to reprice these test year storage field loss volumes based on the actual Gas Stored Underground cost per MCF at 9/30/03 of $5.38. Line 14 of schedule RJH-14 shows that this proposed reprice results in a pro forma test year storage field loss expense increase of approximately $264,000.

Q. DO YOU AGREE WITH THESE LG&E-PROPOSED ADJUSTMENTS?

A. No. The Company's proposal assumes that the actual Gas Stored Underground unit cost of $5.38 at the end of the test year will be representative of the average monthly purification and storage field loss unit costs that will actually be experienced during the rate effective period of this gas base rate case. I believe this is an improper assumption. Future gas purification and storage field loss unit costs are not known and measurable now, nor will they be at the time that the Commission decides this case. In this regard, the response to AG-1-34 shows that while the Company's actual gas stored underground unit cost was $5.35 per MCF in the first 5 months of 2001, those monthly unit cost then gradually decreased to $3.78 in August 2002 after which date there has been a gradual increase in these unit costs. Thus, these gas unit costs have historically experienced upward and downward trends and it would therefore be incorrect to assume that the actual unit gas cost at a single point in time in the test year would be representative of the unit gas costs to be experienced by the Company during the rate effective period of this case. It should also be noted that the Company's proposal to reprice its test year purification volume and storage field losses with the actual test year-end Gas Stored Underground unit cost per MCF is internally inconsistent with the fact that the Company has not proposed to similarly reprice its average test year Gas Stored Underground volume based on the actual unit cost at September 30, 2003. Rather, the Company's proposed Gas Stored Underground balance claimed in its gas rate base has been priced out based on the actual average test year Gas Stored Underground unit cost per MCF. I have accepted that proposed Gas Stored Underground balance for ratemaking purposes in this case and, similarly, recommend that the Company's test year purification volume and storage field losses be priced out based on the average gas unit costs applicable to gas purification and gas storage field losses that were actually experienced during the test year. In other words, this recommendation requires that the Commission reject the Company's proposals regarding the repricing of its test year purification expense and storage field losses.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PRO FORMA TEST YEAR GAS AFTER-TAX OPERATING INCOME?

A. As shown on schedule RJH-14, the previously discussed recommendation increases the Company's proposed pro forma test year gas after-tax operating income by approximately $256,000.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS ISSUE?

A. Yes. In its response to PSC-3-25 (a), the Company leaves the impression that its purification expense and storage field loss proposals in the current case are "consistent with the adjustment proposed by LG&E and approved by the Commission in Case No. 2000-080." If this is indeed the Company's claim, I need to point out that this is not correct. The previously referenced "adjustment proposed by LG&E and approved by the Commission in Case No. 2000-080," was discussed on pages 9-10 of Mr. Williams' testimony in Case No. 2000-080. There he said:

> Storage losses represent the natural gas loss from the Company owned underground storage fields. During the test period the Company calculated and recorded storage losses for two of its storage fields, Doe Run and Magnolia. The Company, in performing its inventory analysis, believed there were also gas losses at its Muldraugh storage field and retained a consultant to perform an analysis. The consultant verified that there were losses and calculated the loss for the test period. This known and measurable adjustment calculates the dollar amount of gas loss from Muldraugh that was not recorded in the test year. This was done by taking the gas Mcf times the <u>average storage price for the test year</u>. The losses at this storage field will be an ongoing expense. [emphasis supplied]

Williams Exhibit 1, Schedule H in Case No. 2000-080 shows that the above referenced storage field loss proposal resulted in a pro forma test year expense increase of approximately $304,000. Thus, the Company's proposal in Case No. 2000-080 was to recognize pro forma additional storage loss volumes for the test year, and did not at all involve a reprice of its test year storage field losses with a unit cost other than the actual average test year storage loss unit cost. Furthermore, in the Company's Case No. 2000-080 storage field loss proposal, the Company quantified the pro forma storage field loss cost by applying the actual average storage price for the test year to the pro forma storage field loss MCF volume. By contrast, in the current case, the test year already includes the proper level of storage field loss volume, but now the Company proposes to reprice this test year storage field loss volume at a unit price other than the actual average test year storage loss unit cost.

- **Miscellaneous Expense Adjustments**

Q. PLEASE DESCRIBE THE MISCELLANEOUS EXPENSE ADJUSTMENTS SHOWN ON SCHEDULE RJH-15.

A. First, I recommend the removal from test year gas operating expenses of $10,413 for expenses associated with employee gifts, award banquets, parties and other social events (e.g., company picnics). Based on my review of prior Commission Orders,[19] it is my understanding that the Commission has a ratemaking policy of removing the previously referenced expense types from rate consideration. I would agree that these types of expenses have nothing to do with the provision of safe and reliable electric service and, therefore, should not be charged to the ratepayers. In AG-1-77, the AG requested the Company to provide the test year expense amount for each of the previously referenced expense types. In response to this request, the Company stated that while the total test year gas expenses for employee gifts, award banquets, social events and parties, and other employee related social expenses amount to $20,825, it could not provide those expenses broken out by the specific expense types that were requested in AG-1-77. Since there is no further breakout of the total $20,825 expense amount, and in order to be conservative, I have assumed that 50% of the $20,825, or $10,413, is associated with employee gifts, award banquets, parties and other social events that should be removed for ratemaking

[19] Particularly KPSC Orders involving Kentucky-American Water Company, such as the KPSC's Orders in Case Nos. 97-034, 95-554, 90-321, 89-348 and 10481.

purposes in this case.

Second, I recommend the removal from test year gas operating expenses portions of the Company's American Gas Association (AGA) dues that are associated with legislative and regulatory advocacy, legislative and regulatory policy research, advertising, marketing and public relations. I do not believe that these expenses should be charged to the ratepayers as they produce no material benefit to the ratepayers. In PSC-3-48, the Company was requested to provide the total test year AGA expense level, as well as a breakdown of this test year AGA expense level by the categories that I just listed, in the same detail as shown for the Company's electric EEI expenses in the response to AG-1-85. While the Company, in its response to PSC-3-48, provided the total test year AGA expense level, it did not provide the requested breakdown on this total expense level. Absent this AGA expense breakdown, I have conservatively assumed that 25% of AGA's test year expenses are associated with the type of activities referenced earlier. The total AGA dues included in LG&E's test year gas operating expenses amount to $103,752. Applying the 25% disallowance rate to these test year AGA dues results in the recommended AGA expense disallowance of approximately $26,000. If the Company is able to provide the AGA expense breakdown requested in PSC-3-48, the currently recommended AGA expense disallowance could be updated based on this information.

Q. WHAT IS THE IMPACT OF YOUR MISCELLANEOUS EXPENSE ADJUSTMENT RECOMMENDATIONS ON THE COMPANY'S PROPOSED TEST YEAR GAS AFTER-TAX OPERATING INCOME ?

A. As shown on schedule RJH-15, the recommended miscellaneous expense adjustments increase the Company's proposed test year gas after-tax operating income by approximately $22,000.

- **Other Expense Issues**

Q. IN THE PARALLEL KENTUCKY UTILITIES ("KU") RATE CASE, AG WITNESS MAJOROS HAS IDENTIFIED CERTAIN ISSUES THAT HAVE NOT BEEN ADDRESSED BY YOU IN THIS LG&E RATE CASE. WHAT IS YOUR RECOMMENDED POSITION ON THIS?

A. Consistency would dictate that the two companies be treated for ratemaking purposes in like fashion and I would encourage the Commission to do so. For example, for reasons discussed in his testimony, Mr. Majoros has recommended that the Commission only recognize for ratemaking purposes the actual test year pension and Other Post-Employment Benefit expenses booked by KU, consistent with the Commission's finding in LG&E's prior gas rate case, Case No. 2000-080. The value of this recommendation in the current LG&E gas rate case is a reduction in LG&E's proposed pro forma test year gas operating expenses of approximately $725,000 (see Rives Exhibit 1, Schedule 1.13).

D. REVENUE CONVERSION FACTOR

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AS COMPARED TO YOUR RECOMMENDED REVENUE CONVERSION FACTOR TO BE USED FOR

RATEMAKING PURPOSES IN THIS CASE.

A. As shown on schedule RJH-1, line 6, the Company's proposed Revenue Conversion Factor is approximately 0.5924 whereas the AG's recommended Revenue Conversion Factor is approximately 0.5948. As can be seen from the Revenue Conversion Factor calculations in footnote (4) of schedule RJH-1, the only reason why these two factors are different is that LG&E's proposed factor incorporates a Kentucky state income tax rate of 8.25%, while the AG's recommended factor incorporates a Kentucky state income tax rate of 7.87%. The reasons for this have been discussed previously in this testimony.

Q. **MR. HENKES, DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes, it does.

In Re the Matter of:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	**)))**	**CASE NO: 2003-00433**

AFFIDAVIT

Comes the affiant, Robert J. Henkes, and being duly sworn states that the foregoing testimony and attached schedules were prepared by him are, to the best of his information and belief, true and correct.

State/Commonwealth of Connecticut
County of Fairfield

Subscribed and sworn to before me by the Affiant Robert J. Henkes this the 16th day of March, 2004.

Notary Public, State at Large

OFFICIAL SEAL
Notary Public, Connecticut
Fairfield County
BRIAN R. FALKOWSKI
My Commission Expires Jan. 31, 2007

LOUSIVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
SUMMARY OF REVENUE REQUIREMENT POSITIONS
($000)

	LG&E Gas (1)		Adjustments	AG	
1. Capital Structure	$ 312,143		$ (4,800)	$ 307,343	Sch. RJH-2
2. Rate of Return	7.23%			6.62%	Sch. RJH-2
3. Income Requirement	22,568			20,360	
4. Pro Forma Income	11,250		5,452	16,702	Sch. RJH-4
5. Income Deficiency	11,318			3,659	
6. Revenue Conversion Factor	0.59236556			0.59481897	(4)
7. Overall Revenue Deficiency	$ 19,106		$ (12,956)	$ 6,151	
8. Increase in Misc. Charges	$ 124	(2)	$ (69)	55	(5)
9. Increase in Revenues	18,981	(3)	(12,885)	6,096	
10. Total Rate Increase	$ 19,106		$ (12,956)	$ 6,151	

(1) Rives Exhibits 1, 2 and 7
(2) Response to AG-1-4
(3) Tab 23 and response to AG-1-4

(4)

	LG&E	AG	
Revenues	100.000000	100.000000	
Less: Bad Debt and PSC Fees	(0.672300)	(0.672300)	
	99.327700	99.327700	
Less: State Income Tax @ 8.25%	(8.194535)	(7.817090)	State Income Tax @ 7.87%
	91.133165	91.510610	
Less: Federal Income Tax @ 35%	(31.896609)	(32.028714)	
Revenue Conversion Factor	59.236556	59.481897	

(5) Testimony of David Brown Kinloch

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
ADJUSTED CAPITALIZATION AT 9/30/03
($000)

LG&E PROPOSED:	Adjusted Gas Capitalization (1)	Capitalization Ratios	Cost Rates	Weighted Cost Rates
1. Short Term Debt	$ 11,998	3.84%	1.06%	0.04%
2. A/R Securitization	11,945	3.83%	1.39%	0.05%
3. Long Term Debt	127,400	40.81%	3.77%	1.54%
4. Preferred Stock	11,247	3.60%	2.51%	0.09%
5. Common Equity	149,553	47.92%	11.50%	5.51%
6. Total	$ 312,143	100.00%		7.23%

AG RECOMMENDED:	Adjusted Gas Capitalization	Capitalization Ratios	Cost Rates	Weighted Cost Rates
1. Short Term Debt	$ 11,998	3.90%	1.06%	0.04%
2. A/R Securitization	11,945	3.89%	1.39%	0.05%
3. Long Term Debt	127,400	41.45%	3.77%	1.56%
4. Preferred Stock	11,247	3.66%	2.51%	0.09%
5. Common Equity	144,753 (2)	47.10%	10.35% (3)	4.87%
6. Total	$ 307,343	100.00%		6.62%

(1) Rives Exhibit 2, page 1, column (6)

(2)

LG&E's proposed adjusted common equity balance:	$ 149,553	
Remove LG&E's proposed Minimum Pension Liability add-back:	(4,800)	Rives Exh. 2, page 2, col. (7)
AG-Recommended adjusted common equity balance:	$ 144,753	

(3) Testimony of Dr. Carl Weaver: midpoint of range of 10.10% - 10.60%

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
SUMMARY OF ORIGINAL COST RATE BASE POSITIONS
($000)

	LG&E Gas (1)	Adjustments		AG
1. Utility Plant at Original Cost	$ 519,793			$ 519,793
2. Reserve for Depreciation	(183,373)	4,169	(2)	(179,204)
3. Net Utility Plant	336,420	4,169		340,589
Deduct:				
4. Customer Advances	(9,193)			(9,193)
5. Deferred Income Taxes	(53,931)			(53,931)
6. FAS 109 Deferred Inc. Tax	(2,078)			(2,078)
7. Investment Tax Credit	-			-
8. Total Deductions	(65,202)			(65,202)
Add:				
9. Materials and Supplies	105			105
10. Gas Stored Underground	38,757			38,757
11. Prepayments	325			325
12. Cash Working Capital	5,641	(191)	(3)	5,450
13. Total Additions	44,828	(191)		44,637
14. Total Net Original Rate Base	$ 316,046	$ 3,978		$ 320,024

15. Income Requirement	$ 20,360	Sch. RJH-1, L3
16. Return on Rate Base [L15 / L14]	6.36%	

(1) Rives Exhibit 3, page 1

(2) Annualized impact on depreciation reserve of AG's recommended depreciation expense adjustment - see sch. RJH-8, line 3

(3) DSM expenses removed from test year O&M expenses: $1,527,223 / 8 = $190,903

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
SUMMARY OF PRO FORMA OPERATING INCOME POSITIONS
($000)

	LG&E Gas	
1. LG&E's Proposed Pro Forma After-Tax Operating Income:	$ 11,250 *	Rives Exh. 1, p.3
AG-RECOMMENDED ADJUSTMENTS:		
2. Impact of Re-Stating KY Income Taxes Included in Line 1 From Rate of 8.25% to Effective Rate of 7.87%	To be Calculated by LG&E	
3. Interest Synchonization	873	Sch. RJH-5
4. Unbilled Revenue Adjustment	497	Sch. RJH-6
5. Customer Growth Revenue Annualization	136	Sch. RJH-7
6. Annualized Depreciation Expense	3,458	Sch. RJH-8
7. Additional Promotional Expenses	22	Sch. RJH-9
8. Rate Case Expense	89	Sch. RJH-10
9. I&D Expense Normalization	52	Sch. RJH-11
10. IT Staff Reduction Cost Savings	38	Sch. RJH-12
11. Operating Ratio Adjustments	9	Sch. RJH-13
12. Purification Exp. And Storage Field Losses	256	Sch. RJH-14
13. Miscellaneous Expense Adjustments	22	Sch. RJH-15
14. AG-Recommended Pro Forma After-Tax Operating Income:	$ 16,702	

* This after-tax operating income amount is calculated based on KY state income taxes of 8.25%. These KY income taxes must be re-stated at a rate of 7.87%

LOUSIVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
INTEREST SYNCHRONIZATION ADJUSTMENT
($000)

	LG&E Gas (1)	Adjustments	AG	
1. Adjusted Capitalization	$ 312,143		$ 307,343	Sch. RJH-2
2. Weighted Cost of Debt	1.63%		1.66%	Sch. RJH-2
3. Pro Forma Interest Expense	$ 5,088		$ 5,096	
4. Test Year Per Books Interest Deduction	4,713		2,542	(2)
5. Interest Synchronization Adjustment	375		2,554	
6. Composite Income Tax Rate	40.3625%		40.1155%	(3)
7. Impact on After-Tax Income	$ 151	$ 873	$ 1,025	

(1) Rives Exhibit 1, Schedule 1.37
(2) Responses to AG-1-25 and 2-42
(3) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%.

LOUSIVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
APPLICATION OF OPERATING RATIO TO UNBILLED REVENUE ADJUSTMENT
($000)

LG&E Gas Unbilled Revenue Adjustment:	$000s (1)		Associated MCFs (2)
1. Remove Unbilled Revenues at 9/30/03	$ (6,326)		(517,000)
2. Add Unbilled Revenues at 9/30/02	3,546		450,000
3. Net Impact on Test Year	$ (2,780)		(67,000)
4. Operating Ratio	0.2987	(3)	
5. Test Year Operating Expense Reduction Associated with Unbilled Revenue Adj.	$ (830)		
6. Composite After-Tax Income Factor	0.598845	(4)	
7. Impact on After-Tax Operating Income	$ 497		

(1) Rives Exhibit 1, Schedule 1.00
(2) Attachment to response to KIUC-1-78, p.98 of 441
(3) Seelye Exhibit 9
(4) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUSIVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT

	LG&E Gas (1)	Adjustments	AG	
1. Net Revenue Adjustment	$ (39,680)	226,916	187,236	Sch. RJH-7, p.2
2. Composite After-Tax Income Factor		0.598845 (2)		
3. Impact on After-Tax Operating Income		$ 135,888		

(1) Seelye Exhibit 9, page 1
(2) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
CUSTOMER GROWTH REVENUE ANNUALIZATION ADJUSTMENT

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Test Year 13-mos Avg Customers	Avg 1/2 Year Customer Growth Rate	Test Year Customer Growth Adj [1 x2]	Weather Normalized MCF	Avg MCF Per Customer [4 / 1]	Test Year MCF Growth Adj [3 x 5]	Avg Revenue per MCF	Recommended Revenue Adjustment [6 x 7]
Residential Rate RGS	286,424	0.76%	2,177	23,630,053	82.5	179,588	$ 2.3344	$ 419,231
Commercial Rate CGS		[calculated per LG&E's methodology as shown in response to PSC-3-24]						(81,375)
Industrial Rate IGS		[calculated per LG&E's methodology as shown in response to PSC-3-24]						17,258
Rate G-6		[calculated per LG&E's methodology as shown in response to PSC-3-24]						(3,603)
Rate FT		[calculated per LG&E's methodology as shown in response to PSC-3-24]						(84,527)
TOTAL								$ 266,984
				Less: Associated Operating Expenses @ 0.2987:				(79,748)
				Recommended Net Revenue Adjustment:				$ 187,236

* Source: AG-1-324, p.4:	Residential
1999	270,471
2000	274,541
2001	279,520
2002	283,980
2003	287,256
Avg Annual Compound Growth Rate	1.52%
Avg 1/2 Year Compound Growth Rate	0.76%

LOUSIVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
ANNUALIZED DEPRECIATION EXPENSE ADJUSTMENT
($000)

	LG&E Gas (1)	Adjustments	AG	
1. Annualized Depreciation Expense With New Rates	$ 18,275		$ 12,500	(2)
2. Test Year Per Books Depreciation Expense	16,669		16,669	
3. Depreciation Expense Increase	$ 1,606	$ (5,775)	$ (4,169)	
4. Composite After-Tax Income Factor		0.598845 (3)		
5. Impact on After-Tax Operating Income		$ 3,458		

(1) Rives Exhibit 1, Schedule 1.11
(2) Testimony of Michael Majoros
(3) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
ADDITIONAL PROMOTIONAL EXPENSE ADJUSTMENTS

Additional Promotional Expenses Not Removed by LG&E:		LG&E Gas	
1. Promotional Expenses in Account 909001	$	9,272	(1)
2. Promotional Expenses in Account 909002		1,274	(2)
3. Promotional Expenses in Account 912001		5,382	(3)
4. Promotional Expenses in Account 912005		21,017	(3)
5. Total Additional Promotional Expense Removal	$	36,945	
6. Composite After-Tax Income Factor		0.598845	(4)
7. Impact on After-Tax Operating Income	$	22,124	

(1) Response to AG-1-49 (b)
(2) Response to AG-1-229
(3) Response to AG-1-48
(4) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUSIVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
RATE CASE EXPENSE ADJUSTMENT
($000)

	LG&E Gas (1)	Adjustments	AG	
1. Total Estimated Rate Case Expense	$ 651		$ 207	(2)
2. Amortization Period (Yrs)	3		3	
3. Annual Amortization Expense	$ 217	$ (148)	$ 69	
4. Composite After-Tax Income Factor		0.598845 (3)		
5. Impact on After-Tax Operating Income		$ 89		

(1) Rives Exhibit 1, Schedule 1.16
(2) Response to PSC-2-57 - Updated 2/27/2004
(3) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUSIVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
INJURY AND DAMAGE EXPENSE NORMALIZATION ADJUSTMENT
($000)

	LG&E Gas (1)	Adjustments	AG	
1. Normalized I&D Expenses	$ 706		$ 619	(2)
2. Actual Test Year I&D Expenses	412		412	
3. Expense Adjustment	$ 294	$ (87)	$ 207	
4. Composite After-Tax Income Factor		0.598845 (3)		
5. Impact on After-Tax Operating Income		$ 52		

(1) Rives Exhibit 1, Schedule 1.19

(2) Per Rives Exhibit 1, Schedule 1.19:

	CPI-U Adjusted Electric I&D Expenses	
	LG&E	AG
1998	$ 845	$ -
1999	1,153	1,153
2000	831	831
2001	338	338
2002	360	360
Test Year	-	412
5-Year Average	$ 706	$ 619

(3) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
ADDITIONAL IT STAFF REDUCTION COST SAVINGS
($000)

Additional IT Staff Reduction Cost Savings Not Reflected by LG&E:	LG&E Gas	
1. Reduction in Pension, FAS-106, Medical, Dental, Life Insurance, Long Term Disability and TIA Expenses	$ 64	(1)
2. Composite After-Tax Income Factor	0.598845	(2)
3. Impact on After-Tax Operating Income	$ 38	

(1) Responses to AG-1-62 and AG-2-57: total expense reduction of $306,990 x 21% electric portion = $64,467.

(2) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
OPERATING RATIO EXPENSE SAVINGS
($000)

Operating Ratio Expense Savings Associated with Customer Loss and Temperature Normalization Adjustments That Were Not Reflected by LG&E:	LG&E Gas	
1. Revenue Reduction from Customer Loss due to Plant Closing	$ 34,719	(1)
2. Revenue Reduction from Temperature Normalization Adjustment	13,022	(2)
3. Total Revenue Reduction	47,741	
4. Operating Ratio	0.2987	(3)
5. Test Year Operating Expense Reduction Related to Customer Loss and Temperature Normalization Adjustment	14,260	
6. Composite After-Tax Income Factor	0.598845	(4)
7. Impact on After-Tax Operating Income	$ 8,540	

(1) Rives Exhibit 1, Schedule 1.28
(2) Rives Exhibit 1, Schedule 1.35 and Seelye Exhibit 8
(3) Seelye Exhibit 9
(4) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUSIVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
PURIFICATION EXPENSE AND STORAGE FIELD LOSSES ADJUSTMENTS

	LG&E Gas (1)	
1. Total Purification MCF Volume in Test Year	103,103	
2. Total Average Test Year Purification Cost/MCF	$ 3.80	
3. Total Actual Per Books Test Year Purification Expense	$ 391,419	
4. Total Purification MCF Volume in Test Year	103,103	
5. Actual Gas Stored Underground Unit Cost at 9/30/03	$ 5.38	
6. Pro Forma Test Year Purification Expense	$ 554,210	
7. Pro Forma Test Year Purification Expense Adjustment	$ 162,791	L6 - L3
8. Total Storage Field MCF Losses in Test Year	260,502	
9. Total Average Test Year Storage Field Losses Cost/MCF	$ 4.36	
10. Total Actual Per Books Test Year Purification Expense	$ 1,136,313	
11. Total Storage Field MCF Losses in Test Year	260,502	
12. Actual Gas Stored Underground Unit Cost at 9/30/03	$ 5.38	
13. Pro Forma Test Year Storage Field Losses Expense	$ 1,400,276	
14. Pro Forma Test Year Storage Field Losses Expense Adjustment	$ 263,963	L13 - L10
15. Total Pro Forma Test Year Expense Adjustments Proposed by LG&E	$ 426,754	L7 + L14
16. Composite After-Tax Income Factor	0.598845	(2)
17. Impact on After-Tax Operating Income of AG's Recommendation to Remove LG&E's Proposed Pro Forma Expense Adjustment	$ 255,559	

(1) Rives Exhibit 1, Schedule 1.34

(2) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
MISCELLANEOUS EXPENSE ADJUSTMENTS

Miscellaeous Test Year Expense Adjustments:	LG&E Gas	
1. Remove Expenses for Employee Gifts, Award Banquets, Parties and Social Events	10,413	(2)
2. Remove 25% of AGA Dues	25,938	(3)
3. Total Expense Reduction	$ 36,351	
4. Composite After-Tax Income Factor	0.598845	(4)
5. Impact on After-Tax Operating Income	$ 21,769	

(2) Per response to AG-1-77: 50% x $20,825 = $10,413

(3) - Per response to PSC-3-48: AGA dues in test year:	$ 103,752	
- Portion of AGA activities devoted to legislative and regulatory advocacy; legislative and regulatory policy research; advertising, marketing and public relations:	25.00%	(Estimate)
- AGA dues to be removed from test year	$ 25,938	

(4) Composite of effective KY income tax rate of 7.87% and federal income tax rate of 35% = 40.1155%. 1 - .401155 = .598845.

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APPENDIX I

PRIOR REGULATORY EXPERIENCE OF ROBERT J. HENKES

* = Testimonies prepared and submitted

ARKANSAS

Southwestern Bell Telephone Company Divestiture Base Rate Proceeding*	Docket 83-045-U	09/1983

DELAWARE

Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 41-79	04/1980
Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 80-39	02/1981
Delmarva Power and Light Company Sale of Power Station Generation	Complaint Docket 279-80	04/1981
Delmarva Power and Light Company Electric Base Rate Proceeding	Docket 81-12	06/1981
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 81-13	08/1981
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 82-45	04/1983
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 83-26	04/1984
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 84-30	04/1985
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 85-26	03/1986
Delmarva Power and Light Company Report of DP&L Operating Earnings*	Docket 86-24	07/1986
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 86-24	12/1986 01/1987
Delmarva Power and Light Company Report Re. PROMOD and Its Use in	Docket 85-26	10/1986

Fuel Clause Proceedings*		
Diamond State Telephone Company Base Rate Proceeding*	Docket 86-20	04/1987
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 87-33	06/1988
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 90-35F	05/1991
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 91-20	10/1991
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 91-24	04/1992
Artesian Water Company Water Base Rate Proceeding*	Docket 97-66	07/1997
Artesian Water Company Water Base Rate Proceeding*	Docket 97-340	02/1998
United Water Delaware Water Base Rate Proceeding*	Docket 98-98	08/1998
Delmarva Power and Light Company Revenue Requirement and Stranded Cost Reviews	Not Docketed	12/1998
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Direct Test.)	09/1999
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Supplement. Test)	10/1999
Tidewater Utilities/ Public Water Co. Water Base Rate Proceedings*	Docket No. 99-466	03/2000
Delmarva Power & Light Company Competitive Services Margin Sharing Proceeding*	Docket No. 00-314	03/2001
Artesian Water Company Water Base Rate Proceeding*	Docket No. 00-649	04/2001
Chesapeake Gas Company	Docket No. 01-307	12/2001

Gas Base Rate Proceeding*		
Tidewater Utilities Water Base Rate Proceeding*	Docket No. 02-28	07/2002
Artesian Water Company Water Base Rate Proceeding*	Docket No. 02-109	09/2002
Delmarva Power & Light Company Electric Cost of Service Proceeding	Docket No. 02-231	03/2003
Delmarva Power & Light Company Gas Base Rate Proceeding*	Docket No. 03-127	8/2003

DISTRICT OF COLUMBIA

District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 870	05/1988
District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 890	02/1990
District of Columbia Natural Gas Co. Waiver of Certain GS Provisions	Formal Case 898	08/1990
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 850	07/1991
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 926	10/1993
Bell Atlantic - District of Columbia SPF Surcharge Proceeding	Formal Case 926	06/19/94
Bell Atlantic - District of Columbia Price Cap Plan and Earnings Review	Formal Case 814 IV	07/1995

GEORGIA

Southern Bell Telephone Company Base Rate Proceeding	Docket 3465-U	08/1984
Southern Bell Telephone Company Base Rate Proceeding	Docket 3518-U	08/1985

Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3673-U	08/1987
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3840-U	08/1989
Southern Bell Telephone Company Base Rate Proceeding	Docket 3905-U	08/1990
Southern Bell Telephone Company Implementation, Administration and Mechanics of Universal Service Fund*	Docket 3921-U	10/1990
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket 4177-U	08/1992
Southern Bell Telephone Company Report on Cash Working Capital*	Docket 3905-U	03/1993
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket No. 4451-U	08/1993
Atlanta Gas Light Company Gas Base Rate Proceeding	Docket No. 5116-U	08/1994
Georgia Independent Telephone Companies Earnings Review and Show Cause Proceedings	Various Dockets	1994
Georgia Power Company Earnings Review - Report to GPSC*	Non-Docketed	09/1995
Georgia Alltel Telecommunication Companies Earnings and Rate Reviews	Docket No. 6746-U	07/1996
Frontier Communications of Georgia Earnings and Rate Review	Docket No. 4997-U	07/1996
Georgia Power Company Electric Base Rate / Accounting Order Proceeding	Docket No. 9355-U	12/1998
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 14618-U	03/2002

FERC

Philadelphia Electric/Conowingo Power Electric Base Rate Proceeding*	Docket ER 80-557/558	07/1981

KENTUCKY

Kentucky Power Company Electric Base Rate Proceeding*	Case 8429	04/1982
Kentucky Power Company Electric Base Rate Proceeding*	Case 8734	06/1983
Kentucky Power Company Electric Base Rate Proceeding*	Case 9061	09/1984
South Central Bell Telephone Company Base Rate Proceeding*	Case 9160	01/1985
Kentucky-American Water Company Base Rate Proceeding*	Case 97-034	06/1997
Delta Natural Gas Company Base Rate Proceeding*	Case 97-066	07/1997
Kentucky Utilities and LG&E Company Environmental Surcharge Proceeding	97-SC-1091-DG	01/1999
Delta Natural Gas Company Experimental Alternative Regulation Plan*	Case No. 99-046	07/1999
Delta Natural Gas Company Base Rate Proceeding*	Case No. 99-176	09/1999
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2000-080	06/2000
Kentucky-American Water Company Base Rate Proceeding*	Case No. 2000-120	07/2000
Jackson Energy Cooperative Corporation Electric Base Rate Proceeding*	Case No. 2000-373	02/2001
Kentucky-American Water Company	Case No. 2000-120	02/2001

Base Rate Rehearing*		
Kentucky-American Water Company Rehearing Opposition Testimony*	Case No. 2000-120	03/2001
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2001-092	09/2001
Louisville Gas & Electric Company and Kentucky Utilities Company Deferred Debits Accounting Order	Case No. 2001-169	10/2001
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2001-244	05/2002

MAINE

Continental Telephone Company of Maine Base Rate Proceeding	Docket 90-040	12/1990
Central Maine Power Company Electric Base Rate Proceeding	Docket 90-076	03/1991
New England Telephone Corporation - Maine Chapter 120 Earnings Review	Docket 94-254	12/1994

MARYLAND

Potomac Electric Power Company Electric Base Rate Proceeding*	Case 7384	01/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7427	08/1980
Chesapeake and Potomac Telephone Company Western Electric and License Contract	Case 7467	10/1980
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7467	10/1980
Washington Gas Light Company Gas Base Rate Proceeding	Case 7466	11/1980
Delmarva Power and Light Company	Case 7570	10/1981

Electric Base Rate Proceeding*		
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7591	12/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7661	11/1982
Chesapeake and Potomac Telephone Company Computer Inquiry II*	Case 7661	12/1982
Chesapeake and Potomac Telephone Company Divestiture Base Rate Proceeding*	Case 7735	10/1983
AT&T Communications of Maryland Base Rate Proceeding	Case 7788	1984
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7851	03/1985
Potomac Electric Power Company Electric Base Rate Proceeding	Case 7878	1985
Delmarva Power and Light Company Electric Base Rate Proceeding	Case 7829	1985

NEW HAMPSHIRE

Granite State Electric Company Electric Base Rate Proceeding	Docket DR 77-63	1977

NEW JERSEY

Elizabethtown Water Company Water Base Rate Proceeding	Docket 757-769	07/1975
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 759-899	09/1975
Middlesex Water Company Water Base Rate Proceeding	Docket 761-37	01/1976
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 769-965	09/1976

Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings	Docket 761-8	10/1976
Atlantic City Electric Company Electric Base Rate Proceeding*	Docket 772-113	04/1977
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 7711-1107	05/1978
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 794-310	04/1979
Rockland Electric Company Electric Base Rate Proceeding*	Docket 795-413	09/1979
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 802-135	02/1980
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8011-836	02/1981
Rockland Electric Company Electric Base Rate Proceeding*	Docket 811-6	05/1981
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8110-883	02/1982
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket 812-76	08/1982
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 812-76	08/1982
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8211-1030	11/1982
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 829-777	12/1982
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 837-620	10/1983
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8311-954	11/1983

AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1035	02/1984
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 849-1014	11/1984
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1064	05/1985
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER8512-1163	05/1986
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	07/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8609-973	12/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8710-1189	01/1988
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	02/1988
United Telephone of New Jersey Base Rate Proceeding	Docket TR8810-1187	08/1989
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER9009-10695	09/1990
United Telephone of New Jersey Base Rate Proceeding	Docket TR9007-0726J	02/1991
Elizabethtown Gas Company Gas Base Rate Proceeding*	Docket GR9012-1391J	05/1991
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER9109145J	11/1991
Jersey Central Power and Light Company Electric Fuel Clause Proceeding	Docket ER91121765J	03/1992
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR9108-1393J	03/1992
Public Service Electric and Gas Company	Docket ER91111698J	07/1992

Electric and Gas Base Rate Proceedings*

Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER92090900J	12/1992
Middlesex Water Company Water Base Rate Proceeding*	Docket WR92090885J	01/1993
Elizabethtown Water Company Water Base Rate Proceeding*	Docket WR92070774J	02/1993
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER91111698J	03/1993
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR93040114	08/1993
Atlantic City Electric Company Electric Fuel Clause Proceeding	Docket ER94020033	07/1994
Borough of Butler Electric Utility Various Electric Fuel Clause Proceedings	Docket ER94020025	1994
Elizabethtown Water Company Water Base Rate Proceeding	Non-Docketed	11/1994
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER 94070293	11/1994
Rockland Electric Company Electric Fuel Clause Proceeding and Purchased Power Contract By-Out	Docket Nos. 940200045 and ER 9409036	12/1994
Jersey Central Power & Light Company Electric Fuel Clause Proceeding	Docket ER94120577	05/1995
Elizabethtown Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR95010010	05/1995
Middlesex Water Company Purchased Water Adjustment Clause Proceeding	Docket WR94020067	05/1995
New Jersey American Water Company* Base Rate Proceeding	Docket WR95040165	01/1996
Rockland Electric Company	Docket ER95090425	01/1996

Electric Fuel Clause Proceeding		
United Water of New Jersey Base Rate Proceeding*	Docket WR95070303	01/1996
Elizabethtown Water Company Base Rate Proceeding*	Docket WR95110557	03/1996
New Jersey Water and Sewer Adjustment Clauses Rulemaking Proceeding*	Non-Docketed	03/1996
United Water Vernon Sewage Company Base Rate Proceeding*	Docket WR96030204	07/1996
United Water Great Gorge Company Base Rate Proceeding*	Docket WR96030205	07/1996
South Jersey Gas Company Base Rate Proceeding	Docket GR960100932	08/1996
Middlesex Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR96040307	08/1996
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER96030257	08/1996
Public Service Electric & Gas Company and Atlantic City Electric Company Investigation into the continuing outage of the Salem Nuclear Generating Station*	Docket Nos. ES96039158 & ES96030159	10/1996
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket No.EC96110784	01/1997
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No.WR96100768	03/1997
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER97020105	08/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	11/1997
Atlantic City Electric Company Limited Issue Rate Proceeding*	Docket No.ER97080562	12/1997

Rockland Electric Company Limited Issue Rate Proceeding	Docket No.ER97080567	12/1997
South Jersey Gas Company Limited Issue Rate Proceeding	Docket No.GR97050349	12/1997
New Jersey American Water Company Limited Issue Rate Proceeding	Docket No.WR97070538	12/1997
Elizabethtown Water Company and Mount Holly Water Company Limited Issue Rate Proceedings	Docket Nos. WR97040288, WR97040289	12/1997
United Water of New Jersey, United Water Toms River and United Water Lambertville Limited Issue Rate Proceedings	Docket Nos.WR9700540, WR97070541, WR97070539	12/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	01/1998
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No. WR97080615	01/1998
New Jersey-American Water Company Base Rate Proceeding*	Docket No.WR98010015	07/1998
Consumers New Jersey Water Company Merger Proceeding	Docket No.WM98080706	12/1998
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER98090789	02/1999
Middlesex Water Company Base Rate Proceeding*	Docket No.WR98090795	03/1999
Mount Holly Water Company Base Rate Proceeding - Phase I*	Docket No. WR99010032	07/1999
Mount Holly Water Company Base Rate Proceeding - Phase II*	Docket No. WR99010032	09/1999
New Jersey American Water Company Acquisitions of Water Systems	Docket Nos. WM9910018 WM9910019	09/1999 09/1999

Mount Holly Water Company Merger with Homestead Water Utility	Docket No. WM99020091	10/1999
Applied Wastewater Management, Inc. Merger with Homestead Treatment Utility	Docket No.WM99020090	10/1999
Environmental Disposal Corporation (Sewer) Base Rate Proceeding*	Docket No.WR99040249	02/2000
Elizabethtown Gas Company Gas Cost Adjustment Clause Proceeding DSM Adjustment Clause Proceeding	Docket No.GR99070509 Docket No. GR99070510	03/2000 03/2000
New Jersey American Water Company Gain on Sale of Land	Docket No. WM99090677	04/2000
Jersey Central Power & Light Company NUG Contract Buydown	Docket No. EM99120958	04/2000
Shore Water Company Base Rate Proceeding	Docket No. WR99090678	05/2000
Shorelands Water Company Water Diversion Rights Acquisition	Docket No. WO00030183	05/2000
Mount Holly and Elizabethtown Water Companies Computer and Billing Services Contracts	Docket Nos. WO99040259 WO9904260	06/2000 06/2000
United Water Resources, Inc. Merger with Suez-Lyonnaise	Docket No. WM99110853	06/2000
E'Town Corporation Merger with Thames, Ltd.	Docket No. WM99120923	08/2000
Consumers Water Company Water Base Rate Proceeding*	Docket No. WR00030174	09/2000
Atlantic City Electric Company Buydown of Purchased Power Contract	Docket No. EE00060388	09/2000
Applied Wastewater Management, Inc. Authorization for Accounting Changes	Docket No. WR00010055	10/2000
Elizabethtown Gas Company Gas Cost Adjustment Clause Proceeding DSM Adjustment Clause Proceeding	Docket No. GR00070470 Docket No. GR00070471	10/2000 10/2000

Trenton Water Works Water Base Rate Proceeding*	Docket No. WR00020096	10/2000
Middlesex Water Company Water Base Rate Proceeding*	Docket No. WR00060362	11/2000
New Jersey American Water Company Land Sale - Ocean City	Docket No. WM00060389	11/2000
Pineland Water Company Water Base Rate Proceeding*	Docket No. WR00070454	12/2000
Pineland Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR00070455	12/2000
Elizabethtown Gas Company Regulatory Treatment of Gain on Sale of Property*	Docket No. GR00070470	02/2001
Wildwood Water Utility Water Base Rate Proceeding*	Docket No. WR00100717	04/2001
Roxbury Water Company Water Base Rate Proceeding	Docket No. WR01010006	06/2001
SB Water Company Water Base Rate Proceeding	Docket No. WR01040232	06/2001
Pennsgrove Water Company Water Base Rate Proceeding*	Docket No. WR00120939	07/2001
Public Service Electric & Gas Company Gas Base Rate Proceeding* Direct Testimony	Docket No. GR01050328	08/2001
Public Service Electric & Gas Company Gas Base Rate Proceeding* Surrebuttal Testimony	Docket No. GR01050328	09/2001
Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR01040205	10/2001
Middlesex Water Company Financing Proceeding	Docket No. WF01090574	12/2001

New Jersey American Water Company Financing Proceeding	Docket No. WF01050337	12/2001
Consumers New Jersey Water Company Stock Transfer/Change in Control Proceeding	Docket No. WF01080523	01/2002
Consumers New Jersey Water Company Water Base Rate Proceeding	Docket No. WR02030133	07/2002
New Jersey American Water Company Change of Control (Merger) Proceeding*	Docket No. WM01120833	07/2002
Borough of Haledon – Water Department Water Base Rate Proceeding*	Docket No. WR01080532	07/2002
New Jersey American Water Company Change of Control (Merger) Proceeding	Docket No. WM02020072	09/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Direct Testimony*	Docket No. ER02050303	10/2002
United Water Lambertville Land Sale Proceeding	Docket No. WM02080520	11/2002
United Water Vernon Hills & Hampton Management Service Agreement	Docket No. WE02080528	11/2002
United Water New Jersey Metering Contract With Affiliate	Docket No. WO02080536	12/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Surrebuttal and Supplemental Surrebuttal Testimonies*	Docket No. ER02050303	12/2002
Public Service Electric & Gas Company Minimum Pension Liability Proceeding	Docket No. EO02110853	12/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02050303	12/2002
Public Service Electric & Gas Company Electric Deferred Balance Proceeding Direct Testimony*	Docket No. ER02050303	01/2003

Rockland Electric Company Electric Base Rate Proceeding Direct Testimony*	Docket No. ER02100724	01/2003
Public Service Electric & Gas Company Supplemental Direct Testimony*	Docket No. ER02050303	02/2003
Rockland Electric Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02100724	02/2003
Consumers New Jersey Water Company Acquisition of Maxim Sewerage Company	Docket No. WM02110808	05/2003
Rockland Electric Company Audit of Competitive Services	Docket No. EA02020098	06/2003
New Jersey Natural Gas Company Audit of Competitive Services	Docket No. GA02020100	06/2003
Public Service Electric & Gas Company Audit of Competitive Services	Docket No. EA02020097	06/2003
Mount Holly Water Company Water Base Rate Proceeding*	Docket No. WR03070509	12/2003
Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR03070510	12/2003
New Jersey-American Water Company Water and Sewer Base Rate Proceeding*	Docket No. WR03070511	12/2003
Applied Wastewater Management, Inc. Water and Sewer Base Rate Proceeding*	Docket No. WR03030222	01/2004

NEW MEXICO

Southwestern Public Service Company Electric Base Rate Proceeding*	Case 1957	11/1985
El Paso Electric Company Rate Moderation Plan	Case 2009	1986
El Paso Electric Company	Case 2092	06/1987

Electric Base Rate Proceeding		
Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2147	03/1988
El Paso Electric Company Electric Base Rate Proceeding*	Case 2162	06/1988
Public Service Company of New Mexico Phase-In Plan*	Case 2146/Phase II	10/1988
El Paso Electric Company Electric Base Rate Proceeding*	Case 2279	11/1989
Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2307	04/1990
El Paso Electric Company Rate Moderation Plan*	Case 2222	04/1990
Generic Electric Fuel Clause - New Mexico Amendments to NMPSC Rule 550	Case 2360	02/1991
Southwestern Public Service Company Rate Reduction Proceeding	Case 2573	03/1994
El Paso Electric Company Base Rate Proceeding	Case 2722	02/1998

<u>OHIO</u>

Dayton Power and Light Company Electric Base Rate Proceeding	Case 76-823	1976

<u>PENNSYLVANIA</u>

Duquesne Light Company Electric Base Rate Proceeding*	R.I.D. No. R-821945	09/1982
AT&T Communications of Pennsylvania Base Rate Proceeding*	Docket P-830452	04/1984
AT&T Communications of Pennsylvania Base Rate Proceeding*	Docket P-830452	11/1984

National Fuel Gas Distribution Company Gas Base Rate Proceeding*	Docket R-870719	12/1987

RHODE ISLAND

Blackstone Valley Electric Company Electric Base Rate Proceeding	Docket No. 1289	
Newport Electric Company Report on Emergency Relief		

VERMONT

Continental Telephone Company of Vermont Base Rate Proceeding	Docket No. 3986	
Green Mountain Power Corporation Electric Base Rate Proceeding	Docket No. 5695	01/1994
Central Vermont Public Service Corp. Rate Investigation	Docket No. 5701	04/1994
Central Vermont Public Service Corp. Electric Base Rate Proceeding*	Docket No. 5724	05/1994
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5780	01/1995
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5857	01/1996

VIRGIN ISLANDS

Virgin Islands Telephone Corporation Base Rate Proceeding*	Docket 126	