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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY, INC. FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	)	CASE NO. 2008-00252 C/W CASE NO. 2007-00564

ATTORNEY GENERAL'S PRE-FILED TESTIMONY

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and files the following testimony in the above-styled matter.

Respectfully submitted,
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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	))))	CASE NO. 2008-00252

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

October 29, 2008

Louisville Gas and Electric Company
Case No. 2008-00252 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 capitalization 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 capitalization 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. J. Randall Woolridge, concerning the appropriate capital structure ratios, cost rates for short- and long term debt, the return on common equity, and the resulting overall rate of return for the Company in this proceeding;
2. Mr. Michael Majoros, concerning the appropriate depreciation rates to be adopted by the Commission in this case; and

3. Mr. Glenn A. Watkins, concerning LG&E's proposed electric temperature normalization adjustment.

In developing this testimony, I have reviewed and analyzed the Company's July 29, 2008 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 April 30, 2008, the end of the test period in this case, amounts to $1.780.079 million which is $3.949 million lower than the adjusted electric capitalization of $1,784.028 million proposed by LG&E [Schedule RJH-1, line 1 and Schedule RJH-2].
3. The AG's expert rate of return witness, Dr. Woolridge, has at this time recommended a short-term debt cost rate of 2.63%, long-term debt cost rate of 5.30%, and a return on equity of 9.90%. These recommended capital cost rates, together with Dr. Woolridge's recommended capital structure ratios produce the AG's recommended overall rate of return on capitalization for LG&E's electric operations of 7.65%. By comparison, the Company has proposed an overall rate of return on capitalization of 8.35% for its electric operations [Schedule RJH-2].

The recommended rate of return on capitalization of 7.65% is equivalent to a rate of return of 7.46% on the Company's adjusted electric rate base [Schedule RJH-3, line 16]. The Company has not presented an equivalent proposed overall return on rate base number for its electric operations.

4. The appropriate pro forma adjusted electric rate base measured as of April 30, 2008, the end of the test period in this case, amounts to $1,824.594 million. The recommended return on rate base amounts to 7.46% [Schedule RJH-3].

5. The appropriate pro forma test period electric operating income amounts to $168.733 million, which is $29.176 million higher than LG&E's proposed test period electric operating income of $139.557 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 .62143063. This factor has been used by both the Company and the AG [Schedule RJH-1, line 6].

7. The application of the recommended overall rate of return of 7.65% to the recommended capitalization of $1,780.079 million, combined with the recommended pro forma test period operating income of $168.733 million and the revenue conversion factor of .62143063 indicates that the Company has an annual revenue *excess* for its electric operations of $52.375 million. This represents a difference of $67.516 million from the Company's proposed annual electric revenue *deficiency* of $15.141 million [Schedule RJH-1, lines 1-7].

IV. REVENUE REQUIREMENT ISSUES

A. CAPITALIZATION

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

A. The Company has proposed an adjusted electric capitalization of $1,784.016 million. As shown on Rives Exhibit 2, the starting point of the Company's proposed pro forma adjusted electric capitalization is the actual per books total company capitalization as of 4/30/08 of approximately $2,180.475 million, consisting of short term debt, long term debt, and common equity. The Company then applied an electric non-ECR rate base ratio of 79.94% to its actual 4/30/08 capitalization of $2,180.475 million, resulting in its proposed non-ECR electric capitalization balance of $1,743.072 million. Next, the Company made 4 pro forma electric capitalization adjustments in order to arrive at its proposed adjusted electric capitalization of $1,784.016 million. These 4 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 (OVEC); (3) the addition of the Job Development Tax Credit balance allocated to electric operations; and (4) the addition of the Advanced Coal Investment Tax Credit balance.

Q. IS THE METHOD USED BY THE COMPANY IN THE DETERMINATION OF ITS PROPOSED ADJUSTED CAPITALIZATION CONSISTENT WITH THE METHOD PRESCRIBED BY THE COMMISSION IN THE COMPANY'S PRIOR RATE CASE IN CASE NO. 2003-00433 AND THE RATE CASE BEFORE THAT IN CASE NO. 1998-426?

A. No. The method currently prescribed by the Commission and used in setting LG&E's rates in its prior two rate cases first calculates the allocated electric capitalization by multiplying the total company capitalization by an electric rate base ratio that has *not* first been adjusted by the removal of ECR-related rate base, as the Company has done in the instant rate proceeding. As the next step, the Commission-prescribed method would then remove all ECR-related capital from the electric-allocated capitalization.

Q. HAS THE COMPANY PRESENTED THE ELECTRIC-ALLOCATED ADJUSTED CAPITALIZATION AS DETERMINED IN ACCORDANCE WITH THE COMMISSION-PRESCRIBED CALCULATION METHOD?

A. Yes. The Company has presented the calculations and end-results of the Commission-prescribed methodology in Appendix B of Rives Exhibit 2. As shown in Appendix B, under the Commission-prescribed calculation methodology, the Company's electric-allocated adjusted capitalization amounts to $1,780.090 million as compared to the Company's proposed electric-allocated adjusted capitalization of $1,784.016 million.

Q. WHAT MAKES UP THE DIFFERENCE BETWEEN THE COMMISSION-PRESCRIBED ELECTRIC-ALLOCATED CAPITALIZATION METHODOLOGY AND THE CALCULATION METHODOLOGY PROPOSED BY THE COMPANY?

A. The difference is that the Commission-prescribed calculation method *does not* recognize the ECR-related deferred income taxes in removing the ECR-related net rate base investment from the electric capitalization whereas the Company-proposed calculation method in this case *does* recognize ECR-related deferred income taxes in calculating the adjusted electric capitalization.

Q. HAS THIS DEFERRED TAX ISSUE PREVIOUSLY BEEN ADDRESSED BY THE COMMISSION?

A. Yes. In both Case No. 1998-426 and the instant rate proceeding, the Company has argued that if ECR-related deferred taxes are considered in the determination of the Company's electric rate base, they should similarly be considered in the determination of the Company's capitalization, otherwise there would not be an accurate reconciliation between the Company's electric rate base and capitalization. However, the Commission has consistently held that since deferred taxes represent non-investor supplied funds that are not funded by the Company's capitalization, they should not be considered in the determination of the Company's adjusted capitalization. And the Commission has long recognized that a complete reconciliation between a utility's rate base and capitalization may be an appropriate theoretical concept, in practice a utility's rate base is rarely equal to its capitalization. In this regard, the Commission made the following rulings in its Order on Rehearing in LG&E's Case No. 1998-426:

> In its February 9, 2000 Order, the Commission granted rehearing on three issues raised by LG&E: the amount of environmental surcharge [ECR] to be excluded from LG&E's capitalization ...
>
> LG&E argues that the Commission's adjustment to LG&E's capitalization is in error because the adjustment did not recognize Pollution Control Deferred Income Taxes ("PC DIT"). By not recognizing the PC DIT, LG&E claims that the adjustment to its capitalization was excessive and resulted in an overstatement of its revenue sufficiency. LG&E contends that when determining the revenue sufficiency, the exclusion of the environmental surcharge components in base rate calculations should be neutral. To achieve this neutrality, LG&E states that the environmental surcharge amounts removed from its capitalization must be the same as the amounts removed from its rate base. Finally, LG&E takes the position that the April 6, 1995 Order establishing its environmental surcharge equated its environmental surcharge rate base with its environmental surcharge capitalization.
>
> One of the basic theories of rate-making is the concept that a utility's net original cost rate base should be equal to its capitalization. While accepting this theoretical concept, the Commission has long recognized that a utility's rate base is rarely equal to its capitalization....
>
> In determining a utility's revenue requirements, the Commission does not adjust the rate base or capitalization to be equal. Rather, the Commission's Orders state two different rates of return; one on rate base and one on capital. But when the rate base and capital are multiplied by their respective rates of return, they produce the same net operating income found reasonable by the Commission...
>
> The Commission is not persuaded by the evidence or arguments presented by LG&E...
>
> LG&E has acknowledged that the PC DIT are not funded by its capitalization, but are the result of differences between book and tax accounting practices, and requirements prescribed by the applicable tax code...
>
> Therefore, the adjustments to LG&E's rate base and capitalization to remove the impacts of its environmental surcharge will remain as originally calculated in the January 7, 2000 Order.

Q. HAS THE COMPANY IN THE INSTANT PROCEEDING PRESENTED ANY ARGUMENTS THAT ARE DIFFERENT FROM THE ARGUMENTS IT PRESENTED IN CASE NO. 1998-426.

A. No, it has not.

Q. COULD YOU NOW DISCUSS YOUR RECOMMENDED ADJUSTED ELECTRIC CAPITALIZATON BALANCE?

A. Yes. Based on the previously discussed findings and conclusions, I recommend that the adjusted electric-allocated capitalization be determined based on the Commission-prescribed calculation method. As shown on Schedule RJH-2, page 2 this results in a recommended adjusted electric-allocated capitalization of $1,780.079 million.

B. RATE OF RETURN ON CAPITALIZATION

Q. PLEASE DESCRIBE THE AG'S RECOMMENDED RATE OF RETURN ON CAPITALIZATION.

A. As shown on Schedule RJH-2, page 1, the AG recommends an overall return on capitalization of 7.65% as compared to the Company's proposed overall rate of return number of 8.35%. The AG-recommended overall rate of return number is based on the capital structure ratios and capital cost rates recommended by the AG's rate of return expert, Dr. Woolridge. As shown on Schedule RJH-2, page 1, Dr. Woolridge recommends a short-term debt cost rate of 2.63%, long-term debt cost rate of 5.30% and a return on equity of 9.90%.

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 return requirement rate making policy adopted by the Commission in all of LG&E's prior base rate proceedings.

C. RATE BASE AND RETURN ON 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. Yes. As shown on Rives Exhibits 3 and 4, the Company is proposing an adjusted original cost rate base of $1,795.222 million.

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 schedule RJH-3. The starting point is LG&E's proposed unadjusted electric original cost rate base of $1,826.018 million measured as of the end of the test year, April 30, 2008. From that starting point, I then removed the Company's proposed net ECR rate base balance[1] of approximately $13.285 million to arrive at the Company's proposed electric rate base balance of $1,812.733 million that excludes all ECR rate base items not rolled into base rates. Finally, I reflected total net rate base additions of $11.861 million to arrive at my recommended adjusted original cost rate base for LG&E's electric operations of $1,824.594 million. This recommended adjusted rate base of $1,824.594 million is $29.372 million higher than the Company's proposed adjusted rate base of $1,795.222 million.

Q. WHY IS YOUR RECOMMENDED ADJUSTED ORIGINAL COST RATE BASE $29.372 MILLION HIGHER THAN THE COMPANY'S PROPOSED ORIGINAL COST RATE BASE?

A. As just discussed, I have reflected non-ECR related rate base adjustments that *increase* the rate base by $11.861 million whereas the Company has proposed non-ECR related rate base adjustments that *decrease* the rate base by $17.511 million.

[1] Representing the net of the total ECR rate base balance and the ECR rate base balance rolled into base rates.

This explains why my recommended adjusted rate base is $29.372 million higher than the Company's proposed adjusted rate base. Below, I have listed the component reasons for this rate base differential of $29.372 million:

	LG&E Rate Base	AG Rate Base	Difference
Depreciation Reserve Adj.	$(16.723)	$15.363	$32.086
Remove Prepaid PSC Fees	-	(.502)	(.502)
CWC Adjustment	(.788)	(3.000)	(2.212)
Total	$(17.511)	$11.861	$29.372

As shown in the above table, by far the largest reason for the rate base differential is the pro forma impact on the depreciation reserve resulting from LG&E's proposal to increase its test year per books depreciation expenses and AG's recommendation to decrease the test year per books depreciation expenses.

Q. PLEASE DISCUSS EACH OF THE RECOMMENDED RATE BASE ADJUSTMENTS TOTALING $11.861 MILLION.

A. The first rate base adjustment of $15.363 million shown on line 2 of the third column of Schedule RJH-3 is a direct result of the AG's recommended annualized depreciation expense adjustment shown on Schedule RJH-8, line 3. This annualized depreciation expense adjustment will be discussed later in this testimony.

The second rate base adjustment of $.502 million shown on line 10 of Schedule RJH-3 represents my recommendation to remove prepaid PSC assessments from the total prepayment balance in rate base. This adjustment follows well-established and long-standing Commission ratemaking policy.

The third rate base adjustment of $3 million shown on line 11 of Schedule RJH-3 is to adjust the test year per books cash working capital requirement for the pro forma impact on cash working capital of all of the Company's proposed O&M expense adjustments in this case. In its response to AG-1-15, the Company has acknowledged that the correct cash working capital adjustment resulting from its proposed pro forma O&M expense adjustments should be a reduction of $3 million rather than the cash working capital reduction of $.788 million reflected in the Company's as-filed position. It should be noted that the appropriate cash working capital amount to be reflected for ratemaking purposes in this case should ultimately be based on the reflection of all Commission-ordered pro forma test year electric operation and maintenance expenses allowed in this case.

Q. HAVE YOU CALCULATED THE APPROPRIATE RETURN ON RATE BASE FOR LG&E'S ELECTRIC OPERATIONS IN THIS CASE?

A. Yes, as shown on Schedule RJH-3, lines 14 through 16, the Company's appropriate return on rate base in this case is 7.46%

D. OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND 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 $139.557 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 $29.176 million to total recommended pro forma test period electric operating income of $168.733 million. Each of the recommended electric operating income adjustments will be discussed in detail in the subsequent sections of this testimony.

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

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

A. Yes. The Commission 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. An income tax adjustment should be made for the difference between the pro forma synchronized interest expenses and the test year per books interest expenses.

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. However, since the AG's recommended capitalization and weighted cost of debt numbers are different from those proposed by LG&E, the AG's recommended synchronized interest level is slightly lower than LG&E's proposed synchronized interest level.

Q. WHAT IS THE IMPACT OF THESE DIFFERENT SYNCHRONIZED INTEREST LEVELS ON THE COMPANY'S PROPOSED TEST YEAR AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-5, the AG's recommended interest synchronization adjustment decreases the Company's proposed test year after-tax income by approximately $2,000.

- **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. I believe so. The Company has proposed that its unbilled revenues as of April 30, 2008, the end of the test year, be removed and be replaced by the unbilled revenues as of April 2007, the beginning of the test year. Since the unbilled revenues at the end of the test year are $.785 million higher than the unbilled revenues at the beginning of the test year, the Company's proposed unbilled revenue adjustment increases the base rate revenue requirement and corresponding base rate increase requested in this case by $.785 million. However, as can be seen from the analysis on Schedule RJH-6, only $.343 million of the $.785 million unbilled revenue differential is caused by the difference in unbilled base rate revenues at April 30, 2008 vs. April 30, 2007. Thus, the majority ($.442 million) of the Company's proposed $.785 million unbilled revenue adjustment is caused by the difference in unbilled FAC, DSM, ECR and other unbilled non-base rate surcharge revenues at April 30, 2008 vs. April 30, 2007. On page 8, lines 18 - 23 of his testimony, Company witness Bellar states that the costs and revenues associated with ratemaking mechanisms such as the fuel adjustment clause, ECR clause or DSM cost recovery should have no effect on the calculation of the base revenue deficiency and corresponding base rate increase that LG&E is requesting in this case. Yet, this is exactly what the Company is proposing to do through its proposed unbilled revenue adjustment. In summary, I believe it is inappropriate to increase the base rate revenue requirement in this case by $.785 million if $.442 million of this proposed base rate revenue requirement is caused by the end-of-test year vs. beginning-of-test year differential in unbilled FAC, DSM and ECR surcharge revenues. In addition, the Company has not similarly proposed an adjustment for the differential in the associated end-of-test year vs. beginning-of-test year differential in unbilled FAC, DSM and ECR surcharge costs.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE?

A. I recommend that the Company's proposed unbilled revenue adjustment be limited to the unbilled base rate revenues and exclude any unbilled revenue considerations for the FAC, DSM, ECR and other surcharge mechanisms. As shown on Schedule RJH-6, my recommendation would increase the Company's proposed test year after-tax income by $.276 million.

- **Electric Temperature Normalization Adjustment**

Q. PLEASE EXPLAIN THE ADJUSTMENTS THAT YOU HAVE REFLECTED ON SCHEDULE RJH-7 REGARDING THE COMPANY'S PROPOSED TEMPERATURE NORMALIZATION ADJUSTMENT.

A. As shown on Schedule RJH-7, lines 1 and 2, I have eliminated the Company's proposed electric temperature normalization revenue and associated variable expense reductions based on the recommendations made by AG witness Glenn Watkins with regard to this issue. I should note that if the Commission were to adopt an electric temperature normalization adjustment, there should be an additional expense adjustment in the form of a reduction in PSC assessments and uncollectible expenses. This expense adjustment should be calculated by applying the combined PSC assessment/uncollectible expense rate of .3438% to the amount of the temperature normalization related revenue reduction.

Q. WHAT IS THE IMPACT ON THE COMPANY'S TEST YEAR AFTER-TAX INCOME OF THE DIFFERENCE BETWEEN THE AG'S RECOMMENDED AND THE COMPANY'S PROPOSED TEMPERATURE NORMALIZATION ADJUSTMENTS?

A. As shown on Schedule RJH-7, the difference between the AG's recommended and the Company's proposed temperature normalization adjustments increases the Company's proposed test year after-tax operating income by $6 million.

- **Annualized Depreciation Expense**

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 $32.086

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 approximately $20 million.

- **Labor Cost Adjustment**

Q. PLEASE EXPLAIN THE REASON FOR THE RECOMMENDED LABOR COST ADJUSTMENT SHOWN ON SCHEDULE RJH-9.

A. The recommended labor cost adjustment consists of two parts. The first part represents a labor cost adjustment of $.287 million to correct for an error in the Company's as-filed labor cost adjustment calculations. The second part represents a labor cost adjustment of $.189 million to remove certain executive incentive compensation expenses from the test year electric operating expenses.

As shown on schedule RJH-9, the recommended total labor cost adjustment increases the Company's proposed test year electric after-tax operating income by approximately $.297 million.

- **Employee Benefit Cost Adjustment**

Q. PLEASE EXPLAIN THE REASON FOR THE RECOMMENDED EMPLOYEE BENEFIT COST ADJUSTMENT SHOWN ON SCHEDULE RJH-10.

A. The recommended employee benefit cost adjustment total of $.470 million results from corrections made by the Company in its as-filed cost adjustments for pension, OPEB and Post-Employment Benefit expenses.

As shown on schedule RJH-10, the recommended total employee benefit cost adjustment increases the Company's proposed test year electric after-tax operating income by approximately $.293 million.

- **<u>MISO Net Expense Adjustment</u>**

Q. WHAT IS THE HISTORY OF THE NET MISO COST ISSUE IN THIS CASE?

A. In its May 31, 2006 Order in Case No. 2003-00266, the Commission authorized LG&E to exit the Midwest Independent Transmission System Operator ("MISO"). The Order further prescribed the following accounting treatment for the MISO exit fee and the MISO Schedule 10 fees then and currently embedded in the Company's base rates:

> [T]he Commission concludes that it is reasonable to establish a regulatory asset for the actual amount of the exit fee, subject to adjustment for future MISO credits, if any, and a regulatory liability for the MISO Schedule 10 charges, which are the only MISO costs now included in existing rates. This accounting treatment will have no immediate impact on LG&E's and KU's rates as it defers the rate-making disposition of these amounts until subsequent base rate cases.

In the instant proceeding, LG&E has presented its proposed ratemaking treatment for this issue.

Q. WHAT IS THE COMPANY'S PROPOSED RATEMAKING TREATMENT OF THIS ISSUE?

A. The Company's actual regulatory asset balance for the MISO exit fees at the end of the test year, 4/30/08, amounts to approximately $12.372 million. The Company's actual regulatory liability balance for its cumulative MISO Schedule 10 rate collections at the end of the test year amounts to approximately $5.570 million. As shown on Reference Schedule 1.23, the Company is proposing to amortize the net MISO cost balance of approximately $6.802 million over a 5-year period for a proposed annual amortization expense of approximately $1.360 million. The Company further proposes that the continuing MISO Schedule 10 rate collections and MISO exit fee credits booked between 4/30/08 and the rate effective date of the instant rate case be deferred as regulatory liabilities for rate recognition in the Company's next base rate case.

Q. DO YOU AGREE WITH THIS RATEMAKING PROPOSAL FOR THE NET MISO COSTS?

A. I agree with the Company's proposal to amortize the net balance of the MISO exit fees and cumulative MISO Schedule 10 collections over a 5-year period. However, I do not agree with the Company's proposal to limit the amortization to the actual balances existing at the end of the test year while leaving the rate recognition for continuing post-test year MISO exit fee credits and MISO Schedule 10 collections until the next base rate case.

Q. WHAT RATE TREATMENT DO YOU RECOMMEND FOR THIS ISSUE?

A. At a minimum, the rate recognition for this issue in this case should include the continuing MISO exit fee credits and MISO Schedule 10 collections from the end of the test year until the expected February 6, 2009 rate effective date[2] of this rate case. As shown on Schedule RJH-11, line 9, the recognition of these post-test year MISO exit fee credits and MISO Schedule 10 rate collections would result in a 5-year net MISO cost amortization of $.824 million as opposed to the Company's proposed net MISO cost amortization of $1.360 million based on the actual balances at the end of the test year.

In addition, the Company has provided information showing expected MISO exit fee credits of $1.554 million during the approximate 6-year period from the rate effective date in this case until the first quarter of the year 2015. This would equate to an average annual MISO exit fee credit of $.259 million. It is my recommendation that this average annual exit fee credit be recognized for ratemaking purposes as well. As shown on Schedule RJH-11, line 15, this would result in a recommended annual net MISO cost amortization of $.565 million.

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

A. As shown on Schedule RJH-11, lines 15 - 19, the difference between my

[2] See the Company's response to AG-1-44.

recommended annual net MISO cost amortization of $.565 million and the Company's proposed annual net MISO cost amortization of $1.360 million increases the Company's test year after-tax income by $.495 million.

- **<u>New Bank Credit Facilities Adjustment</u>**

Q. HAVE YOU MADE AN ADJUSTMENT TO THE COMPANY'S PROPOSED ADJUSTMENT FOR THE NEW BANK CHARGE CREDIT FACILITY CHARGES?

A. Yes. As shown on Schedule RJH-12, the Company has proposed an expense adjustment of $2.375 million for this item. This proposed cost amount assumes letters of credit associated with two anticipated bond issues totaling $211.335 million, an estimate letter of credit fee of 1.1%, and associated annual recurring legal fees of $50,000. None of these assumptions are firm at this time. For example, in its response to AG-2-18, the Company states with regard to the anticipated bond issues of $211.335 million:

> The company currently expects to close on the two bonds in late November 2008 or early December 2008. However, the capital markets are extremely volatile and market conditions may result in the need to modify this plan.

The letter of credit fees are also uncertain at this time. While the Company initially assumed an annual fee of 1.1% of the total bond issuance amount, in September 2008 it revised the estimated annual fee to .5% and most recently revised it again to a rate of .7%. The Company has also provided no support for the legal expense of

$50,000 and has not clarified that this is an annual recurring expense. For these reasons, I do not believe that the expense adjustment amount proposed by the Company in this case is known and measurable at this time.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE BASED ON THE FOREGOING FINDINGS AND CONCLUSIONS?

A. I have decided to take a conservative position on this matter. Specifically, rather than rejecting the Company's proposed expense adjustment for the reason that it is not known and measurable at this time, I have assumed the same bond issuance amount of $211.335 million and the same $50,000 annual legal fees proposed by the Company. However, I have reflected the most recent available letter of credit fee of .7%, as opposed to the Company's assumed fee of 1.1%. As shown on Schedule RJH-12, based on these conservative assumptions, my recommendation at this time is to reflect a pro forma expense adjustment of $1.529 million on a total company basis. This recommended expense adjustment should be updated when firm, actual information has become available regarding the amount and timing of the bond issuances, the letter of credit percentage fee, and the annual recurring legal fees prior to the close of record in this case.

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

A. As shown on Schedule RJH-12, my recommendations regarding this issue increase the Company's proposed test year after-tax electric operating income by $.390 million.

- **Kentucky Coal Credit Adjustment**

Q. HAS THE COMPANY MADE AN ADJUSTMENT TO REMOVE KENTUCKY COAL TAX CREDITS FROM ITS TEST YEAR PROPERTY TAXES?

A. Yes. As shown on Reference Schedule 1.33, the Company has removed $1,135,572 worth of Kentucky coal tax credits from its test year property taxes.

Q. WHY HAS THE COMPANY MADE THIS ADJUSTMENT?

A. The reason for the Company's proposed adjustment is explained on pages 6-7 of Ms. Scott's testimony:

> This adjustment is to remove the Kentucky coal tax credit received by the Company during the test year and applied to property taxes. The coal tax credit was established by Kentucky Revised Statute 141.0405 and is contingent on the Company's annual level of Kentucky coal purchases versus the 1999 baseline level of purchases. The Company must apply for the credit annually and, if approved, the coal tax credit must be applied first to income taxes, and any remaining credit may be applied to property taxes. The coal tax credit statute expires in 2009. Due to its upcoming expiration and its contingent nature, the credit is not fixed, cannot be considered to be an on-going reduction to property tax expenses, and is removed from the test year.

Q. DO YOU AGREE WITH THE COMPANY THAT THE KENTUCKY COAL TAX CREDIT SHOULD BE REMOVED FROM THE TEST YEAR IN THIS

CASE BECAUSE IT EXPIRES IN 2009?

A. No. As confirmed in its response to AG-2-12, if the Company generates coal tax credits from coal purchases in 2008 and 2009, the tax credits will be available as property tax or income tax credits in calendar years 2009 and 2010. The Company has acknowledged that, if applicable, it will apply for these future coal tax credits. Given that the Company has proposed in this case to recognize for ratemaking purposes the amortization expense associated with the Mill Creek Ash Dredging regulatory asset which is scheduled to expire in April 2010, it would be reasonable and consistent to give rate recognition to potential coal tax credit bookings which will not expire until December 2010. In addition, with the anticipation of another rate case in conjunction with Trimble County Unit 2 going into service in the summer of 2010, there should be no concern that the rate recognition of potential coal tax credits through December 2010 will have a negative financial impact on LG&E.

Q. DO YOU AGREE WITH THE COMPANY THAT THE KENTUCKY COAL TAX CREDIT SHOULD BE REMOVED FROM THE TEST YEAR IN THIS CASE BECAUSE OF ITS CONTINGENT NATURE?

A. No. As confirmed in the response to PSC-2-79, LG&E has qualified for the coal tax credit in each of the last six years, 2002 through 2007. Based on this history, I believe it is unreasonable to assume that the Company's ability to utilize these tax credits will suddenly cease in the years 2009 and 2010.

Q. BASED ON THE FOREGOING FINDINGS AND CONCLUSIONS, WHAT RATEMAKING TREATMENT ARE YOU RECOMMENDING FOR THIS ISSUE IN THIS CASE?

A. I recommend rate recognition of a normalized annual Kentucky coal tax credit amount based on the average of the actual coal tax credits experienced by the Company in the most recent 5-year period. As shown in Schedule RJH-13, this results in a recommended normalized annual coal tax credit amount of $1.158 million. To be conservative,[3] I also recommend that this coal tax credit be reflected as a property tax credit rather than as a Kentucky income tax credit.

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

A. As shown on Schedule RJH-13, my recommendation increases the Company's test year after-tax income by $.722 million.

- **Amortization of Recycle Credit**

Q. HAS THE COMPANY MADE AN ADJUSTMENT TO REMOVE KENTUCKY RECYCLE TAX CREDITS FROM ITS TEST YEAR KENTUCKY INCOME TAXES?

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[3] As shown on Schedule RJH-13, treating the tax credit as a property tax credit will increase the Company's after-tax income by $722,000. Based on the response to AG-2-12(e), Mr. Henkes is of the understanding that if the tax credit would be used as a Kentucky income tax credit, it would increase the Company's after-tax income by $753,000 ($1,158,000 x 65%).

A. Yes. As shown on Reference Schedule 1.41, the Company has removed $741,478 worth of Kentucky Recycle Credits from the test year. The effect of this adjustment is that it increases the test year pro forma Kentucky income taxes by $741,478.

Q. WHY HAS THE COMPANY MADE THIS ADJUSTMENT?

A. The reason for the Company's proposed adjustment is explained on page 9 of Ms. Scott's testimony:

> The Kentucky recycle tax credit adjustment removes an adjustment made during the test year that relates to prior periods. The Kentucky recycle credit was originally generated in 1999, in accordance with Kentucky Revised Statute 141.390. The unused portion of the recycle credit is carried forward and used on Kentucky income tax returns, as possible.

Q. DO YOU AGREE WITH THE COMPANY THAT THE KENTUCKY RECYCLE TAX CREDIT SHOULD BE REMOVED FROM THE TEST YEAR IN THIS CASE BECAUSE IT RELATES TO PRIOR PERIODS?

A. No. While this tax credit was generated in 1999, it was available for utilization on the Company's consolidated Kentucky income tax returns in the future, provided that tax liabilities existed in those future years. In her response to AG-2-14, Ms. Scott further states with regard to this item:

> (LG&E) expects to have consolidated Kentucky taxable income in the future, enabling it to eventually use the entire recycle credit. Since there is no expiration date the recycle credit carry forward can be applied to future years' state income tax liabilities until fully used.

The Company's response to AG-1-30 shows the history of the utilization of the original recycle tax credit of $8.2 million generated in 1999:

- Recycle credit generated in 1999	$8,193,379
- Recycle credit utilized on 1999 state tax return	(819,338)
- Recycle credit utilized on 2000 state tax return	(1,635,589)
- Recycle credit utilized on 2005 state tax return	(959,537)
- Recycle credit utilized on 2007 state tax return	(741,478)
- Unused balance to be carried forward for future use	$4,037,437

In summary, I do not believe that the remaining available tax credits should be disregarded as a "prior period" item, as the Company is proposing, for the reason that the credit was generated in 1999. The fact is that at the end of the test year in this case, there was still an unused tax credit balance in excess of $4 million available for future use as tax credits on the Company's consolidated Kentucky income tax returns. Furthermore, the Company's proposal to treat this tax credit as a prior period item is inconsistent with its proposal in this case to reflect the amortization expenses of many costs that were deferred prior to the test year. The electric amortization expenses of prior period deferred cost balances are listed in the first column of the response to AG-1-10.

Q. WHAT HAS RECENTLY HAPPENED WITH THE CURRENT UNUSED RECYCLE TAX CREDIT BALANCE OF APPROXIMATELY $4 MILLION?

A. As reported by the Company in its response to AG-2-14, LG&E was paid the entire $4 million unused recycle tax credit balance by its parent company E.ON U.S. LLC in September 2008. Thus, rather than utilizing the current unused recycle tax credit balance in a piece-meal fashion on LG&E's future consolidated state income tax returns, the Company was able to utilize the entire tax credit balance in September

2008.

Q. DO YOU BELIEVE THIS LARGE $4 MILLION PAYMENT SHOULD BE RECOGNIZED FOR RATEMAKING PURPOSES IN THIS CASE?

A. Yes. I believe it would be inequitable to the ratepayers of LG&E to have this large $4 million payment flow to the Company's stockholders, as the Company is proposing in this case. The Company's ratepayers have always been, and still are, responsible for the Company's income tax liabilities and, therefore, should receive the benefit of this large, one-time tax credit.

Q. WHAT RATEMAKING TREATMENT ARE YOU RECOMMENDING FOR THIS ISSUE?

A. I recommend that the $4 million recycle tax credit be amortized to the ratepayers over a five-year period. In order to share a portion of this issue with the Company's stockholders, I also recommend that the unamortized balance of this $4 million item during the 5-year amortization period not be treated as a reduction from rate base and capitalization.

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

A. As shown on Schedule RJH-14, my recommendation increases the Company's test year after-tax income by $.525 million.

- **EEI Dues Adjustment**

Q. PLEASE EXPLAIN YOUR RECOMMENDATION TO REMOVE A PORTION OF THE COMPANY'S ANNUAL EDISON ELECTRIC INSTITUTE (EEI) DUES FOR RATEMAKING PURPOSES IN THIS CASE.

A. The test year electric operating expenses include $413,000 for EEI dues. Certain portions of EEI activities are dedicated to legislative advocacy, regulatory advocacy and public relations which are forms of lobbying activities, as determined by the Commission in LG&E's prior rate case, Case No. 2003-00433. In the prior case, NARUC information[4] was available that identified that 45.35% of EEI's activities accounted for legislative/regulatory advocacy and public relations and, based on that information, the Commission ruled that 45.35% of the Company's EEI dues in that case be disallowed for ratemaking purposes.[5] In its response to AG-1-72 in the current case, the Company has indicated that EEI is no longer preparing the same breakout of activities by NARUC category as provided in the prior case, but that for 2007, EEI determined that 16.15% of 2007 dues was spent on lobbying activities. It is not known whether EEI's determination of what represents lobbying activities is as inclusive as, and exactly similar to, NARUC's classification of EEI's legislative and regulatory advocacy and public relations activities. I have therefore relied on the same 45.35% EEI lobbying expense ratio as established by the Commission in the prior case in my determination of the EEI dues to be excluded

[4] Response to AG-1-85, Case No. 2003-00433.
[5] See pages 51-52 of the PSC Order in Case No. 2003-00433.

for ratemaking purposes in the current case.

As shown on Schedule RJH-15, the application of the lobbying ratio of 45.35% to the test year EEI dues of $413,000 indicates a disallowed expense amount of $187,000. This expense amount should be the responsibility of LG&E's stockholders as they produce no benefits to the Company's ratepayers. My recommendation increases the Company's proposed test year electric after-tax operating income by approximately $117,000.

- **Miscellaneous Expense Adjustments**

Q. PLEASE DESCRIBE THE MISCELLANEOUS ADJUSTMENTS SHOWN ON SCHEDULE RJH-16.

A. First, I recommend the removal from test year electric operating expenses of $70,000 for expenses associated with employee gifts, award banquets, parties and other social events (e.g., company picnics). My recommendation is consistent with previously established Commission-policy that such expenses do not produce benefits to the ratepayers and should be excluded for ratemaking purposes.[6]

Second, I recommend the removal from test year electric operating expenses of $5,000 worth of penalty and fines expenses. Such expenses should be funded by

[6] Similar expenses were excluded from rate recognition in the Company's prior electric rate case – see pages 50-51 in the PSC Order in Case No. 2003-00433.

the Company's stockholders, not ratepayers.

Third, I have removed $15,000 of electric expenses associated with real estate receptions and community involvement. As shown in more detail in the responses to AG-2-19 and 2-24, these expenses are for such items as community trade shows, fundraisers, music, florists, showcase gifts, reception catering, valet parking, service charges, etc. I do not believe that such expenses should be funded by the ratepayers as they have nothing to do with the provision of safe, adequate and proper electric service

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

A. As shown on schedule RJH-16, the recommended miscellaneous expense adjustments increase the Company's proposed test year electric after-tax operating income by approximately $56,000.

- **<u>Outside Labor Expenses</u>**

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING CERTAIN OPERATING EXPENSES INCLUDED IN THE TEST YEAR?

A. Yes. I am concerned about the very high level of outside labor expenses that are included in the Company's test year operating expenses as compared to the similar operating expenses experienced by the Company in recent prior years. This is evident from various data responses, the results of which are outlined below:

	Outside Labor – Other [AG-2-22]	Maintenance Contracts [PSC-2-99]	Maint. of Boiler Plant [PSC-3-15]
2004	$48.106	NA	$24.679
2005	41.138	13.655	26.333
2006	48.506	17.644	25.220
2007	53.075	19.949	30.839
Test Yr.	62.886	24.130	39.886

[$millions]

The data in the above table indicate that the test year outside labor O&M expenses may be abnormally high.

Q. HAVE YOU MADE AN ADJUSTMENT TO NORMALIZE THE TEST YEAR OUTSIDE LABOR O&M EXPENSES BASED ON THE INFORMATION IN THE ABOVE TABLE?

A. No. I felt that not enough information was available to me that would allow me to calculate a reliable and reasonable expense normalization adjustment at this time. However, I do recommend that if the Company, in the rebuttal phase of this proceeding, cannot adequately prove why these high test year outside labor expenses should reasonably be considered annually recurring, then the Commission should calculate and reflect a reasonable outside labor expense normalization adjustment based on the data in the above table.

- **Hurricane Ike Storm Damage Expenses**

Q. DO YOU HAVE ANY COMMENTS ON THE COMPANY'S RECENT CORRESPONDENCE REGARDING STORM DAMAGE EXPENSES INCURRED DUE TO HURRICANE IKE?

A. Yes. In its updated 10/23/08 response to PSC-1-43, the Company reported that it recently incurred extraordinary and material damage to its distribution, transmission and other facilities as a result of hurricane Ike. The response further stated with regard to this issue that:

> No later than Tuesday, October 28, 2008, the Companies will file applications to initiate separate proceedings to seek orders from the Commission to approve the establishment of regulatory assets to accumulate and defer for future recovery the Companies' costs incurred due to Hurricane Ike. If the Commission grants the Companies' requested relief in those separate proceedings, the Companies anticipate asking the Commission in these base rate proceedings for amortization and base rate recovery of the Hurricane Ike regulatory assets.

Since the Company filed this application during the time of this writing, October 29, 2008, the AG cannot take a position on this matter at this time. However, the AG will address this matter at the appropriate time after all discovery, review and analyses of this issue in the Company's October 27, 2008 application have been completed.

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

A. Yes, it does.

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
REVENUE REQUIREMENT
($000)

	LG&E Electric (1)	Adjustments	AG	
1. Capital Structure	$ 1,784,028	$ (3,949)	$ 1,780,079	Sch. RJH-2
2. Rate of Return	8.35%		7.65%	Sch. RJH-2
3. Income Requirement	148,966		136,185	
4. Pro Forma Income	139,557	29,176	168,733	Sch. RJH-4
5. Income Deficiency	9,409		(32,547)	
6. Revenue Conversion Factor	0.62143063		0.62143063	
7. Overall Revenue Deficiency	$ 15,141	$ (67,516)	$ (52,375)	

(1) Rives Exhibit 8, page 1

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
ADJUSTED CAPITALIZATION AT 4/30/08
($000)

LG&E PROPOSED:	Adjusted Electric Capitalization (1)	Capitalization Ratios	Cost Rates	Weighted Cost Rates
1. Short Term Debt	$ 42,444	2.38%	2.63%	0.06%
2. Long Term Debt	805,340	45.14%	5.30%	2.39%
3. Common Equity	936,244	52.48%	11.25%	5.90%
4. Total	$ 1,784,028	100.00%		8.35%

AG RECOMMENDED:	Adjusted Electric Capitalization (2)	Capitalization Ratios	Cost Rates (3)	Weighted Cost Rates
1. Short Term Debt	$ 42,350	2.38%	2.63%	0.06%
2. Long Term Debt	803,558	45.14%	5.30%	2.39%
3. Common Equity	934,171	52.48%	9.90%	5.20%
4. Total	$ 1,780,079	100.00%		7.65%

(1) Rives Exhibit 2, page 1
(2) Schedule RJH-2, page 2 of 2, lines 1, 2 and 3
(3) Testimony of J. Randall Woolridge

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
AG's RECOMMENDED CAPITALIZATION
($000)

	Adjusted Total Co. Capitalization	Electric Rate Base Ratio	Adjusted Electric Capitalization	Adjustments to Capitalization	Total Adjusted Capitalization
	(1)	(1)	(1)	[see below]	
1. ST Debt	51,875	80.53%	41,775	575	42,350
2. LT Debt	984,304	80.53%	792,660	10,898	803,558
3. Equity	1,144,296	80.53%	921,502	12,669	934,171
4. Total	2,180,475		1,755,937	24,142	1,780,079

	Capital Structure Ratios	TC Inventories	Investments in OVEC/Other	JDIC	ECR	ACITC	Total Capitalization Adjustments
	(2)	(2)	(3)	(2)	(2)	(2)	
5. ST Debt	2.38%	(82)	(14)	755	(400)	316	575
6. LT Debt	45.14%	(1,557)	(274)	14,319	(7,585)	5,995	10,898
7. Equity	52.48%	(1,811)	(318)	16,647	(8,818)	6,969	12,669
8. Total	100.00%	(3,450)	(606)	31,721	(16,803)	13,280	24,142

(1) Rives Appendix B - Exhibit 2, page 1 of 2
(2) Rives Appendix B - Exhibit 2, page 2 of 2
(3) Rives Appendix B - Exhibit 2, page 2 of 2, col. (4), corrected for additional removal of non-utility property

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
RETURN ON ORIGINAL COST RATE BASE
($000)

	LG&E Electric (1)	Remove Net ECR (1)	Other Adjustments	AG	
1. Utility Plant at Original Cost	$ 3,701,271	$ (23,799)		$ 3,677,472	
2. Reserve for Depreciation	(1,665,933)	9,025	15,363 (2)	(1,641,545)	
3. Net Utility Plant	2,035,338	(14,774)	15,363	2,035,927	
Deduct:					
4. Customer Advances	(12,090)			(12,090)	
5. Deferred Income Taxes	(295,155)	3,518		(291,637)	
6. FAS 109 Deferred Inc. Tax	(44,277)			(44,277)	
7. Net ARO Assets	(1,129)			(1,129)	
8. Total Deductions	(352,651)	3,518		(349,133)	
Add:					
9. Materials and Supplies	69,130			69,130	
10. Prepayments	3,276		(502) (3)	2,774	
11. Cash Working Capital	66,892	(131)	(3,000) (4)	63,761	
12. Mill Creek Ash Dredging	4,033	(1,898)		2,135	
13. Total Additions	143,331	(2,029)	(3,502)	137,800	
14. Total Net Original Rate Base	$ 1,826,018	$ (13,285)	$ 11,861	$ 1,824,594	
15. Income Requirement				$ 136,185	Sch. RJH-1, L3
16. Return on Rate Base [L15 / L14]				7.46%	

(1) Rives Exhibit 3, page 1

(2) Impact on depreciation reserve of AG's recommended depreciation expense adjustment - see Schedule RJH-8, L3

(3) Per response to AG-1-13: removed prepaid PSC assessments

(4) Per response to AG-1-15: corrected CWC adjustment should be a decrease of $3,000,161

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

	LG&E Electric	
1. LG&E's Proposed Pro Forma After-Tax Operating Income:	$ 139,557	Rives Exh. 1, p.3
AG-RECOMMENDED ADJUSTMENTS:		
2. Interest Synchonization	(2)	Sch. RJH-5
3. Unbilled Revenue Adjustment	276	Sch. RJH-6
4. Temperature Normalization Adjustment	6,000	Sch. RJH-7
5. Annualized Depreciation Expense	20,007	Sch. RJH-8
6. Labor Costs Adjustment	297	Sch. RJH-9
7. Employee Benefit Costs Adjustment	293	Sch. RJH-10
8. MISO Net Expense Adjustment	495	Sch. RJH-11
9. New Bank Credit Facilities Adjustment	390	Sch. RJH-12
10. Kentucky Coal Tax Credit Adjustment	722	Sch. RJH-13
11. Amortization of Recycle Credit	525	Sch. RJH-14
12. EEI Dues Adjustment	117	Sch. RJH-15
13. Miscellaneous Expense Adjustments	56	Sch. RJH-16
14. AG-Recommended Pro Forma After-Tax Operating Income:	$ 168,733	

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

	LG&E Electric (1)	Adjustments	AG	
1. Adjusted Capitalization	$ 1,784,028		$ 1,780,079	Sch. RJH-2
2. Weighted Cost of Debt	2.45%		2.46%	Sch. RJH-2
3. Pro Forma Interest Expense	43,709		$ 43,702	
4. Test Year Per Books Interest Deduction	41,312		41,312	
5. Interest Synchronization Adjustment	2,397		2,390	
6. Composite Income Tax Rate	37.64688%		37.64688%	
7. Impact on After-Tax Income	$ 902	$ (2)	$ 900	

(1) Rives Exhibit 1, Schedule 1.40

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
UNBILLED REVENUE ADJUSTMENT
($000)

	LG&E Electric (1)	Adjustments	AG
Unbilled Revenues at 4/30/07:			
Unbilled Base Revenues	$ 25,639		$ 25,639
FAC Revenues	-		
DSM Revenues	158		
ECR Revenues	347		
MSR/VDT/STOD PCR Revenues	(808)		
Total Unbilled Revenues	$ 25,336		$ 25,639
Unbilled Revenues at 4/30/08:			
Unbilled Base Revenues	$ 25,982		$ 25,982
FAC Revenues	659		
DSM Revenues	120		
ECR Revenues	99		
MSR/VDT/STOD PCR Revenues	(739)		
Total Unbilled Revenues	$ 26,121		$ 25,982
Difference Between 4/30/07 & 4/40/08 Unb. Rev.:			
Unbilled Base Revenues	$ (343)		$ (343)
FAC Revenues	(659)		
DSM Revenues	38		
ECR Revenues	248		
MSR/VDT/STOD PCR Revenues	(69)		
Total Unbilled Revenue Adjustment	$ (785)	$ 442	$ (343)
Composite After-Tax Income Factor (1 - .3764688)		62.35312%	
Impact on After-Tax Income		$ 276	

(1) Rives Exhibit 1, Schedule 1.00; response to AG-1-23; response to AG-2-8

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
TEMPERATURE NORMALIZATION ADJUSTMENT
($000)

	LG&E Electric (1)	Adjustments	AG	
1. Revenue Adjustment	$ (14,374)	$ 14,374	$ -	(2)
2. Variable Expense Adjustment	(4,751)	4,751	-	(2)
3. PSC Assessment and Uncollectibe Expense Adjustment @ .3438% of Line 1	-	-	-	
4. Total Net Weather Normalization Adjustment	$ (9,623)	$ 9,623	$ -	
5. Composite After-Tax Income Factor (1 - .3764688)		62.35312%		
6. Impact on After-Tax Operating Income		$ 6,000		

(1) Seelye Exhibit 19
(2) Testimony of Glenn Watkins

LOUISVILLE 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	$ 116,685	$ (32,086)	$ 84,599	(2)
2. Test Year Per Books Depr. Exp. Excluding ARO and Post-1995 ECR	99,962		99,962	
3. Depreciation Expense Change	$ 16,723	$ (32,086)	$ (15,363)	
4. Composite After-Tax Income Factor (1 - .3764688)		62.35312%		
5. Impact on After-Tax Operating Income		$ 20,007		

(1) Rives Exhibit 1, Schedule 1.11
(2) Testimony of Michael Majoros

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
LABOR COST ADJUSTMENT
($000)

	LG&E Electric (1)	Adjustments	AG	
1. Total Labor and Labor Related Cost Adjustment	$ 2,761	$ (287)	$ 2,474	(2)
2. Remove "Other Compensation" Expenses	-	(189)	(189)	(3)
3. Total Labor Cost Adjustment	$ 2,761	(476)	$ 2,285	
4. Composite After-Tax Income Factor (1 - .3764688)		62.35312%		
5. Impact on After-Tax Operating Income		$ 297		

(1) Rives Exhibit 1, Schedule 1.15
(2) Rives Exhibit 1, Schedule 1.15, Revised
(3) Response to PSC-2-91(f)2 and amended response to PSC-3-4

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
EMPLOYEE BENEFIT COST ADJUSTMENT
($000)

	LG&E Electric (1)	Adjustments	AG	
1. Pension Expense Adjustment	$ 708	$ (213)	$ 495	(2)
2. OPEB Expense Adjustment	423	(235)	188	(2)
3. Post-Employment Benefit Expense Adjustment	620	(22)	598	(2)
4. Total Employee Benefits Expense Adjustment	$ 1,751	$ (470)	$ 1,281	
5. Composite After-Tax Income Factor (1 - .3764688)		62.35312%		
6. Impact on After-Tax Operating Income		$ 293		

(1) Rives Exhibit 1, Schedules 1.16 and 1.17
(2) Rives Exhibit 1, Schedules 1.16 and 1.17, Revised

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
MISO NET COST ADJUSTMENT
($000)

1.	MISO Exit Fee Balance at 4/30/08	$ 12,372	AG-1-45(a)
2.	Estimated MISO Exit Fee Credits 5/1/08 - 2/6/09	(174)	AG-1-45(c)
3.	MISO Exit Fee Balance at 2/6/09	12,198	
4.	Cumulative Schedule 10 Receipts at 4/30/08	5,570	AG-1-46(b)
5.	Schedule 10 Receipts 5/1/08 - 2/6/09	2,506	AG-1-46(c)
6.	Cumulative Schedule 10 Receipts at 2/6/09	8,076	
7.	Net of MISO Exit Fees and Schedule 10 Receipts at Rate Effective Date of 2/6/09 [Line 3 - Line 6]	4,122	
8.	Amortization Period (Yrs)	5	
9.	Annual Amortization of Net MISO Expenses	824	
10.	MISO Exit Fee Balance at 2/6/09 [Line 3]	12,198	
11.	MISO Exit Fee Balance Through 1st Q. 2015	10,644	AG-1-45(a) and AG-2-15(b)
12.	MISO Exit Fee Credits 2/6/09 - 1st Q. 2015	1,554	
13.	Amortization Period (Yrs)	6	
14.	Annual Exit Fee Credits Amortization	259	
15.	Net MISO Expense Amortization [Line 9 - Line 14]	565	
16.	LG&E's Proposed Net MISO Expense Amortization	1,360	Rives Exhibit 1, Schedule 1.23
17.	Recommended Amortization Expense Adjustment	(795)	
18.	Composite After-Tax Income Factor (1 - .3764688)	62.35312%	
19.	Impact on After-Tax Operating Income	$ 495	

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
NEW BANK CREDIT FACILITY EXPENSES
($000)

	LG&E Electric (1)	Adjustments	AG	
1. Cost of New Bank Credit Facilities:				
- Required New Letter of Credit Amount	$ 211,335		$ 211,335	
- Letter of Credit Fee	1.1%		0.7%	(2)
- Total Estimated Fees	2,325		1,479	
- Plus: Legal Costs	50		50	
- Total Cost of New Bank Credit Facilities	2,375	(845)	1,529	
2. Electric Department Ratio		74%		
3. Composite After-Tax Income Factor (1 - .3764688)		62.35312%		
4. Impact on After-Tax Operating Income		$ 390		

(1) Exhibit 1, Schedule 1.32 and response to PSC-2-10
(2) Response to PSC-2-106, updated 10/23/08

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
KENTUCKY COAL TAX CREDIT
($000)

1. Actual Coal Tax Credits Received During Most Recent 5 Years:		
2003	$	719
2004		558
2005		1,712
2006		1,136
2007		1,666
Five-Year Average (Use as Property Tax Credit)		1,158
2. Composite After-Tax Income Factor (1 - .3764688)		62.35312%
3. Impact on After-Tax Operating Income	$	722

Source: Response to PSC-2-79

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
RECYCLE CREDIT AMORTIZATION
($000)

1. Current Remaining Recycle Credit Paid by E.ON U.S. to LG&E in September 2008	$	4,037	(1)
2. Recommended Amortization Period (Yrs)		5	
3. Recommended Annual Recycle Tax Credit		807	
4. Associated Increase in FIT @ 35%		283	
5. Net impact on After-Tax Operating Income [Line 3 - Line 4]	$	525	

(1) Responses to AG-1-30 and AG-2-14

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
EEI DUES ADJUSTMENT
($000)

1.	Total EEI Dues in Test Year	$ 413	(1)
2.	Portion of EEI Dues Related to Legislative & Regulatory Advocacy and Public Relations	45.35%	(2)
3.	Remove Portion of EEI Dues Dedicated to Lobbying	187	
4.	Composite After-Tax Income Factor (1 - .3764688)	62.35312%	
5.	Impact on After-Tax Operating Income	$ 117	

(1) Response to AG-2-20
(2) PSC Order in Case No. 2003-00433, page 51

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
MISCELLANEOUS EXPENSE ADJUSTMENTS
($000)

1. Remove Expenses Related to Employee Gifts, Award Banquets, Social Events, and Parties	$	(70)	(1)
2. Remove Fines and Penalties		(5)	(2)
3. Remove Real Estate Reception and Community Involvement Expenses		(15)	(3)
4. Toal Miscellaneous Expense Adjustments		(90)	
6. Composite After-Tax Income Factor (1 - .3764688)		62.35312%	
7. Impact on After-Tax Operating Income	$	56	

(1) Response to AG-1-75

(2) Response to AG-1-77

(3) Real estate reception expenses (electric)	$	14,496	AG-1-61 & AG-2-19
Community involvement expenses (electric)		638	AG-1-62 & AG-2-24
	$	15,134	

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	Docket 85-26	10/1986

Report Re. PROMOD and Its Use in 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 Gas Base Rate Proceeding*	Docket No. 01-307	12/2001
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	08/2003
Artesian Water Company Water Base Rate Proceeding*	Docket No. 04-42	08/2004
United Water Delaware Water Base Rate Proceeding*	Docket No. 06-174	10/2006

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
Georgia Power Company Electric Base Rate / Alternative Rate Plan Proceeding*	Docket No. 18300-U	12/2004
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 19758-U	03/2005
Georgia Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 25060-U	10/2007

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 Base Rate Rehearing*	Case No. 2000-120	02/2001
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
Northern Kentucky Water District Water District Base Rate Proceeding	Case No. 2003-0224	02/2004
Louisville Gas & Electric Company Electric Base Rate Proceeding*	Case No. 2003-0433	03/2004
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2003-0433	03/2004
Delta Natural Gas Company Base Rate Proceeding*	Case No. 2004-00067	07/2004
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2005-00042	06/2005

Big Sandy Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00125	08/2005
Louisville Gas & Electric Company Value Delivery Surcredit Mechanism*	Case No. 2005-00352	12/2005
Kentucky Utilities Company Value Delivery Surcredit Mechanism*	Case No. 2005-00351	12/2005
Kentucky Power Company Electric Base Rate Proceeding*	Case No. 2005-00341	01/2006
Cumberland Valley Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00187	05/2006
South Kentucky Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00450	07/2006
Duke Energy Kentucky Electric Base Rate Proceeding*	Case No. 2006-00172	09/2006
Atmos Energy Corporation Gas Show Cause Proceeding*	Case No. 2005-00057	09/2006
Inter County Electric Cooperative Electric Base Rate Proceeding	Case No. 2006-00415	04/2007
Atmos Energy Corporation Gas Base Rate Proceeding*	Case No. 2006-00464	04/2007
Columbia Gas of Kentucky Gas Base Rate Proceeding*	Case No. 2007-00008	06/2007
Delta Natural Gas Company Gas Base Rate Proceeding – Alternative Rate Mechanism*	Case No. 2007-00089	08/2007
Nolin Rural Electric Cooperative Corporation Electric Rate Proceeding	Case No. 2006-00466	09/2007
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2006-00022	10/2007
Jasckson Energy Cooperative Electric Base Rate Proceeding	Case No. 2007-00333	03/2008

Jackson Purchase Energy Corporation Electric Base Rate Proceeding	Case No. 2007-00116	04/2008
Blue Grass Energy Cooperative Electric Base Rate Proceeding	Case No. 2008-00011	7/2008

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 Electric Base Rate Proceeding*	Case 7570	10/1981
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	Docket 8311-1064	05/1985

Base Rate Proceeding*

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 Electric and Gas Base Rate Proceedings*	Docket ER91111698J	07/1992
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 Electric Fuel Clause Proceeding	Docket ER95090425	01/1996
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)	Docket No.WR99040249	02/2000

Base Rate Proceeding*

Elizabethtown Gas Company		
Gas Cost Adjustment Clause Proceeding	Docket No.GR99070509	03/2000
DSM Adjustment Clause Proceeding	Docket No. GR99070510	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	Docket Nos. WO99040259	06/2000
Computer and Billing Services Contracts	WO9904260	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	Docket No. GR00070470	10/2000
DSM Adjustment Clause Proceeding	Docket No. GR00070471	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	Docket No. WR02030133	07/2002

Water Base Rate Proceeding

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
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR03110900	04/2004
Consumers New Jersey Water Company Water Base Rate Proceeding	Docket No. WR02030133	07/2004
Roxiticus Water Company Purchased Water Adjustment Clause	Docket No. WR04060454	08/2004
Rockland Electric Company Societal Benefit Charge Proceeding	Docket No. ET04040235	08/2004
Wildwood Water Utility Water Base Rate Proceeding - Interim Rates	Docket No. WR04070620	08/2004
United Water Toms River Litigation Cost Accounting Proceeding	Docket No. WF04070603	11/2004

Lake Valley Water Company Water Base Rate Proceeding	Docket No. WR04070722	12/2004
Public Service Electric & Gas Company Customer Account System Proceeding	Docket No. EE04070718	02/2005
Jersey Central Power and Light Company Various Land Sales Proceedings	Docket No. EM04101107 Docket No. EM04101073 Docket No. EM04111473	02/2005 02/2005 03/2005
Environmental Disposal Corporation Water Base Rate Proceeding	Docket No. WR040080760	05/2005
Universal Service Fund Compliance Filing For 7 New Jersey Electric and Gas Utilities	Docket No. EX00020091	05/2005
Rockland Electric Company Societal Benefit Charge Proceeding	Docket No. ET05040313	08/2005
Public Service Electric & Gas Company Buried Underground Distribution Tariff Proceeding	Docket No. ET05010053	08/2005
Aqua New Jersey Acquisition of Berkeley Water Co. Water Merger Proceeding	Docket No. WM04121767	08/2005
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR05050451	10/2005
Public Service Electric & Gas Company Land Sale Proceeding	Docket No. EM05070650	10/2005
Public Service Electric & Gas Company Merger of PSEG and Exelon Corporation Direct Testimony	Docket No. EM05020106	11/2005
Public Service Electric & Gas Company* Merger of PSEG and Exelon Corporation Surrebuttal Testimony	Docket No. EM05020106	12/2005
Public Service Electric & Gas Company* Financial Review of Electric Operations	Docket No. ER02050303	12/2005
Rockland Electric Company Competitive Services Audit	Docket No. EA02020098	12/2005
Public Service Electric & Gas Company	Docket No. EE04070718	01/2006

Customer Accounting System Cost Recovery		
Roxiticus Water Company Stock Sale and Change of Ownership and Control	Docket No. WM05080755	01/2006
Public Service Electric & Gas Company Competitive Services Audit	Docket No. EA02020097	02/2006
Wildwood Water Company Water Base Rate Proceeding	Docket No. WR05070613	03/2006
Pinelands Water Company Water Base Rate Proceeding*	Docket No. WR05080681	03/2006
Pinelands Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR05080680	03/2006
Aqua New Jersey Water Company Water Base Rate Proceeding*	Docket No. WR05121022	06/2006
Public Service Electric & Gas Company Gas Base Rate Proceeding*	Docket No. GR05100845	07/2006
New Jersey American Company Consolidated Water Base Rate Proceeding,* New Jersey American Water Company, Elizabethtown Water Company, and Mount Holly Water Company	Docket No. WR06030257	10/2006
Roxiticus Water Company Water Base Rate Proceeding	Docket No. WR06120884	04/2007
United Water Company of New Jersey Change of Control Proceeding	Docket No. WM06110767	05/2007
United Water Company of New Jersey Water Base Rate Proceeding*	Docket No. WR07020135	09/2007
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR07040275	09/2007
Maxim Wastewater Company Purchased Sewerage Treatment Adjustment Clause	Docket No. WR07080632	11/2007
Fayson Lake Water Company Financing Case	Docket No. WF07080593	12/2007

Atlantic City Electric Company Sales of Utility Properties	Docket No. EM07100800	12/2007
Atlantic City Sewerage Company Base Rate and Purchased Sewerage Treatment Clause Proceedings	Docket No. WR07110866	04/2008
SB Water Company Water Base Rate Proceeding	Docket No. WR07110840	04/2008
Aqua New Jersey Water Company Water Base Rate Proceeding	Docket No. WR07120955	06/2008
Environmental Disposal Corporation Water Base Rate Proceeding	Docket No. WR07090715	06/2008
Middlesex Water Company Financing Case	Docket No. WF08040213	07/2008
Aqua New Jersey Water Company Franchise Case	Docket No. WE08040230	07/2008
Aqua New Jersey Water Company Financing Case	Docket No. WF08040216	07/2008
New Jersey American Water Company Water Base Rate Proceeding*	Docket No. WR08010020	07/2008
United Water Toms River, Inc. Water Base Rate Proceeding	Docket No. WR08030139	08/2008

<u>NEW MEXICO</u>

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 Electric Base Rate Proceeding	Case 2092	06/1987

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	Docket R-870719	12/1987

Gas Base Rate Proceeding*

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	

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OFFICE OF RATE INTERVENTION
PUBLIC SERVICE LITIGATION BRANCH

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY, INC. FOR AN	)	CASE NO. 2008-00252
ADJUSTMENT OF ITS ELECTRIC AND GAS	)	C/W
BASE RATES	)	CASE NO. 2007-00564

AFFIDAVIT OF ROBERT J. HENKES

State of Connecticut)
)
)

Robert J. Henkes, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Robert J. Henkes

SUBSCRIBED AND SWORN to before me this 21 day of Oct, 2008.

NOTARY PUBLIC

My Commission Expires: 2/28/10

LISA A. LATTANZIO
My Commission
NOTARY
PUBLIC
EXPIRES
02-28-2010
CONNECTICUT

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS	)	
AND ELECTRIC COMPANY FOR AN	)	**CASE NO. 2008-00252**
ADJUSTMENT OF ITS ELECTRIC	)	
AND GAS BASE RATES	)	

DIRECT TESTIMONY

AND EXHIBITS

OF

ROBERT J. HENKES

PERTAINING TO THE GAS CASE

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

October 28, 2008

Louisville Gas and Electric Company
Case No. 2008-00252 Gas 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 gas service.

The purpose of this testimony is to present to the Kentucky Public Service Commission ("KPSC" or the "Commission") the appropriate gas capitalization 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 capitalization 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. J. Randall Woolridge, concerning the appropriate capital structure ratios, cost rates for short- and long term debt, the return on common equity, and the resulting overall rate of return for the Company in this proceeding; and
2. Mr. Michael Majoros, concerning the appropriate depreciation rates to be adopted by the Commission in this case.

In developing this testimony, I have reviewed and analyzed the Company's July 29, 2008 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 also 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 capitalization as of April 30, 2008, the end of the test period in this case, amounts to $425.633 million which is the same as the adjusted gas capitalization of $425.633 million proposed by LG&E [Schedule RJH-1, line 1 and Schedule RJH-2].
3. The AG's expert rate of return witness, Dr. Woolridge, has at this time recommended a short-term debt cost rate of 2.63%, long-term debt cost rate of 5.30%, and a return on equity of 9.20%. These recommended capital cost rates, together with Dr. Woolridge's recommended capital structure ratios produce the AG's recommended overall rate of return on capitalization for LG&E's gas operations of 7.28%. By comparison, the Company has proposed an overall rate of return on capitalization of 8.35% for its gas operations [Schedule RJH-2].

The recommended rate of return on capitalization of 7.28% is equivalent to a rate of return of 6.96% on the Company's adjusted gas rate base [Schedule RJH-3, line 16]. The Company has not presented an equivalent proposed overall return on rate base number for its gas operations.

4. The appropriate pro forma adjusted gas rate base measured as of April 30, 2008, the end of the test period in this case, amounts to $445.619 million. The recommended return on rate base amounts to 6.96% [Schedule RJH-3].

5. The appropriate pro forma test period gas operating income amounts to $23.023 million, which is $5.991 million higher than LG&E's proposed test period gas operating income of $17.032 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 .62143063. This factor has been used by both the Company and the AG [Schedule RJH-1, line 6].

7. The application of the recommended overall rate of return of 7.28% to the recommended capital structure of $425.633 million, combined with the recommended pro forma test period operating income of $23.023 million and the revenue conversion factor of .62143063 indicates that the Company has an annual revenue deficiency for its gas operations of $12.835 million. This is $16.949 million lower than the Company's proposed annual gas revenue deficiency of $29.784 million [Schedule RJH-1, lines 1-7].

IV. REVENUE REQUIREMENT ISSUES

A. CAPITALIZATION

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

A. The Company has proposed an adjusted gas capitalization of $425.633 million. As shown on Rives Exhibit 2, the starting point of the Company's proposed pro forma adjusted gas capitalization is the actual per books total company capitalization as of 4/30/08 of approximately $2,180.475 million, consisting of short term debt, long term debt, and common equity. The Company then applied a gas rate base ratio of 19.47% to its actual 4/30/08 capitalization of $2,180.475 million, resulting in its proposed gas capitalization balance of $424.539 million. Next, the Company adjusted its gas capitalization balance by the addition of the gas-allocated Job Development Tax Credit balance of $1.094 million, resulting in a proposed adjusted gas capitalization of $425.633 million.

Q. DO YOU AGREE WITH THE PREVIOUSLY DESCRIBED ADJUSTED GAS CAPITALIZATION BALANCE PROPOSED BY THE COMPANY?

A. Yes, the Company's proposed adjusted gas capitalization balance of $425.633 has been determined in accordance with a calculation methodology previously prescribed by the Commission.

B. RATE OF RETURN ON CAPITALIZATION

Q. PLEASE DESCRIBE THE AG'S RECOMMENDED RATE OF RETURN ON CAPITALIZATION.

A. As shown on Schedule RJH-2, page 1, the AG recommends an overall return on capitalization of 7.28% as compared to the Company's proposed overall rate of return number of 8.35%. The AG-recommended overall rate of return number is based on the capital structure ratios and capital cost rates recommended by the AG's rate of return expert, Dr. Woolridge. As shown on Schedule RJH-2, page 1, Dr. Woolridge recommends a short-term debt cost rate of 2.63%, long-term debt cost rate of 5.30% and a return on equity of 9.20%.

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 return requirement rate making policy adopted by the Commission in all of LG&E's prior base rate proceedings.

C. RATE BASE AND RETURN ON 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. Yes. As shown on Rives Exhibits 3 and 4, the Company is proposing an adjusted original cost rate base of $438.486 million.

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 of $441.457 million measured as of the end of the test year, April 30, 2008. From that starting point, I then reflected total net rate base additions of $4.162 million to arrive at my recommended adjusted original cost rate base for LG&E's gas operations of $445.619 million. This recommended adjusted rate base of $445.619 million is $7.1333 million higher than the Company's proposed adjusted rate base of $438.486 million.

Q. WHY IS YOUR RECOMMENDED ADJUSTED ORIGINAL COST GAS RATE BASE $7.133 MILLION HIGHER THAN THE COMPANY'S PROPOSED ORIGINAL COST GAS RATE BASE?

A. As just discussed, I have reflected rate base adjustments that *increase* the rate base by $4.162 million whereas the Company has proposed rate base adjustments that *decrease* the rate base by $2.971 million. This explains why my recommended adjusted rate base is $7.133 million higher than the Company's proposed adjusted rate base. Below, I have listed the component reasons for this rate base differential of $7.133 million:

	LG&E Rate Base	AG Rate Base	Difference
Depreciation Reserve Adj.	$(3.489)	$4.269	$7.758
Remove Prepaid PSC Fees	-	(.195)	(.195)
CWC Adjustment	.518	.088	(0.430)
Total	$(2.971)	$4.162	$7.133

As shown in the above table, by far the largest reason for the rate base differential is the pro forma impact on the depreciation reserve resulting from LG&E's proposal to increase its test year per books depreciation expenses and AG's recommendation to decrease the test year per books depreciation expenses.

Q. PLEASE DISCUSS EACH OF THE RECOMMENDED RATE BASE ADJUSTMENTS TOTALING $4.162 MILLION.

A. The first rate base adjustment of $4.269 million shown on line 3 of the third column of Schedule RJH-3 is a direct result of the AG's recommended annualized depreciation expense adjustment shown on Schedule RJH-7, line 3. This annualized depreciation expense adjustment will be discussed later in this testimony.

The second rate base adjustment of $.195 million shown on line 10 of Schedule RJH-3 represents my recommendation to remove prepaid PSC assessments from the total gas prepayment balance in rate base. This adjustment follows well-established and long-standing Commission ratemaking policy.

The third rate base adjustment of $88,000 shown on line 11 of Schedule RJH-3 is to adjust the test year per books cash working capital requirement for the pro forma impact on cash working capital of all of the Company's proposed O&M expense adjustments in this case. In its response to AG-1-16, the Company has acknowledged that the correct cash working capital adjustment resulting from its proposed pro forma O&M expense adjustments should be an increase of $88,000 rather than the cash working capital increase of $518,000 reflected in the Company's as-filed position. It should be noted that the appropriate cash working capital amount to be reflected for ratemaking purposes in this case should ultimately be based on the reflection of all Commission-ordered pro forma test year electric operation and maintenance expenses allowed in this case.

Q. HAVE YOU CALCULATED THE APPROPRIATE RETURN ON RATE BASE FOR LG&E'S GAS OPERATIONS IN THIS CASE?

A. Yes, as shown on Schedule RJH-3, lines 14 through 16, the Company's appropriate return on rate base in this case is 6.96%

D. OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND 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 $17.032 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 $5.991 million to total recommended pro forma test period gas operating income of $23.023 million. Each of the recommended gas operating income adjustments will be discussed in detail in the subsequent sections of this testimony.

- **Interest Synchronization**

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

A. Yes. The Commission 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. An income tax adjustment should be made for the difference between the pro forma synchronized interest expenses and the test year per books interest expenses.

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. However, since the AG's recommended weighted cost of debt number is slightly higher than that proposed by LG&E, the AG's recommended synchronized interest level is slightly higher than LG&E's proposed synchronized interest level.

Q. WHAT IS THE IMPACT OF THESE DIFFERENT SYNCHRONIZED INTEREST LEVELS ON THE COMPANY'S PROPOSED TEST YEAR AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-5, the AG's recommended interest synchronization adjustment increases the Company's proposed test year after-tax income by $8,000.

- **Unbilled Revenue Adjustment**

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

A. I believe so. The Company has proposed that its unbilled revenues as of April 30, 2008, the end of the test year, be removed and be replaced by the unbilled revenues as of April 2007, the beginning of the test year. Since the unbilled revenues at the end of the test year are $1.203 million higher than the unbilled revenues at the beginning of the test year, the Company's proposed unbilled revenue adjustment increases the base rate revenue requirement and corresponding base rate increase requested in this case by $1.203 million. However, as can be seen from the analysis on Schedule RJH-6, only $37,000 of the $1.203 unbilled revenue differential is caused by the difference in unbilled base rate revenues at April 30, 2008 vs. April 30, 2007. Thus, almost the entire unbilled revenue adjustment of $1.203 million proposed by the Company is caused by the difference in unbilled GSC, DSM, and VDT surcharge revenues at April 30, 2008 vs. April 30, 2007. On page 8, lines 18 - 23 of his testimony, Company witness Bellar states that the costs and revenues associated with ratemaking mechanisms such as the fuel adjustment clause, ECR clause or DSM cost recovery should have no effect on the calculation of the base revenue deficiency and corresponding base rate increase that LG&E is requesting in this case. Yet, this is exactly what the Company is proposing to do through its proposed unbilled revenue adjustment. In summary, I believe it is inappropriate to increase the base rate revenue requirement in this case by $1.203 million if virtually the entire revenue requirement is caused by the end-of-test year vs. beginning-of-test year differential in unbilled GSC, DSM and VDT surcharge revenues. In addition, the Company has not similarly proposed an adjustment for the differential in the associated end-of-test year vs. beginning-of-test year differential in unbilled GSC and DSM costs.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE?

A. I recommend that the Company's proposed unbilled revenue adjustment be limited to the unbilled base rate revenues and exclude any unbilled revenue considerations for the GSC, DSM, and VDT surcharge mechanisms. As shown on Schedule RJH-6, my recommendation would increase the Company's proposed test year after-tax income by $.773 million.

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

Q. PLEASE EXPLAIN THE REASON FOR THE RECOMMENDED ANNUALIZED DEPRECIATION EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-7.

A. The annualized depreciation expense adjustment shown on Schedule RJH-7 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 $7.758

million lower annualized gas 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 $4.837 million.

- **<u>Labor Cost Adjustment</u>**

Q. PLEASE EXPLAIN THE REASON FOR THE RECOMMENDED LABOR COST ADJUSTMENT SHOWN ON SCHEDULE RJH-8.

A. The recommended labor cost adjustment consists of two parts. The first part represents a labor cost adjustment of $76,000 to correct for an error in the Company's as-filed labor cost adjustment calculations. The second part represents a labor cost adjustment of $50,000 to remove certain executive incentive compensation expenses from the test year gas operating expenses.

As shown on schedule RJH-8, the recommended total labor cost adjustment increases the Company's proposed test year gas after-tax operating income by approximately $79,000.

- **<u>Employee Benefit Cost Adjustment</u>**

Q. PLEASE EXPLAIN THE REASON FOR THE RECOMMENDED EMPLOYEE BENEFIT COST ADJUSTMENT SHOWN ON SCHEDULE RJH-9.

A. The recommended employee benefit cost adjustment total of $.125 million results from corrections made by the Company in its as-filed cost adjustments for pension, OPEB and Post-Employment Benefit expenses.

As shown on schedule RJH-9, the recommended total employee benefit cost adjustment increases the Company's proposed test year gas after-tax operating income by approximately $78,000.

- **New Bank Credit Facilities Adjustment**

Q. HAVE YOU MADE AN ADJUSTMENT TO THE COMPANY'S PROPOSED ADJUSTMENT FOR THE NEW BANK CHARGE CREDIT FACILITY CHARGES?

A. Yes. As shown on Schedule RJH-10, the Company has proposed an expense adjustment of $2.375 million for this item. This proposed cost amount assumes letters of credit associated with two anticipated bond issues totaling $211.335 million, an estimated letter of credit fee of 1.1%, and associated annual recurring legal fees of $50,000. None of these assumptions are firm at this time. For example, in its response to AG-2-18, the Company states with regard to the anticipated bond issues of $211.335 million:

> The company currently expects to close on the two bonds in late November 2008 or early December 2008. However, the capital markets are extremely volatile and market conditions may result in the need to modify this plan.

The letter of credit fees are also uncertain at this time. While the Company initially assumed an annual fee of 1.1% of the total bond issuance amount, in September 2008 it revised the estimated annual fee to .5% and most recently revised it again to a rate of .7%. The Company has also provided no support for the legal expense of $50,000 and has not clarified that this is an annual recurring expense. For these reasons, I do not believe that the expense adjustment amount proposed by the Company in this case is known and measurable at this time.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE BASED ON THE FOREGOING FINDINGS AND CONCLUSIONS?

A. I have decided to take a conservative position on this matter. Specifically, rather than rejecting the Company's proposed expense adjustment for the reason that it is not known and measurable at this time, I have assumed the same bond issuance amount of $211.335 million and the same $50,000 annual legal fees proposed by the Company. However, I have reflected the most recent available letter of credit fee of .7%, as opposed to the Company's assumed fee of 1.1%. As shown on Schedule RJH-10, based on these conservative assumptions, my recommendation at this time is to reflect a pro forma expense adjustment of $1.529 million on a total company basis. This recommended expense adjustment should be updated when firm, actual information has become available regarding the amount and timing of the bond issuances, the letter of credit percentage fee, and the annual recurring legal fees prior to the close of record in this case.

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

A. As shown on Schedule RJH-10, my recommendations regarding this issue increase the Company's proposed test year after-tax gas operating income by $.137 million.

- **MGP Amortization Expense Adjustment**

Q. WHAT IS THE ISSUE WITH REGARD TO THE MANUFACTURERS GAS PLANT ("MGP") AMORTIZATION EXPENSE ADDRESSED ON SCHEDULE RJH-11?

A. As shown in the responses to AG-1-10 and AG-1-65, the test year includes approximately $81,000 worth of MGP amortization expenses which will no longer be booked as of September 30, 2008 because at that date the deferred MGP costs will be fully amortized. Since this represents a non-recurring expense, I recommend that it be removed for ratemaking purposes in this case.

As shown on Schedule RJH-11, my recommendation increases the Company's proposed after-tax gas operating income by $51,000.

- **AGA Dues Adjustment**

Q. PLEASE EXPLAIN YOUR RECOMMENDATION TO REMOVE A

PORTION OF THE COMPANY'S ANNUAL AMERICAN GAS ASSOCIATION ("AGA") DUES FOR RATEMAKING PURPOSES IN THIS CASE.

A. The test year gas operating expenses include $128,000 for AGA dues. Certain portions of AGA activities are dedicated to legislative/regulatory advocacy and other lobbying activities that make up the Public Affairs function of AGA. The Commission has always held that lobbying-related expenses should be treated below-the-line for ratemaking purposes, and I agree with that policy. In response to AG-1-73(b) in this case, the Company provided a functional breakout of AGA activities showing that 27.93% of AGA's activities are related to the combined Public Affairs/Communications function. The response did not provide a further breakout of the 27.93% between lobbying-related Public Affairs and non-lobbying related Communications activities. However, the response to Post-Hearing Question No. 11 in the Company's prior rate case, Case No. 2003-00433, *did* show such a breakout and indicated that 22.59% of AGA's activities are dedicated to the Public Affairs function. Thus, in order not to overstate my recommended adjustment to remove lobbying expenses, I have applied the lower 22.59% ratio to the test year total AGA dues of $128,000, resulting in a recommended lobbying expense adjustment of $29,000.

As shown on Schedule RJH-12, my recommendation increases the Company's proposed test year after-tax gas operating income by $18,000.

- **Miscellaneous Expense Adjustments**

Q. PLEASE DESCRIBE THE MISCELLANEOUS ADJUSTMENTS SHOWN ON SCHEDULE RJH-13.

A. First, I recommend the removal from test year gas operating expenses of $8,000 for expenses associated with employee gifts, award banquets, parties and other social events (e.g., company picnics). My recommendation is consistent with previously established Commission-policy that such expenses do not produce benefits to the ratepayers and should be excluded for ratemaking purposes.[1]

Second, I recommend the removal from test year gas operating expenses of approximately $2,000 worth of penalty and fines expenses. Such expenses should be funded by the Company's stockholders, not ratepayers.

Third, I have removed approximately $7,000 of gas expenses associated with real estate receptions and community involvement. As shown in more detail in the responses to AG-2-19 and 2-24, these expenses are for such items as community trade shows, fundraisers, music, florists, showcase gifts, reception catering, valet parking, service charges, etc. I do not believe that such expenses should be funded by the ratepayers as they have nothing to do with the provision of safe, adequate and reliable gas service.

[1] Similar expenses were excluded from rate recognition in the Company's prior electric rate case – see pages 50-51 in the PSC Order in Case No. 2003-00433.

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-13, the recommended miscellaneous expense adjustments increase the Company's proposed test year gas after-tax operating income by approximately $11,000.

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

A. Yes, it does.

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
REVENUE REQUIREMENT
($000)

	LG&E Gas (1)	Adjustments	AG	
1. Capital Structure	$ 425,633	$ 0	$ 425,633	Sch. RJH-2
2. Rate of Return	8.35%		7.28%	Sch. RJH-2
3. Income Requirement	35,540		31,000	
4. Pro Forma Income	17,032	5,991	23,023	Sch. RJH-4
5. Income Deficiency	18,508		7,976	
6. Revenue Conversion Factor	0.62143063		0.62143063	
7. Overall Revenue Deficiency	$ 29,784	$ (16,949)	$ 12,835	

(1) Rives Exhibit 8, page 2

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
ADJUSTED CAPITALIZATION AT 4/30/08
($000)

LG&E PROPOSED:	Adjusted Gas Capitalization (1)	Capitalization Ratios	Cost Rates	Weighted Cost Rates
1. Short Term Debt	$ 10,126	2.38%	2.63%	0.06%
2. Long Term Debt	192,138	45.14%	5.30%	2.39%
3. Common Equity	223,369	52.48%	11.25%	5.90%
4. Total	$ 425,633	100.00%		8.35%

AG RECOMMENDED:	Adjusted Gas Capitalization (2)	Capitalization Ratios	Cost Rates (3)	Weighted Cost Rates
1. Short Term Debt	$ 10,126	2.38%	2.63%	0.06%
2. Long Term Debt	192,138	45.14%	5.30%	2.39%
3. Common Equity	223,369	52.48%	9.20%	4.83%
4. Total	$ 425,633	100.00%		7.28%

(1) Rives Exhibit 2, page 1
(2) Schedule RJH-2, page 2 of 2, lines 1, 2 and 3
(3) Testimony of J. Randall Woolridge

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
AG's RECOMMENDED CAPITALIZATION
($000)

	Adjusted Total Co. Capitalization (1)	Gas Rate Base Ratio (1)	Adjusted Gas Capitalization (1)	Adjustments to Capitalization [see below]	Total Adjusted Capitalization
1. ST Debt	51,875	19.47%	10,100	26	10,126
2. LT Debt	984,304	19.47%	191,644	494	192,138
3. Equity	1,144,296	19.47%	222,795	574	223,369
4. Total	2,180,475		424,539	1,094	425,633

	Capital Structure Ratios (2)	JDIC (2)	Total Capitalization Adjustments
5. ST Debt	2.38%	26	26
6. LT Debt	45.14%	494	494
7. Equity	52.48%	574	574
8. Total	100.00%	1,094	1,094

(1) Rives Appendix B - Exhibit 2, page 1 of 2
(2) Rives Appendix B - Exhibit 2, page 2 of 2
(3) Rives Appendix B - Exhibit 2, page 2 of 2, col. (4), corrected for additional removal of non-utility property

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
RETURN ON ORIGINAL COST RATE BASE
($000)

	LG&E Gas (1)	Adjustments		AG	
1. Utility Plant at Original Cost	$ 677,615			$ 677,615	
2. Reserve for Depreciation	(232,849)	4,269	(2)	(228,580)	
3. Net Utility Plant	444,766	4,269		449,035	
Deduct:					
4. Customer Advances	(8,043)			(8,043)	
5. Deferred Income Taxes	(51,050)			(51,050)	
6. FAS 109 Deferred Inc. Tax	(4,502)			(4,502)	
7. Net ARO Assets	129			129	
8. Total Deductions	(63,466)			(63,466)	
Add:					
9. M&S and Stored Gas	52,611			52,611	
10. Prepayments	818	(195)	(3)	623	
11. Cash Working Capital	6,728	88	(4)	6,816	
12. Mill Creek Ash Dredging	-			-	
13. Total Additions	60,157	(107)		60,050	
14. Total Net Original Rate Base	$ 441,457	$ 4,162		$ 445,619	
15. Income Requirement				$ 31,000	Sch. RJH-1, L3
16. Return on Rate Base [L15 / L14]				6.96%	

(1) Rives Exhibit 3, page 1
(2) Impact on depreciation reserve of AG's recommended depreciation expense adjustment - see Schedule RJH-7, L3
(3) Per response to AG-1-13: removed prepaid PSC assessments
(4) Per response to AG-1-16: corrected CWC adjustment should be an increase of $88,157

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

		LG&E Gas	
1. LG&E's Proposed Pro Forma After-Tax Operating Income:	$	17,032	Rives Exh. 1, p.3
AG-RECOMMENDED ADJUSTMENTS:			
2. Interest Synchonization		8	Sch. RJH-5
3. Unbilled Revenue Adjustment		773	Sch. RJH-6
4. Annualized Depreciation Expense		4,837	Sch. RJH-7
5. Labor Costs Adjustment		79	Sch. RJH-8
6. Employee Benefit Costs Adjustment		78	Sch. RJH-9
7. New Bank Credit Facilities Adjustment		137	Sch. RJH-10
8. MGP Amortization Adjustment		51	Sch. RJH-11
9. AGA Dues Adjustment		18	Sch. RJH-12
10. Miscellaneous Expense Adjustments		11	Sch. RJH-13
13. AG-Recommended Pro Forma After-Tax Operating Income:	$	23,023	

(1) Calculation: $9,623,170 x after-tax income factor of 62.35312% = $6,000,347

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

	LG&E Gas (1)	Adjustments	AG	
1. Adjusted Capitalization	$ 425,633		$ 425,633	Sch. RJH-2
2. Weighted Cost of Debt	2.45%		2.46%	Sch. RJH-2
3. Pro Forma Interest Expense	10,428		$ 10,450	
4. Test Year Per Books Interest Deduction	10,198		10,198	
5. Interest Synchronization Adjustment	230		252	
6. *Composite Income Tax Rate*	37.64688%		37.64688%	
7. Impact on After-Tax Income	$ 87	$ 8	$ 95	

(1) Rives Exhibit 1, Schedule 1.40

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
UNBILLED REVENUE ADJUSTMENT
($000)

	LG&E Gas (1)	Adjustments	AG
Unbilled Revenues at 4/30/07:			
Unbilled Base Revenues	$ 1,367		$ 1,367
GSC Revenues	6,195		
DSM Revenues	45		
VDT Revenues	(44)		
Total Unbilled Revenues	$ 7,563		$ 1,367
Unbilled Revenues at 4/30/08:			
Unbilled Base Revenues	$ 1,330		$ 1,330
GSC Revenues	7,462		
DSM Revenues	30		
VDT Revenues	(56)		
Total Unbilled Revenues	$ 8,766		$ 1,330
Difference Between 4/30/07 & 4/40/08 Unb. Rev.:			
Unbilled Base Revenues	$ 37		$ 37
FAC Revenues	(1,267)		
DSM Revenues	15		
VDT Revenues	12		
Total Unbilled Revenue Adjustment	$ (1,203)	$ 1,240	$ 37
Composite After-Tax Income Factor (1 - .3764688)		62.35312%	
Impact on After-Tax Income		$ 773	

(1) Rives Exhibit 1, Schedule 1.00; response to AG-1-23; response to AG-2-8

LOUISVILLE 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	$ 22,403		$ 14,645	(2)
2. Test Year Per Books Depr. Exp. Excluding ARO and Post-1995 ECR	18,914		18,914	
3. Depreciation Expense Change	$ 3,489	$ (7,758)	$ (4,269)	
4. Composite After-Tax Income Factor (1 - .3764688)		62.35312%		
5. Impact on After-Tax Operating Income		$ 4,837		

(1) Rives Exhibit 1, Schedule 1.11
(2) Testimony of Michael Majoros

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
LABOR COST ADJUSTMENT
($000)

	LG&E Gas (1)	Adjustments	AG	
1. Total Labor and Labor Related Cost Adjustment	$ 734	$ (76)	$ 658	(2)
2. Remove "Other Compensation" Expenses	-	(50)	(50)	(3)
3. Total Labor Cost Adjustment	$ 734	(126)	$ 608	
4. Composite After-Tax Income Factor (1 - .3764688)		62.35312%		
5. Impact on After-Tax Operating Income		$ 79		

(1) Rives Exhibit 1, Schedule 1.15
(2) Rives Exhibit 1, Schedule 1.15, Revised
(3) Response to PSC-2-91(f)2 and amended response to PSC-3-4

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
EMPLOYEE BENEFIT COST ADJUSTMENT
($000)

	LG&E Gas (1)	Adjustments	AG	
1. Pension Expense Adjustment	$ 188	$ (56)	$ 132	(2)
2. OPEB Expense Adjustment	113	(63)	50	(2)
3. Post-Employment Benefit Expense Adjustment	165	(6)	159	(2)
4. Total Employee Benefits Expense Adjustment	$ 466	$ (125)	$ 341	
5. Composite After-Tax Income Factor (1 - .3764688)		62.35312%		
6. Impact on After-Tax Operating Income		$ 78		

(1) Rives Exhibit 1, Schedules 1.16 and 1.17
(2) Rives Exhibit 1, Schedules 1.16 and 1.17, Revised

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
NEW BANK CREDIT FACILITY EXPENSES
($000)

	LG&E Gas (1)	Adjustments	AG	
1. Cost of New Bank Credit Facilities:				
- Required New Letter of Credit Amount	$ 211,335		$ 211,335	
- Letter of Credit Fee	1.1%		0.7%	(2)
- Total Estimated Fees	2,325		1,479	
- Plus: Legal Costs	50		50	
- Total Cost of New Bank Credit Facilities	2,375	(845)	1,529	
2. Electric Department Ratio		26%		
3. Composite After-Tax Income Factor (1 - .3764688)		62.35312%		
4. Impact on After-Tax Operating Income		$ 137		

(1) Exhibit 1, Schedule 1.32 and response to PSC-2-10
(2) Response to PSC-2-106, updated 10/23/08

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
MGP AMORTIZATION ADJUSTMENT
($000)

	LG&E Gas (1)	Adjustments	AG	
1. MGP Amortization Expense in Test Year	$ 81	$ (81)	$ -	(2)
2. Composite After-Tax Income Factor (1 - .3764688)		62.35312%		
3. Impact on After-Tax Operating Income		$ 51		

(1) Response to AG-1-65
(2) Per response to AG-1-65: amortization is non-recurring as it has expired effective 9/30/08

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC RATE CASE
AGA DUES ADJUSTMENT
($000)

1. Total AGA Dues in Test Year	$	128	(1)
2. Portion of AGA Dues Related to Public Affairs		22.59%	(2)
3. Remove Portion of AGA Dues Dedicated to Lobbying		29	
4. Composite After-Tax Income Factor (1 - .3764688)		62.35312%	
5. Impact on After-Tax Operating Income	$	18	

(1) Response to AG-1-74
(2) Response to Post-Hearing Question No 11 in Case No. 2003-00433

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS RATE CASE
MISCELLANEOUS EXPENSE ADJUSTMENTS
($000)

1. Remove Expenses Related to Employee Gifts, Award Banquets, Social Events, and Parties	$	(8)	(1)
2. Remove Fines and Penalties		(2)	(2)
3. Remove Real Estate Reception and Community Involvement Expenses		(7)	(3)
5. Toal Miscellaneous Expense Adjustments		(17)	
6. Composite After-Tax Income Factor (1 - .3764688)		62.35312%	
7. Impact on After-Tax Operating Income	$	11	

(1) Response to AG-1-75

(2) Response to AG-1-77

(3) Real estate reception expenses (gas)	$	6,574	AG-1-61 & AG-2-19
Community involvement expenses (gas)		522	AG-1-62 & AG-2-24
	$	7,096	

APPENDIX I

<u>PRIOR REGULATORY EXPERIENCE OF ROBERT J. HENKES</u>

* = 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	Docket 85-26	10/1986

Report Re. PROMOD and Its Use in 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 Gas Base Rate Proceeding*	Docket No. 01-307	12/2001
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	08/2003
Artesian Water Company Water Base Rate Proceeding*	Docket No. 04-42	08/2004
United Water Delaware Water Base Rate Proceeding*	Docket No. 06-174	10/2006

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
Georgia Power Company Electric Base Rate / Alternative Rate Plan Proceeding*	Docket No. 18300-U	12/2004
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 19758-U	03/2005
Georgia Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 25060-U	10/2007

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 Base Rate Rehearing*	Case No. 2000-120	02/2001
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
Northern Kentucky Water District Water District Base Rate Proceeding	Case No. 2003-0224	02/2004
Louisville Gas & Electric Company Electric Base Rate Proceeding*	Case No. 2003-0433	03/2004
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2003-0433	03/2004
Delta Natural Gas Company Base Rate Proceeding*	Case No. 2004-00067	07/2004
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2005-00042	06/2005

Big Sandy Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00125	08/2005
Louisville Gas & Electric Company Value Delivery Surcredit Mechanism*	Case No. 2005-00352	12/2005
Kentucky Utilities Company Value Delivery Surcredit Mechanism*	Case No. 2005-00351	12/2005
Kentucky Power Company Electric Base Rate Proceeding*	Case No. 2005-00341	01/2006
Cumberland Valley Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00187	05/2006
South Kentucky Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00450	07/2006
Duke Energy Kentucky Electric Base Rate Proceeding*	Case No. 2006-00172	09/2006
Atmos Energy Corporation Gas Show Cause Proceeding*	Case No. 2005-00057	09/2006
Inter County Electric Cooperative Electric Base Rate Proceeding	Case No. 2006-00415	04/2007
Atmos Energy Corporation Gas Base Rate Proceeding*	Case No. 2006-00464	04/2007
Columbia Gas of Kentucky Gas Base Rate Proceeding*	Case No. 2007-00008	06/2007
Delta Natural Gas Company Gas Base Rate Proceeding – Alternative Rate Mechanism*	Case No. 2007-00089	08/2007
Nolin Rural Electric Cooperative Corporation Electric Rate Proceeding	Case No. 2006-00466	09/2007
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2006-00022	10/2007
Jasckson Energy Cooperative Electric Base Rate Proceeding	Case No. 2007-00333	03/2008

Jackson Purchase Energy Corporation Electric Base Rate Proceeding	Case No. 2007-00116	04/2008
Blue Grass Energy Cooperative Electric Base Rate Proceeding	Case No. 2008-00011	7/2008

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 Electric Base Rate Proceeding*	Case 7570	10/1981
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
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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
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Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings	Docket 761-8	10/1976
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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
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Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	02/1988
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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
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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
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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY, INC. FOR AN	)	CASE NO. 2008-00252
ADJUSTMENT OF ITS ELECTRIC AND GAS	)	C/W
BASE RATES	)	CASE NO. 2007-00564

AFFIDAVIT OF ROBERT J. HENKES

State of Connecticut)
)
)

Robert J. Henkes, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Robert J. Henkes

SUBSCRIBED AND SWORN to before me this 21 day of Oct, 2008.

NOTARY PUBLIC

My Commission Expires: 2/28/10

LISA A. LATTANZIO
NOTARY PUBLIC
CONNECTICUT
My Commission Expires 02-28-2010

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
THE APPLICATION OF THE	)	
LOUISVILLE GAS & ELECTRIC COMPANY	)	**CASE NO. 2008-00252**
TO INCREASE ITS GAS SERVICE RATES	)	

DIRECT TESTIMONY

OF

DR. J. RANDALL WOOLRIDGE

October 28, 2008

Louisville Gas & Electric Company

Direct Testimony of
Dr. J. Randall Woolridge

TABLE OF CONTENTS

LIST OF EXHIBIT

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is J. Randall Woolridge, and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and President of the Nittany Lion Fund, LLC. A summary of my educational background, research, and related business experience is provided in Appendix A.

I. SUBJECT OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by the Kentucky Office of Attorney General ("OAG") to provide an opinion as to the overall fair rate of return or cost of capital for the Louisville Gas & Electric ("LG&E" or "Company") and to evaluate LG&E's rate of return testimony in this proceeding.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First I will review my cost of capital recommendation for LG&E, and review the primary areas of contention between LG&E's rate of return position and OAG. Second, I provide an assessment of capital costs in today's capital markets.

Third, I discuss my proxy group of electric utility companies for estimating the cost of capital for LG&E. Fourth, I present my recommendations for the Company's capital structure and debt cost rate. Fifth, I discuss the concept of the cost of equity capital, and then estimate the equity cost rate for LG&E. Finally, I critique Company's rate of return analysis and testimony. I have a table of contents just after the title page for a more detailed outline.

Q. PLEASE REVIEW YOUR RECOMMENDATIONS REGARDING THE APPROPRIATE RATE OF RETURN FOR LG&E.

A. I am using the capital structure developed by OAG Witness Robert Henkes. My analysis indicates that the capital structure ratios, which are identical to those proposed by the LG&E, are very fair given the capitalizations of electric utility and gas distribution companies. I have adopted the Company's proposed short-term and long-term debt cost rates. I have estimated individual equity cost rates for LG&E's electric utility and gas distribution operations. I have applied the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to a proxy group of publicly-held electric utility companies ("Electric Proxy Group") and gas distribution companies ("Gas Proxy Group"). My analysis indicates an equity cost rate in the range of 8.2%-9.9% for LG&E's electric utility operations and an equity cost rate in the range of 8.2%-9.2% for LG&E's electric utility operations. I have used the upper end of the ranges - 9.9% for electric and 9.2% for gas - as my equity cost rates in recognition of the volatile capital market conditions. However, I reserve the right to update my equity cost rate recommendations prior to hearings. This is because, in my opinion, the current market conditions are in disequilibrium as investors attempt to sort out the economic consequences of the collapse of the financial sector and the unprecedented bail out by the U. S. government. In addition, certain financial data have not been updated to reflect the current economic situation. Using my capital structure and debt and equity cost rates, I am recommending an overall rate of return of 7.65% for the electric utility operations and 7.28% for gas distribution operations. These findings are summarized in Exhibit JRW-1.

Q. PLEASE SUMMARIZE THE PRIMARY ISSUES REGARGING RATE OF RETURN IN THIS PROCEEDING.

A. Mr. S. Bradford Rives provides the Company's proposed capital structure and debt cost rates and Dr. William E. Avera provides LG&E's proposed common equity cost rate. My analysis suggests that the Company's recommended capital structure with a common equity ratio of 52.48% is very fair to LG&E, especially for the electric utility operations. I do employ the Company's debt cost rates. As such, the primary area of contention in this case is the proposed equity cost rate for LG&E. Dr. Avera's equity cost rate estimate is 11.25%, whereas my analysis indicates an equity cost rate of 9.90% is appropriate for LG&E's electric utility operations and 9.20% is appropriate for LG&E's gas distribution operations.

Both Dr. Avera and I have applied the DCF and the CAPM approaches to groups of publicly-held utility companies. Dr. Avera has also used an Expected Earnings approach to estimate an equity cost rate for LG&E. As discussed in my testimony, my equity cost rate recommendation is consistent with the current economic environment. Long-term capital costs are at historical low levels. The yields on long-term Treasury bonds have been in the 4-5 percent range for several years. Prior to this cyclical decline in rates in 2002, these yields had not been this low over an extended period of time since the 1960s. Long-term capital costs are also low due to the decline in the equity risk premium and the Jobs and Growth Tax Relief Reconciliation Act of 2003, which reduced the tax rates on dividend income and capital gains.

Dr. Avera employs a proxy group that includes several companies which receive a low percentage of revenues from regulated utility operations. In addition, he employs an inappropriate non-utility proxy group. With respect to the application of the DCF model, the major area of disagreement is the expected DCF growth rate. Dr. Avera relies on the earnings per share ("EPS") growth rate forecasts of Wall Street analysts and *Value Line* for his DCF growth rate. I demonstrate that there is a well-known upward bias to these growth rate forecasts.

The CAPM approach requires an estimate of the risk-free interest rate, beta, and the equity risk premium. Dr. Avera's risk-free rate is above current market interest rates. However, the primary problem with his CAPM is his market risk premium of 8.90%. I provide evidence that this market risk premium is based on an expected stock market return that is not reflective of current market fundamentals. I also demonstrate that this expected market return is also based on an expected EPS growth rate that is not reasonable given prospective economic and earnings growth. On the other hand, I use a market risk premium which (1) uses alternative approaches to estimating a market premium and (2) employs the results of over thirty studies and surveys of the market risk premium. As I note, my market risk premium is consistent with the market risk premiums (1) discovered in recent academic studies by leading finance scholars, (2) employed by leading investment banks and management consulting firms, and (3) that result from surveys of financial forecasters and corporate CFOs.

Finally, Dr. Avera's Expected Earnings approach is subject to a number of errors and, therefore, does not provide a reliable estimate of the Company's cost of equity capital. Furthermore, this methodology, which is not market-based, has not been used by regulatory commissions for years as an equity cost rate approach.

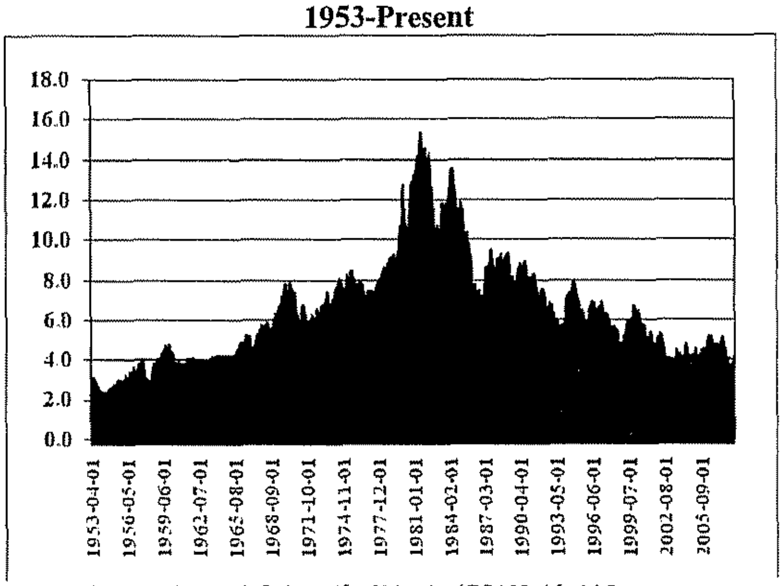
In the end, the most significant areas of disagreement between Dr. Avera and me with respect to the cost of equity are: (1) the appropriate DCF growth rate, and (2) the measurement and magnitude of the market risk premium which is used in CAPM approach.

II. CAPITAL COSTS IN TODAY'S MARKETS

Q. PLEASE DISCUSS CAPITAL COSTS IN TODAY'S MARKETS.

A. Long-term capital cost rates for U.S. corporations are currently at their lowest levels in more than four decades. Corporate capital cost rates are determined by the level of interest rates and the risk premium demanded by investors to buy the debt and equity capital of corporate issuers. The base level of long-term interest rates in the U.S. economy is indicated by the rates on ten-year U.S. Treasury bonds. The rates are provided in the graph below from 1953 to the present. As indicated, prior to the decline in rates that began in the year 2000, the 10-year Treasury yield had not consistently been in the 4-5 percent range over an extended period of time since the 1960s.

Yields on Ten-Year Treasury Bonds
1953-Present



Source: http://research.stlouisfed.org/fred2/series/GS10?cid=115

The second base component of the corporate capital cost rates is the risk premium. The risk premium is the return premium required by investors to purchase riskier securities. The equity risk premium is the return premium required to purchase stocks as opposed to bonds. Since the equity risk premium is not readily observable in the markets (as are bond risk premiums), and there are alternative approaches to estimating the equity premium, it is the subject of much debate. One way to estimate the equity risk premium is to compare the mean returns on bonds and stocks over long historical periods. Measured in this manner, the equity risk premium has been in the 5-7 percent range. But recent studies by leading academics indicate the forward-looking equity risk premium is in the 3-4 percent range. These authors indicate that historical equity risk premiums are upwardly biased measures of expected equity risk premiums. Jeremy Siegel, a Wharton finance professor and author of the book *Stocks for the Long Term*, published a study entitled "The Shrinking Equity Risk Premium."[1] He concludes:

> The degree of the equity risk premium calculated from data estimated from 1926 is unlikely to persist in the future. The real return on fixed-income assets is likely to be significantly higher than estimated on earlier data. This is confirmed by the yields available on Treasury index-linked securities, which currently exceed 4%. Furthermore, despite the acceleration in earnings growth, the return on equities is likely to fall from its historical level due to the very high level of equity prices relative to fundamentals.

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[1] Jeremy J. Siegel, "The Shrinking Equity Risk Premium," *The Journal of Portfolio Management* (Fall, 1999), p. 15.

Alan Greenspan, the former Chairman of the Federal Reserve Board, indicated in an October 14, 1999, speech on financial risk that the fact that equity risk premiums declined during 1990s is "not in dispute." His assessment focused on the relationship between information availability and equity risk premiums.

> There can be little doubt that the dramatic improvements in information technology in recent years have altered our approach to risk. Some analysts perceive that information technology has permanently lowered equity premiums and, hence, permanently raised the prices of the collateral that underlies all financial assets.
>
> The reason, of course, is that information is critical to the evaluation of risk. The less that is known about the current state of a market or a venture, the less the ability to project future outcomes and, hence, the more those potential outcomes will be discounted.
>
> The rise in the availability of real-time information has reduced the uncertainties and thereby lowered the variances that we employ to guide portfolio decisions. At least part of the observed fall in equity premiums in our economy and others over the past five years does not appear to be the result of ephemeral changes in perceptions. It is presumably the result of a permanent technology-driven increase in information availability, which by definition reduces uncertainty and therefore risk premiums. This decline is most evident in equity risk premiums. It is less clear in the corporate bond market, where relative supplies of corporate and Treasury bonds and other factors we cannot easily identify have outweighed the effects of more readily available information about borrowers.[2]

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[2] Alan Greenspan, "Measuring Financial Risk in the Twenty-First Century," Office of the Comptroller of the Currency Conference, October 14, 1999.

In sum, the relatively low interest rates in today's markets as well as the lower risk premiums required by investors indicate that capital costs for U.S. companies are the lowest in decades.

III. PROXY GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR LG&E.

A. I have separately developed an equity cost rate for the electric utility and the gas distribution operations of LG&E. Hence, to develop a fair rate of return recommendation for LG&E, I have evaluated the return requirements of investors on the common stock of a proxy group of publicly-held electric utility companies for LG&E's electric utility operations and a proxy group of gas distribution companies for LG&E's gas distribution operations.

Q. PLEASE DESCRIBE YOUR PROXY GROUPS OF ELECTRIC UTILITY COMPANIES AND GAS DISTRIBUTION COMPANIES.

A. My Electric Proxy Group proxy group consists of twenty-one electric utility companies. This group includes companies that meet the following criteria: (1) listed as an electric utility or as a combination electric and gas utility by *AUS Utility Reports*, (2) regulated electric revenues must be at least 75% of total revenues; (3) current data available in the Standard Edition of the *Value Line Investment Survey*; (4) an investment grade bond rating; and (5) an annual dividend history of three years. Summary financial statistics for the Electric Proxy are listed in Exhibit JRW-2. The average operating revenues and net plant for the Electric Proxy Group are $5,863.7M and $10,435.4M, respectively. On average, the group receives 89% of revenues from regulated electric utility operations, has a 'Baa1' Moody's bond rating, a common equity ratio of 43%, an earned return on common equity of 10.2%, and sells at a market-to-book ratio of 1.63X.

My Gas Proxy Group proxy group consists of ten natural gas distribution companies covered by the Standard Edition of the *Value Line Investment Survey*. These companies include AGL Resource, Atmos Energy, Laclede Group, New Jersey Resources, Nicor, Inc., Northwest Natural Gas Company, Piedmont Natural Gas Company, South Jersey Industries, Southwest Gas, and WGL Holdings. Summary financial statistics for the proxy group are listed in Exhibit JRW-2. The average operating revenues and net plant for the Gas Proxy Group are $2,671.7M and $2,176.7M, respectively. On average, the group receives 68% of revenues from regulated gas operations, has an 'A3' Moody's bond rating, a common equity ratio of 53%, and an earned return on common equity of 11.2%.

IV. <u>CAPITAL STRUCTURE RATIOS AND DEBT COST RATES</u>

Q. WHAT IS THE RECOMMENDED CAPITAL STRUCTURE OF THE COMPANY?

A. The Company's recommended capital structure is shown in Panel A of page 1 of Exhibit JRW-3. The Company is requesting a capital structure consisting of 2.38% short-term debt, 45.14% long-term debt, and a 52.48% common equity.

Q. PLEASE DISCUSS THE CAPITAL STRUCTURE YOU ARE USING IN THIS CASE.

A. Mr. Robert Heinkes has developed OAG's capital structure. Whereas Mr. Henkes has made adjustments to the capital amounts, his recommended capital structure ratios are identical to those proposed by the Company. On page 2 of Exhibit JRW-3 I provide the average common equity ratios for the companies in my proxy groups. The average common equity ratios for the Electric Proxy Group and the Gas Proxy Group are 43.7% and 49.9% respectively. This analysis suggests that the capital structures proposed by the Company and adopted by OAG are very fair to the Company, especially for the electric utility operations.

Q. ARE YOU ADOPTING THE COMPANY'S SHORT-TERM AND LONG-TERM DEBT COST RATES OF 2.63% AND 5.30%?

A. Yes.

III. THE COST OF COMMON EQUITY CAPITAL

A. Overview

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services, however and to the economic benefit to society from avoiding duplication of these services, some public utilities are monopolies. It is not appropriate to permit monopoly utilities to set their own prices because of the lack of competition and the essential nature of the services. Thus, regulation seeks to establish prices that are fair to consumers and at the same time are sufficient to meet the operating and capital costs of the utility (i.e., provide an adequate return on capital to attract investors).

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of the firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition where entry and exit is costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns and the market value and the book value of the firm's securities must be equal.

In the real world, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of that required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, has described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[3]

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically profitable and its market value will exceed book value. If, however, the business earns an ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio is relatively straightforward. A firm that earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm that earns a return on equity below its cost of equity will see its common stock sell at a price below its book value.

[3] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1988), p. 2.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN RETURN ON EQUITY AND MARKET-TO-BOOK RATIOS.

A. This relationship is discussed in a classic Harvard Business School case study entitled "A Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[4]

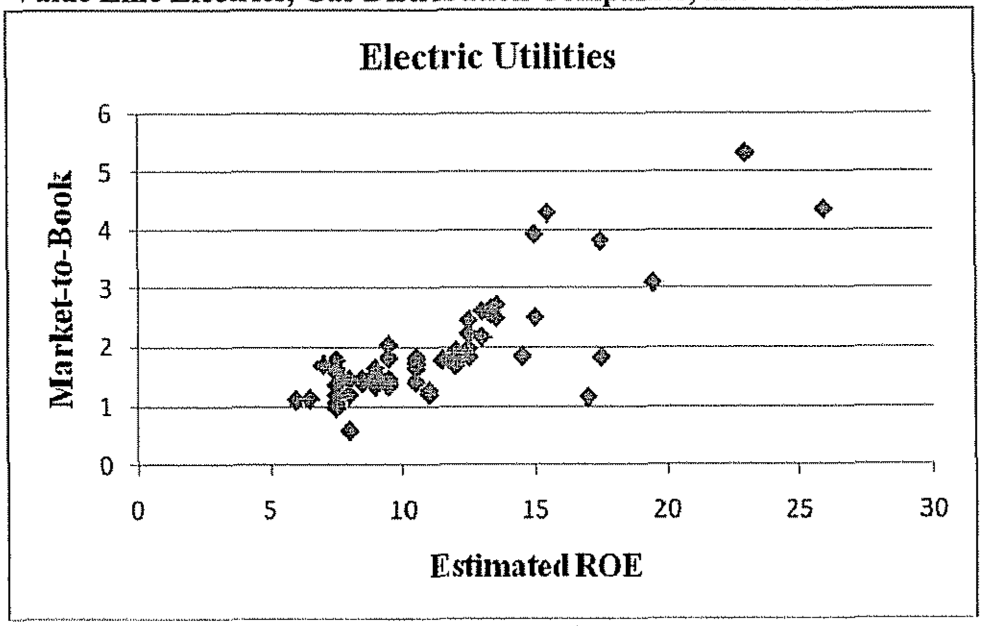
> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity – should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.

Profitability	*Value*
If ROE > K	*then Market/Book > 1*
If ROE = K	*then Market/Book =1*
If ROE < K	*then Market/Book < 1*

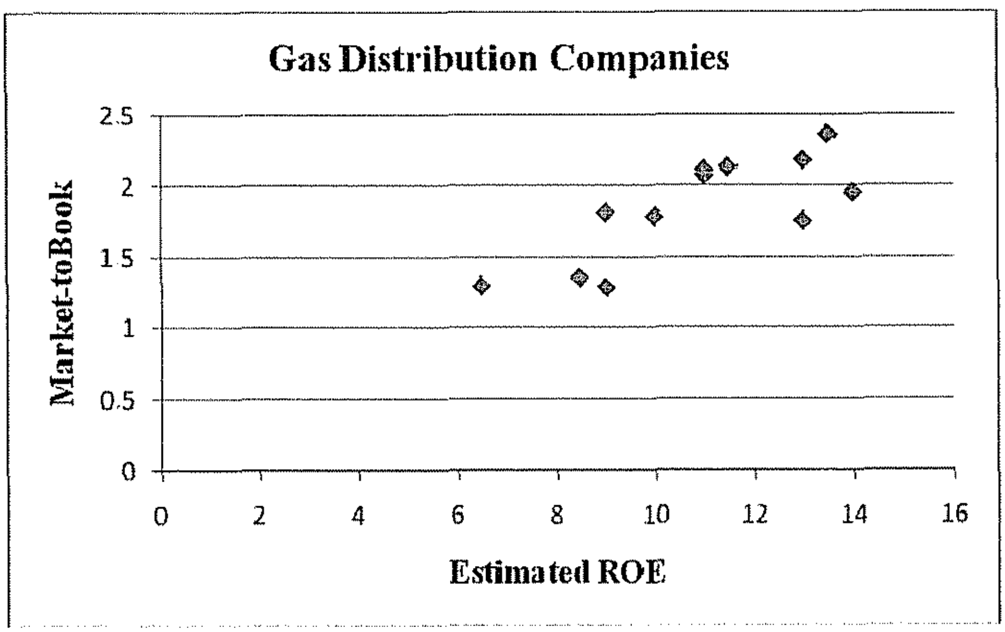
To assess the relationship by industry, as suggested above, I have performed a regression study between estimated return on equity and market-to-book ratios using natural gas distribution, electric utility and water utility companies. I used all companies in these three industries which are covered by *Value Line* and who have estimated return on equity and market-to-book ratio data. The results are presented below.

[4] Benjamin Esty, "A Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.

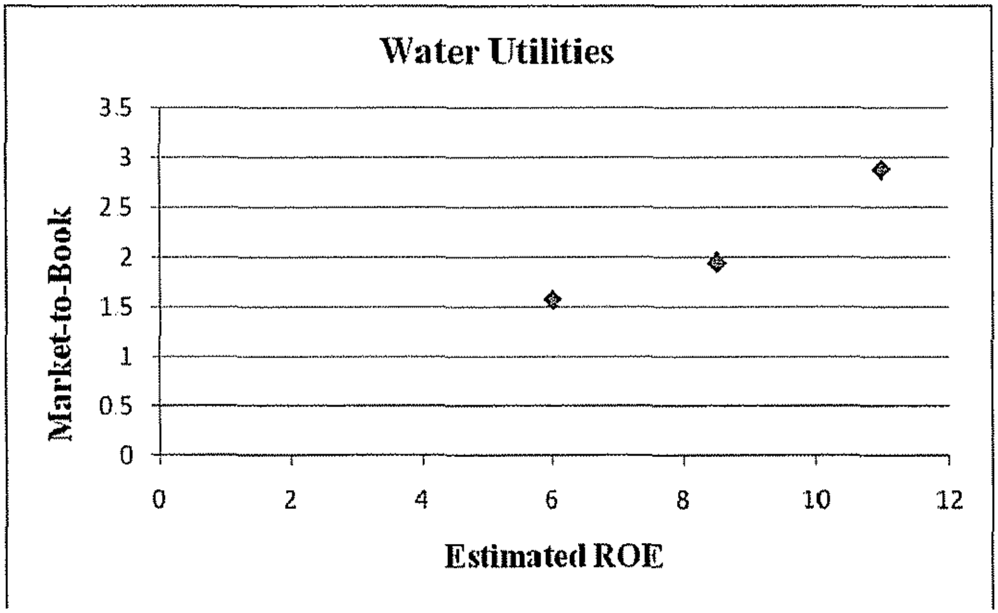
The Relationship Between Estimated ROE and Market-to-Book Ratios
Value Line Electrics, Gas Distribution Companies, and Water Utilities



R-Square = .65
N=56



R-Square = .60
N=12



R-Square = .92
N=4

The average R-squares for the electric, gas, and water companies are 0.65, 0.60, and 0.92.[5] This demonstrates the strong positive relationship between ROEs and market-to-book ratios for public utilities.

Q. WHAT ECONOMIC FACTORS HAVE AFFECTED THE COST OF EQUITY CAPITAL FOR PUBLIC UTILITIES?

A. Exhibit JRW-4 provides indicators of public utility equity cost rates over the past decade. Page 1 shows the yields on 10-year 'A' rated public utility bonds. These yields peaked in the 1990s at 8.5%, then declined and again hit the 8.0 percent range in the year 2000. They subsequently declined, hovering in the 4.5 to 5.0 percent range between 2003 and 2005. They increased to

[5] R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected return on equity). R-squares vary between zero and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

6.0% in June, of 2006, declined and then once again increased to over 6.0% in the summer of 2007. They retreated to the 5.50% range by the end of 2007. Page 2 provides the dividend yields for the fifteen utilities in the Dow Jones Utilities Average over the past decade. These yields peaked in 1994 at 7.2% and have gradually declined over the past decade. As of 2007 these yields and were 3.35%.

Average earned returns on common equity and market-to-book ratios are given on page 3 of Exhibit JRW-4. Over the past decade, earned returns on common equity have consistently been in the 11.0%-13.0% range. The average ROE peaked at 13.45% in 2001 and subsequently declined through the year 2006 before recovering in 2007. Over the past decade, market-to-book ratios for this group have increased gradually but with several ups and downs. The market-to-book average was 1.83 as of 2001, declined to 1.50 in 2003 and increased to 2.2 as of 2007.

The indicators in Exhibit JRW-4, coupled with the overall decrease in interest rates, suggest that capital costs for the Dow Jones Utilities have decreased over the past decade.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide, as well as company-specific, factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF PUBLIC UTILITY COMPANIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries.

Exhibit JRW-5 provides an assessment of investment risk for 100 industries as measured by beta, which according to modern capital market theory is the only relevant measure of investment risk. These betas come from the *Value Line Investment Survey* and are compiled by Aswath Damodoran of New York University.[6] The study shows that the investment

[6] They may be found on the Internet at http:// www.stern.nyu.edu/~adamodar.

risk of public utilities is relatively low. The average beta for electric utilities and gas distribution companies are 0.88 and 0.78, respectively. These figures put electric and gas companies in the bottom twenty percent of all industries and well below the *Value Line* average of 1.24. As such, the costs of equity for the electric utility and gas distribution industries are among the lowest of all industries in the U.S.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return to the stockholder should be commensurate with returns on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All of these decisions must take into consideration the firm involved as well as current conditions in the economy and the financial markets.

Q. HOW DO YOU PLAN TO ESTIMATE THE COST OF EQUITY CAPITAL FOR THE COMPANY?

A. I rely primarily on the DCF model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, I believe that the DCF model provides the best measure of equity cost rates for public utilities. It is my experience that this Commission has traditionally relied on the DCF method. I have also performed a CAPM study, but I give these results less weight because I believe that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities.

B. <u>Discounted Cash Flow Analysis</u>

Q. DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the DCF model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a pro-rata share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm so as to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore, this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

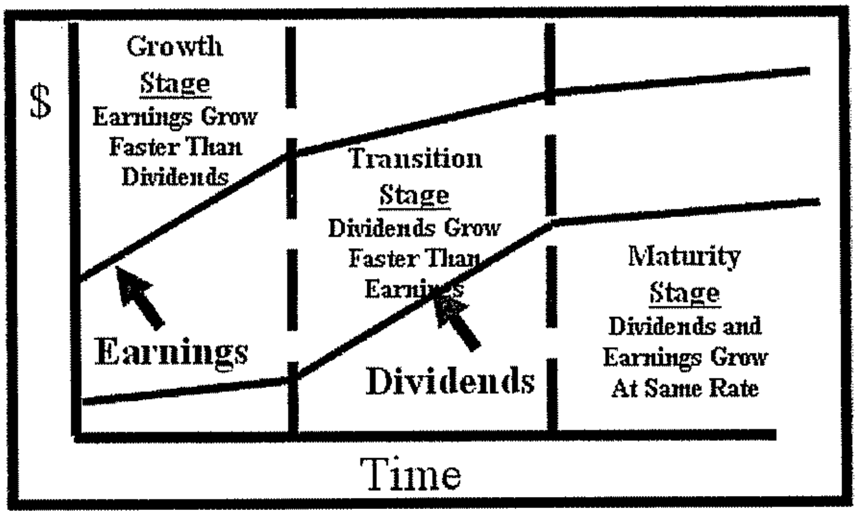
$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots \frac{D_n}{(1+k)^n}$$

where P is the current stock price, D_n is the dividend in year n, and k is the cost of common equity.

Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model ("DDM"). The stages in a three-stage DCF model are discussed below. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a steady-state stage. The dividend-payment stage of a firm depends on the profitability of its internal investments, which, in turn, is largely a function of the life cycle of the product or service. These stages are depicted in the graphic below labeled the Three-Stage DCF Model.[7]

Three-Stage DCF Model



1. Growth stage: Characterized by rapidly expanding sales, high profit margins, and abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.

---

[7] This description comes from William F. Sharp, Gordon J. Alexander, and Jeffrey V. Bailey, *Investments* (Prentice-Hall, 1995), pp. 590-91.

2. Transition stage: In later years increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.

3. Maturity (steady-state) stage: Eventually the company reaches a position where its new investment opportunities offer, on average, only slightly attractive returns on equity. At that time its earnings growth rate, payout ratio, and return on equity stabilize for the remainder of its life. The constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using this model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Q. HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

where D_1 represents the expected dividend over the coming year and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for k in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

Q. IN YOUR OPINION, IS THE CONSTANT-GROWTH DCF MODEL APPROPRIATE FOR PUBLIC UTILITIES?

A. Yes. The economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. However, the primary problem and controversy in applying the DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and expected growth rate). The dividend yield can be measured precisely at any point in time, but tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. PLEASE DISCUSS EXHIBIT JRW-6.

A. My DCF analysis is provided in Exhibit JRW-6. The DCF summary is on page 1 of this Exhibit, and the supporting data and analysis for the dividend yield and expected growth rate are provided on the following pages of the Exhibit.

Q. WHAT DIVIDEND YIELDS ARE YOU EMPLOYING IN YOUR DCF ANALYSIS FOR THE PROXY GROUPS?

A. The dividend yields on the common stock for the companies in the two proxy groups are provided on page 2 of Exhibit JRW-6 for the six-month period ending October 2008. For the DCF dividend yields for the groups, I am using the average of the six month and October 2008 dividend yields. The table below shows these dividend yields.

Proxy Group	6-Month Average Dividend Yield	October 2008 Dividend Yield	DCF Dividend Yield
Electric Proxy Group	4.4%	4.2%	4.3%
Gas Proxy Group	3.5%	3.8%	3.6%

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by: (1) multiplying the expected dividend over the coming quarter by 4 and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm, that pays dividends on a quarterly basis.[8]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as opposed to the coming year

[8] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05, Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR WILL YOU USE FOR YOUR DIVIDEND YIELD?

A. I will adjust the dividend yield by one-half (1/2) the expected growth so as to reflect growth over the coming year.

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

A. There is much debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book value growth to assess long-term potential.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE PROXY GROUPS?

A. I have analyzed a number of measures of growth for companies in the proxy groups. I have reviewed *Value Line's* historical and projected growth rate estimates for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"). In addition, I have utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Bloomberg and Zacks. These services solicit five-year earnings growth rate projections from securities analysts and compile and publish the means and medians of these forecasts. Finally, I have also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS AS WELL AS INTERNAL GROWTH.

A. Historical growth rates for EPS, DPS, and BVPS are readily available to virtually all investors and presumably an important ingredient in forming expectations concerning future growth. However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-run earnings and therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. WHY ARE YOU NOT RELYING EXCLUSIVELY ON THE EPS FORECASTS OF WALL STREET ANALYSTS IN ARRIVING AT A DCF GROWTH RATE FOR THE PROXY GROUP?

A. There are several issues with using the EPS growth rate forecasts of Wall Street analysts as DCF growth rates. First, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long-term, dividend and earnings will have to grow at a similar growth rate. Therefore, in my opinion, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Second, and most significantly, it is well-known that the EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate. This issue is discussed at length in the rebuttal section of this testimony.

Q. PLEASE DISCUSS THE HISTORICAL GROWTH OF THE COMPANIES IN THE GROUPS AS PROVIDED IN THE *VALUE LINE INVESTMENT SURVEY.*

A. Historic growth rates for the companies in the groups, as published in the *Value Line Investment Survey*, are provided on page 3 of Exhibit JRW-6. Due to the presence of outliers among the historic growth rate figures, both the mean and medians are used in the analysis.[9] As shown in Panel A, the historical growth measures in EPS, DPS, and BVPS for the Electric Proxy Group, as measured by the means and medians, range from -0.8% to 4.0%, with an average of 1.7%. The historical growth measures in EPS, DPS, and BVPS are shown in Panel B for the Gas Proxy Group. The range of the means and medians is 1.8% to 7.3%, with an average of 4.5%.

Q. PLEASE SUMMARIZE *VALUE LINE'S* PROJECTED GROWTH RATES FOR THE COMPANIES IN THE PROXY GROUPS.

A. *Value Line's* projections of EPS, DPS, and BVPS growth for the companies in the proxy groups are shown on page 4 of Exhibit JRW-6. As above, due to the presence of outliers, both the mean and medians are used in the analysis. For the Electric Proxy Group, the central tendency measures range from 4.0%

[9] Outliers are observations that are much larger or smaller than the majority of the observations that are being evaluated.

to 7.5%, with an average of 5.2%. The central tendency measures for the Gas Proxy Group range from 3.6% to 5.7%, with an average of 4.5%.

Also provided on page 4 of Exhibit JRW-6 is prospective internal growth for the proxy groups as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. As noted above, internal growth is significant in a primary driver of long-run earnings growth. For the Electric Proxy Group, the average prospective internal growth rate is 4.0%. The average internal growth rate for the Gas Proxy Group is 5.7%.

Q. PLEASE ASSESS GROWTH FOR THE PROXY GROUPS AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED 5-YEAR EPS GROWTH.

A. Zacks and Bloomberg collect, summarize, and publish Wall Street analysts' five-year EPS growth rate forecasts for the companies in the proxy groups. These forecasts are provided for the companies in the proxy group on page 5 of Exhibit JRW-6. The median of the analysts' projected EPS growth rates for the Electric Proxy Group is 6.25% and for the Gas Proxy Group is 5.53%.[10]

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE PROXY GROUPS.

[10] Since there is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services, I have averaged the expected five-year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate by company.

A. The table below shows the summary DCF growth rate indicators for the proxy groups.

DCF Growth Rate Indicators

Growth Rate Indicator	Electric Proxy Group	Gas Proxy Group
Historic *Value Line* Growth in EPS, DPS, and BVPS	1.7%	4.5%
Projected *Value Line* Growth in EPS, DPS, and BVPS	5.2%	4.5%
Internal Growth ROE * Retention Rate	4.0%	5.7%
Projected EPS Growth from Bloomberg and Zacks	6.25%	5.53%

The average of the growth rate indicators for the Electric Proxy Group is 4.3%. Giving greater weight to the projected growth rate indicators and to prospective internal growth, an expected DCF growth rate in the 5.0%-6.0% range is reasonable for the group. I will use the midpoint of this range, 5.5%, as the DCF growth rate for the Electric Proxy Group. For the Gas Proxy Group, the average of the growth rate indicators is 5.07%. Giving greater weight to the projected growth rate indicators, an expected DCF growth rate in the 5.5% range is also reasonable for the Gas Proxy Group.

Q. BASED ON THE ABOVE ANALYSIS, WHAT ARE YOUR INDICATED COMMON EQUITY COST RATES FROM THE DCF MODEL FOR THE TWO GROUPS?

A. My DCF-derived equity cost rate for the groups is:

$$\text{DCF Equity Cost Rate (k)} = \frac{D}{P} + g$$

DCF Equity Cost Rates

	Electric Proxy Group	Gas Proxy Group
Dividend Yield	**4.3%**	**3.6%**
1 + (½ Growth Rate Adjustment)	**1.0275**	**1.0275**
DCF Growth Rate	**5.50%**	**5.50%**
Equity Cost Rate	**9.9%**	**9.2%**

These results are summarized on page 1 of Exhibit JRW-6.

C. Capital Asset Pricing Model Results

Q. PLEASE DISCUSS THE CAPITAL ASSET PRICING MODEL ("CAPM").

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k = R_f + RP$$

The yield on long-term Treasury securities is normally used as R_f. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk, and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to:

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

Where:

- K represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected return on the overall stock market. Frequently, the 'market' refers to the S&P 500;
- (R_f) represents the risk-free rate of interest;
- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—(ß) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta (ß), and the expected equity or market risk premium $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is the yield on long-term Treasury bonds. ß, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium $(E(R_m) - (R_f))$. I will discuss each of these inputs below.

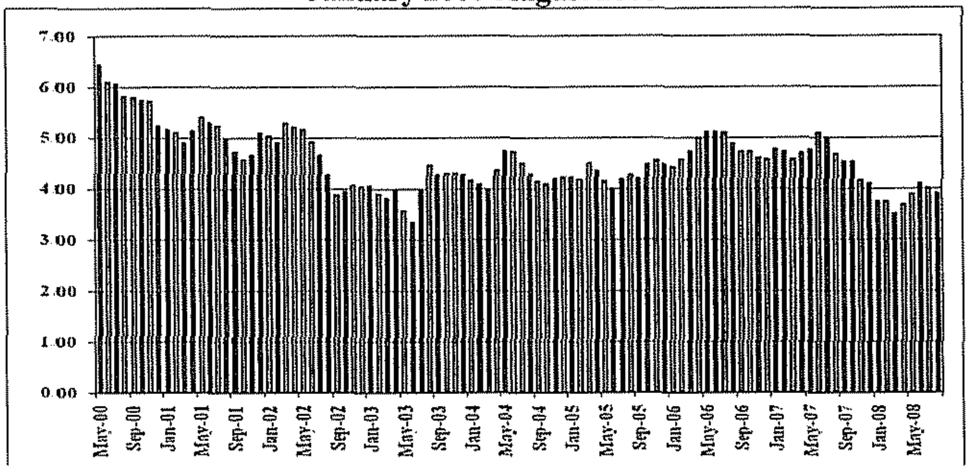
Q. PLEASE DISCUSS EXHIBIT JRW-7.

A. Exhibit JRW-7 provides the summary results for my CAPM study. Page 1 shows the results, and pages 2-5 contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities. However, when the Treasury's issuance of 30-year bonds was interrupted for a period of time in recent years, the yield on 10-year U.S. Treasury bonds replaced the yield on 30-year U.S. Treasury bonds as the benchmark long-term Treasury rate. The 10-year U.S. Treasury yields over the past five years are shown in the chart below. These rates hit a 60-year low in the summer of 2003 at 3.33%. They increased with the rebounding economy and fluctuated in the 4.0-4.50 percent range in recent years until advancing to 5.0% in early 2006 in response to a strong economy and increases in energy, commodity, and consumer prices. In late 2006, long-term interest rates retreated to the 4.5 percent area as commodity and energy prices declined and inflationary pressures subsided. These rates rebounded to the 5.0% level in the first half of 2007. However, ten-year Treasury yields have again fall below 4.0 percent due to the housing and sub-prime mortgage crises and its affect on the economy and financial markets.

Ten-Year U.S. Treasury Yields
January 2000-August 2008



http://research.stlouisfed.org/fred2/series/GS10?cid=115

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. The U.S. Treasury began to issue the 30-year bond in the early 2000s as the U.S. budget deficit increased. As such, the market has once again focused on its yield as the benchmark for long-term capital costs in the U.S. As noted above, the yields on the 10- and 30- year U.S. Treasuries decreased to below 5.0% in 2007 and have remained at these lower levels. In 2008 Treasury yields have been pushed even lower as a result of the mortgage and sub-prime market credit crisis, the turmoil in the financial sector, the prospect of an economic recession, and the government bailout of financial institutions. As of September 22, 2008, as shown in the table below, the rates on 10- and 30- U.S. Treasury Bonds were 3.67% and 4.16%, respectively. However, these yields have been highly volatile over the past two months. Given this recent range and volatility, along with the prospect of higher rates, I will use 4.5% as the risk-free rate, or R_f, in my CAPM.

U.S. Treasury Yields
October 2, 2008

U.S. Treasuries

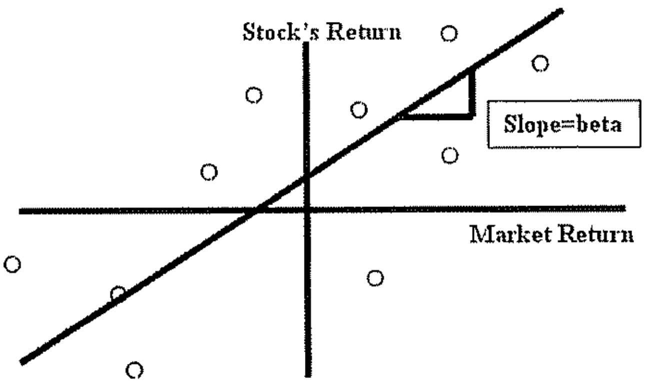
	COUPON	MATURITY DATE	CURRENT PRICE/YIELD
3-MONTH	0.000	01/02/2009	0.67 / .68
6-MONTH	0.000	04/02/2009	1.2 / 1.22
12-MONTH	0.000	09/24/2009	1.42 / 1.46
2-YEAR	2.000	09/30/2010	101-12+ / 1.66
3-YEAR	4.500	09/30/2011	107-10+ / 1.97
5-YEAR	3.125	09/30/2013	101-25+ / 2.73
10-YEAR	4.000	08/15/2018	102-22+ / 3.67
30-YEAR	4.500	05/15/2038	105-25+ / 4.16

Source: www.bloomberg.com

Q. WHAT BETAS ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return as in the following:

Calculation of Beta



The slope of the regression line is the stock's ß. A steeper line indicates the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater than average market risk. A less steep line indicates a lower ß and less market risk.

Numerous online investment information services, such as Yahoo! and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to: (1) the time period over which the ß is measured and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the proxy group, I am using the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 2 of Exhibit JRW-7, the average beta for the companies in both the Electric and Gas Proxy Groups is 0.82.

Q. PLEASE DISCUSS THE OPPOSING VIEWS REGARDING THE EQUITY RISK PREMIUM.

A. The equity or market risk premium - $(E(R_m) - R_f)$ - is equal to the expected return on the stock market (e.g., the expected return on the S&P 500 $(E(R_m))$ minus the risk-free rate of interest (R_f). The equity premium is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the equity risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market.

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE EQUITY RISK PREMIUM.

A. The table below highlights the primary approaches to, and issues in, estimating the expected equity risk premium. The traditional way to measure the equity risk premium was to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called ex post returns, were used as the measures of the market's expected return (known as the ex ante or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson who popularized this method of using historical financial market returns as measures of expected returns. Most historical assessments of the equity risk premium suggest an equity risk premium of 5-7 percent above the rate on long-term U.S. Treasury bonds. However, this can be a problem because: (1) ex post returns are not the same as ex ante expectations, (2) market risk premiums can change over time;

increasing when investors become more risk-averse and decreasing when investors become less risk-averse, and (3) market conditions can change such that ex post historical returns are poor estimates of ex ante expectations.

Risk Premium Approaches

	Historical Ex Post Excess Returns	Surveys	Ex Ante Models and Market Data
Means of Assessing the Equity-Bond Risk Premium	Historical average is a popular proxy for the ex ante premium – but likely to be misleading	Investor and expert surveys can provide direct estimates of prevailing expected returns/premiums	Current financial market prices (simple valuation ratios or DCF-based measures) can give most objective estimates of feasible ex ante equity-bond risk premium
Problems/Debated Issues	Time variation in required returns and systematic selection and other biases have boosted valuations over time, and have exaggerated realized excess equity returns compared with ex ante expected premiums	Limited survey histories and questions of survey representativeness. Surveys may tell more about hoped-for expected returns than about objective required premiums due to irrational biases such as extrapolation.	Assumptions needed for DCF inputs, notably the trend earnings growth rate, make even these models' outputs subjective. The range of views on the growth rate, as well as the debate on the relevant stock and bond yields, leads to a range of premium estimates.

Source: Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003).

The use of historical returns as market expectations has been criticized in numerous academic studies.[11] The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "Ex Ante Models and Market Data," compute ex ante expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[12]

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[11] The problems with using ex post historical returns as measures of ex ante expectations will be discussed at length later in my testimony.

[12] R. Mehra and Edward Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economics* (1985).

Q. PLEASE SUMMARIZE SOME OF THE ACADEMIC STUDIES THAT DEVELOP EX ANTE EQUITY RISK PREMIUMS.

A. Two of the most prominent studies of ex ante expected equity risk premiums were by Eugene Fama and Ken French (2002) and James Claus and Jacob Thomas (2001). The primary debate in these studies revolves around two related issues: (1) the size of expected equity risk premium, which is the return equity investors require above the yield on bonds and (2) the fact that estimates of the ex ante expected equity risk premium using fundamental firm data (earnings and dividends) are much lower than estimates using historical stock and bond return data.

Fama and French (2002), two of the most preeminent scholars in finance, use dividend and earnings growth models to estimate expected stock returns and ex ante expected equity risk premiums.[13] They compare these results to actual stock returns over the period 1951-2000. Fama and French estimate that the expected equity risk premium from DCF models using dividend and earnings growth to be between 2.55% and 4.32%. These figures are much lower than the ex post historical equity risk premium produced from the average stock and bond return over the same period, which is 7.40%. Fama and French conclude that the ex ante equity risk premium estimates using DCF models and fundamental data are superior to those using ex post historical stock returns for three reasons: (1) the estimates are more precise (a lower standard error); (2) the Sharpe ratio, which is measured as the

[13] Eugene F. Fama and Kenneth R. French, "The Equity Premium," *The Journal of Finance*, (April 2002).

[(expected stock return – risk-free rate)/standard deviation], is constant over time for the DCF models but varies considerably over time and more than doubles for the average stock-bond return model; and (3) valuation theory specifies relationships between the market-to-book ratio, return on investment, and cost of equity capital that favor estimates from fundamentals. They also conclude that the high average stock returns over the past 50 years were the result of low expected returns and that the average equity risk premium has been in the 3-4 percent range.

The study by Claus and Thomas of Columbia University provides direct support for the findings of Fama and French.[14] These authors compute ex ante expected equity risk premiums over the 1985-1998 period by: (1) computing the discount rate that equates market values with the present value of expected future cash flows and (2) then subtracting the risk-free interest rate. The expected cash flows are developed using analysts' earnings forecasts. The authors conclude that over this period, the ex ante expected equity risk premium is in the range of 3.0%. Claus and Thomas note that, over this period, ex post historical stock returns overstate the ex ante expected equity risk premium because, as the expected equity risk premium has declined, stock prices have risen. In other words, from a valuation perspective, the present value of expected future returns increase when the required rate of return decreases. The higher stock prices have produced stock

[14] James Claus and Jacob Thomas, "Equity Risk Premia as Low as Three Percent? Empirical Evidence from Analysts' Earnings Forecasts for Domestic and International Stock Market," *Journal of Finance*. (October 2001).

returns that have exceeded investors' expectations, and therefore, ex post historical equity risk premium estimates are biased upwards as measures of ex ante expected equity risk premiums.

Q. PLEASE PROVIDE A SUMMARY OF THE EQUITY RISK PREMIUM STUDIES.

A. Derrig and Orr (2003), Fernandez (2007), and Song (2007) have completed the most comprehensive reviews to date of the research on the equity risk premium.[15] Derrig and Orr's study evaluated the various approaches to estimating equity risk premiums as well as the issues with the alternative approaches and summarized the findings of the published research on the equity risk premium. Fernandez examined four alternative measures of the equity risk premium – historical, expected, required, and implied. He also reviewed the major studies of the equity risk premium and presented the summary equity risk premium results. Song provides an annotated bibliography and highlights the alternative approaches to estimating the equity risk summary.

Page 3 of Exhibit JRW-7 provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr, Fernandez, and Song. In developing page 3 of Exhibit JRW-7, I have categorized the studies as discussed on page 41 of my testimony. I have also included the results of

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[15] Richard Derrig and Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, (August 28, 2003), Pablo Fernandez, "Equity Premium: Historical, Expected, Required, and Implied," IESE Business School Working Paper, (2007), and Zhiyi Song, "The Equity Risk Premium: An Annotated Bibliography," CFA Institute, (2007)

the "Building Blocks" approach to estimating the equity risk premium, including a study I performed, which is presented below. The Building Blocks approach is a hybrid approach employing elements of both historic and ex ante models.

Q. PLEASE DISCUSS YOUR DEVELOPMENT OF AN EQUITY RISK PREMIUM COMPUTED USING THE BUILDING BLOCKS METHODOLOGY.

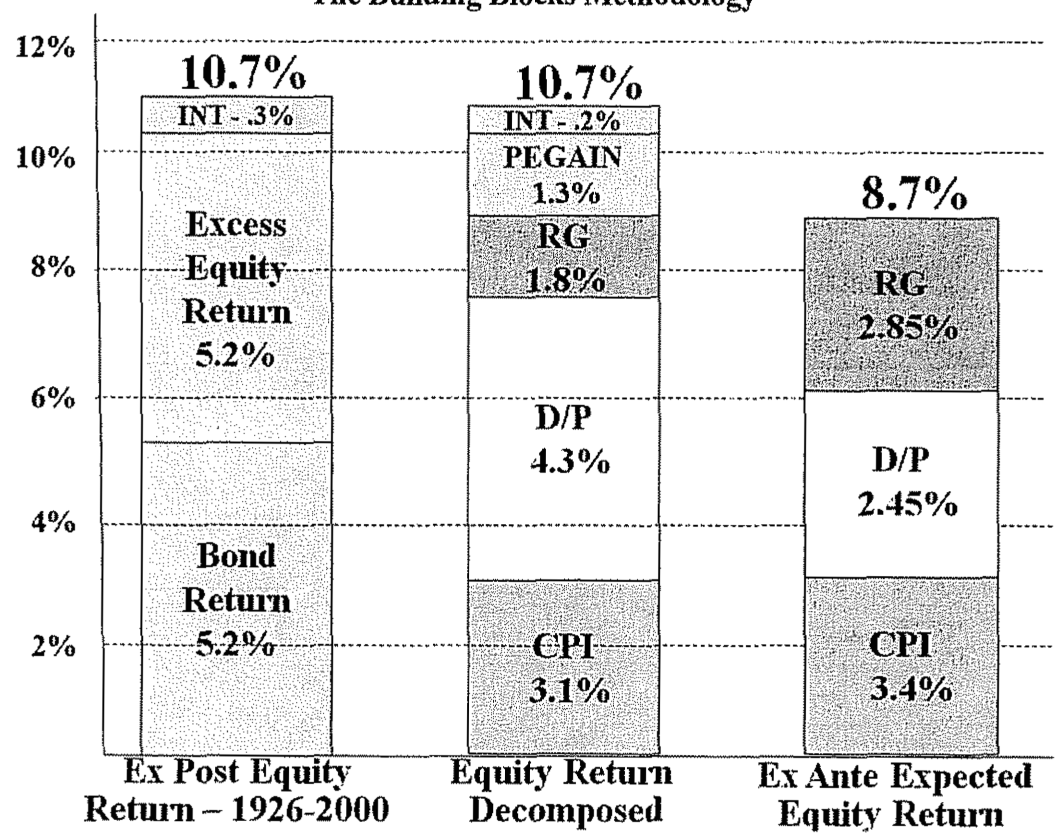
A. Ibbotson and Chen (2003) evaluate the ex post historical mean stock and bond returns in what is called the Building Blocks approach.[16] They use 75 years of data and relate the compounded historical returns to the different fundamental variables employed by different researchers in building ex ante expected equity risk premiums. Among the variables included were inflation, real EPS and DPS growth, ROE and book value growth, and price-earnings ("P/E") ratios. By relating the fundamental factors to the ex post historical returns, the methodology bridges the gap between the ex post and ex ante equity risk premiums. Ilmanen (2003) illustrates this approach using the geometric returns and five fundamental variables – inflation ("CPI"), dividend yield ("D/P"), real earnings growth ("RG"), repricing gains ("PEGAIN") and return interaction/reinvestment ("INT").[17] This is shown in the graph below. The first column breaks the 1926-2000 geometric mean stock return of 10.7% into

[16] Roger Ibbotson and Peng Chen, "Long Run Returns: Participating in the Real Economy," *Financial Analysts Journal*, (January 2003).

[17] Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003), p. 11.

the different return components demanded by investors: the historical U.S. Treasury bond return (5.2%), the excess equity return (5.2%), and a small interaction term (0.3%). This 10.7% annual stock return over the 1926-2000 period can then be broken down into the following fundamental elements: inflation (3.1%), dividend yield (4.3%), real earnings growth (1.8%), repricing gains (1.3%) associated with higher P/E ratios, and a small interaction term (0.2%).

Decomposing Equity Market Returns
The Building Blocks Methodology

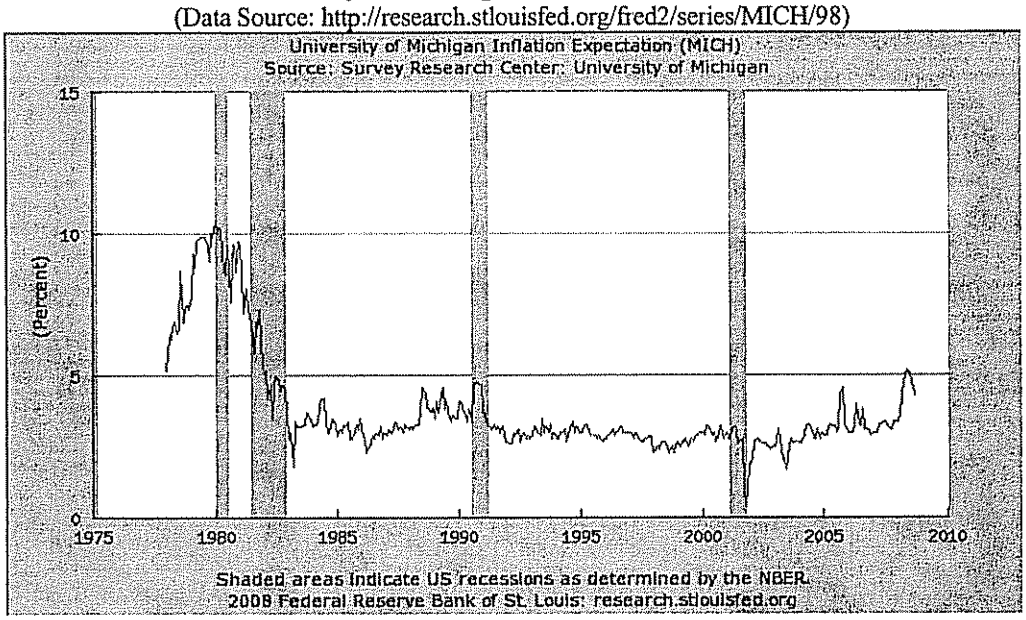


Q. HOW ARE YOU USING THIS METHODOLOGY TO DERIVE AN EX ANTE EXPECTED EQUITY RISK PREMIUM?

A. The third column in the graph above shows current inputs to estimate an ex ante expected market return. These inputs include the following:

CPI – To assess expected inflation, I have employed expectations of the short-term and long-term inflation rate. The graph below shows the expected annual inflation rate according to consumers, as measured by the CPI, over the coming year. This survey is published monthly by the University of Michigan Survey Research Center. In the most recent report, the expected one-year inflation rate was 4.3%.

Expected Inflation Rate
University of Michigan Consumer Research
(Data Source: http://research.stlouisfed.org/fred2/series/MICH/98)



Longer term inflation forecasts are available in the Federal Reserve Bank of Philadelphia's publication entitled *Survey of Professional Forecasters*.[18] This survey of professional economists has been published for

[18]Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters*, (February 12, 2008). The *Survey of*

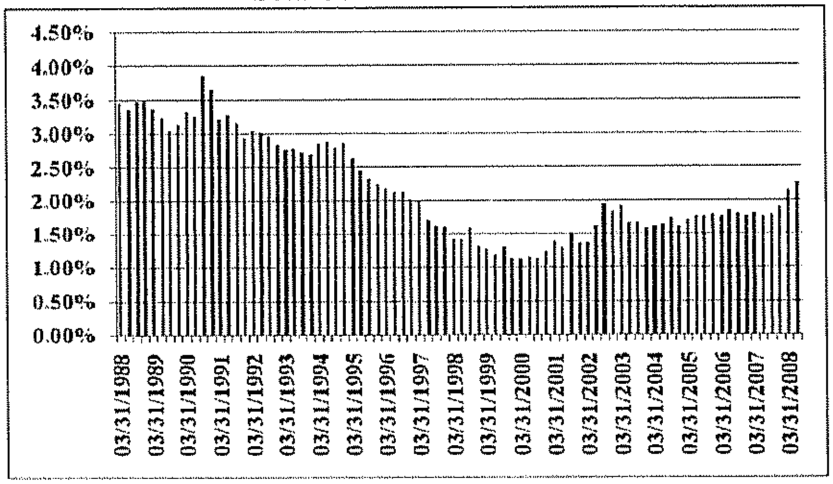
almost 50 years. While this survey is published quarterly, only the first quarter survey includes long-term forecasts of gross domestic product ("GDP") growth, inflation, and market returns. In the first quarter 2008 survey, published on February 12, 2008, the median long-term (10-year) expected inflation rate as measured by the CPI was 2.5% (see page 4 of Exhibit JRW-7).

Given these results, I will use the average of the surveys of the University of Michigan and Federal Reserve Bank of Philadelphia (4.3% and 2.5%), or 3.4%.

D/P – As shown in the graph below, the dividend yield on the S&P 500 has decreased gradually over the past decade. Today, it is far below its average of 4.3% over the 1926-2000 time period. Whereas the S&P dividend yield bottomed out at less than 1.4% in 2000, it is currently at 2.45% which I use in the ex ante risk premium analysis.

Professional Forecasters was formerly conducted by the American Statistical Association ("ASA") and the National Bureau of Economic Research ("NBER") and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER, assumed responsibility for the survey in June 1990.

S&P 500 Dividend Yield



<u>RG</u> – To measure expected real growth in earnings, I use: (1) the historical real earnings growth rate for the S&P 500 and (2) expected real GDP growth. The S&P 500 was created in 1960. It includes 500 companies which come from ten different sectors of the economy. Over the 1960-2007 period, nominal growth in EPS for the S&P 500 was 7.36%. On page 5 of Exhibit JRW-7, real EPS growth is computed using the CPI as a measure of inflation. As indicated by Ibbotson and Chen, real earnings growth over the 1926-2000 period was 1.8%. The real growth figure over 1960-2007 period for the S&P 500 is 3.0 %.

The second input for expected real earnings growth is expected real GDP growth. The rationale is that over the long-term, corporate profits have averaged a relatively consistent 5.50% of U.S. GDP.[19] Real GDP growth, according to McKinsey, has averaged 3.5% over the past 80 years. Expected

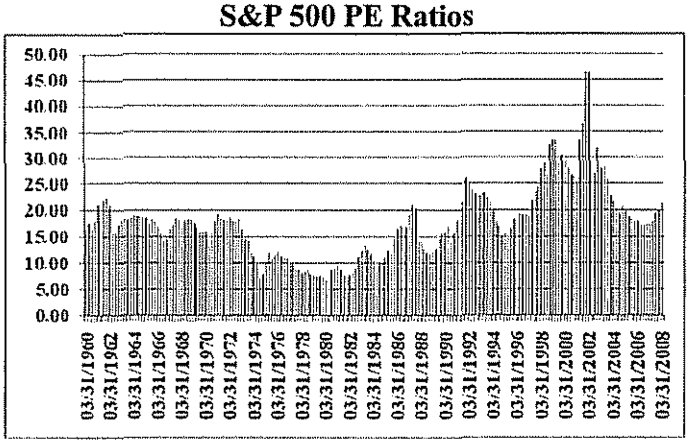
[19]Marc. H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.14.

GDP growth, according to the Federal Reserve Bank of Philadelphia's *Survey of Professional Forecasters*, is 2.75% (see page 4 of Exhibit JRW-7).

Given these results, I will use the average of the historical S&P EPS real growth and the projected real GDP growth (as reported by the Federal Reserve Bank of Philadelphia Survey) -- 3.0% and 2.75% -- or 2.85%, for real earnings growth.

<u>PEGAIN</u> – PEGAIN is the repricing gain associated with an increase in the P/E ratio. It accounted for 1.3% of the 10.7% annual stock return in the 1926-2000 period. In estimating an ex ante expected stock market return, one issue is whether investors expect P/E ratios to increase from their current levels. The graph below shows the P/E ratios for the S&P 500 over the past 25 years. The run-up and eventual peak in P/Es is most notable in the chart. The relatively low P/E ratios (in the range of 10) over two decades ago are also quite notable. As of September 30, 2008, the P/E for the S&P 500 was 22.5.[20]

S&P 500 PE Ratios



[20] Source: www.standardandpoors.com.

Given the current economic and capital markets environment, I do not believe that investors expect even higher P/E ratios. Therefore, a PEGAIN would not be appropriate in estimating an ex ante expected stock market return. There are two primary reasons for this. First, the average historical S&P 500 P/E ratio is 15.74 – thus the current P/E exceeds this figure. Second, as previously noted, interest rates are at a cyclical low not seen in almost 50 years. This is a primary reason for the high current P/Es. Given the current market environment with relatively high P/E ratios and low relative interest rates, investors are not likely to expect to get stock market gains from lower interest rates and higher P/E ratios.

Q. GIVEN THIS DISCUSSION, WHAT IS YOUR EX ANTE EXPECTED MARKET RETURN AND EQUITY RISK PREMIUM USING THE "BUILDING BLOCKS METHODOLOGY"?

A. My expected market return is represented by the last column on the right in the graph entitled "Decomposing Equity Market Returns: The Building Blocks Methodology" set forth on page 46 of my testimony. As shown, my expected market return of 8.70% is composed of 3.40% expected inflation, 2.45% dividend yield, and 2.85% real earnings growth rate.

Q. GIVEN THAT THE HISTORICAL COMPOUNDED ANNUAL MARKET RETURN IS IN EXCESS OF 10%, WHY DO YOU BELIEVE THAT YOUR EXPECTED MARKET RETURN OF 8.70% IS REASONABLE?

A. As discussed above, in the development of the expected market return, stock prices are relatively high at the present time in relation to earnings and dividends, and interest rates are relatively low. Hence, it is unlikely that investors are going to experience high stock market returns due to higher P/E ratios and/or lower interest rates. In addition, as shown in the decomposition of equity market returns, whereas the dividend portion of the return was historically 4.3%, the current dividend yield is only 2.45%. Due to these reasons, lower market returns are expected for the future.

Q. IS YOUR EXPECTED MARKET RETURN OF 8.70% CONSISTENT WITH THE FORECASTS OF MARKET PROFESSIONALS?

A. Yes. In the first quarter 2008 *Survey of Financial Forecasters*, published on February 12, 2008 by the Federal Reserve Bank of Philadelphia, the mean long-term expected return on the S&P 500 was 6.8% (see page 4 of Exhibit JRW-7).

Q. IS YOUR EXPECTED MARKET RETURN CONSISTENT WITH THE EXPECTED MARKET RETURNS OF CORPORATE CHIEF FINANCIAL OFFICERS (CFOs)?

A. Yes. John Graham and Campbell Harvey of Duke University conduct a quarterly survey of corporate CFOs. The survey is a joint project of Duke

University and *CFO Magazine*. In the third quarter 2008 survey, the mean expected return on the S&P 500 over the next ten years was 7.79%.[21]

Q. GIVEN THIS EXPECTED MARKET RETURN, WHAT IS YOUR EX ANTE EQUITY RISK PREMIUM USING THE BUILDING BLOCKS METHODOLOGY?

A. As shown on page 38, the current 30-year U.S. Treasury yield is 4.16%. My ex ante equity risk premium is simply the expected market return from the Building Blocks methodology minus this risk-free rate:

Ex Ante Equity Risk Premium = 8.70% - 4.16% = 4.54%

Q. GIVEN THIS DISCUSSION, HOW ARE YOU MEASURING AN EXPECTED EQUITY RISK PREMIUM IN THIS PROCEEDING?

A. As discussed above, page 3 of Exhibit JRW-7 provides a summary of the results of the equity risk premium studies that I have reviewed. These include the results of: (1) the various studies of the historical risk premium, (2) ex ante equity risk premium studies, (3) equity risk premium surveys of CFOs, Financial Forecasters, and academics, and (4) the Building Block approaches to the equity risk premium. There are results reported for over thirty studies, and the average equity risk premium is 4.56%, which I will use as the equity risk premium in my CAPM study.

[21] The survey results are available at www.cfosurvey.org.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS OF LEADING INVESTMENT FIRMS?

A. Yes. One of the first studies in this area was by Stephen Einhorn, one of Wall Street's leading investment strategists.[22] His study showed that the market or equity risk premium had declined to the 2.0 - 3.0 percent range by the early 1990s. Among the evidence he provided in support of a lower equity risk premium is the inverse relationship between real interest rates (observed interest rates minus inflation) and stock prices. He noted that the decline in the market risk premium has led to a significant change in the relationship between interest rates and stock prices. One implication of this development was that stock prices had increased higher than would be suggested by the historical relationship between valuation levels and interest rates.

The equity risk premiums of some of the other leading investment firms today support the result of the academic studies. An article in *The Economist* indicated that some other firms like J.P. Morgan are estimating an equity risk premium for an average risk stock in the 2.0 - 3.0 percent range above the interest rate on U.S. Treasury Bonds.[23]

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY CFOS?

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[22] Steven G. Einhorn, "The Perplexing Issue of Valuation: Will the Real Value Please Stand Up?" *Financial Analysts Journal* (July-August 1990), pp. 11-16.

[23] For example, see "Welcome to Bull Country," *The Economist* (July 18, 1998), pp. 21-3, and "Choosing the Right Mixture," *The Economist* (February 27, 1999), pp. 71-2.

A. Yes. In the previously referenced third quarter 2008 CFO survey conducted by *CFO Magazine* and Duke University, the expected 10-year equity risk premium was 3.99%.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EX ANTE EQUITY RISK PREMIUMS OF PROFESSIONAL FORECASTERS?

A. Yes. The financial forecasters in the previously referenced Federal Reserve Bank of Philadelphia survey project both stock and bond returns. As shown on page 4 of Exhibit JRW-7, the mean long-term expected stock and bond returns were 6.80% and 4.84%, respectively. This provides an ex ante equity risk premium of 1.96%.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY THE LEADING CONSULTING FIRMS?

A. Yes. McKinsey & Co. is widely recognized as the leading management consulting firm in the world. It published a study entitled "The Real Cost of Equity" in which the McKinsey authors developed an ex ante equity risk premium for the U.S. In reference to the decline in the equity risk premium, as well as what is the appropriate equity risk premium to employ for corporate valuation purposes, the McKinsey authors concluded the following:

> We attribute this decline not to equities becoming less risky (the inflation-adjusted cost of equity has not changed) but to investors demanding higher returns in

real terms on government bonds after the inflation shocks of the late 1970s and early 1980s. We believe that using an equity risk premium of 3.5 to 4 percent in the current environment better reflects the true long-term opportunity cost of equity capital and hence will yield more accurate valuations for companies.[24]

Q. WHAT EQUITY COST RATES ARE INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM study for the proxy groups are provided below:

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

CAPM Equity Cost Rates

	Electric Proxy Group	Gas Proxy Group
Risk-Free Rate	4.5%	4.5%
Beta	0.82	0.82
Equity Risk Premium	4.56%	4.56%
Equity Cost Rate	8.2%	8.2%

V. EQUITY COST RATE SUMMARY

Q. PLEASE SUMMARIZE YOUR EQUITY COST RATE STUDY.

A. The results for my DCF and CAPM analyses for the proxy groups of electric utility and gas distribution companies are indicated below:

	DCF	CAPM
Electric Proxy Group	9.9%	8.2%
Gas Proxy Group	9.2%	8.2%

[24] Marc H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p. 15.

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR THE GROUPS?

A. Given these results, I conclude that the appropriate equity cost rate for Electric Proxy Group in the 8.3%-9.9% range and for the Gas Proxy Group is in the 8.3%-9.2% range. However, since I give greater weight to the DCF model, and due to the current volatile market conditions which are discussed below, I am using the upper end of the range as the equity cost rate. Therefore, I am recommending an equity cost rate of 9.9% for the electric utility business of LG&E and 9.2% for the gas distribution operations of LG&E. In addition, due to the uncertain market conditions, I reserve the right to update my study prior to hearings. Finally, given the common equity ratio proposed by the Company and adopted by the OAG, in comparison to the average common equity ratios for the Electric and Gas Proxy Groups, these recommendations are very fair to the Company.

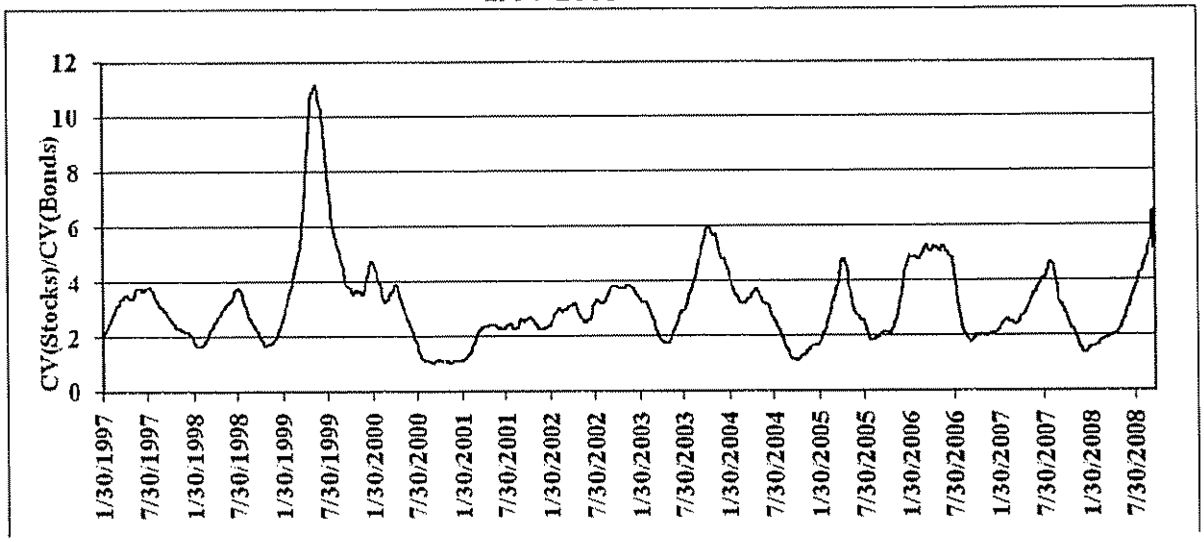
Q. FINALLY, PLEASE DISCUSS THE IMPACT OF RECENT CAPITAL MARKET VOLATILITY CONDITIONS ON THE EQUITY RISK PREMIUM AND THE EQUITY COST RATE.

A. To assess the impact of recent capital market volatility on the equity risk premium and the equity cost rate, one must look at the volatility of stocks relative to bonds. I have performed such an analysis below. To compare the volatility of stock and bonds, one must standardize the volatility measure. This is normally done by dividing the volatility measure, the standard deviation, by the mean. This standardized volatility measure is known as the Coefficient of Variation ("CV").

Q. GIVEN THESE OBSERVATIONS, PLEASE PROVIDE YOUR ASSESSMENT OF THE IMPACT OF RECENT CAPITAL MARKET CONDITIONS ON THE EQUITY COST RATE.

A. I have performed an analysis of the volatility of stocks relative to bonds since 1997. I have used the S&P 500 and the Bear Sterns Bond Price Index ("BSBPI") and computed the CV using a 200-day mean and standard deviation. In Figure 1 below, I have graphed the ratio of the CV(Stock CV)/CV(Bond CV). Hence, this graph shows the standardized volatility of stocks relative to bonds. Higher levels of this ratio represent time periods when stock volatility is high relative to bond volatility, and low levels of this ratio occur during time periods when stock volatility is low relative to bonds. During the last two quarters of 2007, the volatility of bonds increased relative to stocks due to the subprime mortgage crisis. Through October of this year, stocks have increased in volatility relative to bonds. On the relative CV measure, stocks reached a five-year high in terms of relative volatility. As such, current market conditions suggest that stock volatility is high relative to bond volatility. In recognition of this situation, I am using the high end of the range for my equity cost rate recommendation for the electric and gas operations of LG&E.

Coefficient of Variation
S&P 500 Price CV/Bear Sterns Bond Price Index CV
1997-2008



Q. ISN'T YOUR EQUITY COST RATE RECOMMENDATION LOW BY HISTORICAL STANDARDS?

A. Yes it is and appropriately so. My rate of return is low by historical standards for two reasons. First, as discussed above, current capital costs are very low by historical standards, with interest rates at a cyclical low not seen since the 1960s. And second, as previously discussed, the equity or market risk premium has declined.

Q. HOW DO YOU TEST THE REASONABLENESS OF YOUR COST OF EQUITY AND OVERALL RATE OF RETURN RECOMMENDATION?

A. To test the reasonableness of my equity cost rate recommendation, I examine the relationship between the return on common equity and the market-to-book ratios for the companies in the proxy groups of electric utility and gas distribution companies.

Q. WHAT DO THE RETURNS ON COMMON EQUITY AND MARKET-TO-BOOK RATIOS FOR THE PROXY GROUPS INDICATE ABOUT THE REASONABLENESS OF YOUR RECOMMENDATION?

A. Exhibit JRW-2 provides financial performance and market valuation statistics for companies in the two proxy groups. The mean current return on equity and market-to-book ratios for the group is summarized below:

	Current ROE	Market-to-Book Ratio
Electric Proxy Group	10.2 %	1.63
Gas Proxy Group	11.2 %	1.82

Source: Exhibit JRW-2

These results indicate that, on average, these companies are earning returns on equity above their equity cost rates. As such, this observation provides evidence that my recommended equity cost rate is reasonable and fully consistent with the financial performance and market valuation of the proxy groups of electric utility and gas distribution companies.

VI. CRITIQUE OF LG&E'S RATE OF RETURN TESTIMONY

Q. PLEASE EVALUATE THE COMPANY'S RATE OF RETURN POSITION.

A. The Company's proposed rate of return is inflated due to overstated debt and equity cost rates. The debt cost rates were previously discussed. I will now discuss the errors with Dr. Avera's equity cost rate analysis.

Q. PLEASE REVIEW DR. AVERA'S EQUITY COST RATE APPROACHES.

A. Dr. Avera uses a proxy group of electric and gas companies as well as a proxy group of non-utility companies and employs DCF, CAPM, and Expected Earnings equity cost rate approaches.

Q. PLEASE SUMMARIZE DR. AVERA'S EQUITY COST RATE RESULTS.

A. Dr. Avera's equity cost rate estimates for LG&E are summarized in the table below. Based on these figures, he concludes that the appropriate equity cost rate for the Company is 11.25%.

<u>Summary of Dr. Avera's Equity Cost Rate Approaches and Results</u>

Approach	Utility Proxy Group	Non-Utility Proxy Group
DCF	**10.9%**	**12.7%**
RP	**11.9%**	**11.4%**
Expected Earnings	**11.5%**	

Q. PLEASE DISCUSS YOUR ISSUES WITH DR. AVERA'S

RECOMMENDED EQUITY COST RATE.

A. Dr. Avera's proposed return on common equity is too high primarily due to: (a) some of the companies in his utility proxy group, as well as his use of a non-utility proxy group; (b) an excessive adjustment to the dividend yield and an inflated growth rate in his DCF approach; (c) overstated equity risk premium estimates in his CAPM approach; and (d) a flawed Expected Earnings approach.

A. Proxy Groups

Q. PLEASE DISCUSS THE PROBLEM WITH DR. AVERA'S UTILITY PROXY GROUP.

A. Dr. Avera's utility proxy group includes a number of companies that are not appropriate because their operating revenues are from sources other than regulated electric utility services. These companies, and their percent of regulated electric revenues, include: Constellation Energy – 13%, Great Plains Energy – 39%, OGE Energy – 48%, Otter Tail Corp. – 28%, SEMPRA Energy – 27%, Westar Energy – 69%, and Wisconsin Energy – 62%.

Q. PLEASE DISCUSS THE PROBLEM WITH DR. AVERA'S NON-UTILITY PROXY GROUP.

A. Dr. Avera has estimated an equity cost rate for LG&E using a proxy group of 44 non-utility companies. These companies are listed in Exhibit WEA-3. This group includes such companies as Coca-Cola, General Electric, IBM, Johnson & Johnson, McDonald's, Microsoft, and NIKE. While these companies are large and successful, their lines of business are vastly different from the electric and gas utility businesses and they do not operate in highly regulated environment. As such, the non-utility group is not an appropriate proxy for the electric and gas utility operations of LG&E and therefore the equity cost rate results for this group should be ignored.

Q. PLEASE DISCUSS EXHIBIT JRW-8.

A. In Exhibit JRW-8, I have performed an analysis that highlights the significant financial differences between Dr. Avera's non-utility and utility proxy groups. I have shown four different financial measures for the two groups: return on equity, market-to-book ratio, fixed asset turnover, and common equity ratio. The average return on equity for the non-utility group (23.53%) is twice the average return on common equity of the utility group (12.67%). As a result, the average market-to-book ratio of the non-utility group is also about double the average market-to-book ratio of the utility group return (3.53 vs. 1.63). The utility business is very capital intensive, and the fixed asset turnover ("FAT") ratio (revenues/net fixed assets) measures capital intensity with a lower figure indicating higher capital intensity. The FAT ratio for the utility group is only 0.90, while the ratio for the non-utility group is 5.44. Hence, in terms of capital intensity, the non-utility group is very dissimilar to the utility group. The common equity ("CE") ratio (common equity/total capital) measures the percent of capital represented by equity capital. For the utility group, the CE ratio is 53.88%, while the CE ratio for the non-utility group is 73.66%.

Overall, the results in Exhibit JRW-8 indicate that Dr. Avera's non-utility group has a significantly different financial profile than his utility group and therefore should not be used to estimate an equity cost rate for LG&E.

B. <u>DCF Approach</u>

Q. PLEASE SUMMARIZE DR. AVERA'S DCF ESTIMATES.

A. On pages 21-38 of his testimony and in Exhibits WEA-1 – WEA-4, Dr. Avera develops an equity cost rate by applying a DCF model to his utility and non-utility proxy groups. In the traditional DCF approach, the equity cost rate is the sum of the dividend yield and expected growth. For the DCF growth rate, Dr. Avera uses five measures of projected EPS growth – the projected EPS growth of Wall Street analysts as compiled by IBES, Reuters, Zack's, *Value Line* projected EPS growth, and the sum of internal ("br") and external ("sv") growth. Dr. Avera's DCF results are summarized below.

DCF Equity Cost Rate

	Utility Proxy Group	Non-Utility Proxy Group
Adjusted Dividend Yield	**3.7%**	**2.5%**
Expected EPS Growth from V-Line, IBES, Reuters, Zacks, and br+sv	**6.4% - 8.5%**	**9.19% - 10.79%**
DCF Result	**10.5% - 11.5%**	**12.4% - 12.9%**

Q. PLEASE EXPRESS YOUR CONCERNS WITH DR. AVERA'S DCF STUDY.

A. I have several issues with Dr. Avera's DCF equity cost rate. These are the utility

and non-utility proxy groups, and the DCF growth rate measures. The errors in the proxy groups were discussed above. The DCF growth rate measures are reviewed below.

Q. PLEASE CRITIQUE DR. AVERA'S DCF GROWTH RATE MEASURES.

A. Dr. Avera employs five different DCF growth rate measures - the projected EPS growth of Wall Street analysts as compiled by IBES, Reuters, Zack's, *Value Line* projected EPS growth, and sustainable growth as measured by the sum of internal ("br") and external ("sv") growth.

Q. PLEASE INITIALLY DISCUSS DR. AVERA'S RELIANCE ON THE PROJECTED EPS GROWTH RATES OF WALL STREET ANALYSTS AND *VALUE LINE*.

A. It seems highly unlikely that investors today would rely excessively on the forecasts of securities analysts and ignore historical growth in arriving at expected growth. It is well known in the academic world that the EPS forecasts of securities analysts are overly optimistic and biased upwards. In addition, as I show below, *Value Line*'s EPS forecasts are excessive and unrealistic.

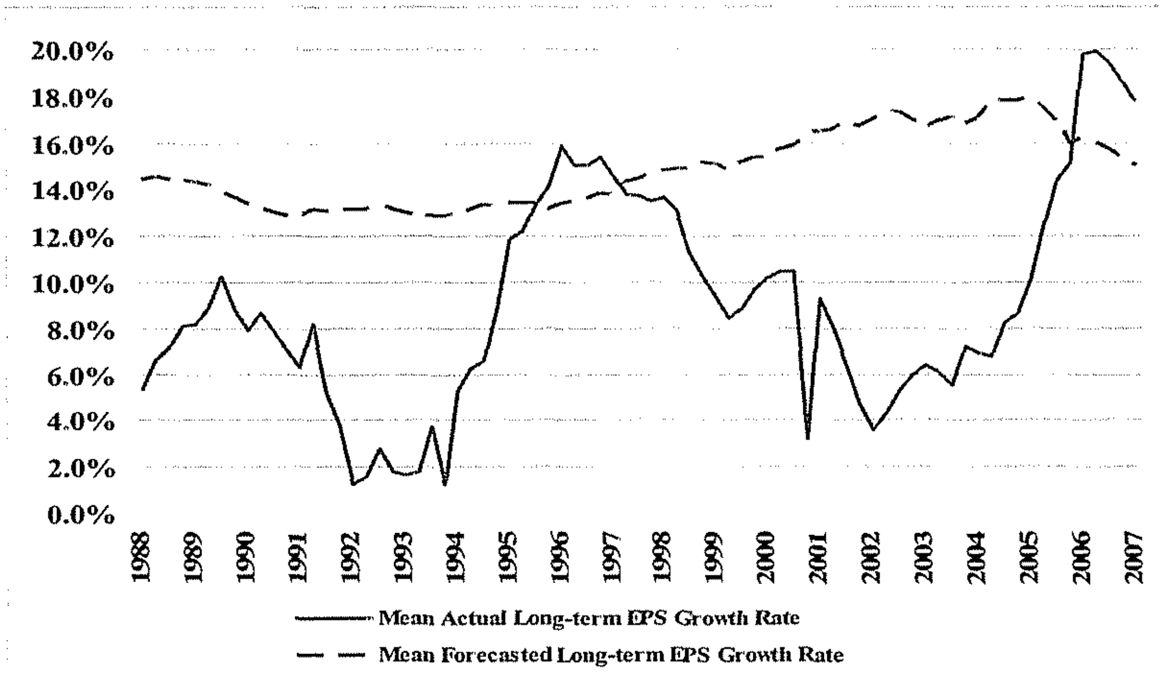
Q. PLEASE REVIEW THE BIAS IN ANALYSTS' GROWTH RATE FORECASTS.

A. Analysts' growth rate forecasts are collected and published by Zacks, First Call, I/B/E/S, and Reuters. These services retrieve and compile EPS forecasts from

Wall Street analysts. These analysts come from both the sell side (Merrill Lynch, Paine Webber) and the buy side (Prudential Insurance, Fidelity).

The problem with using these forecasts to estimate a DCF growth rate is that the objectivity of Wall Street research has been challenged, and many have argued that analysts' EPS forecasts are overly optimistic and biased upwards. To evaluate the accuracy of analysts' EPS forecasts, I have compared actual 3-5 year EPS growth rates with forecasted EPS growth rates on a quarterly basis over the past 20 years for all companies covered by the I/B/E/S data base. In the graph below, I show the average analysts' forecasted 3-5 year EPS growth rate with the average actual 3-5 year EPS growth rate. Because of the necessary 3-5 year follow-up period to measure actual growth, the analysis in this graph only: (1) covers forecasted and actual EPS growth rates through 1999 and (2) includes only companies that have 3-5 years of actual EPS data following the forecast period.

Long-Term Forecasted Versus Actual EPS Growth Rates
1988-2007



Source: Patrick J. Cusatis and J. Randall Woolridge, "The Accuracy of Analysts' Long-Term Earnings Per Share Growth Rate Forecasts," (July, 2008).

The following example shows how the results can be interpreted. For the 3-5-year period prior to the first quarter of 1999, analysts had projected an EPS growth rate of 15.13%, but companies only generated an average annual EPS growth rate over the 3-5 years of 9.37%. This projected EPS growth rate figure represented the average projected growth rate for over 1,510 companies, with an average of 4.88 analysts' forecasts per company. For the entire twenty-year period of the study, for each quarter there were on average 5.60 analysts' EPS projections for 1,281 companies. Overall, my findings indicate that forecast errors for long-term estimates are predominantly positive, which indicates an upward bias in growth rate estimates. The mean and median forecast errors over the observation period are 143.06% and

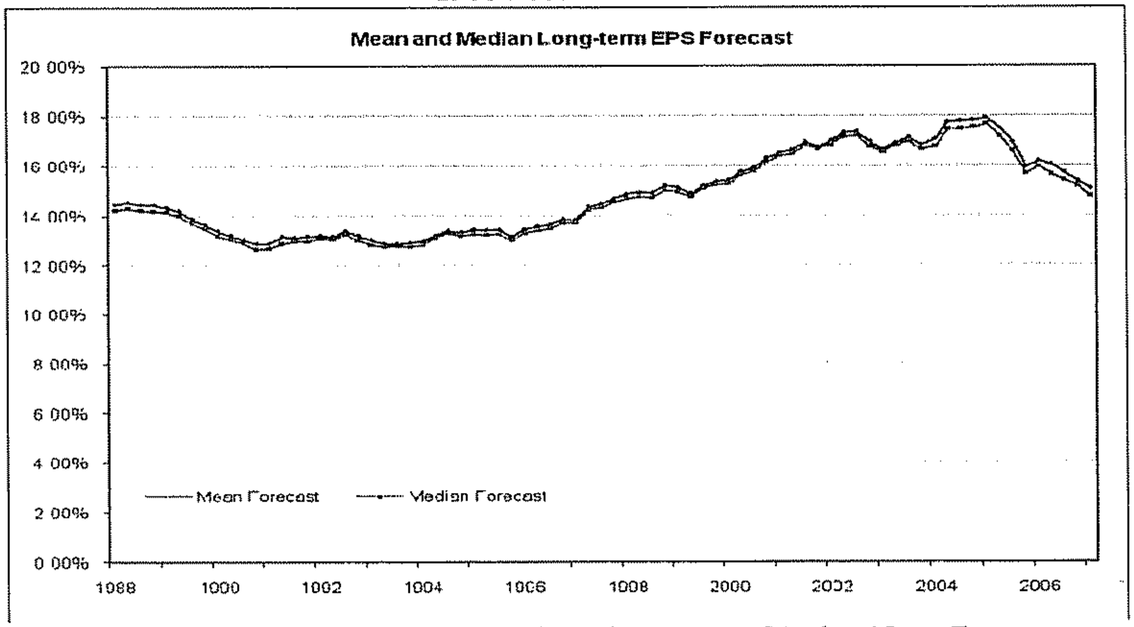
75.08%, respectively. The forecast errors are negative for only eleven of the eighty quarterly time periods: five consecutive quarters starting at the end of 1995 and six consecutive quarters starting in 2006. As shown in the figure below, the quarters with negative forecast errors were for the 3-5 year periods following earnings declines associated with the 1991 and 2001 economic recessions in the U.S. Overall. Thus, there is evidence of a persistent upward bias in long-term EPS growth forecasts.

The post-1999 period has seen the boom and then the bust in the stock market, an economic recession, 9/11, and the Iraq war. Furthermore, and highly significant in the context of this study, we have also had the New York State investigation of Wall Street firms and the subsequent Global Securities Settlement in which nine major brokerage firms paid a fine of $1.5B for their biased investment research.

To evaluate the impact of these events on analysts' forecasts, the graph below provides the average 3-5-year EPS growth rate projections for all companies provided in the I/B/E/S database on a quarterly basis from 1988 to 2006. In this graph no comparison to actual EPS growth rates is made, and hence, there is no follow-up period. Therefore, 3-5 year growth rate forecasts are shown until 2006, and since companies are not lost due to a lack of follow-up EPS data, these results are for a larger sample of firms. Analysts' forecasts for EPS growth were higher for this larger sample of firms, with a more pronounced run-up and then decline around the stock market peak in 2000. The average projected growth rate hovered in the 14.5%-17.5% range until

1995 and then increased dramatically over the next five years to 23.3% in the fourth quarter of the year 2000. Forecasted EPS growth has since declined to the 15.0% range.

Long-Term IBES Forecasted EPS Growth Rates
1988-2007



Source: Patrick J. Cusatis and J. Randall Woolridge, "The Accuracy of Analysts' Long-Term Earnings Per Share Growth Rate Forecasts," (July, 2008).

Q. WHAT IMPACT HAVE RECENT STOCK MARKET AND REGULATORY DEVELOPMENTS HAD ON ANALYSTS' EPS GROWTH RATE FORECASTS?

A. Analysts' EPS growth rate forecasts have subsided somewhat since the stock market peak of 2000. In addition, the apparent conflict of interest within investment firms with investment banking and analysts' operations was addressed in the Global Analysts Research Settlements ("GARS"). GARS, as agreed upon on April 23, 2003 between the SEC, NASD, NYSE and ten of the largest U.S. investment firms, includes a number of regulations that were introduced to prevent investment bankers from pressuring analysts to provide favorable projections. Nonetheless, despite the new regulations, analysts' EPS growth rate forecasts have not significantly changed and continue to be overly-optimistic. Analysts' long-term EPS growth rate forecasts before and after the GARS, are about two times the level of historic GDP growth. Furthermore, as discussed later in my testimony, historic growth in GDP and corporate earnings has been in the 7% range.

Finally, these observations are supported by a *Wall Street Journal* article entitled "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." The following quote provides insight into the continuing bias in analysts' forecasts:

> Hope springs eternal, says Mark Donovan, who manages Boston Partners Large Cap Value Fund. "You would have thought that, given what happened in the last three years, people would have given up the ghost. But in large measure they have not."
>
> These overly optimistic growth estimates also show that, even with all the regulatory focus on too-bullish analysts allegedly influenced by their firms' investment-banking relationships, a lot of things haven't changed: Research remains rosy and many believe it always will.[25]

Q. IS THE BIAS IN ANALYSTS' GROWTH RATE FORECASTS GENERALLY KNOWN IN THE MARKETS?

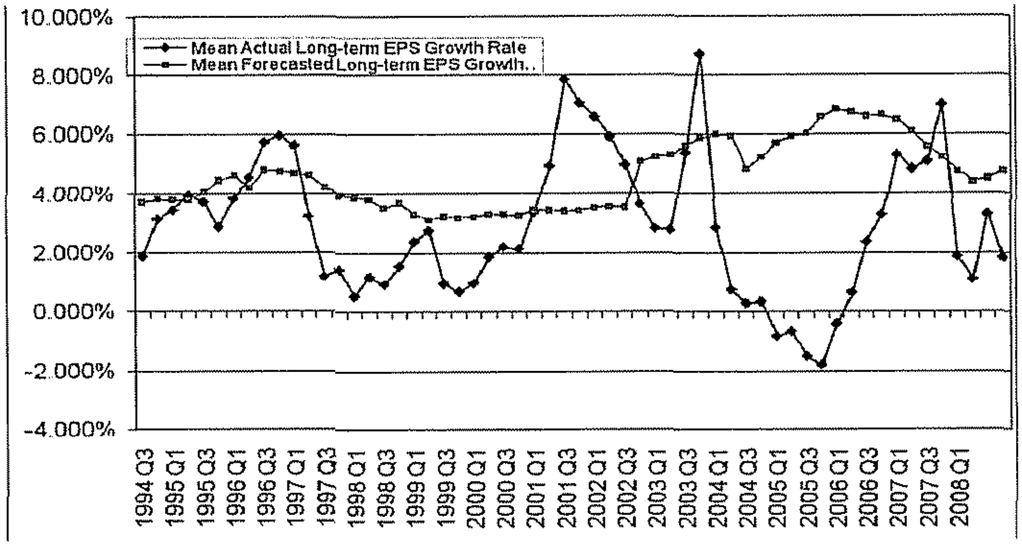
A. Yes. Exhibit JRW-9 provides a recent article published in the *Wall Street Journal* that discusses the upward bias in analysts' EPS growth rate forecasts.

[25] Ken Brown, "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." *Wall Street Journal*, (January 27, 2003), p. C1.

Q. ARE ANALYSTS' EPS GROWTH RATE FORECASTS LIKEWISE UPWARDLY BIASED FOR ELECTRIC UTILITY COMPANIES?

A. Yes. To evaluate whether analysts' EPS growth rate forecasts are upwardly biased for electric utility companies, I conducted a study similar to the one described above using a group of electric utility companies. The results are shown in the chart below. The projected EPS growth rates have declined from about six percent in the 1990s to about five percent in the 2000s. As shown, the achieved EPS growth rates have been volatile. Overall, the upward bias in EPS growth rate projections is not as pronounced for electric utility companies it is for all companies. Over the entire period, the average quarterly 3-5 year projected and actual EPS growth rates are 4.59% and 2.90%, respectively. These results are consistent with the results for companies in general -- analysts' projected EPS growth rate forecasts are upwardly-biased for utility companies.

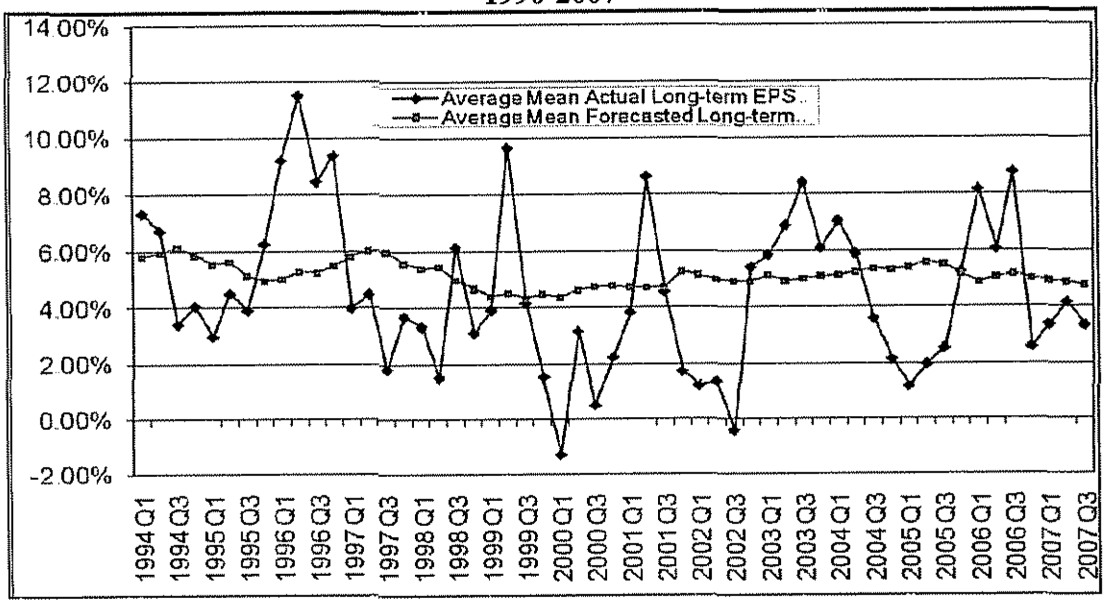
Analysts' 3-5-Year Forecasted Versus Actual EPS Growth Rates
Electric Utility Companies
1990-2008



Q. ARE ANALYSTS' EPS GROWTH RATE FORECASTS ALSO UPWARDLY BIASED FOR NATURAL GAS DISTRIBUTION COMPANIES?

A. Yes. To evaluate whether analysts' EPS growth rate forecasts are upwardly biased for natural gas distribution companies, I conducted a study similar to the one described above using a group of gas companies. The results are shown in the chart below. The projected EPS growth rates have declined from about six percent in the 1990s to about five percent in the 2000s. As shown, the achieved EPS growth rates have been volatile. Overall, the upward bias in EPS growth rate projections is not as pronounced for gas distribution companies it is for all companies. Over the entire period, the average quarterly 3-5 year projected and actual EPS growth rates are 5.15% and 4.53%, respectively. The results here are consistent with the results for companies in general -- analysts' projected EPS growth rate forecasts are upwardly-biased for utility companies.

Analysts' 3-5-Year Forecasted Versus Actual EPS Growth Rates
Natural Gas Distribution Companies
1990-2007



Q. ARE *VALUE LINE*'S GROWTH RATE FORECASTS SIMILARILY UPWARDLY BIASED?

A. Yes. *Value Line* has a decidedly positive bias to its earnings growth rate forecasts as well. To assess *Value Line*'s earnings growth rate forecasts, I used the *Value Line Investment Analyzer*. The results are summarized in the table below. I initially filtered the database and found that *Value Line* has 3-5 year EPS growth rate forecasts for 2,453 firms. The average projected EPS growth rate was 14.6%. This is high given that the average historical EPS growth rate in the U.S. is about 7%. A major factor seems to be that *Value Line* only predicts negative EPS growth for 47 companies. This is less than two percent of the companies covered by *Value Line*. Given the ups and downs of corporate earnings, this is unreasonable.

Value Line 3-5 year EPS Growth Rate Forecasts

	Average Projected EPS Growth rate	Number of Negative EPS Growth Projections	Percent of Negative EPS Growth Projections
2,453 Companies	**14.6%**	**47**	**1.9%**

To put this figure in perspective, I screened the *Value Line* companies to see what percent of companies covered by *Value Line* had experienced negative EPS growth rates over the past five years. *Value Line* reported a five-year historic growth rate for 2,371 companies. The results shown in the table below indicate that the average 5-year historic growth rate was 12.9%, and *Value Line* reported negative historic growth for 476 firms which represents 20.1% of these companies. It should be noted that the past five years have been a period of rapidly rising corporate earnings growth as the economy and businesses have rebounded from the recession of 2001.

Historical Five-Year EPS Growth Rates for *Value Line* Companies

	Average Historical EPS Growth rate	Number with Negative Historical EPS Growth	Percent with Negative Historical EPS Growth
2,371 Companies	**12.9%**	**476**	**20.1%**

These results indicate that *Value Line*'s EPS forecasts are excessive and unrealistic. It appears that the analysts at *Value Line* are similar to their Wall Street brethren in that they are reluctant to forecast negative earnings growth.

Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF DR. AVERA'S DCF GROWTH RATE.

A. Dr. Avera's DCF equity cost rate is overstated because he has relied so heavily on the upwardly biased EPS growth rate forecasts of Wall Street analysts and *Value Line*.

C. CAPM Analysis

Q. PLEASE DISCUSS DR. AVERA'S CAPM.

A. On pages 38 to 41 and Exhibits WEA-5 and WEA-6, Dr. Avera applies the CAPM method to his utility and non-utility proxy groups. The results are summarized below:

CAPM Equity Cost Rate

	Utility Proxy Group	Non-Utility Proxy Group
Risk-Free Rate	**4.40%**	**4.40%**
Beta	**0.84**	**0.79**
Market Risk Premium	**8.90%**	**8.90%**
CAPM Result	**11.9%**	**11.4%**

Q. WHAT ARE THE ERRORS IN DR. AVERA'S CAPM ANALYSIS?

A. The major flaw in Dr. Avera's CAPM analysis is his equity or market risk premium of 8.90%.

Q. PLEASE REVIEW DR. AVERA'S EQUITY OR MARKET RISK PREMIUM IN HIS CAPM APPROACH.

A. The primary problem with Dr. Avera's CAPM analysis is the size of the market or equity risk premium. Dr. Avera develops an expected market risk premium of 8.90% by: (1) applying the DCF model to the S&P 500 to get an expected market return; and (2) subtracting the risk-free rate of interest. Dr. Avera's estimated market return of 13.3% for the S&P 500 equals the sum of the dividend yield of 2.4% and expected EPS growth rate of 10.9%. The expected EPS growth rate is the average of the expected EPS growth rates from IBES and *Value Line*. The primary error in this approach is his expected DCF growth rate. As previously discussed, the expected EPS growth rates of Wall Street analysts and *Value Line* are upwardly biased. Therefore, as explained below, this produces an overstated expected market return and equity risk premium.

Q. BEYOND YOUR PREVIOUS DISCUSSION OF THE UPWARD BIAS IN ANALYSTS' AND *VALUE LINE*'S EPS GROWTH RATE FORECASTS, WHAT OTHER EVIDENCE CAN YOU PROVIDE THAT DR. AVERA'S S&P 500 GROWTH RATE IS EXCESSIVE?

A. A long-term EPS growth rate of 10.9% is inconsistent with economic and earnings growth in the U.S. The long-term economic and earnings growth rate in the U.S. has only been about 7%. I have performed a study of the growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960. The results are provided on page 1 of Exhibit JRW-10, and a summary is given in the table below.

GNP, S&P 500 Stock Price, EPS, and DPS Growth
1960-Present

Nominal GDP	7.20%
S&P 500 Stock Price Appreciation	7.12%
S&P 500 EPS	7.36%
S&P 500 DPS	5.77%
Average	6.86%

These results offer compelling evidence that a long-run growth rate of about 7% is appropriate for companies in the U.S. By comparison, Dr. Avera's long-run growth rate projection of 10.9% is clearly not realistic. These estimates suggest that companies in the U.S. would be expected to: (1) increase their growth rate of EPS by over 50% in the future and (2) maintain that growth indefinitely in an economy that is expected to grow at about one half his projected growth rates. Such a scenario is not economically feasible or reasonable.

Q. PLEASE PROVIDE A SUMMARY ASSESSMENT OF DR. AVERA'S EQUITY RISK PREMIUM OF 8.9% DERIVED USING AN EXPECTED MARKET RETURN OF 13.3%.

A. Dr. Avera's equity risk premium derived from an expected market return of 13.3% is inflated and does not reflect current market fundamentals or prospective economic and earnings growth. As previously discussed, at the present time stock prices (relative to earnings and dividends) are high while interest rates are low. Major stock market upswings that produce above average returns tend to occur when stock prices are low and interest rates are high. Thus, current market conditions do not suggest above-average expected market return. Consistent with this observation, the financial forecasters in the Federal Reserve Bank of Philadelphia survey expect a market return of 6.80% over the next ten years. In addition, the third quarter 2008 *CFO Magazine* – Duke University Survey of over 500 CFOs shows an expected return on the S&P 500 of 7.79% over the next ten years.

Q. TO CONCLUDE THIS DISCUSSION, PLEASE SUMMARIZE DR. AVERA'S MARKET RISK PREMIUM AND CAPM RESULTS IN LIGHT OF THE EVIDENCE ON RISK PREMIUMS IN TODAY'S MARKETS.

A. Dr. Avera's market risk premium of 8.9% is well in excess of the equity risk premium estimates discovered in recent academic studies by leading finance scholars and is especially out of touch with the real world of finance. Investment banks, consulting firms, and CFOs use the equity risk premium concept every day in making financing, investment, and valuation decisions. The results of studies and surveys from the real world of finance indicate an equity risk premium in the 4 percent range and not in the 8 percent range.

D. <u>Expected Earnings Approach</u>

Q. PLEASE DISCUSS DR. AVERA'S EXPECTED EARNINGS ANALYSIS.

A. In pages 41-42 of his testimony and Exhibit WEA-7, Dr. Avera estimates an equity cost rate of 11.8% for the Company employing an approach he calls the

Expected Earnings ("EE") approach. His methodology simply involves using the expected ROE for the companies in his proxy group as estimated by *Value Line*. This approach is fundamentally flawed for several reasons. First, these results include the profits associated with the unregulated operations of the utility proxy group. As previously noted, the unregulated operations are significant for several of the utility proxy companies. More importantly, since Dr. Avera has not evaluated the market-to-book ratios for these companies, he cannot indicate whether the past and projected returns on common equity are above or below investors' requirements. These returns on common equity are excessive if the market-to-book ratios for these companies are above 1.0. For example, Constellation Energy's projected return on equity is 16.9%. However, I doubt if any financial analyst, including Dr. Avera, would suggest that Constellation has an equity cost rate of 16.9%. Indeed, the market-to-book ratio for Constellation is about 2.0X. This indicates that its return on equity is above its cost of equity capital.

E. <u>Flotation Costs</u>

Q. PLEASE DISCUSS DR. AVERA'S ADJUSTMENT FOR FLOTATION COSTS.

A. While making no specific adjustment, Dr. Avera has recommended that flotation costs be considered in setting a return on equity for the Company. This consideration is erroneous for several reasons. First, the Company has not identified any actual flotation costs. Therefore, the Company is requesting annual revenues in the form of a higher return on equity for flotation costs that have not been identified. Second, it is commonly argued that a flotation cost adjustment (such as that used by the Company) is necessary to prevent the dilution of the existing shareholders. In this case, a floatation cost adjustment is justified by reference to bonds and the manner in which issuance costs are recovered by including the amortization of bond flotation costs in annual financing costs. However, this is incorrect for several reasons:

(1) If an equity flotation cost adjustment is similar to a debt flotation cost adjustment, the fact that the market-to-book ratios for utility companies are over 1.5X actually suggests that there should be a flotation cost reduction (and not increase) to the equity cost rate. This is because when (a) a bond is issued at a price in excess of face or book value, and (b) the difference between market price and the book value is greater than the flotation or issuance costs, the cost of that debt is lower than the coupon rate of the debt. The amount by which market values of utility companies are in excess of book values is much greater than flotation costs. Hence, if common stock flotation costs were exactly like bond flotation costs, and one was making an explicit flotation cost adjustment to the cost of common equity, the adjustment would be downward;

(2) If a flotation cost adjustment is needed to prevent dilution of existing stockholders' investment, then the reduction of the book value of stockholder investment associated with flotation costs can occur only when a company's stock is selling at a market price at/or below its book value. As noted above,

utility companies are selling at market prices well in excess of book value. Hence, when new shares are sold, existing shareholders realize an increase in the book value per share of their investment, not a decrease;

(3) Flotation costs consist primarily of the underwriting spread or fee and not out-of-pocket expenses. On a per share basis, the underwriting spread is the difference between the price the investment banker receives from investors and the price the investment banker pays to the company. Hence, these are not expenses that must be recovered through the regulatory process. Furthermore, the underwriting spread is known to the investors who are buying the new issue of stock, who are well aware of the difference between the price they are paying to buy the stock and the price that the Company is receiving. The offering price which they pay is what matters when investors decide to buy a stock based on its expected return and risk prospects. Therefore, the company is not entitled to an adjustment to the allowed return to account for those costs; and

(4) Flotation costs, in the form of the underwriting spread, are a form of a transaction cost in the market. They represent the difference between the price paid by investors and the amount received by the issuing company. Whereas the Company believes that it should be compensated for these transactions costs, they have not accounted for other market transaction costs in determining a cost of equity for the Company. Most notably, brokerage fees that investors pay when they buy shares in the open market are another market transaction cost. Brokerage fees increase the effective stock price paid by

investors to buy shares. If the Company had included these brokerage fees or transaction costs in their DCF analysis, the higher effective stock prices paid for stocks would lead to lower dividend yields and equity cost rates. This would result in a downward adjustment to their DCF equity cost rate.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A
Educational Background, Research, and Related Business Experience
J. Randall Woolridge

J. Randall Woolridge is a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed Faculty Fellow in Business Administration in the College of Business Administration of the Pennsylvania State University in University Park, PA. In addition, Professor Woolridge is Director of the Smeal College Trading Room and President and CEO of the Nittany Lion Fund, LLC.

Professor Woolridge received a Bachelor of Arts degree in Economics from the University of North Carolina, a Master of Business Administration degree from the Pennsylvania State University, and a Doctor of Philosophy degree in Business Administration (major area-finance, minor area-statistics) from the University of Iowa. At Iowa he received a Graduate Fellowship and was awarded membership in Beta Gamma Sigma, a national business honorary society. He has taught Finance courses at the University of Iowa, Cornell College, and the University of Pittsburgh, as well as the Pennsylvania State University. These courses include corporation finance, commercial and investment banking, and investments at the undergraduate, graduate, and executive MBA levels.

Professor Woolridge's research has centered on the theoretical and empirical foundations of corporation finance and financial markets and institutions. He has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance,* the *Journal of Financial Economics,* and the *Harvard Business Review*. His research has been cited extensively in the business press. His work has been featured in the *New York Times*, *Forbes*, *Fortune*, *The Economist*, *Financial World*, *Barron's*, *Wall Street Journal*, *Business Week*, *Washington Post*, *Investors' Business Daily*, *Worth Magazine*, *USA Today*, and other publications. In addition, Dr. Woolridge has appeared as a guest to discuss the implications of his research on CNN's *Money Line*, CNBC's *Morning Call* and *Business Today*, and Bloomberg Televisions' *Morning Call*.

Professor Woolridge's popular stock valuation book, *The StreetSmart Guide to Valuing a Stock* (McGraw-Hill, 2003), was released in its second edition. He has also co-authored *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation, 1999) as well as a new textbook entitled *Applied Principles of Finance* (Kendall Hunt, 2006). Dr. Woolridge is a founder and a managing director of www.valuepro.net - a stock valuation website

Professor Woolridge has also consulted with and prepared research reports for major corporations, financial institutions, and investment banking firms, and government agencies. In addition, he has directed and participated in over 500 university- and company- sponsored professional development programs for executives in 25 countries in North and South America, Europe, Asia, and Africa.

Dr. Woolridge has prepared testimony and/or provided consultation services in the following cases:

Pennsylvania: Dr. Woolridge has prepared testimony on behalf of the Pennsylvania Office of Consumer Advocate in the following cases before the Pennsylvania Public Utility Commission; Bell Telephone Company (R-811819), Peoples Natural Gas Company (R-832315), Pennsylvania Power Company (R-832409), Western Pennsylvania Water Company (R-832381), Pennsylvania Power Company (R-842740), Pennsylvania Gas and Water Company (R-850178), Metropolitan Edison Company (R-860384), Pennsylvania Electric Company (R-860413), North Penn Gas Company (R-860535), Philadelphia Electric Company (R-870629), Western Pennsylvania Water Company (R-870825), York Water Company (R-870749), Pennsylvania-American Water Company (R-880916), Equitable Gas Company (R-880971), the Bloomsburg Water Co. (R-891494), Columbia Gas of Pennsylvania, Inc (R-891468), Pennsylvania-American Water Company (R-90562), Breezewood Telephone Company (R-901666), York Water Company (R-901813), Columbia Gas of Pennsylvania, Inc. (R-901873), National Fuel Gas Corporation (R-911912), Pennsylvania-American Water Company (R-911909), Borough of Media Water Fund (R-912150), UGI Utilities, Inc. - Electric Utility Division (R-922195), Dauphin Consolidated Water Supply Company - General Waterworks of Pennsylvania, Inc, (R-932604), National Fuel Gas Corporation (R-932548), Commonwealth Telephone Company (I-

920020), Conestoga Telephone and Telegraph Company (I-920015), Peoples Natural Gas Company (R-932866), Blue Mountain Consolidated Water Company (R-932873), National Fuel Gas Corporation (R-942991), UGI - Gas Division (R-953297), UGI - Electric Division (R-953534), Pennsylvania-American Water Company (R-973944), Pennsylvania-American Water Company (R-994638), Philadelphia Suburban Water Company (R-994868;R-994877;R-994878; R-9948790), Philadelphia Suburban Water Company (R-994868), Wellsboro Electric Company (R-00016356), Philadelphia Suburban Water Company (R-00016750), National Fuel Gas Corporation (R-00038168), Pennsylvania-American Water Company (R-00038304), York Water Company (R-00049165), Valley Energy Company (R-00049345), Wellsboro Electric Company (R-00049313), National Fuel Gas Corporation (R-00049656), T.W. Phillips Gas and Oil Co. (R-00051178), PG Energy (R-00061365), City of Dubois Water Company (Docket No. R-00050671), R-00049165), York Water Company (R-00061322), Emporium Water Company (R-00061297), Pennsylvania-American Water Company (R-00072229),

New Jersey: Dr. Woolridge prepared testimony for the New Jersey Department of the Public Advocate, Division of Rate Counsel: New Jersey-American Water Company (R-91081399J), New Jersey-American Water Company (R-92090908J), and Environmental Disposal Corp. (R-94070319).

Alaska: Dr. Woolridge prepared testimony for Attorney General's Office of Alaska: Golden Heart Utilities, Inc. and College Utilities Corp. (Water Public Utility Service TA-29-118 and Sewer Public Utility Service TA-82-97), Anchorage Water and Wastewater Utility (TA-106-122).

Arizona: Dr. Woolridge prepared testimony for Utility Division staff of the Arizona Corporation Commission, Arizona Public Service Company (Docket No. E-01345A-06-0009).

Hawaii: Dr. Woolridge prepared testimony for the Hawaii Office of the Consumer Advocate: East Honolulu Community Services, Inc. (Docket No. 7718).

Delaware: Dr. Woolridge prepared testimony for the Delaware Division of Public Advocate: Artesian Water Company (R-00-649). Dr. Woolridge prepared testimony for the staff of the Public Service Commission: Artesian Water Company (R-06-158).

Ohio: Dr. Woolridge prepared testimony for the Ohio Office of Consumers' Council: SBC Ohio (Case No. 02-1280-TP-UNC R-00-649), and Cincinnati Gas & Electric Company (Case No. 05-0059-EL-AIR).

Texas: Dr. Woolridge prepared testimony for the Atmos Cities Steering Committee: Mid-Texas Division of Atmos Energy Corp. (Docket No. 9670).

New York: Dr. Woolridge prepared testimony for the County of Nassau in New York State: Long Island Lighting Company (PSC Case No. 942354).

Florida: Dr. Woolridge prepared testimony for the Office of Public Counsel in Florida: Florida Power & Light Co. (Docket No. 050045-EL).

Indiana: Dr. Woolridge prepared testimony for the Indiana Office of Utility Consumer Counsel (OUCC) in the following cases: Southern Indiana Gas and Electric Company (IURC Cause No. 43111 and IURC Cause No. 43112).

Oklahoma: Dr. Woolridge prepared testimony for the Oklahoma Industrial Energy Companies (OIEC) in the following cases: Public Service Company of Oklahoma (Cause No. PUD 200600285), Oklahoma Gas & Electric Company (Cause No. PUD 200700012

Appendix A
Educational Background, Research, and Related Business Experience
J. Randall Woolridge

Connecticut: Dr. Woolridge prepared testimony for the Office of Consumer Counsel in Connecticut: United Illuminating (Docket No. 96-03-29), Yankee Gas Company (Docket No. 04-06-01), Southern Connecticut Gas Company (Docket No. 03-03-17), the United Illuminating Company (Docket No 05-06-04), Connecticut Light and Power Company (Docket No. 05-07-18), Birmingham Utilities, Inc. (Docket No. 06-05-10), Connecticut Water Company (Docket No. 06-07-08), Connecticut Natural Gas Corp. (Docket No 06-03-04), Aquarion Water Company (Docket No. 07-05-09), Yankee Gas Company (Docket No. 06-12-02), and Connecticut Light and Power Company (Docket No. 07-07-01).

California: Dr. Woolridge prepared testimony for the Office of Ratepayer Advocate in California: San Gabriel Valley Water Company (Docket No. 05-08-021), Pacific Gas & Electric (Docket No. 07-05-008), San Diego Gas & Electric (Docket No. 07-05-007), and Southern California Edison (Docket No. 07-05-003).

South Carolina: Dr. Woolridge prepared testimony for the Office of Regulatory Staff in South Carolina: South Carolina Electric and Gas Company (Docket No. 2005-113-G), Carolina Water Service Co. (Docket No. 2006-87-WS), Tega Cay Water Company (Docket No. 2006-97-WS), United Utilities Companies, Inc. (Docket No. 2006-107-WS).

Missouri: Dr. Woolridge prepared testimony for the Department of Energy in Missouri: Kansas City Power & Light Company (CASE NO. ER-2006-0314). Dr. Woolridge prepared testimony for the Office of Attorney General of Missouri: Union Electric Company (CASE NO. ER-2007-0002)

Kentucky: Dr. Woolridge prepared testimony for the Office of Attorney General in Kentucky: Kentucky-American Water Company (Case No. 2004-00103), Union Heat, Light, and Power Company (Case No. 2004-00042), Kentucky Power Company (Case No. 2005-00341), Union Heat, Light, and Power Company (Case No. 2006-00172), Atmos Energy Corp. (Case No. 2006-00464), Columbia Gas Company (Case No. 2007-00008), Delta Natural Gas Company (Case No. 2007-00089), Kentucky-American Water Company (Case No. 2007-00143)

Washington, D.C.: Dr. Woolridge prepared testimony for the Office of the People's Counsel in the District of Columbia: Potomac Electric Power Company (Formal Case No. 939).

Washington: Dr. Woolridge consulted with trial staff of the Washington Utilities and Transportation Commission on the following cases: Puget Energy Corp. (Docket Nos. UE-011570 and UG-011571); and Avista Corporation (Docket No. UE-011514).

Kansas: Dr. Woolridge prepared testimony on behalf of the Kansas Citizens' Utility Ratepayer Board in the following cases: Western Resources Inc. (Docket No. 01-WSRE-949-GIE), UtiliCorp (Docket No. 02-UTCG701-CIG), and Westar Energy, Inc. (Docket No. 05-WSEE-981-RTS).

FERC: Dr. Woolridge has prepared testimony on behalf of the Pennsylvania Office of Consumer Advocate in the following cases before the Federal Energy Regulatory Commission: National Fuel Gas Supply Corporation (RP-92-73-000) and Columbia Gulf Transmission Company (RP97-52-000).

Vermont: Dr. Woolridge prepared testimony for the Department of Public Service in the Central Vermont Public Service (Docket No. 6988) and Vermont Gas Systems, Inc. (Docket No. 7160).

Exhibit JRW-1

Louisville Gas & Electric Company
Cost of Capital

Electric Utility Operations
Capitalization at April 30, 2008

Capital Source	Capitalization Amount*	Capitalization Ratio*	Cost Rate	Weighted Cost Rate
Short-Term Debt	42,350	2.38%	2.63%	0.06%
Long-Term Debt	803,558	45.14%	5.30%	2.39%
Common Equity	934,171	52.48%	9.90%	5.20%
Total	1,780,079	100.00%		7.65%

Gas Utility Operations
Capitalization at April 30, 2008

Capital Source	Capitalization Amount*	Capitalization Ratio*	Cost Rate	Weighted Cost Rate
Short-Term Debt	10,126	2.38%	2.63%	0.06%
Long-Term Debt	192,138	45.14%	5.30%	2.39%
Common Equity	223,369	52.48%	9.20%	4.83%
Total	425,633	100.00%		7.28%

* *Capitalization ratios developed on page 1 of Exhibit JRW-3*

Exhibit JRW-2
Louisville Gas & Electric Company
Summary Financial Statistics

Panel A
Electric Proxy Group

Company	Operating Revenue ($mil)	Percent Elec Revenue	Net Plant ($mil)	Moody's Bond Rating	Long-Term Interest Coverage	Primary Service Area	Common Equity Ratio*	Return on Equity	Market to Book Ratio
ALLETE, Inc. (NYSE-ALE)	849.8	87	1,153.1	NR	6.0	MN, WS	60	13.2	163
Ameren Corporation (NYSE-AEE)	7,671.0	82	15,566.0	Baa2	4.2	IL, MO	46	10.4	129
American Electric Power Co. (NYSE-AEP)	14,078.0	90	31,004.0	Baa1	3.0	11 States	39	14.9	145
Central Vermont Public Serv. Corp. (NYSE-C	340.7	100	327.6	NR	4.1	VT	50	8.8	133
Cleco Corporation (NYSE-CNL)	1,042.7	95	1,877.6	Baa1	2.5	LA	49	12.5	149
DPL Inc.(NYSE-DPL)	1,552.1	100	2,793.0	A2	6.2	OH	36	NM	308
Edison International (NYSE-EIX)	13,283.0	80	17,698.0	A2	2.1	CA	43	12.7	173
Empire District Electric Co. (NYSE-EDE)	501.2	87	1,222.3	Baa1	2.2	MO,KS,OK,AR	45	7.0	126
FirstEnergy Corporation (NYSE-FE)	13,242.0	88	16,703.0	Baa2	4.6	OH,PA,NJ	40	13.7	237
FPL Group, Inc. (NYSE-FPL)	15,278.0	76	30,499.0	Aa3	3.2	FL	42	12.1	230
Hawaiian Electric Industries, Inc. (NYSE-HE)	2,712.0	81	2,460.5	Baa2	2.9	HI	29	9.3	165
IDACORP, Inc. (NYSE-IDA)	902.6	100	2,687.8	A3	2.4	ID,OR	46	6.6	114
Northeast Utilities (NYSE-NU)	5,637.9	84	7,452.6	Baa1	2.8	CT,NH,MA	42	7.9	144
NSTAR (NYSE-NST)	3,173.0	78	4,176.9	A1	3.3	MA	40	7.4	207
Pinnacle West Capital Corp. (NYSE-PNW)	3,628.0	86	8,570.9	Baa2	3.0	AZ	52	8.8	94
PNM Resources, Inc. (NYSE-PNM)	1,625.0	100	2,972.7	Baa3	0.0	NM	40	NM	57
Progress Energy Inc. (NYSE-PGN)	8,885.0	100	16,986.0	A2	2.9	NC,SC,FL	46	7.3	134
Southern Company (NYSE-SO)	16,070.1	99	34,562.6	A2	4.1	GA,AL,FL,MS	41	13.7	227
UIL Holdings Corporation (NYSE-UIL)	941.5	100	969.6	Baa2	4.2	CT	44	10.5	186
UniSource Energy Corporation (NYSE-UNS)	1,424.2	85	2,505.8	Baa2	1.7	AZ	26	6.5	169
Xcel Energy Inc. (NYSE-XEL)	10,298.9	78	16,955.1	A3	2.9	CO,MN,WS,ND,SD,MI	43	9.9	141
Mean	5,863.7	89	10,435.4	Baa1	3.3		43	10.2	163

Data Source: AUS *Utility Reports*, September, 2008; Service Area and Long-Term Interest Coverage are from *Value Line Investment Survey*, 2008

Panel B
Gas Proxy Group

Company	Operating Revenue ($mil)	Percent Gas Revenue	Net Plant ($mil)	Moody's Bond Rating	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio*	Return on Equity	Market to Book Ratio
AGL Resources Inc. (NYSE-ATG)	2,510.0	68%	3,563.0	A3	3.0	GA,VA	44	8.3%	1.49
Atmos Energy Corporation (NYSE-ATO)	6,782.7	52%	4,012.9	Baa3	2.8	LA,KY,TX, CO,KS	49	8.4%	1.17
Laclede Group, Inc. (NYSE-LG)	2,117.8	53%	813.1	A3	3.0	MO	57	13.2%	2.12
New Jersey Resources Corp. (NYSE-NJR)	3,244.3	33%	990.4	NR	4.8	NJ,Canada	55	NM	2.27
NICOR Inc. (NYSE-GAS)	3,437.3	84%	2,759.6	A1	5.9	IL	65	14.3%	2.07
Northwest Natural Gas Co. (NYSE-NWN)	1,026.8	98%	1,443.8	A2	4.0	OR,WA	52	11.0%	2.02
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	1,925.1	82%	2,191.6	A3	4.0	NC,SC,TN	51	12.1%	2.21
South Jersey Industries, Inc. (NYSE-SJI)	936.0	62%	956.9	Baa1	3.3	NJ	56	12.6%	2.09
Southwest Gas Corporation (NYSE-SWX)	2,172.0	84%	2,866.6	Baa3	2.3	AZ,NV,CA	46	8.3%	1.24
WGL Holdings, Inc. (NYSE-WGL)	2,564.8	59%	2,168.7	A2	5.7	DC,MD,VA	58	12.2%	1.51
Mean	2,671.7	68%	2,176.7	A3	3.9		53	11.2%	1.82

Data Source: AUS *Utility Reports*, September, 2008; Service Area, and Pre-Tax Interest Coverage is from *Value Line Investment Survey*, 2008

Exhibit JRW-3
Louisville Gas & Electric Company
Capital Structure Ratios

Panel A - LG&E Recommended Capitalization Ratios

Capital	Capitalization Ratios
Short-Term Debt	2.38%
Long-Term Debt	45.14%
Common Equity	52.48%
Total Capital	100.00%

Source: Testimony of Mr. S. Bradford Rives

Panel B - LG&E - OAG Capitalization Ratios
Electric Utility Operations

Short-Term Debt	42,350	2.38%
Long-Term Debt	803,558	45.14%
Common Equity	934,171	52.48%
Total	1,780,079	100.00%

Gas Utility Operations

Short-Term Debt	10,126	2.38%
Long-Term Debt	192,138	45.14%
Common Equity	223,369	52.48%
Total	425,633	100.00%

Exhibit JRW-3
Louisville Gas & Electric Company
Capital Structure Ratios

Company	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Mean
ALLETE, Inc. (NYSE-ALE)	62.0	62.0	63.0	63.0	63.0	60.0	60.0	60.0	60.0	57.0	61.0
Ameren Corporation (NYSE-AEE)	49.0	49.0	49.0	47.0	47.0	47.0	47.0	47.0	46.0	46.0	47.4
American Electric Power Co. (NYSE-AEP)	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
Central Vermont Public Serv. Corp. (NYSE-CV)	59.0	59.0	59.0	60.0	60.0	51.0	51.0	51.0	50.0	50.0	55.0
Cleco Corporation (NYSE-CNL)	56.0	56.0	56.0	54.0	54.0	51.0	51.0	51.0	49.0	49.0	52.7
DPL Inc.(NYSE-DPL)	34.0	34.0	34.0	35.0	35.0	35.0	36.0	36.0	36.0	39.0	35.4
Edison International (NYSE-EIX)	44.0	44.0	44.0	44.0	44.0	43.0	43.0	43.0	43.0	42.0	43.4
Empire District Electric Co. (NYSE-EDE)	45.0	45.0	45.0	48.0	48.0	45.0	45.0	45.0	45.0	44.0	45.5
FirstEnergy Corporation (NYSE-FE)	43.0	43.0	43.0	42.0	42.0	41.0	41.0	41.0	40.0	40.0	41.6
FPL Group, Inc. (NYSE-FPL)	43.0	43.0	43.0	44.0	44.0	43.0	43.0	43.0	42.0	42.0	43.0
Hawaiian Electric Industries, Inc. (NYSE-HE)	27.0	27.0	27.0	27.0	27.0	29.0	29.0	29.0	29.0	38.0	28.9
IDACORP, Inc. (NYSE-IDA)	48.0	48.0	48.0	47.0	47.0	46.0	46.0	46.0	46.0	46.0	46.8
Northeast Utilities (NYSE-NU)	43.0	43.0	43.0	43.0	43.0	42.0	42.0	42.0	42.0	40.0	42.3
NSTAR (NYSE-NST)	41.0	41.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.2
Pinnacle West Capital Corp. (NYSE-PNW)	50.0	50.0	50.0	49.0	49.0	49.0	49.0	49.0	52.0	52.0	49.9
PNM Resources, Inc. (NYSE-PNM)	47.0	47.0	47.0	47.0	47.0	47.0	40.0	40.0	40.0	41.0	44.3
Progress Energy Inc. (NYSE-PGN)	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	43.0	45.7
Southern Company (NYSE-SO)	42.0	42.0	42.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.3
UIL Holdings Corporation (NYSE-UIL)	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
UniSource Energy Corporation (NYSE-UNS)	28.0	28.0	28.0	29.0	29.0	27.0	27.0	27.0	26.0	26.0	27.5
Xcel Energy Inc. (NYSE-XEL)	43.0	43.0	43.0	44.0	44.0	43.0	43.0	43.0	43.0	42.0	43.1
Mean	44.4	44.4	44.4	44.4	44.4	43.3	43.0	43.0	42.8	42.9	43.7

Data Source: AUS *Utility Reports*

Panel B
Gas Proxy Group

Company	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Mean
AGL Resources Inc. (NYSE-ATG)	43.0	43.0	42.0	42.0	42.0	47.0	47.0	47.0	44.0	44.0	44.1
Atmos Energy Corporation (NYSE-ATO)	46.0	46.0	47.0	47.0	47.0	50.0	50.0	50.0	49.0	49.0	48.1
Laclede Group, Inc. (NYSE-LG)	41.0	41.0	40.0	40.0	40.0	40.0	48.0	48.0	57.0	57.0	45.2
New Jersey Resources Corp. (NYSE-NJR)	50.0	50.0	49.0	49.0	49.0	55.0	55.0	55.0	55.0	51.0	51.8
NICOR Inc. (NYSE-GAS)	58.0	58.0	58.0	52.0	52.0	65.0	65.0	65.0	65.0	66.0	60.4
Northwest Natural Gas Co. (NYSE-NWN)	48.0	48.0	48.0	47.0	47.0	52.0	52.0	52.0	52.0	52.0	49.8
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	48.0	46.0	46.0	45.0	45.0	45.0	51.0	51.0	51.0	48.0	47.6
South Jersey Industries, Inc. (NYSE-SJI)	48.0	48.0	48.0	50.0	50.0	56.0	56.0	56.0	56.0	52.0	52.0
Southwest Gas Corporation (NYSE-SWX)	43.0	43.0	43.0	43.0	43.0	46.0	46.0	46.0	46.0	46.0	44.5
WGL Holdings, Inc. (NYSE-WGL)	54.0	54.0	51.0	51.0	51.0	58.0	58.0	58.0	58.0	60.0	55.3
Mean	47.9	47.7	47.2	46.6	46.6	51.4	52.8	52.8	53.3	52.5	49.9

Data Source: AUS *Utility Reports*

Exhibit JRW-4

Long-Term 'A' Rated Public Utility Bonds

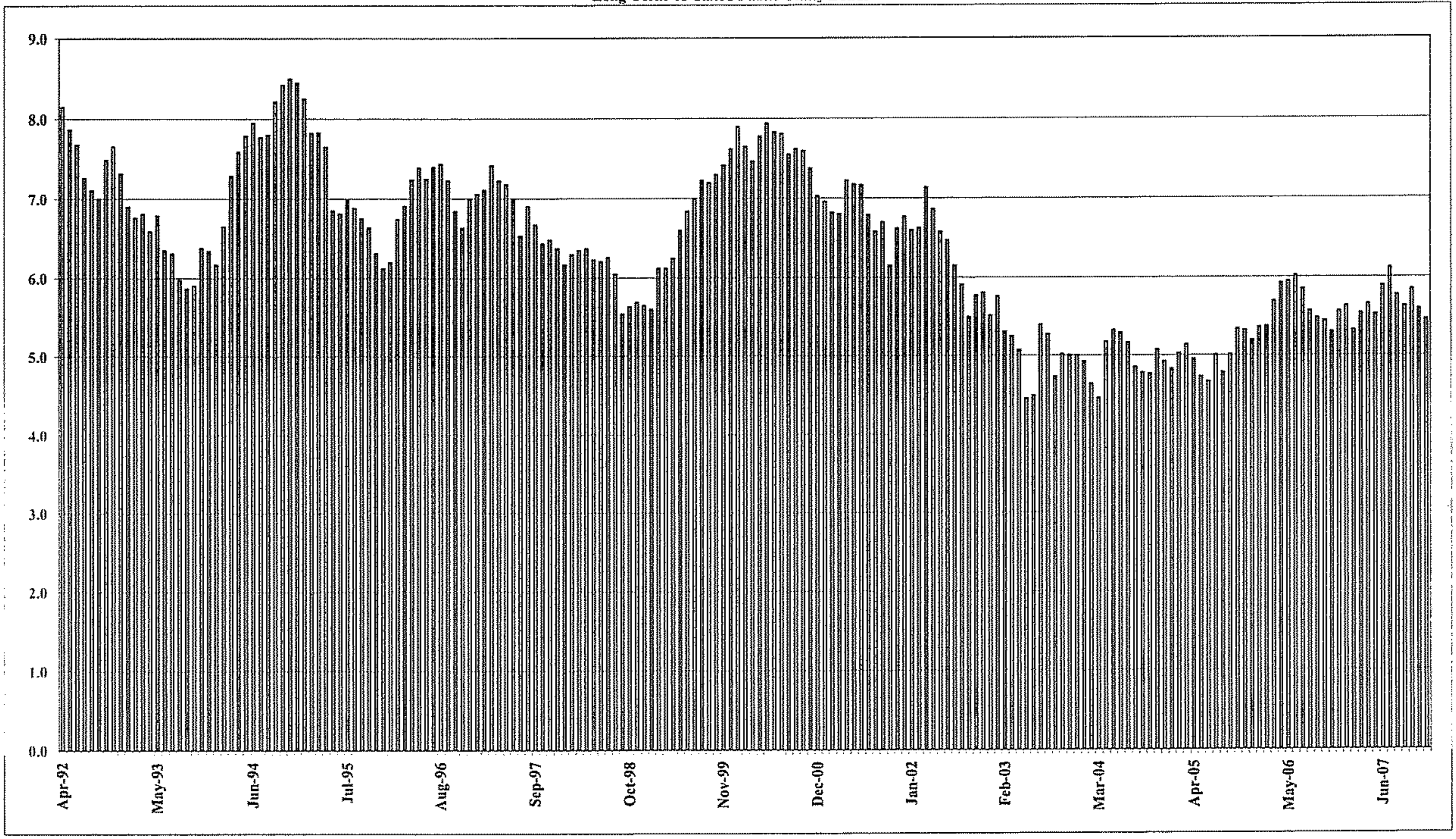
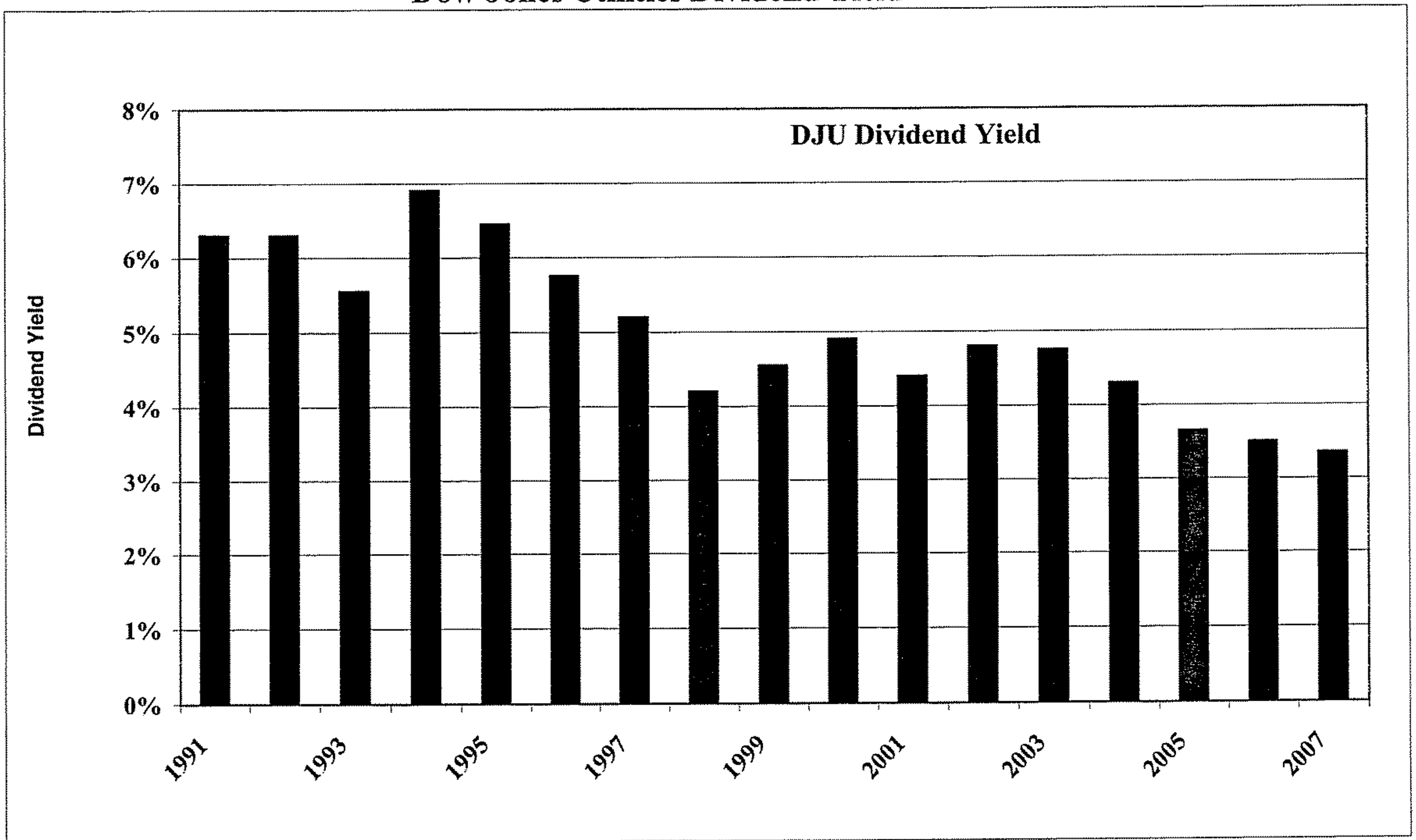


Exhibit JRW-4

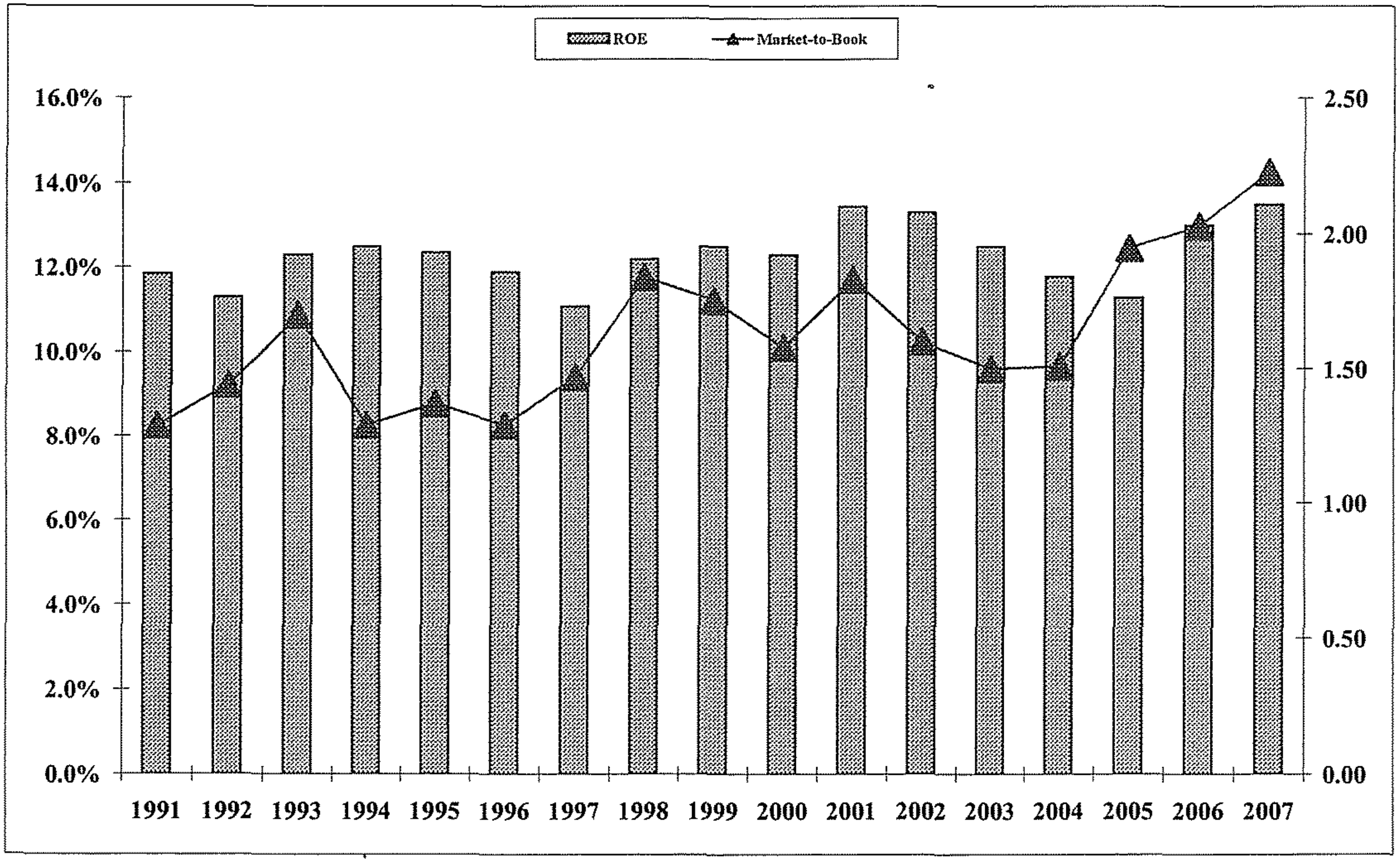
Dow Jones Utilities Dividend Yield



Data Source: Value Line Investment Survey

Exhibit JRW-4

Dow Jones Utilities - Market to Book and ROE



Data Source: Value Line Investment Survey

Exhibit JRW-5

Industry Average Betas

Industry Name	Number of Firms	Beta	Industry Name	Number of Firms	Beta	Industry Name	Number of Firms	Beta
Semiconductor	138	2.59	Telecom. Services	152	1.34	Utility (Foreign)	6	1.01
Semiconductor Equip	16	2.51	Electronics	179	1.32	Petroleum (Producing)	186	1.00
Wireless Networking	74	2.20	Investment Co.(Foreign)	15	1.31	Environmental	89	1.00
E-Commerce	56	2.08	Educational Services	39	1.27	Grocery	15	0.99
Entertainment Tech	38	2.06	Retail (Special Lines)	164	1.26	Home Appliance	11	0.95
Telecom. Equipment	124	1.98	Hotel/Gaming	75	1.25	Insurance (Life)	40	0.94
Steel (Integrated)	14	1.97	Heavy Construction	12	1.25	Electric Util. (Central)	25	0.93
Internet	266	1.97	Retail Building Supply	9	1.23	Paper/Forest Products	39	0.93
Manuf. Housing/RV	18	1.92	Railroad	16	1.23	Restaurant	75	0.93
Power	58	1.87	Industrial Services	196	1.22	Natural Gas (Div.)	31	0.93
Computers/Peripherals	144	1.86	Newspaper	18	1.21	Healthcare Information	38	0.91
Drug	368	1.78	Aerospace/Defense	69	1.19	Property Management	12	0.91
Coal	18	1.71	Metal Fabricating	37	1.19	R.E.I.T.	147	0.90
Steel (General)	26	1.71	Machinery	126	1.19	Household Products	28	0.89
Securities Brokerage	31	1.66	Chemical (Diversified)	37	1.16	Insurance (Prop/Cas.)	87	0.89
Precision Instrument	103	1.66	Financial Svcs. (Div.)	294	1.14	Beverage	44	0.89
Homebuilding	36	1.64	Office Equip/Supplies	25	1.13	Electric Utility (West)	17	0.88
Advertising	40	1.60	Packaging & Container	35	1.12	Maritime	52	0.87
Retail Automotive	16	1.58	Precious Metals	84	1.11	Apparel	57	0.87
Cable TV	23	1.56	Retail Store	42	1.11	Bank (Midwest)	38	0.85
Computer Software/Svcs	376	1.56	Furn/Home Furnishings	39	1.10	Toiletries/Cosmetics	21	0.85
Auto & Truck	28	1.54	Oilfield Svcs/Equip.	113	1.10	Electric Utility (East)	27	0.84
Recreation	73	1.54	Medical Services	178	1.10	Canadian Energy	13	0.80
Entertainment	93	1.53	Foreign Electronics	10	1.08	Food Wholesalers	19	0.79
Chemical (Basic)	19	1.52	Building Materials	49	1.07	Water Utility	16	0.78
Biotechnology	103	1.51	Pharmacy Services	19	1.07	Natural Gas Utility	26	0.78
Shoe	20	1.47	Chemical (Specialty)	90	1.06	Food Processing	123	0.77
Auto Parts	56	1.45	Metals & Mining (Div.)	78	1.05	Oil/Gas Distribution	15	0.72
Medical Supplies	274	1.43	Information Services	38	1.05	Investment Co.	18	0.71
Air Transport	49	1.40	Trucking	32	1.04	Tobacco	11	0.70
Human Resources	35	1.38	Diversified Co.	107	1.03	Bank (Canadian)	8	0.67
Publishing	40	1.35	Petroleum (Integrated)	26	1.02	Bank	504	0.63
Electrical Equipment	86	1.35	Reinsurance	11	1.01	Thrift	234	0.59
						Total/Average	7364	1.24

Data Source: http://pages stern nyu edu/~adamodar/

Exhibit JRW-6

Louisville Gas & Electric Company
Discounted Cash Flow Analysis

Panel A
Electric Proxy Group

Dividend Yield*	4.3%
Adjustment Factor	1.0275
Adjusted Dividend Yield	4.4%
Growth Rate**	5.5%
Equity Cost Rate	9.9%

Panel B
Gas Proxy Group

Dividend Yield*	3.6%
Adjustment Factor	1.0275
Adjusted Dividend Yield	3.7%
Growth Rate**	5.5%
Equity Cost Rate	9.2%

* Page 2 of Exhibit JRW-6
** Based on data provided on pages 3, 4, and 5 of Exhibit JRW-6

Exhibit JRW-6

Louisville Gas & Electric Company
Monthly Dividend Yields
May-October 2008

Panel A
Electric Proxy Group

Company	May	June	July	Aug	Sep	Oct	Mean
ALLETE, Inc. (NYSE-ALE)	4.1%	4.0%	3.8%	4.2%	4.0%	3.8%	4.0%
Ameren Corporation (NYSE-AEE)	5.5%	5.5%	5.9%	6.3%	6.0%	6.1%	5.9%
American Electric Power Co. (NYSE-AEP)	3.7%	3.8%	3.9%	4.2%	4.3%	4.3%	4.0%
Central Vermont Public Serv. Corp. (NYSE-CV)	3.7%	4.1%	4.7%	4.4%	3.7%	3.7%	4.1%
Cleco Corporation (NYSE-CNL)	3.7%	3.6%	3.7%	3.8%	3.5%	3.4%	3.6%
DPL Inc.(NYSE-DPL)	4.0%	3.9%	3.9%	4.1%	4.5%	4.2%	4.1%
Edison International (NYSE-EIX)	2.3%	2.3%	2.4%	2.4%	2.7%	3.0%	2.5%
Empire District Electric Co. (NYSE-EDE)	5.9%	6.1%	6.4%	6.7%	5.9%	5.6%	6.1%
FirstEnergy Corporation (NYSE-FE)	2.9%	2.9%	2.8%	2.9%	3.1%	3.2%	3.0%
FPL Group, Inc. (NYSE-FPL)	2.7%	2.7%	2.7%	2.7%	2.9%	3.2%	2.8%
Hawaiian Electric Industries, Inc. (NYSE-HE)	5.0%	4.7%	4.7%	5.2%	4.9%	4.4%	4.8%
IDACORP, Inc. (NYSE-IDA)	3.7%	3.8%	3.8%	4.1%	3.9%	3.8%	3.9%
Northeast Utilities (NYSE-NU)	3.0%	3.0%	3.2%	3.5%	3.1%	3.2%	3.2%
NSTAR (NYSE-NST)	4.4%	4.2%	4.1%	4.4%	4.2%	3.9%	4.2%
Pinnacle West Capital Corp. (NYSE-PNW)	5.8%	6.2%	6.5%	6.7%	6.0%	6.0%	6.2%
NM Resources, Inc. (NYSE-PNM)	6.7%	6.5%	6.8%	8.0%	4.2%	4.2%	6.1%
Progress Energy Inc. (NYSE-PGN)	5.8%	5.8%	5.8%	6.0%	5.6%	5.5%	5.8%
Southern Company (NYSE-SO)	4.4%	4.5%	4.8%	4.8%	4.5%	4.4%	4.6%
UIL Holdings Corporation (NYSE-UIL)	5.6%	5.5%	5.4%	5.9%	5.1%	4.9%	5.4%
UniSource Energy Corporation (NYSE-UNS)	3.6%	2.9%	2.8%	3.2%	2.9%	3.1%	3.1%
Xcel Energy Inc. (NYSE-XEL)	4.4%	4.3%	4.6%	4.8%	4.6%	4.4%	4.5%
Mean	4.3%	4.3%	4.4%	4.7%	4.3%	4.2%	4.4%

Source: *AUS Utility Reports*, monthly issues

Panel B
Gas Proxy Group

Company	May	June	July	Aug	Sep	Oct	Mean
AGL Resources Inc. (NYSE-ATG)	4.7%	4.6%	4.9%	5.0%	5.1%	5.0%	4.9%
Atmos Energy Corporation (NYSE-ATO)	4.8%	4.6%	4.8%	5.1%	4.7%	4.6%	4.8%
Laclede Group, Inc. (NYSE-LG)	4.1%	3.6%	3.7%	3.9%	3.2%	3.0%	3.6%
New Jersey Resources Corp. (NYSE-NJR)	3.4%	3.3%	3.3%	3.5%	3.1%	2.9%	3.3%
NICOR Inc. (NYSE-GAS)	5.2%	4.7%	4.3%	4.8%	4.2%	3.7%	4.5%
Northwest Natural Gas Co. (NYSE-NWN)	3.3%	3.4%	3.2%	3.4%	3.1%	2.8%	3.2%
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	3.8%	3.9%	3.8%	4.2%	3.7%	3.1%	3.7%
South Jersey Industries, Inc. (NYSE-SJI)	2.9%	2.8%	2.8%	2.9%	3.1%	2.8%	2.9%
Southwest Gas Corporation (NYSE-SWX)	3.0%	2.9%	2.9%	3.2%	3.0%	2.8%	3.0%
WGL Holdings, Inc. (NYSE-WGL)	4.2%	4.0%	4.0%	4.2%	4.3%	4.0%	4.1%
Mean	3.9%	3.8%	3.8%	4.0%	3.8%	3.5%	3.8%

Data Source: AUS *Utility Reports*, monthly issues

Exhibit JRW-6

Louisville Gas & Electric Company
DCF Equity Cost Growth Rate Measures
***Value Line* Historic Growth Rates**

Panel A
Electric Proxy Group

Company	*Value Line* Historic Growth					
	Past 10 Years			Past 5 Years		
	Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
ALLETE, Inc. (NYSE-ALE)	NA	NA	NA	NA	NA	NA
Ameren Corporation (NYSE-AEE)	1.0%	0.0%	3.5%	-0.5%	0.0%	5.5%
American Electric Power Co. (NYSE-AEP)	-1.0%	-4.5%	0.0%	3.0%	-9.0%	0.0%
Central Vermont Public Serv. Corp. (NYSE-CV)	-2.5%	1.0%	1.0%	-2.5%	1.0%	2.0%
Cleco Corporation (NYSE-CNL)	2.5%	1.5%	6.5%	-2.0%	0.5%	7.0%
DPL Inc.(NYSE-DPL)	1.0%	1.5%	-0.5%	-1.0%	1.0%	2.5%
Edison International (NYSE-EIX)	7.0%	1.0%	4.5%	0.0%	0.0%	17.5%
Empire District Electric Co. (NYSE-EDE)	-1.0%	0.0%	2.0%	2.0%	0.0%	2.0%
FirstEnergy Corporation (NYSE-FE)	6.0%	2.0%	5.5%	6.0%	4.5%	4.5%
FPL Group, Inc. (NYSE-FPL)	6.0%	5.0%	6.5%	6.5%	6.5%	7.5%
Hawaiian Electric Industries, Inc. (NYSE-HE)	-0.5%	0.5%	1.5%	-3.0%	0.0%	2.0%
IDACORP, Inc. (NYSE-IDA)	-1.0%	-4.5%	3.5%	-7.0%	-8.5%	2.5%
Northeast Utilities (NYSE-NU)	11.0%	-4.5%	0.5%	8.5%	10.0%	2.5%
NSTAR (NYSE-NST)	4.5%	3.0%	3.5%	3.5%	3.5%	4.0%
Pinnacle West Capital Corp. (NYSE-PNW)	1.0%	7.0%	4.5%	-2.5%	5.5%	3.5%
PNM Resources, Inc. (NYSE-PNM)	2.0%	14.5%	5.5%	-5.0%	9.5%	5.0%
Progress Energy Inc. (NYSE-PGN)	0.0%	3.0%	6.0%	-4.5%	2.5%	3.0%
Southern Company (NYSE-SO)	3.0%	2.0%	1.0%	3.5%	2.5%	3.0%
UIL Holdings Corporation (NYSE-UIL)	-2.0%	0.0%	0.5%	-6.0%	0.0%	-1.0%
UniSource Energy Corporation (NYSE-UNS)	-5.5%	0.0%	17.5%	3.0%	15.5%	8.5%
Xcel Energy Inc. (NYSE-XEL)	-3.5%	-4.5%	-1.0%	-2.0%	-8.5%	-1.5%
Mean	1.4%	1.2%	3.6%	0.0%	1.8%	4.0%
Median	1.0%	1.0%	3.5%	-0.8%	1.0%	3.0%
Data Source: *Value Line Investment Survey*, 2008.	Average of Mean and Median F			1.7%		

Panel B
Gas Proxy Group

Company	*Value Line* Historic Growth					
	Past 10 Years			Past 5 Years		
	Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
AGL Resources Inc. (NYSE-ATG)	7.0%	2.5%	6.5%	15.0%	4.0%	10.5%
Atmos Energy Corporation (NYSE-ATO)	3.5%	2.5%	7.0%	7.5%	1.5%	9.0%
Laclede Group, Inc. (NYSE-LG)	3.0%	1.0%	3.0%	9.5%	1.0%	4.5%
New Jersey Resources Corp. (NYSE-NJR)	6.5%	3.5%	7.5%	6.0%	4.0%	10.0%
NICOR Inc. (NYSE-GAS)	1.5%	3.5%	3.0%	-1.5%	1.0%	4.0%
Northwest Natural Gas Co. (NYSE-NWN)	3.0%	1.5%	3.5%	6.5%	2.0%	3.5%
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	5.0%	5.0%	6.0%	6.0%	4.5%	6.5%
South Jersey Industries, Inc. (NYSE-SJI)	9.5%	2.5%	7.5%	12.5%	4.5%	12.5%
Southwest Gas Corporation (NYSE-SWX)	12.0%	0.0%	3.0%	6.0%	0.0%	3.5%
WGL Holdings, Inc. (NYSE-WGL)	2.0%	1.5%	4.0%	5.0%	1.5%	3.5%
Mean	5.3%	2.4%	5.1%	7.3%	2.4%	6.8%
Median	4.3%	2.5%	5.0%	6.3%	1.8%	5.5%
Data Source: *Value Line Investment Survey*, 2008.	Average of Mean and Median F			4.5%		

Exhibit JRW-6

Louisville Gas & Electric Company
DCF Equity Cost Growth Rate Measures
***Value Line* Projected Growth Rates**

Panel A
Electric Proxy Group

Company	*Value Line* Projected Growth Est'd. '05-'07 to '11-'13 Earnings	Dividends	Book Value	*Value Line* Internal Growth Return on Equity	Retention Rate	Internal Growth
ALLETE, Inc. (NYSE-ALE)	2.5%	5.5%	6.5%	9.5%	36.0%	3.4%
Ameren Corporation (NYSE-AEE)	3.5%	0.0%	3.0%	9.5%	28.0%	2.7%
American Electric Power Co. (NYSE-AEP)	7.5%	8.0%	6.5%	12.0%	42.0%	5.0%
Central Vermont Public Serv. Corp. (NYSE-CV)	7.5%	0.0%	3.5%	7.5%	43.0%	3.2%
Cleco Corporation (NYSE-CNL)	10.5%	9.5%	6.0%	11.0%	37.0%	4.1%
DPL Inc.(NYSE-DPL)	11.0%	5.0%	9.0%	19.0%	43.0%	8.2%
Edison International (NYSE-EIX)	5.0%	7.0%	9.0%	11.5%	61.0%	7.0%
Empire District Electric Co. (NYSE-EDE)	10.0%	1.5%	3.5%	10.5%	29.0%	3.0%
FirstEnergy Corporation (NYSE-FE)	11.0%	8.5%	7.5%	15.5%	55.0%	8.5%
FPL Group, Inc. (NYSE-FPL)	9.5%	7.5%	8.5%	13.0%	54.0%	7.0%
Hawaiian Electric Industries, Inc. (NYSE-HE)	7.5%	1.0%	2.5%	11.5%	33.0%	3.8%
IDACORP, Inc. (NYSE-IDA)	2.0%	0.0%	2.0%	7.5%	47.0%	3.5%
Northeast Utilities (NYSE-NU)	11.5%	6.0%	5.5%	8.5%	52.0%	4.4%
NSTAR (NYSE-NST)	7.5%	7.0%	5.5%	14.5%	38.0%	5.5%
Pinnacle West Capital Corp. (NYSE-PNW)	2.0%	2.0%	2.0%	8.0%	27.0%	2.2%
PNM Resources, Inc. (NYSE-PNM)	-1.0%	1.5%	0.0%	6.0%	30.0%	1.8%
Progress Energy Inc. (NYSE-PGN)	5.0%	1.0%	1.5%	9.5%	25.0%	2.4%
Southern Company (NYSE-SO)	5.5%	4.5%	6.0%	14.0%	32.0%	4.5%
UIL Holdings Corporation (NYSE-UIL)	4.5%	0.0%	1.0%	10.5%	20.0%	2.1%
UniSource Energy Corporation (NYSE-UNS)	2.0%	6.5%	3.5%	7.5%	32.0%	2.4%
Xcel Energy Inc. (NYSE-XEL)	7.5%	3.0%	4.5%	11.0%	47.0%	5.2%
Mean	6.3%	4.0%	4.6%	10.8%	38.6%	4.2%
Median	7.5%	4.5%	4.5%	10.5%	37.0%	3.9%
Average of Mean and Median Figures =		5.2%			Average =	4.0%

Data Source: *Value Line Investment Survey, 2008*

Panel B
Gas Proxy Group

Company	*Value Line* Projected Growth Est'd. '05-'07 to '11-'13 Earnings	Dividends	Book Value	*Value Line* Internal Growth Return on Equity	Retention Rate	Internal Growth
AGL Resources Inc. (NYSE-ATG)	3.0%	4.0%	1.5%	14.0%	41.0%	5.7%
Atmos Energy Corporation (NYSE-ATO)	4.5%	2.0%	3.5%	9.5%	42.0%	4.0%
Laclede Group, Inc. (NYSE-LG)	4.5%	2.5%	5.5%	11.5%	44.0%	5.1%
New Jersey Resources Corp. (NYSE-NJR)	8.5%	6.0%	9.0%	12.5%	52.0%	6.5%
NICOR Inc. (NYSE-GAS)	5.0%	0.0%	5.0%	14.0%	49.0%	6.9%
Northwest Natural Gas Co. (NYSE-NWN)	7.0%	5.5%	3.5%	11.0%	44.0%	4.8%
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	7.0%	4.0%	4.0%	13.0%	40.0%	5.2%
South Jersey Industries, Inc. (NYSE-SJI)	6.0%	5.5%	3.5%	16.5%	58.0%	9.6%
Southwest Gas Corporation (NYSE-SWX)	7.5%	4.0%	4.0%	9.5%	69.0%	6.6%
WGL Holdings, Inc. (NYSE-WGL)	3.5%	2.5%	5.0%	10.5%	39.0%	4.1%
Mean	5.7%	3.6%	4.5%	12.2%	47.8%	5.8%
Median	5.5%	4.0%	4.0%	12.0%	44.0%	5.5%
Average of Mean and Median Figures =		4.5%			Average =	5.7%

Data Source: *Value Line Investment Survey, 2008*

Exhibit JRW-6

Louisville Gas & Electric Company
DCF Equity Cost Growth Rate Measures
Analysts Projected EPS Growth Rate Estimates

Panel A
Electric Proxy Group

Company	Sym	Bloomberg Mean	Bloomberg # Estimates	Zack's Mean	Zack's # Estimates	Average
ALLETE, Inc. (NYSE-ALE)	ALE	7.50%	2	5.00%	1	6.25%
Ameren Corporation (NYSE-AEE)	AEE	6.50%	2	5.00%	5	5.75%
American Electric Power Co. (NYSE-AEP)	AEP	4.95%	4	6.25%	4	5.60%
Central Vermont Public Serv. Corp. (NYSE-CV)	CV	-	0	-	-	-
Cleco Corporation (NYSE-CNL)	CNL	14.14%	2	14.00%	1	14.07%
DPL Inc.(NYSE-DPL)	DPL	13.95%	2	10.67%	3	12.31%
Edison International (NYSE-EIX)	EIX	8.25%	5	8.00%	3	8.13%
Empire District Electric Co. (NYSE-EDE)	EDE	34.00%	1	-	-	34.00%
FirstEnergy Corporation (NYSE-FE)	FE	9.00%	3	8.33%	3	8.67%
FPL Group, Inc. (NYSE-FPL)	FPL	9.83%	7	9.97%	6	9.90%
Hawaiian Electric Industries, Inc. (NYSE-HE)	HE	2.75%	2	4.17%	3	3.46%
IDACORP, Inc. (NYSE-IDA)	IDA	6.00%	2	6.00%	2	6.00%
Northeast Utilities (NYSE-NU)	NU	7.02%	5	10.00%	3	8.51%
NSTAR (NYSE-NST)	NST	6.33%	3	6.75%	4	6.54%
Pinnacle West Capital Corp. (NYSE-PNW)	PNW	4.67%	3	6.67%	3	5.67%
PNM Resources, Inc. (NYSE-PNM)	PNM	10.16%	5	6.00%	4	8.08%
Progress Energy Inc. (NYSE-PGN)	PGN	5.02%	5	5.00%	6	5.01%
Southern Company (NYSE-SO)	SO	5.50%	4	5.00%	5	5.25%
UIL Holdings Corporation (NYSE-UIL)	UIL	6.00%	1	6.00%	1	6.00%
UniSource Energy Corporation (NYSE-UNS)	UNS	-	0	-	-	-
Xcel Energy Inc. (NYSE-XEL)	XEL	6.00%	4	6.00%	4	6.00%
Median		6.50%	3.0	6.13%	3.0	6.25%

Source:Bloomberg October 20, 2008

Panel B
Gas Proxy Group

Company	Sym	Bloomberg Mean	Bloomberg # Estimates	Zack's Mean	Zack's # Estimates	Average
AGL Resources	ATG	5.38%	4	4.75%	4	5.1%
Atmos Energy	ATO	4.83%	6	5.43%	7	5.1%
Laclede Group, Inc.	LG	-	-	10.00%	1	10.0%
New Jersey Resources	NJR	6.33%	3	8.00%	2	7.2%
Nicor Inc.	GAS	4.38%	4	5.75%	4	5.1%
Northwest Natural Gas Company	NWN	4.13%	4	6.50%	4	5.3%
Piedmont Natural Gas, Inc.	PNY	5.00%	1	5.60%	5	5.3%
South Jersey Industries	SJI	7.33%	3	7.75%	4	7.5%
Southwest Gas	SWX	5.33%	3	8.00%	2	6.7%
WGL Holdings, Inc.	WGL	4.00%	1	7.50%	2	5.8%
Median		5.00%	3.2	7.00%	3.5	5.53%

Source:Bloomberg October 20, 2008

Exhibit JRW-7

Capital Asset Pricing Model

Panel A
Electric Proxy Group

Risk-Free Interest Rate	**4.50%**
Beta*	**0.82**
Ex Ante Equity Risk Premium**	**4.56%**
CAPM Cost of Equity	**8.2%**

Panel B
Gas Proxy Group

Risk-Free Interest Rate	**4.50%**
Beta*	**0.82**
Ex Ante Equity Risk Premium**	**4.56%**
CAPM Cost of Equity	**8.2%**

* See page 2 of Exhibit JRW-7
** See page 3 of Exhibit JRW-7

Exhibit JRW-7

Louisville Gas & Electric Company
Beta

Panel A
Electric Proxy Group

Company	Beta
ALLETE, Inc. (NYSE-ALE)	0.90
Ameren Corporation (NYSE-AEE)	0.80
American Electric Power Co. (NYSE-AEP)	0.85
Central Vermont Public Serv. Corp. (NYSE-CV)	1.05
Cleco Corporation (NYSE-CNL)	1.00
DPL Inc.(NYSE-DPL)	0.80
Edison International (NYSE-EIX)	0.90
Empire District Electric Co. (NYSE-EDE)	0.85
FirstEnergy Corporation (NYSE-FE)	0.75
FPL Group, Inc. (NYSE-FPL)	0.80
Hawaiian Electric Industries, Inc. (NYSE-HE)	0.75
IDACORP, Inc. (NYSE-IDA)	0.90
Northeast Utilities (NYSE-NU)	0.75
NSTAR (NYSE-NST)	0.80
Pinnacle West Capital Corp. (NYSE-PNW)	0.80
PNM Resources, Inc. (NYSE-PNM)	0.85
Progress Energy Inc. (NYSE-PGN)	0.75
Southern Company (NYSE-SO)	0.65
UIL Holdings Corporation (NYSE-UIL)	0.80
UniSource Energy Corporation (NYSE-UNS)	0.75
Xcel Energy Inc. (NYSE-XEL)	0.80
Mean	0.82

Data Source: *Value Line Investment Survey, 2008.*

Panel B
Gas Proxy Group

Company	Beta
AGL Resources Inc. (NYSE-ATG)	0.85
Atmos Energy Corporation (NYSE-ATO)	0.80
Laclede Group, Inc. (NYSE-LG)	0.80
New Jersey Resources Corp. (NYSE-NJR)	0.80
NICOR Inc. (NYSE-GAS)	0.90
Northwest Natural Gas Co. (NYSE-NWN)	0.75
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	0.80
South Jersey Industries, Inc. (NYSE-SJI)	0.80
Southwest Gas Corporation (NYSE-SWX)	0.80
WGL Holdings, Inc. (NYSE-WGL)	0.85
Mean	0.82

Data Source: *Value Line Investment Survey, 2008.*

Exhibit JRW-7

Louisville Gas & Electric Company
Capital Asset Pricing Model
Equity Risk Premium

Category	Study Authors	Publication Date	Time Period Of Study	Methodology	Return Measure	Range Low	Range High	Midpoint of Range	Mean	Average
Historical Risk Premium										
	Ibbotson	2008	1926-2007	Historical Stock Returns - Bond Returns	Arithmetic				6.50%	
					Geometric				4.90%	
	Bate	2008	1900-2007	Historical Stock Returns - Bond Returns	Geometric				4.50%	
	Shiller	2006	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				7.00%	
					Geometric				5.50%	
	Damodoran	2006	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				6.70%	
					Geometric				5.10%	
	Siegel	2005	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				6.10%	
					Geometric				4.60%	
	Dimson, Marsh, and Staunton	2006	1900-2005	Historical Stock Returns - Bond Returns	Arithmetic				5.50%	
	Goyal & Welch	2006	1872-2004	Historical Stock Returns - Bond Returns					4.77%	
	AVERAGE									5.56%
Ex Ante Models (Puzzle Research)										
	Claus Thomas	2001	1985-1998	Abnormal Earnings Model					3.00%	
	Arnott and Bernstein	2002	1810-2001	Fundamentals - Div Yld + Growth					2.40%	
	Constantinides	2002	1872-2000	Historical Returns & Fundamentals - P/D & P/E					6.90%	
	Cornell	1999	1926-1997	Historical Returns & Fundamental GDP/Earnings		3.50%	5.50%	4.50%	4.50%	
	Easton, Taylor, et al	2002	1981-1998	Residual Income Model					5.30%	
	Fama French	2002	1951-2000	Fundamental DCF with EPS and DPS Growth		2.55%	4.32%		3.44%	
	Harris & Marston	2001	1982-1998	Fundamental DCF with Analysts' EPS Growth					7.14%	
	Best & Byrne	2001								
	McKinsey	2002	1962-2002	Fundamental (P/E, D/P, & Earnings Growth)		3.50%	4.00%		3.75%	
	Siegel	2005	1802-2001	Historical Earnings Yield	Geometric				2.50%	
	Grabowski	2006	1926-2005	Historical and Projected		3.50%	6.00%	4.75%	4.75%	
	Maheu & McCurdy	2006	1885-2003	Historical Excess Returns, Structural Breaks,		4.02%	5.10%	4.56%	4.56%	
	Bostock	2004	1960-2002	Bond Yields, Credit Risk, and Income Volatility		3.90%	1.30%	2.60%	2.60%	
	Bakshi & Chen	2005	1982-1998	Fundamentals - Interest Rates					7.31%	
	Donaldson, Kamstra, & Kramer	2006	1952-2004	Fundamental, Dividend yld., Returns,, & Volatility		3.00%	4.00%	3.50%	3.50%	
	Campbell	2008	1982-2007	Historical & Projections (D/P & Earnings Growth)		4.10%	5.40%		4.75%	
	Best & Byrne	2001	Projection	Fundamentals - Div Yld + Growth					2.00%	
	Fernandez	2007	Projection	Required Equity Risk Premium					4.00%	
	DeLong & Magin	2008	Projection	Earnings Yield - TIPS					3.22%	
	Damodoran	2008	Projection	Fundamentals - Implied from FCF to Equity Model					4.37%	
	Social Security									
	Office of Chief Actuary		1900-1995							
	John Campbell	2001	1860-2000	Historical & Projections (D/P & Earnings Growth)	Arithmetic	3.00%	4.00%	3.50%	3.50%	
			Projected for 75 Years		Geometric	1.50%	2.50%	2.00%	2.00%	
	Peter Diamond	2001	Projected for 75 Years	Fundamentals (D/P, GDP Growth)		3.00%	4.80%	3.90%	3.90%	
	John Shoven	2001	Projected for 75 Years	Fundamentals (D/P, P/E, GDP Growth)		3.00%	3.50%	3.25%	3.25%	
	AVERAGE									4.03%
Surveys										
	Survey of Financial Forecasters	2008	10-Year Projection	About 50 Financial Forecastsers					1.96%	
	Duke - CFO Magazine Survey	2008	10-Year Projection	Approximately 500 CFOs					3.99%	
	Welch - Academics	2008	30-Year Projection	Random Academics		5.00%	5.74%		5.37%	
	AVERAGE									3.77%
Building Block										
	Ibbotson and Chen	2008	1926-2007	Historical Supply Model (D/P & Earnings Growth)	Arithmetic			6.23%	5.24%	
					Geometric			4.24%		
	Woolridge		2008	Current Supply Model (D/P & Earnings Growth)					4.54%	
	AVERAGE									4.89%
OVERALL AVERAGE										4.56%

Exhibit JRW-7

Louisville Gas & Electric Company

Survey of Professional Forecasters
Philadelphia Federal Reserve Bank
Long-Term Forecasts

Table Seven
LONG-TERM (10 YEAR) FORECASTS

SERIES: CPI INFLATION RATE		SERIES: REAL GDP GROWTH RATE	
STATISTIC		STATISTIC	
MINIMUM	1.600	MINIMUM	2.200
LOWER QUARTILE	2.200	LOWER QUARTILE	2.500
MEDIAN	2.500	MEDIAN	2.750
UPPER QUARTILE	2.750	UPPER QUARTILE	2.800
MAXIMUM	4.200	MAXIMUM	3.100
MEAN	2.520	MEAN	2.700
STD. DEV.	0.520	STD. DEV.	0.230
N	45	N	43
MISSING	5	MISSING	7
SERIES: PRODUCTIVITY GROWTH		SERIES: STOCK RETURNS (S&P 500)	
STATISTIC		STATISTIC	
MINIMUM	0.900	MINIMUM	2.700
LOWER QUARTILE	1.800	LOWER QUARTILE	6.000
MEDIAN	2.000	MEDIAN	6.500
UPPER QUARTILE	2.200	UPPER QUARTILE	8.000
MAXIMUM	3.000	MAXIMUM	9.000
MEAN	2.000	MEAN	6.800
STD. DEV.	0.390	STD. DEV.	1.300
N	39	N	31
MISSING	11	MISSING	19
SERIES: BOND RETURNS (10-YEAR)		SERIES: BILL RETURNS (3-MONTH)	
STATISTIC		STATISTIC	
MINIMUM	3.200	MINIMUM	2.400
LOWER QUARTILE	4.500	LOWER QUARTILE	3.000
MEDIAN	5.000	MEDIAN	4.000
UPPER QUARTILE	5.200	UPPER QUARTILE	4.250
MAXIMUM	5.800	MAXIMUM	5.300
MEAN	4.840	MEAN	3.840
STD. DEV.	0.590	STD. DEV.	0.680
N	38	N	38
MISSING	12	MISSING	12

Source: Philadelphia Federal Researve Bank, Survey of Professional Forecasters, February 12, 2008.
http://www.phil.frb.org/files/spf/spfq107.pdf

Exhibit JRW-7

Louisville Gas & Electric Company
CAPM
Real S&P 500 EPS Growth Rate

Year	S&P 500 EPS	Annual Inflation CPI	Inflation Adjustment Factor	Real S&P 500 EPS	
1960	3.10	1.48		3.10	
1961	3.37	0.07	1.01	3.35	
1962	3.67	1.22	1.02	3.59	
1963	4.13	1.65	1.04	3.99	
1964	4.76	1.19	1.05	4.55	
1965	5.30	1.92	1.07	4.97	
1966	5.41	3.35	1.10	4.90	
1967	5.46	3.04	1.14	4.80	
1968	5.72	4.72	1.19	4.81	
1969	6.10	6.11	1.26	4.83	10-Year
1970	5.51	5.49	1.34	4.13	2.89%
1971	5.57	3.36	1.38	4.04	
1972	6.17	3.41	1.43	4.33	
1973	7.96	8.80	1.55	5.13	
1974	9.35	12.20	1.74	5.37	
1975	7.71	7.01	1.86	4.14	
1976	9.75	4.81	1.95	4.99	
1977	10.87	6.77	2.08	5.22	
1978	11.64	9.03	2.27	5.13	
1979	14.55	13.31	2.57	5.66	10-Year
1980	14.99	12.40	2.89	5.18	2.30%
1981	15.18	8.94	3.15	4.82	
1982	13.82	3.87	3.27	4.23	
1983	13.29	3.80	3.40	3.91	
1984	16.84	3.95	3.53	4.77	
1985	15.68	3.77	3.66	4.28	
1986	14.43	1.13	3.70	3.90	
1987	16.04	4.41	3.87	4.15	
1988	22.77	4.42	4.04	5.64	
1989	24.03	4.65	4.22	5.69	10-Year
1990	21.73	6.11	4.48	4.85	-0.65%
1991	19.10	3.06	4.62	4.14	
1992	18.13	2.90	4.75	3.81	
1993	19.82	2.75	4.88	4.06	
1994	27.05	2.67	5.01	5.40	
1995	35.35	2.54	5.14	6.88	
1996	35.78	3.32	5.31	6.74	
1997	39.56	1.70	5.40	7.33	
1998	38.23	1.61	5.48	6.97	
1999	45.17	2.68	5.63	8.02	10-Year
2000	52.00	3.39	5.82	8.93	6.29%
2001	44.23	1.55	5.92	7.48	
2002	47.24	2.38	6.06	7.80	
2003	54.15	1.88	6.17	8.77	
2004	67.01	3.26	6.37	10.51	5-Year
2005	68.32	3.42	6.60	10.35	3.00%
2006	81.96	2.54	6.77	12.11	
2007	87.51	4.08	7.04	12.43	
Data Source: http://pages.stern.nyu.edu/~adamodar/				Real EPS Growth	**3.0%**

Exhibit JRW-8
Louisville Gas & Electric Company
Financial Performance Indicators - Dr. Avera's Non-Utility and Utility Proxy Groups

Non-Utility Proxy Group

Company Name	Return on Common Equity	Price To Book Value	Fixed Asset Turnover	Common Equity Ratio
3M Company	34.86	3.47	3.72	74.50
Abbott Labs	24.91	5.01	3.45	65.20
Aflac Inc.	18.37	2.45		85.70
Allergan Inc.	15.38	3.46	5.74	70.20
Allstate Corp.	21.21	0.80		79.50
Anheuser-Busch	67.11	14.35	1.89	25.60
Automatic Data Proc	19.83	3.68	10.78	99.20
Bank of America	10.39	0.78		41.40
Bard (C.R.)	21.99	4.42	6.39	92.50
Becton Dickinson	22.42	4.04	2.55	82.00
Brown-Forman 'B'	25.50	4.25	5.15	80.50
Coca-Cola	27.50	4.95	3.40	86.90
Colgate-Palmolive	86.54	17.39	4.57	37.90
Commerce Bancshs.	13.52	2.08		72.40
Fortune Brands	14.09	1.09	5.04	59.00
Gannett Co.	11.38	0.28	2.84	68.80
Gen'l Electric	19.44	1.74	2.22	26.60
Gen'l Mills	19.76	3.55	4.39	58.80
Genuine Parts	18.63	2.15	25.45	91.60
Heinz (H.J.)	44.75	7.29	4.78	28.50
Hormel Foods	15.78	2.17	6.41	84.30
Johnson & Johnson	27.89	4.22	4.31	86.00
Kimberly-Clark	35.63	4.99	2.26	54.30
Kraft Foods	10.64	1.66	3.46	67.90
Lilly (Eli)	28.27	2.83	2.17	74.80
Lockheed Martin	29.60	3.88	9.69	69.50
Medtronic Inc.	25.87	4.04	6.09	66.50
Meredith Corp.	20.26	1.12	7.84	69.00
NIKE Inc. 'B'	22.16	3.75	9.85	94.70
Northrop Grumman	9.81	0.91	6.79	80.60
PepsiCo Inc.	32.22	5.31	3.52	80.20
Pfizer Inc.	23.51	1.80	3.08	89.80
Procter & Gamble	17.46	2.90	4.05	73.20
Sigma-Aldrich	19.24	3.87	2.99	88.60
Sysco Corp.	32.44	4.58	12.98	63.30
Tootsie Roll Ind.	8.08	2.02	2.45	98.80
Torchmark Corp.	15.70	0.98		82.10
United Parcel Serv.	35.86	4.42	2.81	61.90
Walgreen Co.	18.38	2.19	6.56	100.00
Wal-Mart Stores	19.94	3.34	3.86	65.90
Washington Federal	10.24	1.14		100.00
Washington Post	8.33	0.97	3.26	89.30
Weis Markets	7.05	1.26	4.64	100.00
Average	23.53	3.53	5.44	73.66

Data Source: *Value Line Investment Analyzer*

Utility Proxy Group

Company Name	Return on Common Equity	Price To Book Value	Fixed Asset Turnover	Common Equity Ratio
ALLETE	11.79	1.55	0.76	64.40
Alliant Energy	11.26	1.37	0.73	61.90
Consol. Edison	10.43	1.32	0.66	53.10
Constellation Energy	14.66	0.86	2.17	52.40
Dominion Resources	14.86	2.39	0.73	41.10
Duke Energy	7.18	0.99	0.41	69.10
Entergy Corp.	14.42	2.23	0.55	43.90
Exelon Corp.	26.89	3.59	0.78	45.70
Integrys Energy	5.49	1.12	2.31	58.30
MDU Resources	12.80	1.48	1.16	68.40
PG&E Corp.	11.66	1.55	0.56	50.40
Public Serv. Enterprise	18.07	2.17	0.97	45.50
SCANA Corp.	10.81	1.40	0.61	49.70
Sempra Energy	13.51	1.36	0.77	63.70
Vectren Corp.	11.59	1.48	0.90	49.80
Wisconsin Energy	10.85	1.56	0.55	49.20
Xcel Energy Inc.	9.07	1.23	0.60	49.40
Average	12.67	1.63	0.90	53.88

THE WALL STREET JOURNAL.

Study Suggests Bias in Analysts' Rosy Forecasts

By ANDREW EDWARDS
March 21, 2008; Page C6

Despite an economy teetering on the brink of a recession -- if not already in one -- analysts are still painting a rosy picture of earnings growth, according to a study done by Penn State's Smeal College of Business.

The report questions analysts' impartiality five years after then-New York Attorney General Eliot Spitzer forced analysts to pay $1.5 billion in damages after finding evidence of bias.

"Wall Street analysts basically do two things: recommend stocks to buy and forecast earnings," said J. Randall Woolridge, professor of finance. "Previous studies suggest their stock recommendations do not perform well, and now we show that their long-term earnings-per-share growth-rate forecasts are excessive and upwardly biased."

The report, which examined analysts' long-term (three to five years) and one-year per-share earnings expectations from 1984 through 2006 found that companies' long-term earnings growth surpassed analysts' expectations in only two instances, and those came right after recessions.

Over the entire time period, analysts' long-term forecast earnings-per-share growth averaged 14.7%, compared with actual growth of 9.1%. One-year per-share earnings expectations were slightly more accurate: The average forecast was for 13.8% growth and the average actual growth rate was 9.8%.

"A significant factor in the upward bias in long-term earnings-rate forecasts is the reluctance of analysts to forecast" profit declines, Mr. Woolridge said. The study found that nearly one-third of all companies experienced profit drops over successive three-to-five-year periods, but analysts projected drops less than 1% of the time.

The study's authors said, "Analysts are rewarded for biased forecasts by their employers, who want them to hype stocks so that the brokerage house can garner trading commissions and win underwriting deals."

They also concluded that analysts are under pressure to hype stocks to generate trading commissions, and they often don't follow stocks they don't like.

Write to Andrew Edwards at andrew.edwards@dowjones.com

Growth Rates
GNP, S&P 500 Price, EPS, and DPS

	GDP	S&P 500	Earnings	Dividends	
1960	526.4	58.11	3.10	1.98	
1961	544.7	71.55	3.37	2.04	
1962	585.6	63.1	3.67	2.15	
1963	617.7	75.02	4.13	2.35	
1964	663.6	84.75	4.76	2.58	
1965	719.1	92.43	5.30	2.83	
1966	787.8	80.33	5.41	2.88	
1967	832.6	96.47	5.46	2.98	
1968	910.0	103.86	5.72	3.04	
1969	984.6	92.06	6.10	3.24	
1970	1038.5	92.15	5.51	3.19	
1971	1127.1	102.09	5.57	3.16	
1972	1238.3	118.05	6.17	3.19	
1973	1382.7	97.55	7.96	3.61	
1974	1500.0	68.56	9.35	3.72	
1975	1638.3	90.19	7.71	3.73	
1976	1825.3	107.46	9.75	4.22	
1977	2030.9	95.1	10.87	4.86	
1978	2294.7	96.11	11.64	5.18	
1979	2563.3	107.94	14.55	5.97	
1980	2789.5	135.76	14.99	6.44	
1981	3128.4	122.55	15.18	6.83	
1982	3255.0	140.64	13.82	6.93	
1983	3536.7	164.93	13.29	7.12	
1984	3933.2	167.24	16.84	7.83	
1985	4220.3	211.28	15.68	8.20	
1986	4462.8	242.17	14.43	8.19	
1987	4739.5	247.08	16.04	9.17	
1988	5103.8	277.72	22.77	10.22	
1989	5484.4	353.4	24.03	11.73	
1990	5803.1	330.22	21.73	12.35	
1991	5995.9	417.09	19.10	12.97	
1992	6337.7	435.71	18.13	12.64	
1993	6657.4	466.45	19.82	12.69	
1994	7072.2	459.27	27.05	13.36	
1995	7397.7	615.93	35.35	14.17	
1996	7816.9	740.74	35.78	14.89	
1997	8304.3	970.43	39.56	15.52	
1998	8747.0	1229.23	38.23	16.20	
1999	9268.4	1469.25	45.17	16.71	
2000	9817.0	1320.28	52.00	16.27	
2001	10128.0	1148.09	44.23	15.74	
2002	10469.6	879.82	47.24	16.08	
2003	10960.8	1111.91	54.15	17.88	
2004	11685.9	1211.92	67.01	19.41	
2005	12433.9	1248.29	68.32	22.38	**Average**
2006	13194.7	1418.3	81.96	25.05	
2007	13843.0	1468.36	87.51	27.73	
Growth	**7.20%**	**7.11%**	**7.36%**	**5.77%**	**6.86%**

Data Sources: GDPA - http://research.stlouisfed.org/fred2/categories/106
S&P 500, EPS and DPS - http://pages.stern.nyu.edu/~adamodar/

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY, INC. FOR AN	)	CASE NO. 2008-00252
ADJUSTMENT OF ITS ELECTRIC AND GAS	)	C/W
BASE RATES	)	CASE NO. 2007-00564

AFFIDAVIT OF DR. J. RANDALL WOOLRIDGE

Commonwealth of)
Pennsylvania)
)
)

Dr. J. Randall Woolridge, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Dr. J. Randall Woolridge

Dr. J. Randall Woolridge

SUBSCRIBED AND SWORN to before me this 30 day of October, 2008.

Mary L. Hart

NOTARY PUBLIC

My Commission Expires:

NOTARIAL SEAL
Mary L. Hart, Notary Public
State College Boro., Centre County
My commission expires August 25, 2009

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY, INC. FOR AN	)	CASE NO. 2008-00252
ADJUSTMENT OF ITS ELECTRIC AND GAS	)	C/W
BASE RATES	)	CASE NO. 2007-00564

Direct Testimony of
Michael J. Majoros, Jr.

on Behalf of
the Office of the Attorney General

October 28, 2008

TABLE OF CONTENTS

I. Introduction

Q. State your name, position, and business address.

A. My name is Michael J. Majoros, Jr. I am Vice President of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"), located at 1111 14th Street, N.W., Suite 300, Washington, D.C. 20005.

Q. Describe Snavely King.

A. Snavely King is an economic consulting firm founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs, and economic performance of regulated firms and industries. Snavely King represents the interests of government agencies, businesses, and individuals who are consumers of telecom, public utility, and transportation services.

We have a professional staff of twelve economists, accountants, engineers and cost analysts. Most of our work involves the development, preparation, and presentation of expert witness testimony before Federal and state regulatory agencies. Over the course of our 37-year history, members of the firm have participated in more than 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. Have you prepared a summary of your qualifications and experience?

A. Yes, Appendix A is a summary of my qualifications and experience. Appendix B contains a tabulation of my appearances as an expert witness before state and Federal regulatory agencies.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Attorney General of the Commonwealth of Kentucky ("AG").

II. Subject of Testimony

Q. What is the subject of your testimony?

A. My testimony addresses depreciation, specifically the Companies' regulatory liabilities for cost of removal.

Q. Are you the same Michael J. Majoros, Jr. who submitted testimony in Case Nos. 2007-00564 and 2007-00565, Louisville Gas and Electric Company and Kentucky Utilities' ("LG&E," "KU," or, collectively "the Companies") recent depreciation study filings?

A. Yes, I am. In those cases I reviewed the Companies' depreciation proposals and submitted my own recommended depreciation rates. My recommended rates have been incorporated by Attorney General witness Robert Henkes in his depreciation adjustment in the instant cases.

III. Cost of Removal Regulatory Liability

Q. What is the cost of removal regulatory liability?

A. The cost of removal regulatory liability is the amount of money the Companies have collected over time for cost of removal, less any amount expended for that purpose. The Financial Accounting Standards Board's (FASB) Statement of Financial Accounting Standard No. 143 ("SFAS No. 143") requires these amounts to be shown as a regulatory liability for GAAP purposes. For ratemaking purposes the amounts are included in accumulated depreciation. Unless the state regulatory body takes action, these amounts are not specifically recognized as regulatory liabilities for ratemaking purposes.

Q. Did you discuss the Companies' cost of removal regulatory liabilities in your testimony in Case Nos. 2007-00564 and 2007-00565?

A. Yes. I discussed the liabilities briefly on pages 18 and 19 of my direct testimony in those cases, and noted that as of December 31, 2007, KU and LG&E had reported $291.6 million and $241 million cost of removal regulatory liabilities, respectively.[1] I also noted the following growth of these regulatory liabilities:

> These regulatory liabilities have increased by $56.5 million (KU) and $33.1 million (LG&E), from the amounts I highlighted in Case Nos. 2003-00433 and 2003-00434. In other words, just since their last rate cases, the Companies have collected almost $90 million more from ratepayers than they have spent on actual cost of removal.[2]

Q. Did you make any recommendations in those cases regarding the cost of removal regulatory liabilities?

A. No, I did not. Although I normally would make recommendations regarding the cost of removal regulatory liability, in Case Nos. 2007-00564 and 2007-00565 I chose to focus instead on the Companies' unnecessary switch to the ELG procedure and the inclusion of future inflation in their cost of removal estimates.

Q. What do you normally recommend regarding the cost of removal regulatory liability?

[1] Note that since the Companies became subsidiaries of E.ON, they are no longer required to file reports with the SEC. The most recent SEC financial reports available are as of September 30, 2006. 2007 amounts provided in responses to AG 1-100 (LG&E), 1-93 and 2-6 (KU). KU amount is KY jurisdictional.

[2] Majoros Direct Testimony, Case Nos 2007-00564 and 2007-00565, page 19. Footnote deleted.

A. In most cases I recommend that this liability be reclassified from accumulated depreciation to Account 254 - Other Regulatory Liabilities for regulatory accounting, reporting and ratemaking purposes. Based on the policy decisions of some consumer advocate clients, I have also recommended that the regulatory liability be returned to ratepayers through a specific amortization period.

Q. Have you made similar recommendations before the Kentucky Public Service Commission ("KPSC")?

A. Yes. In KU and LG&E's most recent rate cases, Case Nos. Nos. 2003-00433 and 2003-00434 I recommended that the existing cost of removal reserve be amortized back to ratepayers in the post-hearing brief.[3] The Commission rejected my recommendation.[4] More recently, I proposed the establishment of a regulatory liability for ratemaking purposes in Case No. 2005-00042 regarding Union Light, Heat and Power Company. The proposal was not accepted.[5]

Q. Why have you brought up the issue in this case?

A. I have brought the issue up because Staff explicitly asked the Companies about it during discovery. Staff Third Data Request Question No. 21(c) (LG&E) and No. 22(c) (KU) asked the Company to "describe all favorable and unfavorable consequences to [LG&E/KU] if the Commission were to require reclassification of [LG&E's/KU's] asset removal costs from accumulated depreciation to a

[3] Orders, Case Nos. 2003-00433, pages 29-30 and 2003-00434, page 25.
[4] Orders, Case Nos. 2003-00433 and 2003-00434, pages 32 and 27, respectively.
[5] Case No. 2005-00042, Order issued December 22, 2005, p. 39.

regulatory liability account for regulatory reporting purposes."[6] I have quoted LG&E's response below. KU provided a similar response.

> If the Commission were to require the reclassification of LG&E's costs of removal from accumulated depreciation to a regulatory liability account for regulatory reporting purposes, a favorable consequence would be that it would create consistency between GAAP reporting and regulatory reporting. An unfavorable consequence would be the *inconsistency that would be created* with prior years' regulatory reporting. There would be no impact on the ratemaking treatment of the costs of removal, regardless of where they are recorded, since a basic concept behind including cost of removal as a component of depreciation rates is to prevent generational inequities. No other consequences have been identified by LG&E.[7]

Q. What is your opinion of the Companies' responses?

A. The responses indicate that even LG&E and KU agree there are no real consequences of reclassifying the cost of removal regulatory liabilities from accumulated depreciation to a regulatory liability account for ratemaking purposes. The alleged consequence of "inconsistency with prior reporting" does not have merit in this case. After all, the requirement to reclassify the amounts for GAAP purposes only came into being relatively recently, with the implementation of SFAS No. 143 in 2003. Because the FERC declined to require the reclassification for regulatory purposes an inconsistency developed between the GAAP and regulatory books. Furthermore, the Companies obviously do not shy away from accounting changes, as evident by their proposed unnecessary switch from ALG to ELG for computing depreciation rates – a procedure change

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[6] Staff 3rd Data Request, Qs. 21(c) (LG&E) and 22(c) (KU). Note that KU was initially asked the question in Staff's 2nd Data Request, Q. 98(c) but did not address the question to Staff's satisfaction.
[7] Staff 3rd Data Request, Q. 21(c) (LG&E).

that would cause a $34.6 million increase to depreciation expense, all other things being equal.[8]

Q. Do you see any favorable consequences of the reclassification that the Companies failed to mention?

A. Yes. As I mentioned earlier, because E.ON does not file 10-K reports with the SEC, these amounts are no longer publicly available. Absent a specific request for the amount in a proceeding such as a rate case, the Commission will not know how much the Companies have collected for cost of removal over and above what they have spent. Reclassification would allow the Commission to track these amounts. Reclassification would also protect ratepayer interests in these amounts. Without that protection, current and future ratepayers face the strong possibility of losing substantial prepaid funds they have submitted to the Company for future cost of removal. LG&E, KU and virtually all other utilities, consider amounts in accumulated depreciation, even excessive amounts, to be *their* money, i.e. capital recovery with no refund obligation. It is certainly fair and reasonable for any Commission to recognize excessive cost of removal collections as a refundable regulatory liability until the utility spends them on their intended purpose.

Q. Have any other Commissions recognized non-legal asset retirement obligations as regulatory liabilities?

A. Yes. Recently, in Application No. 04-12-014, involving Southern California Edison Company, the California Public Utilities Commission specifically

[8] Majoros Direct Testimony, Case Nos. 2007-00564 and 2007-00565, page 12.

recognized that Company's non-legal asset retirement obligations collections as a regulatory liability.[9]

IV. Recommendation

Q. What do you recommend?

A: I recommend that the Commission specifically recognize LG&E and KU's regulatory liabilities for cost of removal as reported on their GAAP statements as regulatory liabilities for ratemaking purposes. The Companies should be required to report these amounts and reclassify them from accumulated depreciation to Account 254-Other Regulatory Liabilities for regulatory accounting, reporting and ratemaking purposes. This will result in equivalent GAAP and regulatory accumulated depreciation and regulatory liability amounts for "non-legal" cost of removal.[10]

Q. Does this change have any revenue requirement effect?

A. No, it is merely a revenue neutral reclassification of a rate base reduction from one account to another.

Q. Does this conclude your testimony?

A. Yes, it does.

[9] Southern California Edison 2006 GRC, Application No. 04-12-014, Decision 06-05-016, issued May 11, 2006, p. 204:16.7.1.

[10] The phrase "non-legal" emanates from the FERC's Order No. 631. It is used to distinguish legally required asset retirement obligations from those which lead to the cost of removal regulatory liability discussed above. Importantly, the phrase "non-legal" should not be construed to imply any "illegality."

Michael J. Majoros, Jr.

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice and appeared before the U.S. EPA and the Maryland State Legislature on matters regarding the accounting and plant life effects of electric plant modifications and the financial capacity of public utilities to finance environmental controls. He has estimated economic damages suffered by black farmers in discrimination suits.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.
Controller/Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.

Michael J. Majoros, Jr.

Date	Jurisdiction / Agency	Docket	Utility
		Federal Courts	
2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority
		State Legislatures	
2006	Maryland General Assembly 61/	SB154	Maryland Healthy Air Act
2006	Maryland House of Delegates 62/	HB189	Maryland Healthy Air Act
		Federal Regulatory Agencies	
1979	FERC-US 19/	RP79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC 53/	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.
		State Regulatory Agencies	
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph

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1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.

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1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company

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2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 40/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company

Michael J. Majoros, Jr.

2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.
2005	Florida 50/	041291-EI	Florida Power & Light Company
2005	California 59/	A.04-12-014	Southern California Edison Co.
2005	Kentucky 36/	2005-00042	Union Light Heat & Power
2005	Florida 50/	050045 & 050188-EI	Florida Power & Light Co.
2005	Kansas 38/ 40/	05-WSEE-981-RTS	Westar Energy, Inc.
2006	Delaware 24/	05-304	Delmarva Power & Light Company
2006	California 59/	A.05-12-002	Pacific Gas & Electric Co.
2006	New Jersey 1/	GR05100845	Public Service Electric and Gas Co.
2006	Colorado 60/	06S-234EG	Public Service Co. of Colorado
2006	Kentucky 36/	2006-00172	Union Light, Heat & Power
2006	Kansas 40/	06-KGSG-1209-RTS	Kansas Gas Service
2006	West Virginia 2/	06-0960-E-42T, 06-1426-E-D	Allegheny Power
2006	West Virginia 2/	05-1120-G-30C, 06-0441-G-PC, et al.	Hope Gas, Inc. and Equitable Resources, Inc.
2007	Delaware 24/	06-284	Delmarva Power & Light Company
2007	Kentucky 36/	2006-00464	Atmos Energy Corporation
2007	Colorado 60/	06S-656G	Public Service Co. of Colorado
2007	California 59/	A.06-12-009, A.06-12-010	San Diego Gas & Electric Co., and Southern California Gas Co.
2007	Kentucky 36/	2007-00143	Kentucky-American Water Co.
2007	Kentucky 36/	2007-00089	Delta Natural Gas Co.
2008	Kansas 40/	08-ATMG-280-RTS	Atmos Energy Corporation
2008	New Jersey 1/	GR07110889	New Jersey Natural Gas Co.
2008	North Dakota 37/	PU-07-776	Northern States Power/Xcel Energy

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia 2/	93-1165-E-D	Potomac Edison
West Virginia 2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation

Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate	33/ Michigan Attorney General
2/ West Virginia Consumer Advocate	34/ New Mexico Attorney General
3/ Pennsylvania OCA	35/ Environmental Protection Agency Enforcement Staff
4/ Florida Office of Public Advocate	36/ Kentucky Attorney General
5/ Toms River Fire Commissioner's	37/ North Dakota Public Service Commission
6/ Iowa Office of Consumer Advocate	38/ Kansas Industrial Group
7/ D.C. People's Counsel	39/ City of Witchita
8/ Maryland's People's Counsel	40/ Kansas Citizens' Utility Rate Board
9/ Idaho Public Service Commission	41/ NIPSCO Industrial Group
10/ Western Burglar and Fire Alarm	42/ Hawaii Division of Consumer Advocacy
11/ U.S. Dept. of Defense	43/ Nevada Bureau of Consumer Protection
12/ N.M. State Corporation Comm.	44/ GCI
13/ City of Philadelphia	45/ Wisc. Citizens' Utility Rate Board
14/ Resorts International	46/ Vermont Department of Public Service
15/ Woodlake Condominium Association	47/ Oklahoma Corporation Commission
16/ Illinois Attorney General	48/ National Assn. of State Utility Consumer Advocates
17/ Mass Coalition of Municipalities	49/ Nova Scotia Utility and Review Board
18/ U.S. Department of Energy	50/ Florida Office of Public Counsel
19/ Arizona Electric Power Corp.	51/ Maryland Public Service Commission
20/ Kansas Corporation Commission	52/ MCI
21/ Public Service Comm. – Nevada	53/ Transmission Agency of Northern California
22/ SC Dept. of Consumer Affairs	54/ Florida Industrial Power Users Group
23/ Georgia Public Service Comm.	55/ Sierra Club
24/ Delaware Public Service Comm.	56/ Our Children's Earth Foundation
25/ Conn. Ofc. Of Consumer Counsel	57/ National Parks Conservation Association, Inc.
26/ Arizona Corp. Commission	58/ Missouri Office of the Public Counsel
27/ AT&T	59/ The Utility Reform Network
28/ AT&T/MCI	60/ Colorado Office of Consumer Counsel
29/ IN Office of Utility Consumer Counselor	61/ MD State Senator Paul G. Pinsky
30/ Unitel (AT&T – Canada)	62/ MD Speaker of the House Michael Busch
31/ Public Interest Advocacy Centre	
32/ U.S. General Services Administration	

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY, INC. FOR AN	)	CASE NO. 2008-00252
ADJUSTMENT OF ITS ELECTRIC AND GAS	)	C/W
BASE RATES	)	CASE NO. 2007-00564

AFFIDAVIT OF MICHAEL MAJOROS

District of Columbia)
)
)

Michael Majoros, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Michael Majoros

SUBSCRIBED AND SWORN to before me this 20th day of October, 2008.

NOTARY PUBLIC

My Commission Expires: March 14, 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2008-000252
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY	)))	CASE NO. 2007-00564

PREPARED DIRECT TESTIMONY AND SCHEDULES

OF

GLENN A. WATKINS

ON BEHALF OF THE

KENTUCKY OFFICE OF THE ATTORNEY GENERAL

OCTOBER 30, 2008

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is James Center III, 1051 East Cary Street, Suite 601, Richmond, VA 23219.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Principal and Senior Economist with Technical Associates, Inc., which is an economic and financial consulting firm with offices in Richmond, Virginia.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Office of Rate Intervention of the Kentucky Office of Attorney General ("OAG").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.

A. Except for a six-month period during 1987 in which I was employed by Old Dominion Electric Cooperative as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities, and have provided expert testimony in Alabama, Arizona, Georgia, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, Ohio, Illinois, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. I hold an M.B.A. and B.S. in economics from Virginia Commonwealth University. I am a member of several professional organizations as well as a Certified Rate of Return Analyst. A more complete description of my education and experience is provided in my Schedule GAW_1 to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Technical Associates has been retained by the OAG to evaluate the reasonableness of Louisville Gas & Electric Company's ("LG&E" or "Company") proposed electric weather normalization adjustment, electric and gas class cost of service studies (CCOSS), proposed distribution of revenues by class, and residential electric and gas rate designs. The purpose of my testimony, therefore, is to comment on LG&E's proposals on these issues and to present my findings and recommendations based on the results of the studies I have undertaken on behalf of the OAG.

ELECTRIC WEATHER NORMALIZATION

Q. HAVE YOU EXAMINED LG&E'S PROPOSED ELECTRIC WEATHER NORMALIZATION ADJUSTMENT IN THIS CASE?

A. Yes.

Q. WHAT IS THE NET EFFECT OF THE COMPANY'S PROPOSED WEATHER NORMALIZATION ADJUSTMENT?

A. LG&E witness William Seelye sponsors a weather normalization adjustment that will impact customers' ultimate rates in two respects: the first is the overall revenue requirement effect and the second is a rate design effect. In terms of the overall revenue requirement effect, Mr. Seelye adjusts actual test year revenues and variable expenses downward to correct for what he considers to be unusual (or abnormal) weather occurring during the test year. In other words, the Company does not expect to achieve the same level of kWh sales (and revenue) that was experienced during the test year on a going forward basis. Mr. Seelye's weather normalization adjustment results in reduction to actual test year revenues of $14.374 million and a reduction in variable expenses of $4.751 million. This downward adjustment to actual net revenues has an upward impact on the Company's revenue requirement on a going forward basis; i.e., all other things constant, this adjustment increases the revenue requirement. The second aspect of this weather normalization adjustment is the rate design effect. Because the weather adjustment reduces test year kWh sales, there are fewer units (kWh) to collect the overall revenue requirement such that there is an additional upward pressure on customers resulting from the weather normalization adjustment.

Q. MR. WATKINS, WHAT IS THE BASIS FOR LG&E'S REQUEST TO ADJUST ITS ACTUAL TEST YEAR SALES VOLUMES AND REVENUES?

A. As a result of abnormal weather, the Company claims that actual test year sales volumes (kWh) were greater than can be expected on a going forward basis.

Q. DO YOU AGREE THAT THE COMPANY'S PROPOSED ELECTRIC WEATHER NORMALIZATION ADJUSTMENT SHOULD BE USED FOR RATEMAKING PURPOSES?

A. From a conceptual standpoint, the general consensus of public utility commissions throughout the United States is that it is unreasonable to weather normalize electric utility revenues for ratemaking purposes. In this regard, this Commission would be well advised to continue its current practice of not considering electric weather normalization which is consistent with the vast majority of other states. This would translate to a disallowance of $9.6230 million from the company's request in net revenue ($14.374 million in revenue less $4.751 million in variable expense).

Q. DO CUSTOMERS KWH ENERGY USAGES VARY MATERIALLY WITH CHANGES IN WEATHER CONDITIONS?

A. Yes for some customers, and no for other customers. As a result of variances in electrical appliance and equipment saturations, some customers' electric usage varies significantly with changes in weather (temperature) while other customers' energy usage vary much less. For example, on an extremely hot summer day, residential customers will generally use considerably more electricity than on a mild, spring like day due to air conditioning load. On the other hand, the total electricity used by an industrial customer may not be materially different on the hot verses mild days due to this customer's non-weather sensitive load over shadowing its space cooling requirements (at least in terms of ambient outdoor temperatures).

Q. OVER THE COURSE OF AN ENTIRE YEAR, DO PERIODS OF MILD WEATHER OFFSET PERIODS OF EXTREME WEATHER IN TERMS OF ELECTRICITY USAGE?

A. In general, yes. This is particularly true for electricity sales.

Q. PLEASE EXPLAIN.

A. Although the following is common knowledge, it is important to consider how electricity is used and how weather affects this usage. For purposes of my explanation, I will focus on residential customers. As indicated earlier, there is no doubt that weather, primarily temperature, effects energy usage. In the summer there are periods of days that are very hot and electricity sales are elevated. Similarly there are mild days throughout the summer in which electricity sales are depressed due to reduced air conditioner loads. These hot and mild periods occur virtually every year. The question then arises if a particular cooling season (summer) as a whole is abnormally warm with an attendant abnormally high level of energy sales. In addition to cooling load (air conditions), electricity is also used for space heating by many customers in the winter. Similar to severe and mild weather in the summer, electricity sales on a daily basis are affected in the winter due to electric heating requirements. In addition to weather sensitive appliances, residential customers use a significant amount of electricity for other appliances that do not vary with weather; e.g., refrigerators/freezers, televisions, etc. Because of these factors and situations, annual electricity sales tend to be much more stable than say, natural gas sales, which are predominated by space heating load requirements in the winter. For these reasons, it is rare for commissions to consider weather normalization for electric utilities. In this regard, and as a matter of policy, the Commission would be well guided to continue its practice of not considering weather normalization for Kentucky electric utilities.

Q. WE KNOW THAT RESIDENTIAL KWH SALES VARY DUE TO WEATHER CONDITIONS ON A DAY-TO-DAY BASIS BUT HOW DOES ONE DETERMINE IF WEATHER IS ABNORMAL OVER THE COURSE OF A SEASON?

A. There is no definitive answer to this question. There is no doubt that a summer day in the high 90's is a hot day and warmer than "average". However, the question that must be answered is whether the summer overall was "abnormal". Similarly, one must determine if a winter season is materially different than normal; i.e., extremely severe or mild. With regard to seasonal variations from year to year, there is significant debate as to what constitutes departure from what is reasonably normal or expected. The National Oceanic and Atmospheric Administration ("NOAA"), National Climatic Data Center defines normal weather as a thirty-year average for the most recent completed three decades. In other words, the current NOAA definition of normal weather is for the period 1971 through 2000. Because of short-term trends in seasonal weather patters, shorter periods are sometimes used to define normal weather as well as using the most recent thirty years to define normal. I am also aware of instances in which much longer periods are used to define normal weather for a season.

Even with these differences in defining "normal" weather, one cannot say that the weather was particularly extreme simply because there is somewhat of a deviation from a historical average. In other words, assume the average maximum temperature for a given summer day is 85 degrees. If the actual temperature is 87 degrees, I do not believe it can be said that this is "abnormal" or "extreme" for that day. In this regard, the determination of "abnormal" or "extreme" is truly subjective.

Q. EVEN THOUGH THE DEFINITION OF ABNORMAL WEATHER IS SUBJECTIVE, ARE THERE METHODS THAT CAN BE USED TO FAIRLY AND REASONABLY DEFINE NORMAL AND ABNORMAL WEATHER?

A. Yes.

Q. PLEASE EXPLAIN.

A. Remembering that we should be concerned about the overall variation in weather over an entire season (hearting or cooling), a banding approach is, in my opinion, a fair and reasonable way to determine if a season's weather falls inside or outside of a band of reasonably normal weather. This banding approach is used by Mr. Seelye in this case. To the extent the Commission authorizes a weather normalization adjustment in this case, I could support the concept of banding, as it eliminates quibbling over minor variances from a pre-determined average or "normal" weather pattern.

Q. PLEASE EXPLAIN THIS BANDING APPROACH IN LAYMAN'S TERMS.

A. The traditional unit to measure summer temperatures over time is cooling degree days ("CDD") and the traditional unit to measure winter temperatures over time is Heating Degree Days ("HDD").[1] Assume that "normal" or average CDD's over the entire cooling season are 1,000. As discussed earlier, if the actual CDD were say 1010, we likely would not consider this an abnormally warm summer. However, if we subjectively determine a relative percentage of time in which we deem weather as abnormal, we can apply a simple statistical technique to determine the bands of normalcy. If we assume the variations in weather from year to year are random (no trend or pattern) we can subjectively define a percentage of time (years) in which weather is considered normal. For example, suppose we decide (subjectively) that weather occurring 75% of the time within a long term average is normal and the remaining 25% of the time the weather is defined as abnormal (12.5% mild and 12.5% severe), we can quantify the bands of normal weather. Consider the following hypothetical example:

Seasonal Cooling Degree Days

```
                900            1,000            1,100
←---------------|----------------|----------------|---------------→
Abnormal → |               ←Normal→               | ← Abnormal
```

If we know that 75% of the time a season's CDD fall between 900 and 1,100 we would define this range as normal. If a season's actual CDD's are greater than 1,100 we would deem that season as abnormally warm. Similarly, if the actual CDD's in a season are less than 900 we would deem that season abnormally mild. This is the approach proposed by Mr. Seelye. As indicated earlier, I support this approach but it must be emphasized that the range of normalcy is subjective and should be determined by the Commission. It should also be noted that this approach requires the assumption that annual seasonal weather variations are truly random; i.e., no trends or patterns are present.

Q. IN YOUR HYPOTHETICAL EXAMPLE, YOU USED A NORMALCY BAND OF 75%. WHAT BAND IS USED BY MR. SEELYE?

A. Approximately sixty-eight percent.

[1] CDD is traditionally defined as 65 degrees minus the average temperature (High and Low) for a day. HDD is traditionally defined as average temperature minus 65 degrees. CDD and HDD cannot be negative.

Q. HOW DID MR. SEELYE SELECT SIXTY-EIGHT PERCENT AS HIS NORMAL BAND FOR WEATHER?

A. This 68% is a convenient percentage in statistics in that it represents the percentage of time that one can expect weather to vary within plus or minus one standard deviation. There is nothing especially significant about a standard deviation of 1.0, as the exact same statistical techniques can be used at any level selected for normalcy; e.g., 50%, 75%, etc.

Q. WHAT WEATHER PATTERNS WERE ACTUALLY EXPERIENCED IN THE LG&E SERVICE AREA DURING THE TEST YEAR?

A. Overall, the cooling season (summer period) was exceptionally warm during the test year, whereas the heating season (winter period) was somewhat milder than average. The following is a comparison of monthly CDD and HDD to the most recent 30-year average for CDD and HDD:

Month	CDD or HDD Actual Test Year	30-Year Average	Difference
Cooling Season (CDD)			
June	376	306	70
July	396	438	<42>
August	629	407	222
September	350	204	146
Total	1,751	1,355	396
Heating Season (HDD)			
November	480	500	<20>
December	712	833	<121>
January	935	954	<19>
February	787	769	18
March	569	558	11
Total	3,483	3,614	<131>

As can be seen above, August and September 2007 were exceptionally warmer than the 30-year average, while December 2007 was considerably milder than the 30-year average.

Q. WHY ARE APRIL, MAY AND OCTOBER NOT PROVIDED IN THE TABLE ABOVE?

A. These months are considered shoulder months. Days in April and May can be cool or fairly warm such that these months are comprised of heating degree days and cooling degree days. As such, heating and air conditioning loads are usually not predictable in April and May. The same is true for October. Generally, the early part of October is warm and air conditioning load is still present. By the middle to end of October, the weather cools to the point that there is some heating load. As such, October is not very consistent as far as what can be considered "normal" weather.

Q. MR. WATKINS, IT IS GENERALLY FAIRLY COOL IN APRIL AND FAIRLY WARM BY THE END OF MAY IN KENTUCKY. WOULD IT BE APPROPRIATE TO CONSIDER EACH APRIL AS PART OF THE HEATING SEASON AND LATE MAY AS PART OF THE COOLING SEASON?

A. In my opinion no. Both of these months experience considerable variation between periods cold enough for space heating, mild enough for open windows, and warm enough for air conditioning load.

Q. FOR PURPOSES OF WEATHER NORMALIZATIONS, HOW DO YOU DEFINE LG&E'S COOLING AND HEATING SEASONS?

A. I define LG&E's cooling season as the months of June through September and the heating season as the months of November through March.

Q. IF THE COMMISSION ACCEPTS A BANDING APPROACH AS PROPOSED BY MR. SEELYE AND SUPPORTED BY YOU, HOW SHOULD THIS APPROACH BE APPLIED TO THE HEATING AND COOLING SEASONS?

A. The banding should be applied separately to the entire heating season and again separately for the entire cooling season. This is a major difference in the manner in which Mr. Seelye applied his weather banding, in that Mr. Seelye applies a weather normalcy band to each individual month. Mr. Seelye's monthly banding results in a bias to the annual normalized sales volumes.

Q. PLEASE EXPLAIN.

A. As discussed earlier, a given heating or cooling season is comprised of days in which it is milder than expected and more severe than expected. The overall objective is to consider the overall effects of weather during a heating or cooling season and Mr. Seelye's monthly banding does not meet this objective. To illustrate, consider the actual experience of July and August during the test year. July's actual CDDs were 396 which compare to a 30-year average July CDD of 438. This is a difference of -42 CDD which indicates that July was somewhat milder than the long-term average. Because this deviation from average (-42) does not fall outside of Mr. Seelye's monthly band, it is not adjusted and this mild weather for July is not considered any further in his analysis.

However, August was adjusted by Mr. Seelye because this individual month's weather fell outside of his monthly band. The actual CDDs for August in the test year were 629. This compares with a long-term average of 407 for August and is a difference of 222 CDDs. This exceptionally hot weather during August 2007 falls outside of Mr. Seelye's normalcy band and August's kWh sales were adjusted downward. However, no adjustment or consideration was given to the somewhat milder weather experienced during July 2007.

Q. HOW HAVE YOU ESTIMATED THE EFFECTS OF WEATHER ON CUSTOMER'S ELECTRICITY USAGE?

A. As discussed earlier, variations in electricity sales during the summer are affected by variations in air conditioning load, while winter kWh sales variations are affected by changes in space heating load. The two uses cannot be measured together and must be examined separately. Therefore, I have conducted separate analyses for the cooling (summer) and heating (winter) seasons.

I conducted linear regression analyses by season for each rate class in order to develop a weather sensitive usage coefficient for each class. In other words, the weather sensitive coefficient measures the incremental level at which a classes kWh usage varies with an incremental change in weather (CDD in summer, HDD in winter). Specifically, I developed a separate regression model for each class and each season (cooling and heating). These regression models were developed based on daily kWh usage and daily degree days. In other words, the cooling season is comprised of four months (June through September). My model was developed using each daily observation during this season (142 days). Because usage patterns can and do vary significantly between weekdays and weekends/holidays, I have also reflected this reality in my analysis of daily observations. With regard to the Residential class, I have expressed daily kWh usage on a per customer basis in order to prevent any skewness in my regression models. The Commercial and Industrial classes were analyzed on a total class basis.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING WEATHER NORMALIZATION FOR LG&E'S ELECTRIC OPERATIONS DURING THE TEST YEAR?

A. Based on my analyses, I conclude that the overall cooling season (summer) during the test year was exceptionally warm which translated into exceptionally high summer energy sales for LG&E. This weather (and attendant kWh sales) falls beyond what can reasonably be expected on a going-forward basis and warrants a downward adjustment. Although the test year's heating season was somewhat milder than normal, these sales do not warrant adjustment.

Q. IS THERE ANY BIAS IN YOUR CONCLUSION THAT SUMMER KWH SALES SHOULD BE ADJUSTED DOWNWARD DUE TO EXCEPTIONALLY SEVERE WEATHER, BUT WINTER KWH SALES DO NOT WARRANT AN OPPOSITE UPWARD ADJUSTMENT DUE TO A SOMEWHAT MILDER WINTER?

A. As long as a banding approach is used, the answer is no. This is because the summer normalization is made only to the outer limit of the "normalcy" band and not all the way to an average historical experience. Thus, while it is true that the milder winter sales somewhat offset the extreme weather-related summer sales, each season reflects a reasonable level of what can be expected on a going-forward basis.

Q. WHAT ARE THE RESULTS OF YOUR WEATHER NORMALIZATION ANALYSIS FOR LG&E'S ELECTRIC OPERATIONS?

A. My Schedule GAW_2 presents the results of my weather normalization analysis for LG&E's electric operations. Page 1 of this Schedule provides a summary of each class' kWh and revenue adjustment as well as the adjustment required to variable expenses. Pages 2 through 12 present the detailed kWh adjustment for each class. My weather normalization analysis results in a reduction to actual test year revenues of $9.038 million and a reduction to actual test year expenses of $2.985 million.

Q. YOU HAVE ALREADY DISCUSSED YOUR DISAGREEMENT WITH MR. SEELYE REGARDING MONTHLY VERSUS SEASONAL ANALYSIS AND ADJUSTMENTS. DO YOU HAVE ANY OTHER DISAGREEMENTS WITH MR. SEELYE'S PROPOSED WEATHER NORMALIZATION ANALYSES?

A. Yes.

Q. PLEASE EXPLAIN THESE OTHER DISAGREEMENTS.

A. I disagree with Mr. Seelye's decision to use the step-wise multiple regression technique as well as his inclusion of numerous weather-related variables. At the outset I want it to be clear that I understand and appreciate Mr. Seelye's desire to conduct his statistical analysis on an objective basis. However, Mr. Seelye's procedures are not warranted and often produce conflicting model results.

We have already established that weather generally affects electricity sales. On an hourly or daily basis, these weather factors can include ambient temperature, wind velocity, relative humidity, the degree of cloud cover, whether snow cover is present to insulate structures, whether a thunderstorm appears on a hot afternoon and dramatically and suddenly reduces load (and sales), wind direction, and perhaps a few more factors.

Mr. Seelye has attempted to consider many of these short-term factors in his modeling analysis by using a technique known as step-wise regression. This statistical technique selects a combination of possible variables to be considered and selects an equation that maximizes certain statistic parameters. This step-wise technique is simply a mathematical algorithm calculated by a computer. In other words, the variables offered to a computer in the step-wise technique are simply sets of numbers. Obviously, the computer has no ability to determine if the potential variables are consistent with the task at hand or even if they make sense from a conceptual perspective. There is no doubt that variables selected using the step-wise technique is objective. However, this technique is no substitute for informed human judgment. In their much respected text book, Applied Regression Analysis, Norman Draper and Harry Smith render the following opinion regarding the step-wise procedure used for econometric regression analyses:

> ***Opinion.*** We believe this to be one of the best of the variable selection procedures and recommend its use. It makes economical use of computer facilities, and it avoids working with more *X*'s than are necessary while improving the equation at every stage. However, stepwise regression can easily be abused by the "amateur" statistician. As with all the procedures discussed, sensible judgment is still required in the initial selection of variables and in the critical examination of the model through examination of residuals. It is easy to rely too heavily on the automatic selection performed in the computer. [Third Edition, page 338]

As a result of Mr. Seelye's attempt to be unnecessarily surgically precise, he arrives at nonsensical conclusions and models. As an illustration, remember that Mr. Seelye developed a separate regression equation, by class, for each month. Consider and compare Mr. Seelye's step-wise derived Residential models for July and August.

Variable	July 1/	August 1/
Intercept	-9,073,496	1,166,041
Maximum Temperature	246,777	--
Minimum Temperature	--	145,063
Cloudy	--	-492,074
CDD70	227,194	512,577
Weekend	--	762,045

1/ Per Seelye Exhibit 17.

Mr. Seelye's step-wise procedures result in a finding that in July, kWh sales are a function (related to) of maximum temperature and cooling degree days (CDD70). However, in August, the computer determined that Residential kWh sales are not a function of this set of explanatory variables, but rather, minimum temperature (the opposite concept of what would be expected), cloudiness, and weekdays versus weekend days. Related to the inconsistency of these adjoining summer months is the level in which kWh usage varies with changes in overall average daily temperatures (CDD70).

Notice that the July model has a CDD70 coefficient of 227,194, while the August coefficient of 512,577. What this means is that, all other things constant, kWh sales will vary by 227,194 kWh for each variation in CDD70 during July, but will vary by 512,577 in August.

There are many more inconsistencies and seemingly non-sensical results for other months as well as across classes, that I will not dwell on. In my opinion, and that of the industry, HDD and CDD are the accepted and most appropriate explanatory variables.

ELECTRIC CLASS COST OF SERVICE

Q. PLEASE EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS").

A. First, I note that there are two general types of cost of service studies used for public utility ratemaking: marginal cost studies; and embedded, fully allocated cost studies. LG&E has utilized a traditional embedded cost of service concept in this case for purposes of establishing its overall retail revenue requirement, as well as for its class cost of service study ("CCOSS"). As such, I will limit my explanation to embedded class cost of service studies.

Embedded cost of service studies are often referred to as fully allocated cost studies. This is because the vast majority of an electric utility's plant investment serves all customers, and the majority of expenses are incurred in a joint manner such that these costs cannot be specifically attributed to any individual customer or group of customers. To the extent that certain costs can be specifically attributable to a particular customer (or group of customers), these costs are often directly assigned in a CCOSS. However, the vast majority of LG&E's Production, Transmission, and Distribution plant and expenses are incurred jointly to serve all (or most) customers. These joint costs are then allocated to rate classes. It is generally recognized that to the extent possible, joint costs should be allocated to classes based on the concept of cost causation; i.e., costs are allocated based on specific factors that cause costs to be incurred by the utility. Although cost analysts generally strive to abide by the concept of cost causation to the greatest extent practical, some costs (particularly overhead costs), cannot be attributed to specific exogenous factors and must be subjectively assigned or allocated to rate classes. With regards to those costs in which cost causation can be attributed, cost of service experts often disagree as to what is the most cost causative factor; e.g., peak demand, energy usage, number of customers, etc.

Q. PLEASE EXPLAIN HOW CCOSS RESULTS SHOULD BE USED IN THE RATEMAKING PROCESS.

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive certain costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records, as well as fundamental differences in opinions regarding the design or cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned earlier, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required.

In this regard, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS results as one of many tools in assigning revenue responsibility.

Q. PLEASE EXPLAIN HOW YOU PROCEEDED WITH YOUR ANALYSIS OF LG&E'S CCOSS.

A. The process in which I conducted my analysis in this case was identical to how I evaluate all CCOSSs. First, I reviewed the structure and organization of the Company's CCOSS. Once the basic structure was understood, I reviewed the accuracy and completeness of the primary drivers (allocators) used to assign costs to rate schedules and classes. Next, I reviewed LG&E's selection of allocators to specific rate base, revenue and expense accounts. Finally, I adjusted certain aspects of the Company's study to better reflect cost causation and cost incidence by rate schedule and customer class.

Q. DID YOU FIND THE COMPANY'S STUDY TO BE MATHEMATICALLY ACCURATE?

A. Yes. Perhaps the most fundamental requirement of an embedded CCOSS is that the sum of the parts (classes) must equal the whole (system). This is true with respect to the allocation of financial accounts, as well as the various allocation factors. Furthermore, certain costs previously allocated are carried forward for other purposes such as for the development of composite or internal allocators and for the assignment of income taxes. In all regards, I found Mr. Seelye's CCOSS to be mathematically accurate.

Q. DID YOUR EXAMINATION RESULT IN ANY DISAGREEMENTS WITH THE ASSUMPTIONS OR METHODOLOGIES USED BY MR. SEELYE?

A. Yes. I have two material disagreements with Mr. Seelye's CCOSS.

Q. PLEASE OUTLINE YOUR TWO MATERIAL DISAGREEMENTS.

A. The two substantial disagreements that I have with Mr. Seelye are his "Modified Base-Intermediate-Peak" method to allocate generation costs and his classification of distribution plant between customer-related and demand-related.

A. <u>Generation</u>

Q. YOU INDICATE THAT ONE OF YOUR DISAGREEMENTS WITH MR. SEELYE IS HIS USE OF WHAT HE REFERS TO AS A MODIFIED BASE-INTERMEDIATE-PEAK METHOD TO ALLOCATE GENERATION COSTS. ARE THERE OTHER METHODOLOGIES WHICH MAY BE USED TO ALLOCATE GENERATION- RELATED PLANT AND EXPENSES?

A. Yes. There are several demand allocation methods utilized in the electric industry. The current National Association of Regulatory Utility Commissioners ("NARUC") <u>Electric Utility Cost Allocation Manual</u> discusses at least thirteen embedded demand allocation methods, while Dr. James Bonbright noted the existence of at least 29 demand allocation methods in his treatise, <u>Principles of Public Utilities Rates</u>.

Q. WHY DO SO MANY GENERATION ALLOCATION METHODS EXIST FOR THE ELECTRIC INDUSTRY?

A. Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, production facilities are joint costs; i.e., used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate throughout the year, there would be no disagreement as to the proper assignment of generation-related costs: all analysts would agree that energy usage in terms of kWh would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that LG&E experiences periods (hours) of much higher demand during certain times of the year and across various hours of the day. Moreover, all customer classes do not contribute in equal proportions to these varying demands placed on the generation system. To complicate matters, the electric utility industry is somewhat unique in that there is a distinct energy/capacity trade-off relating to generation costs. That is, utilities design their mix of production facilities (generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there is enough available capacity to meet peak demands. The trade-off occurs between the level of fixed investment per unit of capacity (KW) and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investments per KW, whereas smaller units with higher variable production costs generally require significantly less investment per KW. Due to varying levels of demand placed on the system over the course of each day, month, and year there is a unique optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy; i.e., its cost of service.

Therefore, as a result of the energy/capacity cost trade-off, and the fact that the service requirements of each utility are unique, many different allocation methodologies have evolved in an attempt to equitably allocate joint production costs to individual classes.

Q. PLEASE EXPLAIN.

A. Total production costs vary each hour of the year. Theoretically, energy and capacity costs should be allocated to classes each and every hour of the year. This would result in 8,760 hourly allocations during non-leap years. Although such an analysis is certainly possible with today's technology, the time and cost necessary for such an undertaking would likely exceed the additional benefits obtained over simpler methods. This is because the analyst does not know precise class loads each and every hour, and subjective decisions must still be made regarding the assignment of fixed investment (capacity costs) to individual hours. With this practical constraint in mind, each method has its strengths and weaknesses regarding its reasonableness in reflecting cost causation as well as the cost and effort required to produce a study.

Q. BRIEFLY, DISCUSS THE STRENGTHS AND WEAKNESSES OF COMMON PRODUCTION COST ALLOCATION METHODOLOGIES.

A. A brief description of the most common fully allocated cost methodologies and attendant strengths and weaknesses are as follows:

Single Coincident Peak ("1-CP") -- The basic concept underlying the 1-CP method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. As such, advocates of the 1-CP method reason that customers (or classes) should be responsible for fixed capacity costs based on their respective contributions to this peak system load. The major advantages to the 1-CP method are that the concepts are easy to understand, the analyses required to conduct a CCOSS are relatively simple, and the data requirements are significantly less than some of the more complex methods.

The 1-CP method has several shortcomings, however. First, and foremost, is the fact that the 1-CP method totally ignores the capacity/energy trade-off inherent in the electric utility industry. That is, the sole criterion for assigning one hundred percent of fixed capacity costs is the classes' relative contributions to load during a single hour of the year. This method does not consider, in any way, the extent to which customers use these facilities during the other 8,759 hours of the year. This may have severe consequences because a utility's planning decisions regarding the amount and type of generation capacity to build and install is predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration. To illustrate, if a utility had a peak load of 15,000 MW and its actual optimal generation mix included an assortment of nuclear, coal, hydro, combined cycle and combustion turbine units, the total cost of capacity is significantly higher than if the utility only had to consider meeting 15,000 MW for 1 hour of the year. This is because the utility would install the cheapest type of plant, (i.e., peaker units) if it only had to consider one hour a year.

There are two other major shortcomings of the 1-CP method. First, the results produced with this method can be unstable from year to year. This is because the hour in which a utility peaks annually is largely a function of weather. Therefore, annual peak load depends on when severe weather occurs. If this occurs on a weekend or holiday, relative class contributions to the peak load will likely be significantly different than if the peak occurred during a weekday. The other major shortcoming of the 1-CP method is often referred to as the "free ride" problem. This problem can easily be seen with a summer peaking utility that peaks about 5:00 p.m. Because street lights are not on at this time of day, this class will not be assigned any capacity costs at all and enjoy a free ride on the assignment of generation costs that this class requires.

<u>Summer and Winter Coincident Peak ("S/W Peak")</u> -- The S/W Peak method was developed because some utilities' annual peak load occurs in the summer during some years and in the winter during others. Because customers' usage and load characteristics may vary by season, the S/W Peak attempts to recognize this characteristic. This method is essentially the same as the 1-CP method except that two hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the 1-CP method, and in my opinion, is only marginally more reasonable than the 1-CP method. However, it is my understanding that LG&E is consistently a summer peaking utility. Therefore, this methodology is likely not well suited in this instance.

<u>Twelve Monthly Coincident Peak ("12-CP")</u> -- Arithmetically, the 12-CP method is essentially the same as the 1-CP method except that class contributions to each monthly peak are considered. Although the 12-CP method bears little resemblance to how utilities design and build their systems, the results produced by this method better reflect the cost incidence of a utility's generation facilities.

Most electric utilities have distinct seasonal load patterns such that there are high system peaks during the winter and summer months, and significantly lower system peaks during the spring and autumn months. By assigning class responsibilities based on their respective contributions throughout the year, consideration is given to the fact that utilities will call on all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods. Therefore, the capacity/energy trade-off is implicitly considered to a small extent under this method.

The major shortcoming of the 12-CP method is that accurate load data is required by class throughout the year. This generally requires a utility to maintain on-going load studies. However, once a system to record class load data is in place, the administration and maintenance of such a system is not overly cumbersome for larger utilities.

Peak and Average ("P&A") -- The various P&A methodologies rest on the premise that a utility's actual generation facilities are placed into service to meet peak load and serve consumers demands throughout the entire year. Hence, the P&A method assigns capacity costs partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year. Although there is not universal agreement on how peak demands should be measured or how the weighting between Peak and Average demands should be performed, many P&A studies use class contributions to coincident-peak demand for the "peak" portion, while some studies weight the Peak and Average loads based on the system coincident load factor and others give equal weight to energy usage and peak demand.

The major strengths of the P&A method are that an attempt is made to recognize the capacity/energy trade-off in the assignment of fixed capacity costs, and that data requirements are minimal.

Although the recognition of the capacity/energy trade-off is admittedly arbitrary under the P&A method, most other allocation methods also suffer to some degree of arbitrariness.

Average and Excess ("A&E") -- The A&E method also considers both peak demands and energy consumption throughout the year. However, the A&E method is much different than the P&A method in both concept and application. The A&E method recognizes class load diversity within a system, such that all classes do not call on the utility's resources to the same degree, at the same times. Mechanically, the A&E method weights average and excess demands based on system coincident load factor. Individual class "excess" demands represent the difference between the class non-coincident peak demand and its average annual demand. The classes' "excess" demands are then summed to determine the system excess demand. Under this method, it is important to distinguish between coincident and non-coincident demands. This is because if coincident, instead of non-coincident, demands are used when calculating class excesses, the end result will be exactly the same as that achieved under 1-CP method.

Although the A&E method bears virtually no resemblance to how generation systems are designed, this method can produce fair and reasonable results for many utilities. This is because no class will receive a free-ride under this method, and because recognition is given to average consumption as well as to the additional costs imposed by not maintaining a perfectly constant load.

A potential shortcoming of this method is that customers that only use power during off-peak periods will be overburdened with costs. Under the A&E method, off-peak customers will be assigned a higher percentage of capacity costs because their non-coincident load factor may be very low even though they call on the utility's resources only during cheap off-peak periods.

Equivalent Peaker ("EP") -- The EP method combines certain aspects of traditional embedded cost methods with those used in forward-looking marginal cost studies. The EP method often relies on planning information in order to classify individual generating units as energy- or demand-related and considers the need for a mix of base load intermediate and peaking generation resources.

The EP method has substantial intuitive appeal in that base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units that are seldom used and only called upon during peak load periods are allocated based on peak demands to those classes contributing to the system peak load. However, this method requires a significant amount of data.

<u>Base-Intermediate-Peak ("BIP")</u> -- The BIP method is an accepted allocation approach that attempts to recognize the capacity/energy trade-off that actually exists within a utility's portfolio of generation assets. A utility's base load units tend to run during all periods of the year; i.e., both peak load periods as well as to satisfy energy requirements in the most efficient manner possible during minimum demand periods (e.g., during the middle of the night). Because base load units operate regardless of peak requirements, they are most appropriately classified as energy-related. At the opposite end of the spectrum are peaking units, such as combustion turbines. These units operate with high variable costs and are only utilized to help meet peak period demands. As such, peakers are classified as peak demand-related. Intermediate plants (e.g., many combined cycle units) are not as efficient as large base load plants but more efficient than peaking units. For this reason, Intermediate plants are not called upon (dispatched) during periods of minimum (base) load but are dispatched before, and more frequently, than peaker units. Therefore, Intermediate plants can be said to serve a dual purpose: partially energy-related and partially demand-related. Intermediate plants are typically classified as partially energy-related and partially demand-related based on their respective capacity factors.[2] In my opinion, the BIP method is an excellent cost allocation approach for many utilities as it captures the actual differences in the capacity/energy trade-off that exist across a utility's generation mix. The BIP method may not be appropriate for utilities that purchase the majority of their energy needs or for utilities with an inefficient mix of generating resources.

Q. MR. WATKINS, YOU HAVE DISCUSSED THE STRENGTHS AND WEAKNESSES OF THE MORE COMMON GENERATION ALLOCATION METHODOLOGIES. ARE ANY OF THESE METHODS CLEARLY INFERIOR IN YOUR VIEW?

A. Yes. In my opinion the 1-CP and seasonal CP (such as 4-CP) methods do not reasonably reflect cost causation for integrated electric utilities because these methods totally ignore the utilization of a utility's facilities. Perhaps the simplest way to explain this is to consider that the methodology selected is used to allocate Generation plant

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2 Capacity factor is the ratio of average utilization (output) over a year to peak hour output.

investment. Generation investment costs vary from a low of a few hundred dollars per KW of capacity for high running cost (energy cost) peakers to several thousand dollars per KW for base load nuclear facilities with low running costs. If a utility were only concerned with being able to meet peak load with no regard to running costs, it would simply install inexpensive peakers. Under such an unrealistic system design, plant costs would be much lower than in reality but running costs; i.e., variable fuel costs would be astronomical, and would result in a higher overall cost to serve customers. The 1-CP and seasonal CP methods totally ignore this very important fact.

Q. MR. SEELYE HAS USED WHAT HE REFERS TO AS A MODIFIED BIP METHOD TO ALLOCATE GENERATION COSTS. DID HE CALCULATE THE BIP METHOD IN A REASONABLE MANNER?

A. Mr. Seelye's Modified BIP method does not follow the generally accepted BIP approach, and in fact, I have never seen Mr. Seelye's method used before. However, I would be reluctant to say his approach is totally unreasonable.

Whereas Mr. Seelye's Modified BIP method does allocate a portion of generation facilities based on energy and a portion on peak demands, his approach does not reflect the actual mix of supply resources utilized by LG&E. At this point, it should be noted that LG&E's and Kentucky Utilities' ("KU") generation resources are centrally dispatched. Both Mr. Seelye and I have recognized this combined central dispatch in our allocation studies. When I refer to LG&E's actual generation resources, I am referring to the joint resources of LG&E and KU and not the individual legal ownership of these plants for booking purposes.

The traditional BIP method is a supply-based approach that classifies generation plant between energy-related and demand-related; i.e., it considers the actual supply characteristics of a utility's generation portfolio. These supply based classifications are then allocated to classes based on demand-side criteria (kWh usage and peak demand).

Mr. Seelye's approach ignores the actually supply-side characteristics of EON's generation portfolio because it only considers relative differences in system usages and demands. In fact, given LG&E's customers combined usage and demand profiles, Mr. Seelye's approach would classify a utility's generation investment exactly the same regardless of its actual portfolio mix of plants. Mr. Seelye's classification would be identical if LG&E's portfolio mix was comprised entirely of base load units or entirely of peaking units. In my opinion, this assumption (or result) is not consistent with the intent of the BIP method. Namely, to recognize the capacity/energy tradeoff actually present in a system.

Q. HAVE YOU CONDUCTED A CLASS COST OF SERVICE STUDY USING A TRADITIONAL BIP APPROACH?

A. Yes.

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR TRADITIONAL BIP METHOD.

A. During the discovery phase of this proceeding, LG&E provided the hourly loads (output) of each EON generation unit during the test year. In other words, for each EON generating unit, I was provided hourly output during the test year. With this data, I examined the timing, frequency, and level of dispatch for each EON generating unit. This examination revealed clear and distinct patterns for individual generating units. Many units are clearly base load in nature, others are clearly peaker facilities, and some units are neither base load or clearly peaker, but intermediate plants. From this examination, I was able to classify each generating unit as base, intermediate, or peak. Base load plants were classified as 100% energy-related, peaker units were classified as 100% demand-related, and intermediate plants were classified as partially energy-related and partially demand-related based on their individual capacity factors. The results of my BIP generation classification is presented in my Schedule GAW_3. It should be noted that EON's hydroelectric facilities were classified as 100% energy-related as these facilities are largely run-of-river or flood control dams. My BIP classification study results in the following aggregate generation classification:

Energy-related:	82.78%
Demand-related:	17.22%

Q. WHAT ARE THE CLASS RATES OF RETURN ON RATE BASE AT CURRENT RATES UTILIZING YOUR TRADITIONAL BIP METHOD TO CLASSIFY GENERATION PLANT?

A. Individual class rates of return utilizing the traditional BIP classification method, compared to Mr. Seelye's Modified BIP are presented below:

Class	OAG Traditional BIP	Seelye Modified BIP
R	6.58%	5.45%
GS	13.96%	13.17%
LC-Pri.	8.75%	9.89%
LC-Sec.	10.88%	10.42%
LC-TOD-Pri.	5.74%	7.47%
LC-TOD-Sec.	8.02%	9.58%
LP-Pri.	9.87%	11.38%
LP-Sec.	9.46%	9.89%
LP-TOD-Trans.	4.66%	8.39%
LP-TOD-Pri.	4.43%	7.16%
LP-TOD-Sec.	8.76%	10.94%
Sp. Contracts A	0.51%	8.71%
Sp. Contracts B	1.98%	3.67%
Sp. Contracts C	0.49%	6.36%
PSL	3.91%	6.02%
SLE	1.31%	11.75%
OL	7.03%	8.71%
TLE	-0.68%	2.07%
STOD-Pr.	3.33%	4.24%
STOD-Sec.	4.61%	5.68%
TOTAL COMPANY	7.77%	7.77%

B. <u>Distribution</u>

Q. AS WE MOVE DOWNSTREAM FROM GENERATION THROUGH TRANSMISSION, TO THE DISTRIBUTION SYSTEM, HOW HAS THE COMPANY ASSIGNED DISTRIBUTION COSTS TO RATE SCHEDULES AND CUSTOMER CLASSES?

A. Mr. Seelye has allocated Distribution plant and expenses partially on the basis of number of customers and partially on the basis of peak demand. I concur with Mr.

Seelye's selection of customer and demand allocators for Distribution plant. However, there is often controversy regarding the portion of Distribution plant that should be allocated on number of customers and the portion that should be allocated on demand. This separation between customer-related and demand-related Distribution plant is referred to as the classification of Distribution plant.

Q. PLEASE EXPLAIN THE TERM "CLASSIFICATION OF DISTRIBUTION PLANT."

A. In the broadest sense, an embedded CCOSS is undertaken using a three-tiered approach. First, costs are functionalized as Production, Transmission, Distribution, General, and/or customer. These functionalized costs are then classified as energy, demand, or customer-related. Finally, classified costs are then allocated to individual classes. With respect to the classification of Distribution plant, it is generally recognized that there are no energy-related costs. That is, the distribution system is designed to meet localized peak demands. However, largely as a result of differences in customer densities throughout a utility's service area, electric utility Distribution plant often is classified as partially demand-related and partially customer-related.

Q. WHY IS THE CLASSIFICATION OF DISTRIBUTION PLANT IMPORTANT IN CCOSS ANALYSES?

A. The classification of Distribution plant may be the single most important factor affecting class rates of return. To illustrate the importance of this issue, consider the Residential class: whereas this class may account for only 40% to 50% of peak demand, it is responsible for a much higher percentage of the number of customers. Therefore, given the level of investment associated with Distribution plant, wide variations in class rates of return can result from different customer/demand classifications.

Q. WHY ARE THE DIFFERENCES IN CUSTOMER DENSITIES IMPORTANT IN THE ASSIGNMENT OF DISTRIBUTION COSTS TO INDIVIDUAL CLASSES?

A. Possibly the best way to answer this question is by way of example. Consider two different electric utilities: one similar to LG&E with urban, suburban, and rural service areas and one similar to Consolidated Edison Company, which is mainly urban. With respect to the utility with a rural service area, many miles of conductors and associated plant must be installed in order to serve the demands of relatively few customers. Conversely, many more customers are served on a per mile basis for the urban utility. For the urban utility, it may be fair and reasonable to allocate Distribution plant solely on the basis of peak demands. However, with respect to the utility with a rural service area, such an allocation may be unfair if some classes are located mainly in urban or suburban areas, while other classes of customers are located in urban, suburban, and rural areas. As a result, many utilities classify Distribution plant as partially demand- related and partially customer-related. In this manner, a portion of Distribution plant is allocated based on a peak demand, and a portion allocated based on number of customers.

Q. HOW DOES ONE DETERMINE HOW MUCH DISTRIBUTION PLANT SHOULD BE CLASSIFIED AS DEMAND-RELATED AND HOW MUCH AS CUSTOMER-RELATED?

A. Once the decision is made that Distribution plant should be allocated considering both peak demand and number of customers, there are two generally accepted methods for determining the portions or percentages that should be allocated on each basis. These two methods are known as the minimum size and zero-intercept approaches. Under both methods, a study is conducted for each major plant account within the distribution system. That is, each account is studied and assigned its own customer and demand components.

The minimum size method rests on the premise that the minimum, or smallest size, installed equipment makes up the distribution network to connect customers to the distribution system, and that all larger sizes of equipment serve peak demands. In practice, the cost per unit of the smallest sized installed equipment is determined. This minimum cost per unit is then multiplied by the total number units in the system to arrive at a total customer amount. The total customer amount is then divided by the total cost for the account to determine the customer percentage. As the compliment, one minus the customer percentage equals the demand percentage.

The zero-intercept method is similar to the minimum size method, except for the determination of the minimum cost per unit. The zero-intercept method recognizes that even the smallest installed piece of equipment has a demand component, because it too is designed and installed to meet the peak load placed on that equipment. The zero-intercept method attempts to arrive at the "theoretical" cost of a piece of plant or equipment capable of carrying zero load. This is accomplished using statistical regression techniques whereby the per unit costs of various sizes of equipment are determined and a best fitting line is fitted into an equation form. The point at which the fitted line intersects the cost axis at zero size is called the zero-intercept. The zero-intercept cost then serves as the minimum, or zero size, cost per unit.

Q. IS ONE METHOD PREFERRED OVER THE OTHER?

A. In general, I prefer to use the zero-intercept method when possible and appropriate. However, as with most aspects of ratemaking where there is not a universally accepted formula, each approach has its advantages and disadvantages. The major criticisms I have regarding the minimum size method is that this method tends to overstate the customer percentage because even the smallest installed size is used to meet some level of peak demand. The primary weaknesses of the zero-intercept method are that more data and a good working knowledge of statistical linear regression analyses are required, and sometimes there is no strong correlation between costs and sizes (capacity) of distribution equipment.

Q. HOW APPROPRIATE IS EITHER METHOD FROM A DESIGN OR OPERATIONAL PERSPECTIVE?

A. First and foremost, the classification of Distribution plant as partially customer-related and partially demand-related results from the view that the allocation of these plant items based solely on peak demands would not be equitable to some classes. I emphasize this point, because many analysts "lose sight of the forest for the trees". When classifying individual accounts within Distribution plant, analysts sometimes ignore (or do not understand) how a distribution system is designed and connected.

There are three major factors the analyst should keep in mind when classifying Distribution plant. First, there are often alternatives across plant and equipment. For example, the need for a particular transformer may be erased if a larger size conductor is used. Alternatively, fewer and smaller poles may be required if lighter conductors are used. Second, and more importantly, is the fact that purchasing economies are usually present. For example, there are dozens of various types of overhead conductors manufactured. However, due to purchasing economies, a utility may only purchase a few different sizes of conductor. This may result in some "over capacity", yet, the total installed cost is less than if every segment of the system is optimally designed. Third, most components of the distribution system are somewhat oversized for other reasons such as safety, reliability, and growth uncertainty.

Although, these three factors are reflective of how distribution systems are actually designed and installed, neither the minimum size nor the zero-intercept method account for these factors. In fact, the presence of these three factors can seriously skew the results of either method. If the weakness is not captured or recognized, inequitable class allocations may result.

Q. HOW DID MR. SEELYE CLASSIFY DISTRIBUTION PLANT BETWEEN CUSTOMER-RELATED AND DEMAND-RELATED COMPONENTS?

A. My Seelye claims to have conducted a zero-intercept analysis to develop customer/demand classifications for distribution Overhead lines, underground lines, and transformers. I take exception to Mr. Seelye's reference to his proposed classifications as a "zero-intercept" derived study, and I disagree with his approach.

Q. PLEASE EXPLAIN HOW AN INDUSTRY ACCEPTED ZERO-INTERCEPT STUDY IS CONDUCTED.

A. Under accepted industry practices, which are well documented in various cost allocation manuals,[3] the zero-intercept method is very straight-forward. First, various types of equipment are separated by size and type. Next, historical accounting costs are

[3] See for example the National Association of Regulatory Utility Commissions ("NARUC") Electric Utility Cost Allocation Manual, 1992, pages 92 through 94.

trended by vintage year to reflect cost differences over time. For each size and type of equipment, the total dollars and total units (feet or number of units) are considered as well as the capacity (size) of each type of equipment. Because the overall objective is to estimate the cost of a "zero-size" piece of equipment, total costs are divided by total units (feet or unit) for each type of equipment to derive an average cost per foot or per unit. A regression model is then developed based on the following form:

cost/unit = a + b (size)

The resulting intercept (a) produces the estimated cost per unit of a "zero-size" piece of equipment. This estimated zero-size cost per unit is then multiplied by the total units in the system to estimate a zero-size total cost. The ratio of total zero size costs to trended total actual costs represents the percentage of zero-size equipment and serves as the customer percentage.

The above industry standard is in stark contrast to Mr. Seelye's method presented in his Seelye Exhibits 28, 29, and 30. Mr. Seelye refers to his approach as a "weighted regression analysis." Although this "weighted regression analysis" is a clever arithmetic exercise, it violates theoretical statistical principles of linear regression and skews his results. Moreover, on page 74 of his direct testimony, Mr. Seelye states:

> "Like most electric utilities, the number of feet of conductors on LG&E's system is not uniformly distributed over all sizes of wire. For example, LG&E has over 20 million feet of 1/0 overhead conductor, but only 10,421 feet of 1,000 MCM overhead conductor. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept."

It is interesting at best that Mr. Seelye finds LG&E's system to be typical of other utilities, yet, his approach varies dramatically from the industry practice that has been used by countless utilities, Commissions, and analysts for decades.

To understand the bias in Mr. Seelye's "weighted regression analysis," we must fully understand the mathematical model he derives. Using Overhead conductors as an example, consider Mr. Seelye's analysis presented in his Exhibit 28. Although not shown in his exhibit, Mr. Seelye's equation for Overhead conductors is:

$$(\text{cost per foot x feet}^{0.5}) = 0 + 2.2913(\text{feet}^{0.5}) + 0.00818(\text{capacity x feet}^{0.5})$$

Notice that the equation's true intercept is forced to zero. However, if capacity is set to zero, the second term [0.00818(capacity x feet$^{0.5}$)] becomes zero. If we then ask what is the cost for a foot of a zero capacity conductor we see that feet$^{0.5}$ = 1$^{0.5}$ = 1, such that the cost for one foot becomes $2.2913. This is the zero-intercept used by Mr. Seelye.

To illustrate the bias in Mr. Seelye's analysis, consider the following hypothetical example of his approach for a system "not uniformly distributed over all sizes of wire":

Total	Cost Per Foot (y)	Capacity (x)	Feet (n)	$y(n^{0.5})$	$n^{0.5}$	$x(n^{0.5})$
350.00	3.50	2.00	100	35	10.00	20.00
250.00	5.00	4.00	50	35.355339	7.07	28.28
62,500.00	6.25	6.00	10,000	625	100.00	600.00
164.00	8.20	8.00	20	36.671515	4.47	35.78
99.50	9.95	10.00	10	31.464663	3.16	31.62

Under the correct, and accepted zero-intercept method, the following regression equation results:

cost/feet = 1.75 + 0.805(size)

Therefore, a zero-size cost is estimated to be $1.75 per foot. Using the same data, the following equation is produced using Mr. Seelye's approach:

cost per foot x feet$^{0.5}$ = 0 + 1.9815(feet$^{0.5}$) + 0.7120(size x feet$^{0.5}$)

Mr. Seelye's approach results in a zero cost per foot of $1.9815 as compared to the industry accepted cost per foot of $1.75.

Q. WHAT ARE THE RESULTS OF MR. SEELYE'S CLASSIFICATION OF DISTRIBUTION PLANT?

A. Mr. Seelye classifies distribution plant as follows:

Account	Percentage	
	Customer	Demand
Overhead Conductors	60.56%	39.44%
Underground Conductors	62.65%	37.35%
Lines Transformers	48.75%	51.25%

Q. HAVE YOU CONDUCTED AN INDEPENDENT ANALYSIS TO CLASSIFY LG&E'S DISTRIBUTION PLANT?

A. Yes. Although I prefer to use the zero-intercept method when possible, the data is such that this method is not reliable in this instance. This is because the regression equations produce negative intercept values (illogical) and have low R^2 (poor fits). As a result, I conducted a minimum size analysis, which by its very nature tends to overstate the customer percentage of distribution plant. I used the same data relied upon by Mr. Seelye in his Exhibits 28, 29, and 30 and selected a reasonable minimum size for each account (Overhead conductors, underground conductors, and line transformers) based on the data provided. The following are my selected minimum sizes and resulting customer/demand classifications:

Account	Minimum Size	Percentage	
		Customer	Demand
Overhead Conductors	$1.4869	39.3%	60.7%
Underground Conductors	$1.658	20.1%	79.9%
Line Transformers	$606.63	26.5%	73.5%

Q. WHAT ARE YOUR CCOSS RESULTS USING THESE CUSTOMER/DEMAND CLASSIFICATIONS?

A. My recommended distribution plant classifications coupled with a traditional BIP approach to classify generation resources are reflected in my recommended CCOSS. The detail of this CCOSS is provided in my Schedule GAW_4 and are summarized below:

Class	ROR At Current Rates OAG Recommended	Seelye
R	7.22%	5.45%
GS	13.61%	13.17%
LC-Pri.	8.07%	9.89%
LC-Sec.	9.99%	10.42%
LC-TOD-Pri.	5.17%	7.47%
LC-TOD-Sec.	7.26%	9.58%
LP-Pri.	9.15%	11.38%
LP-Sec.	8.62%	9.89%
LP-TOD-Trans.	4.66%	8.39%
LP-TOD-Pri.	3.95%	7.16%
LP-TOD-Sec.	7.99%	10.94%
Sp. Contracts A	0.17%	8.71%
Sp. Contracts B	1.50%	3.67%
Sp. Contracts C	0.03%	6.36%
PSL	4.29%	6.02%
SLE	0.72%	11.75%
OL	7.51%	8.71%
TLE	-0.57%	2.07%
STOD-Pri.	2.84%	4.24%
STOD-Sec.	3.99%	5.68%
TOTAL COMPANY	7.77%	7.77%

As can be seen above, my CCOSS study which is based on accepted industry practices, produces significantly different results than those obtained by Mr. Seelye.

ELECTRIC CLASS REVENUE DISTRIBUTION

Q. PLEASE DESCRIBE LG&E'S PROPOSED DISTRIBUTION OF ITS REQUESTED OVERALL ELECTRIC REVENUE INCREASE TO INDIVIDUAL CUSTOMER CLASSES.

A. LG&E witness Seelye presents the Company's proposed distribution of its requested $14.75 million revenue increase to customer classes. In large part, Mr. Seelye proposes that the Residential and lighting classes should be responsible for almost all of the entire rate increase proposed by LG&E. According to Mr. Seelye, this proposed increase is based on his CCOSS results. However, Mr. Seelye apparently ignored his own CCOSS study results for certain classes. For example, even though the LC-TOD primary class is contributing slightly less than the current system average rate of return (7.47% compared to 7.77%), Mr. Seeyle assigns no revenue increase to this class. Similar situations exist for the LP-TOD Primary and Special Contracts "A" classes.

A summary of LG&E's proposed revenue increase for each customer class is shown below:

	LG&E Proposed Electric Increase		
Class	Amount	Percent	Percent of Avg.
R	$13,673,276	3.81%	230%
GS	228,601	0.18%	11%
LC-Pri.	0	0.00%	0%
LC-Sec.	0	0.00%	0%
LC-TOD-Pri.	0	0.00%	0%
LC-TOD-Sec.	0	0.00%	0%
LP-Pri.	0	0.00%	0%
LP-Sec.	0	0.00%	0%
LP-TOD-Trans.	-8,461	-0.03%	-2%
LP-TOD-Pri.	0	0.00%	0%
LP-TOD-Sec.	0	0.00%	0%
Sp. Contracts A	-145,782	-2.05%	-124%
Sp. Contracts B	0	0.00%	0%
Sp. Contracts C	0	0.00%	0%
PSL	199,009	3.39%	205%
SLE	0	0.00%	0%
OL	462,434	5.12%	309%
TLE	9,376	4.12%	249%
STOD-Pri.	45,334	6.01%	363%
STOD-Sec.	287,867	5.27%	318%
TOTAL COMPANY	$14,751,654	1.66%	100%

Q. MR. WATKINS, IN YOUR OPINION ARE LG&E'S PROPOSED CUSTOMER CLASS REVENUE INCREASES REASONABLE?

A. No.

Q. DO YOU HAVE AN ALTERNATIVE REVENUE INCREASE DISTRIBUTION TO THAT PROPOSED BY MR. SEELYE?

A. Yes, I do. Using the results of my CCOSS as a guide, and also considering principles of gradualism, fairness and equity, I propose an equitable and cost based mechanism to assign class revenue increases at LG&E's requested overall revenue level.

My proposed revenue distribution is presented in my Schedule GAW_5 and results in the following class increases:

Class	OAG Proposed Electric Increase		
	Amount	Percent	Percent of Avg.
R	$6,987,615	1.95%	118%
GS	1,059,478	0.83%	50%
LC-Pri.	165,183	1.66%	100%
LC-Sec.	1,812,934	1.24%	75%
LC-TOD-Pri.	389,305	2.07%	125%
LC-TOD-Sec.	344,591	1.66%	100%
LP-Pri.	89,466	1.24%	75%
LP-Sec.	452,458	1.24%	75%
LP-TOD-Trans.	543,277	2.07%	125%
LP-TOD-Pri.	1,933,032	2.07%	125%
LP-TOD-Sec.	44,764	1.66%	100%
Sp. Contracts A	176,845	2.49%	150%
Sp. Contracts B	270,913	2.49%	150%
Sp. Contracts C	71,528	2.49%	150%
PSL	121,435	2.07%	125%
SLE	4,805	2.49%	150%
OL	149,549	1.66%	100%
TLE	5,649	2.49%	150%
STOD-Pri.	15,622	2.07%	125%
STOD-Sec.	113,204	2.07%	125%
TOTAL COMPANY	$14,751,654	1.66%	100%

My specific electric revenue allocation methodology is as follows, with the actual calculations provided in Schedule GAW_5.

First, I recognize class cost of service and the concept of gradualism. In doing so, I recommend a graduated scale of increases such that no class receives a rate decrease and that all class increases are limited to a range of 50% of the system average percentage increase to 150% of the system average increase. In order to recognize the higher than system average ROR's provided by certain classes, I increased these higher than average ROR classes less than the system average percentage. Similarly, those classes with low rates of return were increased by a higher percentage. Finally, due to its size relative to the system, the Residential class was treated as a residual.

Q. MR. WATKINS, PLEASE PROVIDE YOUR RECOMMENDED SCALE BACK METHOD TO ASSIGN CLASS REVENUE INCREASES SHOULD THE COMMISSION AUTHORIZE AN OVERALL REVENUE REQUIREMENT INCREASE LESS THAN THAT PROPOSED BY LG&E OR AN OVERALL DECREASE AS RECOMMENDED BY THE OAG.

A. I recommend that my customer class revenue increases be reduced proportionally downward.

<u>RESIDENTIAL ELECTRIC RATE DESIGN</u>

Q. PLEASE DESCRIBE LG&E'S CURRENT RESIDENTIAL RATE STRUCTURE?

A. Currently, Residential rates include a fixed monthly customer charge of $5.00 and a flat kWh energy charge.

Q. WITH RESPECT TO THE CURRENT RESIDENTIAL CUSTOMER CHARGE OF $5.00, DOES LG&E PROPOSE AN INCREASE TO THIS FIXED MONTHLY RATE?

A. Yes. LG&E proposes an increase to the monthly Residential customer charge from the current $5.00 level to $8.23.

Q. DOES MR. SEELYE PROVIDE ANY JUSTIFICATION FOR THE LARGE INCREASE IN THE FIXED CUSTOMER CHARGE?

A. As part of his CCOSS, Mr. Seelye functionalizes all costs that include an assignment of overheads to each functional and classification category. Within Mr. Seelye's CCOSS, these fully allocated costs that are classified as "customer" equate to a monthly residential "customer allocated cost" of $16.43.

Q. DO YOU AGREE WITH MR. SEELYE'S "CUSTOMER COST" ANALYSIS?

A. No. Mr. Seelye's customer cost analysis includes not only those costs that are directly attributable to customers but also assigns a significant level of corporate overhead costs. In my opinion, any customer cost analysis used as a basis for establishing fixed monthly customer charges should only include direct customer costs.

Q. HAVE YOU CONDUCTED SUCH A DIRECT CUSTOMER COST ANALYSIS?

A. Yes. The results of my direct customer costs analysis are presented in my Schedule GAW_6 and result in a monthly Residential customer cost of $2.98.

Q. WHAT IS YOUR RECOMMENDATION AS TO RESIDENTIAL CUSTOMER CHARGES IN THIS CASE?

A. Given that my direct customer cost analysis results in a monthly customer cost of $2.98, I recommend maintaining the current monthly customer charge of $5.00 regardless of any increase or decrease in revenue requirement authorized by this Commission.

Q. DOES LG&E'S PROPOSED 65% INCREASE TO THE RESIDENTIAL CUSTOMER CHARGE PROMOTE OR DISCOURAGE CONSERVATION?

A. LG&E's proposed increased reliance on customer charge revenue will discourage conservation from its electric customers as a larger percentage of customers' bills will be collected from a fixed monthly charge that does not vary with usage. As such, the Company proposed 65% increase to the fixed customer charge would send a price signal to customers that is contrary to conservation efforts and encourage additional usage of electricity.

NATURAL GAS OPERATIONS

Q. HAVE YOU EXAMINED MR. SEELYE'S NATURAL GAS CLASS COST OF SERVICE STUDY?

A. Yes.

Q. WHAT METHODOLOGY DID MR. SEELYE USE FOR PURPOSES OF HIS NATURAL GAS CCOSS?

A. Mr. Seelye used what is known as the Peak Responsibility method to allocate Mains costs. Furthermore, Mr. Seelye separated LG&E's Mains into "high pressure" and "low pressure" systems. Finally, Mr. Seelye classified both high pressure and lower pressure Mains as partially customer-related and partially demand-related.

Q. DO YOU HAVE ANY MAJOR DISAGREEMENTS WITH MR. SEELYE'S NATURAL GAS CCOSS?

A. Yes.

Q. PLEASE OUTLINE YOUR DISAGREEMENTS.

A. I disagree with Mr. Seelye's use of the Peak Demand method to allocate distribution Mains (low and high pressure).

Q. PLEASE EXPLAIN PEAK RESPONSIBILITY METHOD.

A. The Peak Responsibility method is similar in concept to the 1-CP method previously discussed for the electric industry. The major difference is that whereas the 1-CP electric method is generally based on actual loads and demands, the Peak Responsibility method is based on estimated loads at design day temperatures. In other words, design day demands are not known as historical loads, but rather estimate class demand under the most extreme weather conditions.

Q. IS THERE A METHOD THAT IS PREFERRED OVER THE PEAK RESPONSIBILITY METHOD FOR LG&E'S NATURAL GAS OPERATIONS?

A. Yes. The Peak and Average method is far superior for LG&E's natural gas operations.

Q. PLEASE EXPLAIN WHY THE PEAK AND AVERAGE METHOD IS PREFERRED.

A. There are several reasons why the Peak and Average Method is preferred and why the Peak Responsibility method is not appropriate LG&E. The first is the recognition of how and why natural gas consumers are customers of LG&E. That is, customers connect to LG&E's system in order to meet their natural gas needs throughout the year. Indeed, the Company's Mains are utilized each and every day of the year and recognition of annual usage (throughput) is a logical basis for cost assignment.

Another shortcoming of the Peak Responsibility method using design day demand is that the "design day" is a moving target over time. That is, whereas natural gas Mains are planned and installed to serve customers in excess of fifty years into the future, design day demand (as used by Mr. Seelye) is a function of the mix, usage per customer, and number of customers today. In addition LG&E's commercial centers have obviously changed over the last few decades. Yet, Mr. Seeyle assumes the entire Company system was optimally designed and installed to meet today's mix and level of customers.

Q. HAVE YOU CONDUCTED A CLASS COST OF SERVICE STUDY THAT UTILIZES THE PEAK AND AVERAGE METHOD?

A. Yes. I have accepted all other aspects (allocators and classifications) of Mr. Seelye's natural gas CCOSS except for his use of the Peak Responsibility method. It should be noted that while I disagree conceptually with Mr. Seelye that <u>any</u> portion of distribution Mains should be classified as partially customer related, I have accepted his classification since his recommended customer percentages of Mains are relatively small.[4]

Q. PLEASE PRESENT THE RESULTS OF YOUR NATURAL GAS CCOSS UTILIZING THE PEAK AND AVERAGE METHOD.

A. The following is a summary of class rates of return at current rates utilizing my recommended Peak and Average method to allocate distribution Mains. Also provided are Mr. Seeyle's results using his Peak Responsibility method.

[4] Mr. Seeyle customer percentage of high pressure mains is 6.97% while high customer percentage of low pressure mains is 14.82%.

Class	ROR at Current Rates OAG Peak & Average	Seelye Peak Responsibility
RSG	3.53%	2.77%
CGS	6.42%	5.37%
IGS	6.15%	6.52%
AAGS	2.36%	14.65%
FT	0.37%	18.73%
SP	-3.73%	22.04%
Total Company	3.88%	3.88%

The details of my recommended natural gas CCOSS are provided in my Schedule GAW_7.

NATURAL GAS CLASS REVENUE DISTRIBUTION

Q. PLEASE DESCRIBE LG&E'S PROPOSED DISTRIBUTION OF ITS REQUESTED OVERALL NATURAL GAS REVENUE INCREASE TO INDIVIDUAL CUSTOMER CLASSES.

A. LG&E witness Seelye presents the Company's proposed distribution of its requested $29.76 million revenue increase to customer classes. In large part, Mr. Seelye proposes that the Residential class should be responsible for almost all of the entire rate increase proposed by LG&E. According to Mr. Seelye, this proposed increase is based on his CCOSS results.

A summary of LG&E's proposed natural gas revenue increase for each customer class is shown below:

	LG&E Proposed Natural Gas Increase		
Class	Amount	Percent	Percent of Avg.
RGS	$25,482,608	37.00%	125%
CGS	4,012,950	16.75%	57%
IGS	55,838	3.03%	10%
AAGS	23,962	9.77%	33%
FT	175,907	4.10%	14%
SP	11,200	0.70%	2%
TOTAL COMPANY	$29,762,465	29.53%	100%

Q. MR. WATKINS, IN YOUR OPINION ARE LG&E'S PROPOSED NATURAL GAS CUSTOMER CLASS REVENUE INCREASES REASONABLE?

A. No.

Q. DO YOU HAVE AN ALTERNATIVE REVENUE INCREASE DISTRIBUTION TO THAT PROPOSED BY MR. SEELYE?

A. Yes, I do. Using the results of my CCOSS as a guide, and also considering Mr. Seelye's CCOSS results in conjunction with the principles of gradualism, fairness and equity, I propose an equal percentage increase for all classes regardless of the overall increase in revenue requirement authorized by the Commission. My proposed across the board class revenue increases are as follows using LG&E's required overall increase of $29.76 million:

	OAG Proposed Natural Gas Increase	
Class	Amount	Percent
RGS	$20,334,498	29.53%
CGS	7,073,326	29.53%
IGS	544,098	29.53%
AAGS	72,380	29.53%
FT	1,265,374	29.53%
SP	472,789	29.53%
TOTAL COMPANY	$29,762,465	29.53%

RESIDENTIAL NATURAL GAS RATE DESIGN

Q. PLEASE DESCRIBE LG&E'S CURRENT RESIDENTIAL RATE STRUCTURE?

A. Currently, Residential rates include a fixed monthly customer charge of $8.50 and a flat base rate usage charge.

Q. WITH RESPECT TO THE CURRENT RESIDENTIAL CUSTOMER CHARGE OF $8.50, DOES LG&E PROPOSE AN INCREASE TO THIS FIXED MONTHLY RATE?

A. Yes. LG&E proposes an increase to the monthly Residential customer charge from the current $8.50 level to $13.65.

Q. DOES MR. SEELYE PROVIDE ANY JUSTIFICATION FOR THE LARGE INCREASE IN THE FIXED CUSTOMER CHARGE?

A. As part of his CCOSS, Mr. Seelye functionalizes all costs that include an assignment of overheads to each functional and classification category. Within Mr. Seelye's CCOSS, these fully allocated costs that are classified as "customer" equate to a monthly residential "customer allocated cost" of $13.71.

Q. DO YOU AGREE WITH MR. SEELYE'S "CUSTOMER COST" ANALYSIS?

A. No. Mr. Seelye's customer cost analysis includes not only those costs that are directly attributable to customers but also assigns a significant level of corporate overhead costs. In my opinion, any customer cost analysis used as a basis for establishing fixed monthly customer charges should only include direct customer costs.

Q. HAVE YOU CONDUCTED SUCH A DIRECT CUSTOMER COST ANALYSIS?

A. Yes. The results of my direct customer costs analysis are presented in my Schedule GAW_8 and result in a monthly Residential customer cost of $6.96.

Q. WHAT IS YOUR RECOMMENDATION AS TO RESIDENTIAL CUSTOMER CHARGES IN THIS CASE?

A. Given the direct customer cost analysis that results in a monthly customer cost of $6.96. I recommend maintaining the current monthly customer charge of $8.50 regardless of any increase in revenue requirement authorized by this Commission.

Q. DOES LG&E'S PROPOSED 61% INCREASE TO THE RESIDENTIAL CUSTOMER CHARGE PROMOTE OR DISCOURAGE CONSERVATION?

A. LG&E's proposed increased reliance on customer charge revenue will discourage conservation from its natural gas customers as a larger percentage of customers' bills will be collected from a fixed monthly charge that does not vary with usage. As such, the

Company's proposed 61% increase to the fixed customer charge would send a price signal to customers that is contrary to conservation efforts and encourage additional usage of natural gas.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

VICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	*M.B.A., Virginia Commonwealth University, Richmond, Virginia*
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jul. 1995-Present	Vice President/Senior Economist, Technical Associates, Inc.
Mar. 1993-1995	Vice President/Senior Economist, C. W. Amos of Virginia
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

A. Costing Studies – Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies – Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and *investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.*

GLENN A. WATKINS

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

LOUISVILLE GAS AND ELECTRIC COMPANY

OAG Adjustment to Reflect Electric Weather Normalization

(12 Months Ended April 30, 2008)

	(1)	(2)	(3)
	OAG Test Year Adjustment to kWh	Energy Rate	OAG Test Year Revenue Adjustment (1) * (2)
Residential Rate R	(110,959,088)	$0.06404	($7,105,820)
General Service Rate GS			
Single Phase	(5,744,499)	0.07621	(437,788)
Three Phase	(10,694,430)	0.07621	(815,023)
Total	(16,438,929)		(1,252,811)
Large Commercial Rate LC			
Secondary	(16,593,235)	0.02702	(448,349)
Primary	(1,270,282)	0.02702	(34,323)
Secondary Small Time of Day	(699,053)	0.03289	(22,992)
Primary Small Time of Day	(108,092)	0.03289	(3,555)
Total	(18,670,661)		(509,219)
Large Commercial Rate LCTOD			
Secondary	(1,735,249)	0.02706	(46,956)
Primary	(2,228,694)	0.02706	(60,308)
Total	(3,963,943)		(107,264)
Industrial Power Rate LP			
Secondary	(2,196,464)	0.02357	(51,771)
Primary	(453,706)	0.02357	(10,694)
Total	(2,650,170)		(62,465)
Industrial Power Rate LPTOD	-		0
Secondary	-	0.02362	0
Primary	-	0.02362	0
Special Contracts	-		0
Fort Knox	-	0.02365	0
DuPont	-	0.02379	0
Louisville Water Company	-	0.02364	0
Lighting			
Street Lighting Rate SLE	-	0.00000	0
Traffic Lighting Rate TLE	-	0.00000	0
Public Street Lighting Rate PSL	-	0.00000	0
Outdoor Lighting Rate OL	-	0.00000	0
Total Company	(152,682,791)		($9,037,579)
Variable Expenses	(152,682,791)	$0.01955	($2,984,949)

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

Residential

	Degree Days			Normal Weather Band							
	Actual [1]	30-year Average [2]	30-year Std Dev [3]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Customer Per Degree Day [4]	Average Customers	kWh Adjustment	Model R-square
Cooling Month (CDD)											
June	376	306									
July	396	438									
August	629	407									
September	350	204									
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	1.60079	358,712	(110,959,088)	92.0941%
Heating Month											
November	480	500									
December	712	833									
January	935	954									
February	787	769									
March	569	558									
	3,483	3,615	347	3,962	3,268	No	479				

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

GS Secondary 1 Phase

	Degree Days			Normal Weather Band						
	Actual [1]	30-year Average [2]	30-year Std Dev [3]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day [4]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	29,728.30	(5,744,499)	91.1264%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

GS Secondary 3 Phase

	Degree Days			Normal Weather Band						
	Actual [1]	30-year Average [2]	30-year Std Dev [3]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day [4]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	55,344.64	(10,694,430)	88.8312%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LC Secondary

	Degree Days			Normal Weather Band						
	Actual [1]	30-year Average [2]	30-year Std Dev [3]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day [4]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	85,871.49	(16,593,235)	92.2827%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LC Primary

	Degree Days			Normal Weather Band						
	Actual [1]	30-year Average [2]	30-year Std Dev [3]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day [4]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	6,573.82	(1,270,282)	88.6240%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LC STOD Secondary

	Degree Days			Normal Weather Band						
	Actual 1/	30-year Average 2/	30-year Std Dev 3/	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day 4/	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	3,617.66	(699,053)	89.1158%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LC STOD Primary

	Degree Days			Normal Weather Band						
	Actual 1/	30-year Average 2/	30-year Std Dev 3/	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day 4/	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	559.38	(108,092)	92.0316%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LC Secondary

	Degree Days			Normal Weather Band						
	Actual [1]	30-year Average [2]	30-year Std Dev [3]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day [4]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	8,980.07	(1,735,249)	93.4691%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LC Primary

	Degree Days			Normal Weather Band						
	Actual 1/	30-year Average 2/	30-year Std Dev 3/	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day 4/	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	11,533.69	(2,228,694)	60.3444%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LP Secondary

	Degree Days			Normal Weather Band						
	Actual [1]	30-year Average [2]	30-year Std Dev [3]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day [4]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	11,366.90	(2,196,464)	94.5151%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

LOUISVILLE GAS AND ELECTRIC

OAG kWh Weather Adjustment
(June through September, 2007)

LP Primary

	Degree Days			Normal Weather Band						
	Actual [1/]	30-year Average [2/]	30-year Std Dev [3/]	Upper Limit	Lower Limit	Adjustment	Boundary Limit less Actual	kWh Per Degree Day [4/]	kWh Adjustment	Model R-square
Cooling Season (CDD)										
Cooling Month										
June	376	306								
July	396	438								
August	629	407								
September	350	204								
Seasonal Aggregate	1,751	1,356	202	1,558	1,154	Yes	(193)	2,347.97	(453,706)	87.8536%
Heating Season (HDD)										
Heating Month										
November	480	500								
December	712	833								
January	935	954								
February	787	769								
March	569	558								
	3,483	3,615	347	3,962	3,268	No	479			

1/ Per NOAA, National Climatic Data Center
2/ 30-year Average 1978 to 2007
3/ Standard deviation of Seasonal Degree Days.
4/ Linear regression model developed based on daily observations of kWh usage, degree days, and binary variable for Weekdays and Holidays.

Schedule GAW_ 3

Eon Generation Unit Classification

Unit	Type	Gross Plant	Percent Energy	Demand	Gross Plant Energy	Gross Plant Demand
Trimble 1	Base	$598.442	100%	0%	$598.442	$0.000
Mill Creek 3	Base	$272.591	100%	0%	$272.591	$0.000
Mill Creek 4	Base	$494.022	100%	0%	$494.022	$0.000
Mill Creek 1	Base	$153.584	100%	0%	$153.584	$0.000
Mill Creek 2	Base	$121.972	100%	0%	$121.972	$0.000
Ghent 1	Base	$341.335	100%	0%	$341.335	$0.000
Cane Run 6	Base	$131.258	100%	0%	$131.258	$0.000
Ghent 4	Base	$365.800	100%	0%	$365.800	$0.000
Ghent 3	Base	$490.572	100%	0%	$490.572	$0.000
Cane Run 5	Base	$89.856	100%	0%	$89.856	$0.000
Cane Run 4	Base	$70.514	100%	0%	$70.514	$0.000
Brown 2	Base	$43.716	100%	0%	$43.716	$0.000
Brown 3	Base	$145.556	100%	0%	$145.556	$0.000
Brown 1	Base	$53.103	100%	0%	$53.103	$0.000
Ghent 2	Base	$148.052	100%	0%	$148.052	$0.000
Green River 4	Intermediate	$42.268	63%	37%	$26.629	$15.639
Tyrone 3	Intermediate	$24.555	69%	31%	$16.943	$7.612
Green River 3	Intermediate	$19.529	68%	32%	$13.280	$6.249
Trimble 5	Peak	$63.319	0%	100%	$0.000	$63.319
Trimble 6	Peak	$55.910	0%	100%	$0.000	$55.910
Trimble 7	Peak	$52.341	0%	100%	$0.000	$52.341
Trimble 8	Peak	$51.951	0%	100%	$0.000	$51.951
Trimble 9	Peak	$52.052	0%	100%	$0.000	$52.052
Trimble 10	Peak	$52.023	0%	100%	$0.000	$52.023
Brown 6	Peak	$58.868	0%	100%	$0.000	$58.868
Brown 7	Peak	$58.872	0%	100%	$0.000	$58.872
Brown 8	Peak	$35.458	0%	100%	$0.000	$35.458
Brown 9	Peak	$45.866	0%	100%	$0.000	$45.866
Brown 10	Peak	$28.591	0%	100%	$0.000	$28.591
Brown 11	Peak	$43.497	0%	100%	$0.000	$43.497
Brown 5	Peak	$45.189	0%	100%	$0.000	$45.189
Paddys Run 13	Peak	$64.098	0%	100%	$0.000	$64.098
Paddys Run 11	Peak	$1.826	0%	100%	$0.000	$1.826
Cane Run 11	Peak	$2.797	0%	100%	$0.000	$2.797
Paddys Run 12	Peak	$3.162	0%	100%	$0.000	$3.162
Zorn 1	Peak	$1.901	0%	100%	$0.000	$1.901
Haefling 1,2 & 3	Peak	$5.345	0%	100%	$0.000	$5.345
Ohio Falls 1- 8	Hydro	$29.739	100%	0%	$29.739	$0.000
Dix Dam 1,2, &3	Hydro	$11.033	100%	0%	$11.033	$0.000
Total		$4,370.563			$3,617.997	$752.566
Percent					82.78%	17.22%

Louisville Gas and Electric
Electric Cost of Service Study
(Summary)

Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
Cost of Service Summary -- Pro-Forma										
total Operating Revenue	$932,384,516	$373,638,974	$132,330,260	$10,108,726	$152,499,710	$19,884,331	$21,868,647	$7,079,501	$38,755,862	$28,577,022
Pro-Forma Adjustments:										
Eliminate Unbilled Revenue	-$785,000	-315,916	-114,501	-8,371	-127,979	-16,281	-18,148	-6,010	-32,360	-23,192
Mismatch in Fuel Cos Recovery	-$50,610,166	-18,161,661	-8,065,964	-620,822	-8,524,116	-1,294,637	-1,338,972	-433,653	-2,244,537	-2,133,998
To Reflect a Full Year of the FAC Roll-	$31,805	11,413	3,812	390	5,357	814	840	273	1,411	1,341
Remove ECR Revenue	-$10,158,132	-4,121,348	-1,483,109	-106,483	-1,855,315	-207,917	-236,442	-77,318	-416,461	-292,061
To Reflect a full Year of the ECR Roll-	$1,215,475	493,141	177,482	12,739	198,067	24,878	28,292	9,252	49,832	34,947
Remove Off-System ECR Revenues	-$748,947	-299,898	-93,199	-8,560	-126,618	-17,441	-18,218	-5,799	-32,113	-26,341
Eliminate Brokered Sales	$2,000,584	717,918	239,783	24,541	336,952	51,184	52,850	17,142	86,725	84,355
Eliminate Rate Refund Acct	$9,763,357	3,929,179	1,424,100	104,115	1,591,721	202,499	225,717	74,745	402,469	288,444
Eliminate DSM Revenue	-$4,381,617	-3,773,223	-297,092	-14,001	-188,346	-49,730	-49,326	0	0	0
Year End Revenue Adjustment	-$764,511	$248,004	-$662,592	$352,824	-$337,723	$0	$0	$448,017	-$697,363	$0
Weather Normalized Electric Operating Revenues	-$14,374,348	-5,158,298	-1,722,861	-176,327	-2,421,028	-367,761	-379,728	-123,187	-637,498	-606,100
Adjustment for Merger Surecredit	$19,478,242	8,645,841	3,090,692	223,971	3,453,144	437,142	401,153	161,193	872,420	113,772
VDT Surecredit Revenues	$7,375,580	2,969,727	1,075,671	77,877	1,203,462	162,190	171,163	58,189	304,075	216,031
Sub-Total	-$41,959,678	-$14,917,139	-$4,427,898	-$138,087	-$6,592,320	-$1,085,260	-$1,068,809	$120,864	-$2,341,398	-$2,342,801
Total Pro-Forma Operating Revenue	$890,424,838	$358,721,834	$127,902,362	$9,970,639	$145,907,390	$18,799,071	$20,799,838	$7,200,364	$36,414,465	$26,234,221
Operating Expenses										
Operation and Maintenance Expenses	617,893,122	243,482,157	75,350,602	7,011,919	97,542,964	14,580,293	15,100,551	4,892,000	25,504,421	23,146,669
Depreciation and Amortization Expenses	$108,263,300	$46,673,705	$13,219,132	$1,091,365	$15,719,160	$2,253,340	$2,383,613	$751,645	$4,060,589	$3,145,181
Regulatory Credits	-$1,556,535	-$590,760	-$189,889	-$18,571	-$258,676	-$38,546	-$39,768	-$12,755	-$68,728	-$60,615
Accretion Expense	$1,369,410	$527,579	$168,483	$16,568	$229,018	$34,387	$35,479	$11,379	$59,535	$54,057
Property and Other Taxes	$17,703,456	$7,548,257	$2,161,426	$181,473	$2,602,499	$374,899	$395,519	$124,947	$672,720	$530,400
Amortization of Investment Tax Credit	$3,910,846	$1,667,476	$477,476	$40,089	$574,915	$82,818	$87,374	$27,602	$148,610	$117,170
Other Expenses	-$456,255	-$194,068	-$55,704	-$4,684	-$67,148	-$9,679	-$10,208	-$3,227	-$17,363	-$13,754
State and Federal Income Taxes	$42,796,679	$18,033,092	$10,736,660	$383,825	$8,719,033	$455,937	$842,744	$282,134	$1,963,564	$757,733
Specific Assignment of Interruptible Credit	-$6,268,793	$0	$0	$0	$0	$0	$0	$0	$0	-$2,391,305
Allocation of Interruptible Credits	$6,268,793	$2,822,318	$814,344	$85,325	$1,062,405	$128,637	$136,689	$42,306	$257,629	$167,751
Adjustments to Operating Expenses:										
Eliminate mismatch in fuel cost recovery	-50,792,206	-18,227,007	-8,087,782	-623,055	-8,554,776	-1,289,495	-1,341,781	-435,213	-2,252,610	-2,141,674
Remove ECR expenses	-10,942,070	-4,439,404	-1,597,565	-114,679	-1,783,061	-223,963	-254,690	-83,285	-448,601	-314,600
Reflect full year of ECR roll-in	8,811,442	3,574,968	1,286,489	92,349	1,435,865	180,353	205,097	67,068	361,250	253,342
Eliminate brokered sales expenses	-78,168	-28,051	-9,369	-959	-13,168	-2,000	-2,065	-670	-3,487	-3,298
Eliminate DSM Expenses	-3,860,848	-3,324,763	-261,782	-12,337	-165,961	-43,820	-43,453	0	0	0
Year end Expense adjustment	-427,934	137,701	-370,865	197,492	-189,040	0	0	250,777	-390,348	0
Adjustment to annualize depreciation expense	16,722,648	7,209,349	2,041,864	168,575	2,428,025	348,057	368,179	116,101	627,210	485,813
Depreciation adjustment	0	0	0	0	0	0	0	0	0	0
Labor adjustment	2,761,011	1,249,221	354,993	27,014	387,887	55,855	58,217	18,832	99,918	81,433
Adjustment for pension and post Ret Exp. (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Storm damage adjustment	-1,213,974	-858,013	-143,914	-4,525	-86,584	-8,854	-11,176	-3,153	-21,022	-5
Adjustment to eliminate advertising expense (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Amortization of rate case expenses	187,842	74,951	22,959	2,106	29,361	4,378	4,537	1,470	7,670	6,913
Amortization of ESM audit expenses	-10,656	-4,288	-1,554	-114	-1,737	-221	-248	-82	-439	-315
Adjustment for FERC assessment fee (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Adjustment for injuries and damages (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Adjustment for postage rate increase (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Adjustment to property tax expense (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Adjustment to sales and use tax (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Adjustment railcar property tax expense (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Adjustment for EKPC settlement charges	-678,288	-243,407	-81,297	-8,320	-114,242	-17,354	-17,918	-5,812	-30,082	-28,600
Adjustment to reflect reallocation of OVEC demand charges	-3,145,310	-1,128,708	-376,987	-38,682	-529,755	-80,470	-83,089	-26,950	-139,492	-132,623

Louisville Gas and Electric
Electric Cost of Service Study
(Summary)

Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP-Pri	LP-Sec	LP-TOD Trans
Adjustment for MISO schedule 10 expenses	1,380,429	513,597	165,941	16,329	225,378	33,898	34,943	11,214	58,602	53,500
Reflect weather normalized electric sales margins	-4,751,178	-1,704,981	-569,460	-58,282	-800,226	-121,557	-125,512	-40,710	-210,713	-200,335
Adjustment for IT prepaid amortizaton (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0
Adjustment to remove IMEA/IMPA reactive power credits	-330,012	-118,426	-39,554	-4,048	-55,583	-8,443	-8,718	-2,828	-14,636	-13,915
Adjustment to remove reclassified capital lease	1,757,267	707,197	256,318	18,739	288,487	36,447	40,626	13,453	72,439	51,916
Adjustment for new credit facilities bank fees	6,394,978	2,171,162	788,921	57,531	879,544	111,896	124,725	41,302	222,394	159,387
Adjustment to reflect annualized vehicle fuel costs	158,347	63,725	23,097	1,689	25,815	3,284	3,661	1,212	6,527	4,678
Total Expense Adjustments	-39,076,680	-14,375,177	-4,601,569	-283,078	-6,595,767	-1,032,007	-1,048,674	-77,273	-2,055,399	-1,738,382
Total Operating Expenses	750,887,345	303,574,589	98,081,984	8,484,233	119,530,402	18,830,080	17,883,320	6,038,758	30,627,580	23,714,907
Net Operating Income -- Pro-Forma	139,557,494	55,147,245	29,820,378	1,486,406	28,376,987	1,968,991	2,916,518	1,161,606	5,888,884	2,519,314
Net Cost Rate Base	1,826,018,111	778,697,455	222,937,770	18,748,124	268,739,555	38,737,284	40,855,616	12,914,556	69,489,563	55,046,323
Less: ECR Rate Base	13,285,453	5,319,847	1,653,245	151,847	2,244,282	309,375	323,165	102,865	569,652	467,254
Adjustment to Reflect Depreciation Reserve	-16,722,648	-7,209,349	-2,041,884	-168,575	-2,428,025	-348,057	-368,179	-116,101	-627,210	-485,813
Cash Working Capital	-788,376	-314,671	-96,359	-8,840	-123,229	-18,376	-19,041	-6,169	-32,192	-29,012
Adjusted Net Cost Rate Base	1,795,221,634	763,853,688	219,146,303	18,416,651	263,944,019	38,061,477	40,145,230	12,689,421	68,260,510	54,064,243
RoR	7.77%	7.22%	13.81%	8.07%	9.99%	5.17%	7.26%	9.15%	8.62%	4.66%

Louisville Gas and Electric
Electric Cost of Service Study
(Summary)

Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
Cost of Service Summary -- Pro-Forma											
total Operating Revenue	$100,268,170	$2,830,994	$7,781,860	$11,613,536	$3,075,165	$6,222,827	$207,196	$8,619,655	$280,300	$802,735	$5,941,047
Pro-Forma Adjustments:											
Eliminate Unbilled Revenue	-81,748	-2,364	-6,533	-9,266	-2,488	-5,782	-173	-8,143	-242	-645	-4,838
Mismatch in Fuel Cos Recovery	-7,069,940	-171,322	-580,778	-833,978	-228,954	-203,634	-14,926	-228,555	-14,638	-55,850	-391,012
To Reflect a Full Year of the FAC Roll-	4,443	108	365	524	144	128	9	144	9	35	246
Remove ECR Revenue	-1,041,665	-30,811	-83,494	-122,024	-32,095	-72,651	-2,182	-103,494	-3,076	-8,170	-62,039
To Reflect a full Year of the ECR Roll-	124,841	3,687	9,991	14,601	3,840	8,693	261	12,384	368	978	7,423
Remove Off-System ECR Revenues	-89,196	-2,249	-5,776	-11,145	-2,501	-1,644	-121	-1,846	-177	-773	-5,431
Eliminate Brokered Sales	279,470	6,772	22,958	32,967	9,050	8,050	590	9,035	579	2,208	15,456
Eliminate Rate Refund Acct	1,016,728	29,399	81,251	115,498	30,945	71,912	2,152	101,281	3,013	8,019	60,171
Eliminate DSM Revenue	0	0	0	0	0	0	0	0	0	-1,260	-8,840
Year End Revenue Adjustment	$0	$0	$0	$0	$0	-$315,830	-$1,478	$395,736	-$43,432	$0	-$148,674
Weather Normalized Electric Operating Revenues	-2,008,011	-48,659	-164,953	-236,857	-65,028	-57,836	-4,239	-64,914	-4,157	-15,862	-111,056
Adjustment for Merger Surecredit	1,173,992	63,668	0	250,635	66,905	155,464	4,654	219,227	8,505	17,039	128,914
VDT Surecredit Revenues	768,918	22,775	61,468	87,255	23,360	54,246	1,626	76,416	2,275	5,936	44,922
Sub-Total	-$6,922,367	-$128,996	-$665,501	-$711,822	-$196,821	-$358,886	-$13,827	$407,269	-$52,973	-$48,346	-$474,558
Total Pro-Forma Operating Revenue	$93,343,802	$2,701,998	$7,116,358	$10,901,714	$2,878,344	$5,863,941	$193,369	$9,026,923	$227,327	$754,388	$5,466,489
Operating Expenses											
Operation and Maintenance Expenses	78,634,424	1,933,859	6,459,989	9,415,402	2,607,114	3,115,202	175,155	3,703,250	223,096	827,407	4,406,645
Depreciation and Amortization Expenses	$11,662,978	$299,208	$962,001	$1,478,521	$421,113	$1,418,789	$25,594	$1,874,262	$32,305	$96,632	$694,167
Regulatory Credits	-$201,840	-$4,976	-$16,818	-$25,133	-$7,080	-$5,753	-$380	-$6,608	-$416	-$1,654	-$11,605
Accretion Expense	$180,059	$4,439	$15,003	$22,422	$6,316	$5,182	$339	$5,964	$372	$1,475	$10,354
Property and Other Taxes	$1,942,862	$49,632	$160,431	$245,822	$69,933	$218,694	$4,197	$285,223	$5,232	$16,078	$115,210
Amortization of Investment Tax Credit	$429,195	$10,964	$35,441	$54,304	$15,449	$47,870	$927	$63,008	$1,156	$3,552	$25,451
Other Expenses	-$50,237	-$1,282	-$4,147	-$6,343	-$1,803	-$5,601	-$109	-$7,372	-$137	-$415	-$2,974
State and Federal Income Taxes	$1,773,538	$120,897	-$87,602	-$97,199	-$73,079	$267,853	-$3,048	$606,964	$1,079	$3,250	$109,302
Specific Assignment of Interruptible Credit	-$3,875,488	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Allocation of Interruptible Credits	$591,298	$15,950	$19,999	$81,236	$12,015	$0	$0	$0	$1,078	$5,933	$41,880
Adjustments to Operating Expenses:											
Eliminate mismatch in fuel cost recovery	-7,095,369	-171,938	-582,867	-836,978	-229,777	-204,366	-14,980	-229,377	-14,690	-56,051	-392,419
Remove ECR expenses	-1,122,054	-33,189	-89,938	-131,441	-34,572	-78,258	-2,350	-111,481	-3,313	-8,801	-66,826
Reflect full year of ECR roll-in	903,569	26,727	72,425	105,847	27,840	63,019	1,892	89,773	2,668	7,087	53,814
Eliminate brokered sales expenses	-10,820	-265	-897	-1,288	-354	-315	-23	-353	-23	-86	-604
Eliminate DSM Expenses	0	0	0	0	0	0	0	0	0	-1,110	-7,613
Year end Expense adjustment	0	0	0	0	0	-176,785	-827	221,513	-24,311	0	-83,221
Adjustment to annualize depreciation expense	1,801,496	46,217	148,593	228,376	65,046	219,150	3,953	289,604	4,990	14,926	107,223
Depreciation adjustment	0	0	0	0	0	0	0	0	0	0	0
Labor adjustment	292,699	7,483	24,048	36,202	10,211	15,876	749	19,615	1,472	2,387	16,898
Adjustment for pension and post Ret Exp. (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Storm damage adjustment	-41,919	-1,409	-3,154	-6,155	-1,695	-8,059	-184	-10,119	-239	-383	-3,214
Adjustment to eliminate advertising expense (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Amortization of rate case expenses	23,583	581	1,937	2,828	784	979	53	1,171	70	188	1,323
Amortization of ESM audit expenses	-1,110	-32	-89	-126	-34	-78	-2	-111	-3	-9	-66
Adjustment for FERC assessment fee (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment for injuries and damages (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment for postage rate increase (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment to property tax expense (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment to sales and use tax (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment railcar property tax expense (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment for EKPC settlement charges	-94,753	-2,296	-7,784	-11,177	-3,068	-2,729	-200	-3,063	-196	-749	-5,240
Adjustment to reflect reallocation of OVEC demand charges	-439,381	-10,647	-36,095	-51,829	-14,230	-12,655	-929	-14,205	-910	-3,471	-24,300
Adjustment for MISO schedule 10 expenses	177,570	4,372	14,801	22,098	8,222	4,531	332	5,088	362	1,454	10,198
Reflect weather normalized electric sales margins	-663,711	-16,083	-54,522	-78,292	-21,494	-19,117	-1,401	-21,456	-1,374	-5,243	-36,707
Adjustment for IT prepaid amortizaton (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment to remove IMEA/IMPA reactive power credits	-48,101	-1,117	-3,787	-5,438	-1,493	-1,328	-97	-1,490	-95	-364	-2,550
Adjustment to remove reclassified capital lease	182,997	5,291	14,624	20,788	5,570	12,943	387	18,229	542	1,443	10,830
Adjustment for new credit facilities bank fees	561,817	16,245	44,897	63,821	17,099	39,736	1,189	55,965	1,665	4,431	33,249
Adjustment to reflect annualized vehicle fuel costs	16,490	477	1,318	1,873	502	1,166	35	1,643	49	130	976
Total Expense Adjustments	-5,555,097	-129,584	-456,488	-640,891	-173,643	-146,289	-12,402	310,843	-33,337	-44,219	-388,249
Total Operating Expenses	85,531,692	2,299,107	7,087,807	10,528,142	2,876,336	4,913,949	190,274	6,835,535	230,428	708,039	5,000,180

Louisville Gas and Electric
Electric Cost of Service Study
(Summary)

Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
Adjustment for MISO schedule 10 expenses	177,570	4,372	14,601	22,098	6,222	4,531	332	5,086	382	1,454	10,198
Reflect weather normalized electric sales margins	-663,711	-16,083	-54,522	-78,292	-21,494	-19,117	-1,401	-21,458	-1,374	-5,243	-38,707
Adjustment for IT prepaid amortizaton (See Functional Assignment)	0	0	0	0	0	0	0	0	0	0	0
Adjustment to remove IMEA/IMPA reactive power credits	-46,101	-1,117	-3,787	-5,438	-1,493	-1,328	-97	-1,490	-95	-364	-2,550
Adjustment to remove reclassified capital lease	182,997	5,291	14,824	20,788	5,570	12,943	387	18,229	542	1,443	10,830
Adjustment for new credit facilities bank fees	561,817	16,245	44,897	63,821	17,099	39,736	1,189	65,965	1,665	4,431	33,249
Adjustment to reflect annualized vehicle fuel costs	18,490	477	1,318	1,873	502	1,168	35	1,843	49	130	976
Total Expense Adjustments	-5,555,097	-129,584	-458,488	-840,891	-173,643	-148,289	-12,402	310,843	-33,337	-44,219	-388,249
Total Operating Expenses	85,531,692	2,299,107	7,087,807	10,528,142	2,678,338	4,913,949	190,274	6,835,535	230,428	708,039	5,000,180
Net Operating Income -- Pro-Forma	7,812,110	402,890	28,551	373,572	2,007	949,993	3,095	2,101,388	-3,101	48,349	466,309
Net Cost Rate Base	201,059,368	5,132,026	16,598,206	25,384,220	7,214,231	22,416,070	436,111	29,502,991	548,040	1,681,445	11,901,158
Less: ECR Rate Base	1,582,242	39,903	102,456	197,705	44,369	29,170	2,138	32,740	3,136	13,714	96,347
Adjustment to Reflect Depreciation Reserve	-1,801,496	-48,217	-148,593	-228,376	-65,046	-219,150	-3,953	-289,504	-4,990	-14,928	-107,223
Cash Working Capital	-98,980	-2,439	-8,129	-11,868	-3,289	-4,108	-223	-4,915	-294	-790	-5,555
Adjusted Net Cost Rate Base	197,576,649	5,043,469	16,339,028	24,946,271	7,101,527	22,163,642	429,797	29,175,832	539,620	1,632,015	11,692,031
RoR	3.95%	7.99%	0.17%	1.50%	0.03%	4.29%	0.72%	7.51%	-0.57%	2.84%	3.99%

Louisville Gas and Electric
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description		Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP-Pri	LP-Sec	LP-TOD Trans
	RATE BASE											
	Plant-in-Service											
	Intangible Plant											
301.00	ORGANIZATION		$2,240	958	274	23	329	47	50	16	85	67
302.00	FRANCHISE AND CONSENTS		100	43	12	1	15	2	2	1	4	3
302.00	SOFTWARE - COMMON		21,651,799	9,238,846	2,643,499	221,691	3,180,203	457,965	483,243	152,641	822,014	647,327
301.00	ORGANIZATION - COMMON		61,999	26,455	7,570	635	9,106	1,311	1,384	437	2,354	1,854
302.00	FRANCHISE AND CONSENTS - COMMON		3,108	1,326	379	32	457	66	69	22	118	93
	Total Intangible Plant		21,719,248	9,267,626	2,651,734	222,381	3,190,109	459,392	484,748	153,116	824,575	649,344
	Production Plant											
	Steam Production Generation	$1,949,427,033										
330	Hydro Baseload Generation	$29,738,482										
340	Other Production Generation	$225,596,172										
	Total Production	2,204,761,687										
	Energy Related		1,825,101,724	654,945,811	218,750,531	22,388,074	307,396,309	46,694,366	48,213,816	15,638,388	80,942,400	76,956,142
	Demand Related		379,659,962	177,409,143	50,179,406	4,074,927	57,860,252	8,242,324	8,415,511	2,535,501	14,030,856	9,748,473
	Total Production Pant		2,204,761,687	832,354,954	268,929,937	26,463,001	365,256,561	54,936,690	56,629,327	18,173,889	94,973,256	86,704,615
	Transmission Plant											
	Transmission Plant		$255,091,069	96,303,522	31,115,211	3,061,771	42,260,208	6,356,179	6,552,017	2,102,720	10,988,412	10,031,729
	Total Transmission Plant		255,091,069	96,303,522	31,115,211	3,061,771	42,260,208	6,356,179	6,552,017	2,102,720	10,988,412	10,031,729
	Distribution Plant											
360-362	Total Accounts 360-362		$94,845,074	46,108,849	12,252,224	1,004,584	13,654,761	1,983,870	1,981,071	697,942	3,499,854	0
364-365	OVERHEAD LINES	288,850,108										
	Primary:	237,601,861										
	Customer		93,377,531	81,002,988	9,442,654	11,299	605,160	3,164	11,751	9,943	73,218	1,130
	Demand		144,224,330	70,114,530	18,631,107	1,527,671	20,763,848	3,016,734	3,012,477	1,061,313	5,321,988	0
	Secondary	51,248,247										
	Customer		20,140,561	17,478,460	2,037,496	0	130,583	0	2,536	0	15,799	0
	Demand		31,107,686	21,514,614	4,833,748	0	3,180,151	0	423,212	0	789,821	0
366-367	UNDERGROUND LINES	157,900,818										
	Primary:	123,978,007										
	Customer		24,919,579	21,617,196	2,519,853	3,016	161,504	844	3,136	2,654	19,540	302
	Demand		99,058,428	48,157,167	12,796,511	1,049,190	14,261,353	2,072,000	2,069,077	728,947	3,655,330	0
	Secondary	33,922,811										
	Customer		6,818,485	5,917,251	689,784	0	44,208	0	858	0	5,349	0
	Demand		27,104,326	18,745,821	4,211,676	0	2,779,599	0	368,747	0	688,176	0
368	TRANSFORMERS - POWER POOL	108,478,013										
	Customer		28,692,435	24,800,009	2,902,636	0	166,030	0	3,612	0	22,507	0
	Demand		79,785,579	55,181,067	12,397,688	0	8,182,181	0	1,085,461	0	2,025,747	0
369	SERVICES		24,560,987	17,979,330	2,843,624	0	3,111,656	0	60,101	0	512,735	0
370	METERS		34,389,049	23,419,433	9,483,513	12,827	715,927	78,765	20,685	35,868	284,116	10,497
371	CUSTOMER INSTALLATION		0	0	0	0	0	0	0	0	0	0
373	STREET LIGHTING		67,121,503	0	0	0	0	0	0	0	0	0
374	ASSET RETIRE OBLIGATIONS DIST PLANT		37,674	24,796	4,558	201	3,220	394	450	140	809	0
	Total Distribution Plant		776,183,225	452,161,550	95,047,071	3,608,668	67,790,181	7,153,761	9,043,153	2,536,807	16,894,987	11,929
	General Plant											
	Total General Plant		16,654,627	7,108,547	2,033,387	170,625	2,448,221	352,268	371,712	117,412	632,296	497,926
	TOTAL COMMON PLANT		111,473,234	47,565,749	13,609,825	1,141,363	16,373,119	2,357,813	2,487,951	785,684	4,232,100	3,332,733

Louisville Gas and Electric
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
106	COMPLETED CONSTR NOT CLASSIFIED	0	0	0	0	0	0	0	0	0	0
105	PLANT HELD FOR FUTURE USE	649,014	378,080	79,475	3,017	58,883	5,982	7,562	2,121	14,127	10
105	PLANT HELD FOR FUTURE USE	22,013,472	8,310,659	2,685,135	264,220	3,646,909	548,516	565,416	181,457	948,252	885,703
	PROPERTY HELD UNDER CAPITAL LEASE	2,876,958	1,086,127	350,922	34,531	476,617	71,688	73,895	23,715	123,929	113,139
	OTHER	0	0	0	0	0	0	0	0	0	0
	Total General Plant	153,667,305	64,447,161	18,758,844	1,613,657	22,999,550	3,338,265	3,506,535	1,110,570	5,950,714	4,809,511
	Construction Work In Progress										
	CWIP Production	148,057,359	55,140,457	17,815,620	1,753,077	24,196,905	3,639,354	3,751,485	1,203,953	6,291,629	5,743,862
	CWIP Transmission	24,338,419	9,187,632	2,968,480	292,102	4,031,745	606,398	625,081	200,608	1,048,326	957,056
	CWIP Distribution Plant	92,896,770	54,116,536	11,375,621	431,900	8,113,405	856,191	1,082,321	303,615	2,022,061	1,428
	CWIP Common Plant	26,558,015	11,332,334	3,242,508	271,925	3,900,825	561,739	592,743	187,229	1,008,280	794,009
	Total CWIP	289,848,563	129,776,959	35,402,227	2,749,003	40,242,879	5,663,681	6,051,631	1,895,403	10,370,296	7,496,355
	TOTAL PLANT-IN-SERVICE	3,411,422,531	1,454,534,813	416,502,796	34,969,477	501,496,610	72,242,287	76,215,779	24,077,102	129,631,943	102,207,128
	TOTAL UTILITY PLANT	3,701,271,094	1,584,311,771	451,905,022	37,718,480	541,739,489	77,906,968	82,267,410	25,972,505	140,002,239	109,703,482
Accumulated Reserve for Depreciation											
	Intangible Plant										
	Intangible Plant	14,293,347	6,098,988	1,745,095	148,348	2,099,398	302,324	319,011	100,765	542,649	427,330
	Sub-total	14,293,347	6,098,988	1,745,095	148,348	2,099,398	302,324	319,011	100,765	542,649	427,330
	Production Plant										
	Production Plant	1,056,980,153	399,037,534	128,927,134	12,688,571	175,106,878	26,337,083	27,148,546	8,712,706	45,530,928	41,566,876
	Sub-total	1,056,980,153	399,037,534	128,927,134	12,688,571	175,106,878	26,337,083	27,148,546	8,712,706	45,530,928	41,566,876
	Transmisson Plant										
	Transmission Plant	137,604,053	51,949,113	16,784,512	1,651,614	22,796,470	3,428,720	3,534,362	1,134,273	5,927,491	5,411,427
	Sub-total	137,604,053	51,949,113	16,784,512	1,651,614	22,796,470	3,428,720	3,534,362	1,134,273	5,927,491	5,411,427
	Distribution Plant										
	Distribution Plant	395,791,767	230,566,472	48,466,456	1,840,134	34,567,607	3,647,850	4,611,290	1,293,570	8,615,101	6,083
	Sub-total	395,791,767	230,566,472	48,466,456	1,840,134	34,567,607	3,647,850	4,611,290	1,293,570	8,615,101	6,083
	General Plant										
	General & Common Plant	61,263,746	26,141,306	7,479,778	627,273	8,998,381	1,295,813	1,367,334	431,897	2,325,888	1,831,612
	Sub-total	61,263,746	26,141,306	7,479,778	627,273	8,998,381	1,295,813	1,367,334	431,897	2,325,888	1,831,612
	TOTAL ACCUMULATED RESERVE FOR DEPRECIATION	1,665,933,065	713,793,412	203,402,975	16,951,941	243,568,734	35,011,790	36,980,542	11,673,211	62,942,058	49,243,328
Rate Base Adjustments and Working Capital											
	Working Capital Assets										
	Cash Working Capital - Operation and Maintenance Expenses	66,891,862	28,690,590	8,175,601	750,074	10,455,691	1,559,040	1,616,546	523,387	2,731,399	2,461,602
	Materials and Supplies	69,130,135	29,475,149	8,440,143	708,632	10,162,484	1,463,940	1,544,460	487,906	2,626,902	2,071,157
	Prepayments	3,275,528	1,396,593	399,911	33,576	481,519	69,365	73,180	23,118	124,468	98,136
WC	Mill Creek Ash Dredging Project	4,033,077	1,522,692	491,942	48,408	668,148	100,493	103,590	33,245	173,731	158,605
	Sub-total	143,330,602	59,084,924	17,507,797	1,540,691	21,767,843	3,192,838	3,338,775	1,067,656	5,656,500	4,789,500
	Customer Advances										
	Customer Advances	12,069,685	7,700,255	1,492,784	70,116	1,134,856	137,616	159,440	48,788	286,017	39
	Sub-total										
	Other Items										
	Total Accumulated Deferred Income Tax	340,560,816	145,205,573	41,579,292	3,490,988	50,064,187	7,211,916	7,608,588	2,403,607	12,941,100	10,203,293

Louisville Gas and Electric
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
	Sub-total	340,560,816	145,205,573	41,579,292	3,490,988	50,064,187	7,211,916	7,608,588	2,403,607	12,941,100	10,203,293
	TOTAL OTHER RATE BASE	483,891,418	204,290,497	59,087,089	5,031,678	71,832,030	10,404,754	10,945,363	3,471,263	18,597,600	14,992,793
TOTAL RATE BASE		1,826,018,111	776,687,455	222,937,770	18,746,124	268,739,555	38,737,284	40,855,615	12,914,656	69,489,563	55,046,323

Louisville Gas and Electric
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description		LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
	RATE BASE												
	Plant-in-Service												
	Intangible Plant												
301.00	ORGANIZATION		246	6	20	31	9	28	1	36	1	2	15
302.00	FRANCHISE AND CONSENTS		11	0	1	1	0	1	0	2	0	0	1
302.00	SOFTWARE - COMMON		2,373,141	60,641	195,946	300,303	85,439	266,323	5,132	350,641	6,403	19,640	140,781
301.00	ORGANIZATION - COMMON		6,795	174	561	860	245	763	15	1,004	18	56	403
302.00	FRANCHISE AND CONSENTS - COMMON		341	9	28	43	12	38	1	50	1	3	20
	Total Intangible Plant		2,380,533	60,830	196,557	301,239	85,705	267,153	5,148	351,733	6,423	19,701	141,199
	Production Plant												
	Steam Production Generation	$1,949,427,033											
330	Hydro Baseload Generation	$29,738,482											
340	Other Production Generation	$225,596,172											
	Total Production	2,204,761,687											
	Energy Related		254,955,869	6,178,197	20,943,987	30,074,872	8,256,516	7,343,441	538,275	8,242,149	527,864	2,014,048	14,100,671
	Demand Related		32,820,325	906,578	3,042,459	5,737,836	1,827,883	0	0	0	58,768	343,117	2,426,604
	Total Production Pant		287,776,193	7,084,775	23,986,446	35,812,708	10,084,398	7,343,441	538,275	8,242,149	586,632	2,357,165	16,527,275
	Transmission Plant												
	Transmission Plant		33,295,724	819,709	2,776,233	4,143,533	1,166,765	849,637	62,278	953,617	67,873	272,724	1,912,207
	Total Transmission Plant		33,295,724	819,709	2,775,233	4,143,533	1,166,765	849,637	62,278	953,617	67,873	272,724	1,912,207
	Distribution Plant												
360-362	Total Accounts 360-362		9,397,194	233,482	707,525	1,381,099	425,075	387,237	28,268	434,625	13,668	85,228	568,523
364-365	OVERHEAD LINES	288,850,108											
	Primary:	237,601,861											
	Customer		10,395	2,938	226	226	226	943,700	2,938	1,229,568	18,079	678	7,231
	Demand		14,289,661	355,039	1,075,885	2,100,141	646,382	588,845	43,015	660,904	20,782	129,597	864,514
	Secondary	51,248,247											
	Customer		0	634	0	0	0	203,628	634	265,311	3,901	0	1,560
	Demand		0	62,139	0	0	0	76,513	5,589	85,876	2,700	0	123,322
366-367	UNDERGROUND LINES	157,900,818											
	Primary:	123,978,007											
	Customer		2,774	784	60	60	60	251,845	784	328,134	4,825	181	1,930
	Demand		9,814,650	243,854	738,958	1,442,452	443,958	404,440	29,544	453,933	14,274	89,012	593,779
	Secondary	33,922,811											
	Customer		0	215	0	0	0	68,937	215	89,820	1,321	0	528
	Demand		0	54,142	0	0	0	66,666	4,870	74,824	2,353	0	107,451
368	TRANSFORMERS - POWER POOL	108,476,013											
	Customer		0	903	0	0	0	290,090	903	377,964	5,557	0	2,223
	Demand		0	159,376	0	0	0	196,241	14,336	220,256	6,928	0	316,299
369	SERVICES		0	17,930	0	0	0	0	5,846	0	27,828	0	2,039
370	METERS		96,575	27,293	1,288	2,268	2,577	0	29,544	0	180,283	802	8,819
371	CUSTOMER INSTALLATION		0	0	0	0	0	0	0	0	0	0	0
373	STREET LIGHTING		0	0	0	0	0	28,132,656	0	38,988,847	0	0	0
374	ASSET RETIRE OBLIGATIONS DIST PLANT		1,865	55	140	274	84	236	7	292	6	17	130
	Total Distribution Plant		33,613,115	1,158,784	2,524,081	4,928,518	1,518,363	31,611,034	166,512	43,210,354	302,499	305,512	2,598,349
	General Plant												
	Total General Plant		1,825,427	46,645	150,722	230,994	65,720	204,856	3,948	269,714	4,925	15,107	108,274
	TOTAL COMMON PLANT		12,218,000	312,207	1,008,820	1,546,097	439,878	1,371,151	26,423	1,805,258	32,966	101,117	724,700

Louisville Gas and Electric
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	* Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
106	COMPLETED CONSTR NOT CLASSIFIED	0	0	0	0	0	0	0	0	0	0	0
105	PLANT HELD FOR FUTURE USE	28,106	969	2,111	4,119	1,270	26,432	139	36,131	253	255	2,173
105	PLANT HELD FOR FUTURE USE	2,873,305	70,738	239,493	357,572	100,668	73,321	5,374	82,294	5,657	23,535	165,017
	PROPERTY HELD UNDER CAPITAL LEASE	375,515	9,245	31,300	46,731	13,159	9,582	702	10,755	765	3,076	21,566
	OTHER	0	0	0	0	0	0	0	0	0	0	0
	Total General Plant	17,320,353	439,803	1,432,446	2,185,515	620,714	1,685,342	38,587	2,204,152	44,767	143,091	1,021,729
	Construction Work In Progress											
	CWIP Production	19,064,115	469,340	1,589,014	2,372,460	668,054	486,476	35,859	546,012	38,862	156,154	1,094,871
	CWIP Transmission	3,176,508	78,203	264,765	395,305	111,313	81,058	5,942	90,978	6,475	26,019	182,430
	CWIP Distribution Plant	4,022,955	138,688	302,092	589,626	181,724	3,783,337	19,929	5,171,591	36,204	36,565	310,981
	CWIP Common Plant	2,910,886	74,382	240,347	368,351	104,799	326,671	6,295	430,095	7,854	24,091	172,657
	Total CWIP	29,174,463	760,613	2,396,218	3,725,742	1,065,890	4,677,542	67,624	6,238,676	89,396	242,828	1,760,939
	TOTAL PLANT-IN-SERVICE	374,385,918	9,663,901	30,914,763	47,369,611	13,475,945	41,766,606	808,801	54,982,005	1,008,194	3,098,194	22,200,769
	TOTAL UTILITY PLANT	403,560,381	10,324,514	33,310,981	51,095,253	14,541,835	46,434,148	876,625	61,200,681	1,097,590	3,341,022	23,961,698
	Accumulated Reserve for Depreciation											
	Intangible Plant											
	Intangible Plant	1,566,619	40,032	129,353	198,244	56,402	175,812	3,388	231,474	4,227	12,965	92,923
	Sub-total	1,566,619	40,032	129,353	198,244	56,402	175,812	3,388	231,474	4,227	12,965	92,923
	Production Plant											
	Production Plant	137,962,178	3,396,497	11,499,292	17,168,695	4,834,540	3,520,504	258,053	3,951,351	281,236	1,130,044	7,923,306
	Sub-total	137,962,178	3,396,497	11,499,292	17,168,695	4,834,540	3,520,504	258,053	3,951,351	281,236	1,130,044	7,923,306
	Transmisson Plant											
	Transmission Plant	17,960,749	442,176	1,497,047	2,235,150	629,390	458,320	33,595	514,411	36,613	147,116	1,031,504
	Sub-total	17,960,749	442,176	1,497,047	2,235,150	629,390	458,320	33,595	514,411	36,613	147,116	1,031,504
	Distribution Plant											
	Distribution Plant	17,140,018	590,688	1,287,081	2,512,133	774,244	16,119,116	84,908	22,033,848	154,250	155,787	1,324,951
	Sub-total	17,140,018	590,688	1,287,081	2,512,133	774,244	16,119,116	84,908	22,033,848	154,250	155,787	1,324,951
	General Plant											
	General & Common Plant	6,714,600	171,583	554,430	849,708	241,749	753,561	14,522	992,138	18,118	55,572	398,282
	Sub-total	6,714,600	171,583	554,430	849,708	241,749	753,561	14,522	992,138	18,118	55,572	398,282
	TOTAL ACCUMULATED RESERVE FOR DEPRECIATION	181,344,364	4,641,176	14,967,203	22,964,130	6,536,325	21,027,313	394,466	27,723,222	494,444	1,501,484	10,770,966
	Rate Base Adjustments and Working Capital											
	Working Capital Assets											
	Cash Working Capital - Operation and Maintenance Expenses	8,398,221	206,980	669,728	1,006,946	279,068	348,567	18,913	417,030	24,916	67,068	471,298
	Materials and Supplies	7,586,674	193,806	626,468	959,911	273,081	848,169	16,390	1,113,767	20,430	62,783	449,883
	Prepayments	359,472	9,183	29,683	45,483	12,939	40,093	777	52,773	968	2,976	21,316
WC	Mill Creek Ash Dredging Project	526,417	12,960	43,877	65,611	18,447	13,433	985	15,077	1,073	4,312	30,233
	Sub-total	16,870,784	422,928	1,369,755	2,077,850	583,533	1,248,262	37,064	1,598,647	47,388	137,138	972,730
	Customer Advances											
	Customer Advances	652,652	19,477	49,120	95,675	29,514	70,483	2,370	86,282	1,848	5,939	46,013
	Sub-total											
	Other Items											
	Total Accumulated Deferred Income Tax	37,374,782	954,760	3,086,207	4,728,678	1,345,298	4,168,644	80,742	5,486,833	100,648	309,291	2,216,292

Louisville Gas and Electric
Electric Cost of Service Study
(Rate Base)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
	Sub-total	37,374,782	854,760	3,086,207	4,728,878	1,345,298	4,168,644	80,742	5,486,833	100,648	309,291	2,216,292
	TOTAL OTHER RATE BASE	54,245,566	1,377,698	4,475,862	6,808,727	1,928,830	5,416,806	117,808	7,085,480	148,035	448,429	3,189,022
TOTAL RATE BASE		201,059,366	6,132,026	16,598,206	25,384,220	7,214,231	22,418,070	436,111	28,602,991	648,040	1,681,445	11,901,156

Louisville Gas and Electric
Electric Cost of Service Study
(Expenses)

Acct. No.	Account Description		Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
O & M Expenses												
	Steam Production O&M											
500	OPERATION SUPERVISION & ENGINEERING		$2,089,989	783,314	254,280	25,166	347,082	52,280	53,905	17,327	90,417	83,058
501	FUEL		$287,348,507	103,118,280	34,440,622	3,524,833	48,397,231	7,351,878	7,590,902	2,462,146	12,743,771	12,116,164
502	STEAM EXPENSES		$27,325,773	10,316,191	3,333,112	327,982	4,526,983	680,884	701,863	225,247	1,177,097	1,074,615
505	ELECTRIC EXPENSES		$754,249	284,749	92,001	9,053	124,954	18,794	19,373	6,217	32,490	29,662
506	MISC. STEAM POWER EXPENSES		$18,989,296	6,413,902	2,072,301	203,917	2,814,588	423,327	436,370	140,043	731,838	668,122
507	RENTS		$51,252	19,349	6,252	615	8,491	1,277	1,316	422	2,208	2,016
509	ALLOWANCES		$3,372	1,273	411	40	559	84	87	28	145	133
510	MAINTENANCE SUPERVISION & ENGINEERING		$2,346,687	843,763	281,453	28,763	395,002	59,980	61,928	20,079	103,962	98,699
511	MAINTENANCE OF STRUCTURES		$2,279,365	860,520	278,030	27,358	377,616	56,796	58,546	18,789	98,187	89,638
512	MAINTENANCE OF BOILER PLANT		$39,886,283	14,313,369	4,780,635	489,275	6,717,825	1,020,472	1,053,678	341,766	1,768,938	1,681,821
513	MAINTENANCE OF ELECTRIC PLANT		$7,544,241	2,707,284	904,227	92,543	1,270,653	193,016	199,297	64,643	334,584	318,106
514	MAINTENANCE OF MISC STEAM PLANT		$1,334,745	478,979	159,978	16,373	224,807	34,149	35,260	11,437	59,195	56,280
	Sub-total		387,953,739	140,138,972	48,603,303	4,745,920	65,205,872	9,892,735	10,212,524	3,308,144	17,142,832	16,218,314
	Hydraulic Production O&M											
535	OPERATION SUPERVISION & ENGINEERING		$53,088	20,042	6,476	637	8,795	1,323	1,364	438	2,287	2,088
536	WATER FOR POWER		$39,005	14,726	4,758	468	6,482	972	1,002	322	1,680	1,534
537	HYDRAULIC EXPENSES		$0									
538	ELECTRIC EXPENSES		$181,488	60,966	19,698	1,938	26,753	4,024	4,148	1,331	6,956	6,351
539	MISC. HYDRAULIC POWER EXPENSES		$129,702	48,966	15,821	1,557	21,487	3,232	3,331	1,069	5,587	5,101
540	RENTS		$238,696	90,114	29,115	2,865	39,544	5,948	6,131	1,968	10,282	9,387
541	MAINTENANCE SUPERVISION & ENGINEERING		$4,568	1,671	551	56	765	116	119	39	200	188
542	MAINTENANCE OF STRUCTURES		$189,915	71,698	23,165	2,279	31,463	4,732	4,878	1,565	8,181	7,469
543	MAINT. OF RESERVES, DAMS, AND WATERWAYS		$87,399	32,995	10,661	1,049	14,479	2,178	2,245	720	3,765	3,437
544	MAINTENANCE OF ELECTRIC PLANT		$282,889	101,516	33,906	3,470	47,646	7,238	7,473	2,424	12,546	11,928
545	MAINTENANCE OF MISC HYDRAULIC PLANT		$0									
	Sub-total		1,186,753	442,694	144,150	14,320	197,395	29,761	30,691	9,875	51,485	47,482
	Other Power Generation Operation Expense											
546	OPERATION SUPERVISION & ENGINEERING		$28,825	10,882	3,516	348	4,775	718	740	238	1,242	1,134
547	FUEL		$30,157,562	10,822,174	3,814,584	369,935	5,079,346	771,567	796,674	258,405	1,337,474	1,271,606
548	GENERATION EXPENSE		$925,321	349,333	112,868	11,106	153,285	23,058	23,767	7,627	39,860	36,389
549	MISC OTHER POWER GENERATION		$37,651	14,290	4,617	454	6,271	943	972	312	1,630	1,489
550	RENTS		$22,836	8,621	2,785	274	3,783	569	587	188	984	898
551	MAINTENANCE SUPERVISION & ENGINEERING		$16,488	6,225	2,011	198	2,732	411	424	136	710	648
552	MAINTENANCE OF STRUCTURES		$91,930	34,706	11,213	1,103	15,230	2,291	2,361	758	3,960	3,615
553	MAINTENANCE OF GENERATING & ELEC PLANT		$1,860,881	702,631	226,984	22,338	308,287	48,368	47,797	15,339	80,160	73,181
554	MAINTENANCE OF MISC OTHER POWER GEN PLT		$110,415	41,684	13,468	1,325	18,292	2,751	2,836	910	4,756	4,342
	Sub-total		33,252,108	11,990,446	3,992,047	407,078	5,592,011	848,675	876,157	283,914	1,470,778	1,393,302
	Other Power Supply Expense											
555	PURCHASED POWER	81,802,192										
	Demand		10,759,242	4,061,894	1,312,379	129,140	1,782,453	288,091	276,351	88,689	463,470	423,119
	Energy		71,042,950	25,494,076	8,514,968	871,468	11,965,547	1,817,600	1,876,746	608,732	3,150,721	2,995,554
555	PURCHASED POWER OPTIONS		$0									
555	BROKERAGE FEES		$0									
555	MISO TRANSMISSION EXPENSES		$0									

Louisville Gas and Electric
Electric Cost of Service Study
(Expenses)

Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
556	SYSTEM CONTROL AND LOAD DISPATCH	$1,014,056	382,833	123,691	12,171	167,998	25,268	26,046	8,359	43,682	39,879
557	OTHER EXPENSES	-570,439	-215,356	-69,580	-6,847	-94,503	-14,214	-14,652	-4,702	-24,572	-22,433
558	DUPLICATE CHARGES	-2,771,363	-994,516	-332,166	-33,998	-466,772	-70,904	-73,211	-23,746	-122,909	-116,856
	Sub-total	79,474,446	28,728,931	9,549,292	971,935	13,354,721	2,025,841	2,091,280	677,331	3,510,392	3,319,263
	Transmission Expenses										
560	OPERATION SUPERVISION AND ENG	$707,432	267,074	88,290	8,491	117,198	17,627	18,170	5,831	30,474	27,821
561	LOAD DISPATCHING	711,516	288,616	86,789	8,540	117,875	17,729	18,275	5,865	30,650	27,981
562	STATION EXPENSES	1,234,251	465,962	150,650	14,814	204,475	30,754	31,702	10,174	53,167	48,538
563	OVERHEAD LINE EXPENSES	88,952	32,827	10,608	1,044	14,405	2,167	2,233	717	3,746	3,419
565	TRANSMISSION OF ELECTRICITY BY OTHERS	3,214,182	1,213,437	392,058	38,579	532,484	80,089	82,556	26,495	138,455	126,401
566	MISC. TRANSMISSION EXPENSES	3,724,941	1,406,262	454,357	44,709	617,100	92,815	95,675	30,705	160,457	146,487
567	RENTS	22,490	8,491	2,743	270	3,726	560	578	185	869	884
568	MAINTENACE SUPERVISION AND ENG	0	0	0	0	0	0	0	0	0	0
569	STRUCTURES	30,412	11,481	3,710	365	5,038	758	781	251	1,310	1,196
570	MAINT OF STATION EQUIPMENT	996,472	376,194	121,547	11,960	165,083	24,829	25,594	8,214	42,924	39,187
571	MAINT OF OVERHEAD LINES	776,625	293,198	94,730	9,322	128,661	19,351	19,948	6,402	33,454	30,542
572	UNDERGROUND LINES	0	0	0	0	0	0	0	0	0	0
573	MISC PLANT	2,418	913	295	29	401	60	62	20	104	95
575	MARKET FACILITATION, MONITORING AND COMPLIANCE	7,533	2,844	919	90	1,248	188	193	62	325	296
	Sub-total	11,515,224	4,347,297	1,404,591	138,213	1,907,694	286,928	295,769	94,920	498,035	452,849
	Distribution Expense - Operating										
580	OPERATION SUPERVISION AND ENGI	$1,235,544	788,258	221,708	4,651	82,034	9,851	10,349	3,604	21,764	146
581	LOAD DISPATCHING	333,427	182,095	43,073	3,532	48,003	6,974	6,964	2,454	12,304	0
582	STATION EXPENSES	937,276	455,656	121,079	9,927	134,939	19,605	19,577	6,897	34,586	0
583	OVERHEAD LINE EXPENSES	4,516,341	2,972,491	546,386	24,061	386,039	47,218	53,942	16,750	98,954	18
584	UNDERGROUND LINE EXPENSES	440,566	263,494	56,411	2,936	48,121	5,784	6,813	2,041	12,188	1
585	STREET LIGHTING EXPENSE	18,498	0	0	0	0	0	0	0	0	0
586	METER EXPENSES	5,620,801	3,827,846	1,550,058	2,097	117,016	12,545	3,378	5,863	43,169	1,716
586	METER EXPENSES - LOAD MANAGEMENT	0									
587	CUSTOMER INSTALLATIONS EXPENSE	-221,632	-129,111	-27,140	-1,030	-19,357	-2,043	-2,582	-724	-4,824	-3
588	MISCELLANEOUS DISTRIBUTION EXP	2,960,271	1,724,491	362,498	13,763	258,544	27,284	34,490	9,675	64,435	45
588	MISC DISTR EXP -- MAPPIN	0									
589	RENTS	14,166	8,252	1,735	66	1,237	131	165	46	308	0
590	MAINTENANCE SUPERVISION AND EN	$9,951	6,264	1,202	54	894	107	125	38	225	0
591	STRUCTURES	$796,271	387,106	102,863	8,434	114,638	16,656	16,632	5,860	29,383	0
592	MAINTENANCE OF STATION EQUIPME	728,659	354,237	94,129	7,716	104,904	15,241	15,220	5,382	26,888	0
593	MAINTENANCE OF OVERHEAD LINES	12,568,540	8,272,155	1,520,538	66,960	1,074,309	131,403	150,116	48,613	269,812	49
594	MAINTENANCE OF UNDERGROUND LIN	1,540,702	921,464	197,274	10,267	168,283	20,226	23,826	7,139	42,624	3
595	MAINTENANCE OF LINE TRANSFORME	223,512	165,002	31,525	0	17,242	0	2,244	0	4,220	0
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	792,957	0	0	0	0	0	0	0	0	0
597	MAINTENANCE OF METERS	0									
598	MISCELLANEOUS DISTRIBUTION EXPENSES	263,243	153,351	32,235	1,224	22,991	2,426	3,067	860	5,730	4
	Sub-total	32,779,090	20,333,051	4,855,573	154,658	2,559,838	313,407	344,326	112,476	659,768	1,978
	Customer Accounts Expense										
901	SUPERVISION/CUSTOMER ACCTS	$658,533	529,863	67,919	739	39,572	414	1,537	650	4,788	148
902	METER READING EXPENSES	2,117,207	1,702,884	218,361	2,375	127,224	1,330	4,941	2,090	15,392	475
903	RECORDS AND COLLECTION	4,762,532	3,830,537	491,191	5,343	286,182	2,992	11,114	4,702	34,624	1,069

Louisville Gas and Electric
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(Expenses)

Acct. No.	Account Description		Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
904	UNCOLLECTIBLE ACCOUNTS		848,931	682,801	87,556	952	51,013	533	1,881	838	6,172	190
905	MISC CUST ACCOUNTS		258,860	208,203	26,698	290	15,555	163	604	256	1,882	58
	Sub-total		8,646,062	6,954,067	891,724	9,700	519,545	5,432	20,177	8,536	62,858	1,940
	Customer Service & Information Expense											
907	SUPERVISION		$139,749	121,011	14,106	17	904	5	18	15	109	2
908	CUSTOMER ASSISTANCE EXPENSES		4,201,997	3,638,581	424,155	508	27,184	142	528	447	3,289	51
908	CUSTOMER ASSISTANCE EXP-INCENTIVES		0									
909	INFORMATIONAL AND INSTRUCTIONA		332,270	287,718	33,540	40	2,150	11	42	35	260	4
909	INFORM AND INSTRUC -LOAD MGMT		0									
910	MISCELLANEOUS CUSTOMER SERVICE		649,309	562,248	65,542	78	4,201	22	82	69	508	8
911	DEMONSTRATION AND SELLING EXP		0									
912	DEMONSTRATION AND SELLING EXP		0									
913	ADVERTISING EXPENSES		57,093	49,438	5,763	7	369	2	7	6	45	1
915	MDSE-JOBBING-CONTRACT		0									
916	MISC SALES EXPENSE		0									
	Sub-total		5,380,418	4,658,996	543,107	650	34,808	182	676	572	4,211	65
	General Expenses											
920	ADMIN. & GEN. SALARIES-		$13,327,243	6,047,292	1,716,948	130,018	1,867,484	288,831	280,097	90,688	480,866	392,126
921	OFFICE SUPPLIES AND EXPENSES		6,596,133	2,993,023	849,780	64,351	924,285	133,054	138,630	44,884	238,048	194,077
922	ADMINISTRATIVE EXPENSES TRANSFERRED		-1,911,957	-867,559	-246,317	-18,653	-267,914	-38,567	-40,183	-13,010	-69,001	-56,255
923	OUTSIDE SERVICES EMPLOYED		4,480,744	2,033,155	577,254	43,713	627,866	90,383	94,171	30,490	161,705	131,836
924	PROPERTY INSURANCE		3,126,943	1,333,241	381,770	32,053	459,677	68,218	69,860	22,069	118,822	93,684
925	INJURIES AND DAMAGES - INSURAN		2,160,289	980,240	278,310	21,075	302,711	43,576	45,403	14,700	77,963	63,562
926	EMPLOYEE BENEFITS		22,184,705	10,066,403	2,858,055	216,430	3,108,638	447,499	466,254	150,957	800,623	652,738
927	FRANCHISE REQUIREMENTS		26,016	11,092	3,176	267	3,824	551	581	184	989	779
928	REGULATORY COMMISSION FEES		653,611	278,682	79,800	6,700	96,084	13,841	14,603	4,613	24,837	19,582
929	DUPLICATE CHARGES-CR		-32,795	-14,881	-4,225	-320	-4,595	-662	-689	-223	-1,184	-965
930	MISCELLANEOUS GENERAL EXPENSES		921,538	418,152	118,722	8,990	129,131	18,589	19,368	6,271	33,257	27,114
931	RENTS AND LEASES		1,249,895	624,199	152,580	13,125	187,073	27,138	28,521	9,033	48,402	39,119
935	MAINTENANCE OF GENERAL PLANT		4,922,918	2,064,643	600,962	51,695	736,818	106,881	112,338	35,578	190,638	154,079
	Sub-total		57,705,282	25,867,683	7,366,816	569,445	8,171,062	1,177,332	1,226,952	396,232	2,106,066	1,711,477
	TOTAL O & M EXPENSES		617,893,122	243,462,157	75,350,602	7,011,919	97,542,964	14,580,293	15,100,551	4,892,000	25,504,421	23,146,669
	Depreciation Expense											
	Steam Production		$57,680,730	21,775,978	7,035,715	692,322	9,555,801	1,437,248	1,481,530	475,463	2,484,680	2,268,356
	Hydraulic Production		$702,679	265,280	85,711	8,434	116,411	17,509	18,048	5,792	30,269	27,634
	Other Production		$7,423,757	2,802,662	905,527	89,105	1,229,873	184,980	190,679	61,194	319,789	291,947
	Transmission - Kentucky System Property		$6,076,139	2,293,901	741,148	72,930	1,006,617	151,401	156,066	50,086	261,738	238,951
	Transmission - Virginia Property		$0	0	0	0	0	0	0	0	0	0
	Distribution		$25,989,528	15,140,068	3,182,533	120,832	2,289,870	239,535	302,799	84,942	565,708	399
	General & Common Plant		$5,173,681	2,169,811	631,574	54,329	774,350	112,328	118,058	37,391	200,349	161,927
	Intangible Plant		$5,216,787	2,226,008	638,925	53,414	786,238	110,342	118,433	36,777	198,056	155,967
	TOTAL DEPRECIATION EXPENSES		$108,263,300	$46,673,705	$13,219,132	$1,091,365	$15,719,160	$2,253,340	$2,383,613	$751,645	$4,060,689	$3,145,181
	Other Expenses											
	Regulatory Credits	-$1,558,535										
	Production		-$1,539,331	-581,138	-187,763	-18,476	-255,017	-38,355	-39,538	-12,689	-66,309	-60,538

Louisville Gas and Electric
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Acct. No.	Account Description		Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP-Pri	LP-Sec	LP-TOD Trans
	Transmission		-$1,999	-755	-244	-24	-331	-50	-51	-16	-86	-78
	Distribution		-$15,205	-8,858	-1,862	-71	-1,328	-140	-177	-50	-331	0
	Accretion Expense	$1,389,410	$1,372,760	518,253	167,445	16,477	227,421	34,205	35,259	11,316	59,134	53,985
	Production		$1,620	687	222	22	302	45	47	15	78	72
	Transmission		$14,830	8,639	1,816	69	1,295	137	173	48	323	0
	Distribution		$17,703,456	7,548,257	2,161,426	181,473	2,602,499	374,699	395,519	124,947	672,720	530,400
	Property Taxes & Other		$3,910,848	1,687,476	477,478	40,089	574,915	82,818	87,374	27,602	148,610	117,170
	Amortization of Investment Tax Credit		-$458,255	-194,068	-65,704	-4,684	-67,148	-9,679	-10,208	-3,227	-17,363	-13,754
	Gain on Disposition of Allowances		$45,715,737	19,445,205	5,581,415	469,323	6,728,097	969,817	1,022,851	323,326	1,739,723	1,378,126
	Interest		$0									
	Other Deductions		$66,706,661	$28,403,699	$8,144,230	$684,198	$9,810,705	$1,413,697	$1,491,248	$471,272	$2,538,500	$2,005,385
	Total Other Expenses											
	TOTAL EXPENSES		$792,883,083	$318,539,561	$98,713,984	$8,787,482	$123,072,829	$18,247,330	$18,975,412	$6,114,917	$32,101,510	$28,297,236
	Assignment of Innteruptible Credit		-$6,266,793									-2,391,305
	Allocation of Innteruptible Credit		$6,266,793	2,822,318	814,344	65,325	1,062,405	128,637	136,689	42,306	257,629	167,751
	Calculation of Taxable Income and Allocation of Income Taxes:											
	Total Operating Revenue		$932,384,516	$373,638,974	$132,330,260	$10,108,726	$152,499,710	$19,884,331	$21,868,647	$7,079,501	$38,755,862	$28,577,022
	Operating Expenses		$748,703,681	$302,507,423	$92,136,762	$8,402,055	$117,663,812	$17,444,696	$18,129,016	$5,846,652	$30,686,141	$24,756,170
	Interest Expense		$45,715,737	$19,445,205	$5,581,415	$469,323	$6,728,097	$969,817	$1,022,851	$323,328	$1,739,723	$1,378,126
	Taxable Income		$137,954,899	$51,686,345	$34,612,084	$1,237,348	$28,107,800	$1,469,818	$2,716,780	$909,523	$6,329,998	$2,442,726
	Income Taxes											
	State & Federal Income Taxes		$42,796,679	16,033,092	10,736,660	383,825	8,719,033	455,937	842,744	282,134	1,963,564	757,733

Louisville Gas and Electric
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Acct. No.	Account Description		LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
O & M Expenses													
	Steam Production O&M												
500	OPERATION SUPERVISION & ENGINEERING		275,594	6,768	22,920	34,020	9,544	7,173	526	8,051	503	2,245	15,737
501	FUEL		40,140,879	972,711	3,297,473	4,735,082	1,299,928	1,158,169	84,747	1,297,664	83,108	317,097	2,220,044
502	STEAM EXPENSES		3,568,693	87,809	297,288	443,862	124,986	91,014	6,671	102,153	7,271	29,215	204,839
505	ELECTRIC EXPENSES		98,448	2,424	8,208	12,252	3,450	2,512	184	2,820	201	806	5,654
506	MISC. STEAM POWER EXPENSES		2,217,525	54,593	184,833	275,963	77,708	56,587	4,146	63,512	4,520	18,164	127,355
507	RENTS		6,690	165	558	833	234	171	13	192	14	55	384
509	ALLOWANCES		440	11	37	55	15	11	1	13	1	4	25
510	MAINTENANCE SUPERVISION & ENGINEERING		327,011	7,929	28,877	38,649	10,621	9,381	688	10,529	677	2,587	18,110
511	MAINTENANCE OF STRUCTURES		297,514	7,325	24,798	37,025	10,426	7,592	556	8,521	608	2,437	17,087
512	MAINTENANCE OF BOILER PLANT		5,571,877	135,020	457,716	657,265	180,440	160,488	11,764	180,126	11,536	44,016	308,160
513	MAINTENANCE OF ELECTRIC PLANT		1,053,888	25,538	86,574	124,317	34,129	30,355	2,225	34,070	2,182	8,325	58,287
514	MAINTENANCE OF MISC STEAM PLANT		186,456	4,518	15,317	21,995	6,038	5,370	394	6,028	386	1,473	10,312
	Sub-total		53,743,012	1,304,810	4,422,595	6,381,296	1,757,517	1,526,821	111,916	1,713,677	111,065	426,422	2,985,994
	Hydraulic Production O&M												
535	OPERATION SUPERVISION & ENGINEERING		6,929	171	578	862	243	177	13	198	14	57	398
536	WATER FOR POWER		5,091	125	424	634	178	130	10	146	10	42	292
537	HYDRAULIC EXPENSES												
538	ELECTRIC EXPENSES		21,078	519	1,757	2,623	739	538	39	604	43	173	1,211
539	MISC. HYDRAULIC POWER EXPENSES		16,929	417	1,411	2,107	593	432	32	485	35	139	972
540	RENTS		31,156	767	2,597	3,877	1,092	795	58	892	64	255	1,789
541	MAINTENANCE SUPERVISION & ENGINEERING		623	15	51	75	21	17	1	19	1	5	35
542	MAINTENANCE OF STRUCTURES		24,789	610	2,066	3,085	869	633	46	710	51	203	1,424
543	MAINT. OF RESERVES, DAMS, AND WATERWAYS		11,408	281	951	1,420	400	291	21	327	23	93	655
544	MAINTENANCE OF ELECTRIC PLANT		39,518	958	3,246	4,662	1,280	1,138	83	1,278	82	312	2,188
545	MAINTENANCE OF MISC HYDRAULIC PLANT												
	Sub-total		157,521	3,863	13,081	19,344	5,414	4,151	304	4,659	322	1,279	8,962
	Other Power Generation Operation Expense												
546	OPERATION SUPERVISION & ENGINEERING		3,762	93	314	468	132	96	7	108	8	31	216
547	FUEL		4,212,832	102,087	346,074	496,950	136,429	121,341	8,894	136,191	8,722	33,280	232,996
548	GENERATION EXPENSE		120,777	2,973	10,067	15,030	4,232	3,082	226	3,459	246	989	6,936
549	MISC OTHER POWER GENERATION		4,940	122	412	615	173	126	9	141	10	40	284
550	RENTS		2,981	73	248	371	104	76	6	85	6	24	171
551	MAINTENANCE SUPERVISION & ENGINEERING		2,152	53	179	268	75	55	4	62	4	18	124
552	MAINTENANCE OF STRUCTURES		11,999	295	1,000	1,493	420	306	22	344	24	98	689
553	MAINTENANCE OF GENERATING & ELEC PLANT		242,891	5,980	20,245	30,227	8,512	6,198	454	6,957	495	1,990	13,949
554	MAINTENANCE OF MISC OTHER POWER GEN PLT		14,412	355	1,201	1,794	505	368	27	413	29	118	828
	Sub-total		4,616,747	112,031	379,740	547,216	150,583	131,848	9,650	147,760	9,546	38,588	256,194
	Other Power Supply Expense												
555	PURCHASED POWER	81,802,192											
	Demand		1,404,349	34,574	117,054	174,768	49,212	35,836	2,627	40,222	2,863	11,503	80,653
	Energy		9,924,278	240,489	815,255	1,170,679	321,389	285,847	20,953	320,830	20,547	78,398	548,875
555	PURCHASED POWER OPTIONS												
555	BROKERAGE FEES												
555	MISO TRANSMISSION EXPENSES												

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Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
556	SYSTEM CONTROL AND LOAD DISPATCH	132,360	3,259	11,032	16,472	4,638	3,378	248	3,781	270	1,084	7,802
557	OTHER EXPENSES	-74,457	-1,833	-6,206	-9,266	-2,609	-1,900	-139	-2,132	-152	-610	-4,276
558	DUPLICATE CHARGES	-387,143	-9,381	-31,803	-45,668	-12,537	-11,151	-817	-12,515	-802	-3,058	-21,411
	Sub-total	10,999,387	267,107	905,332	1,306,983	360,092	312,010	22,870	350,194	22,727	87,317	611,442
	Transmission Expenses											
560	OPERATION SUPERVISION AND ENG	82,337	2,273	7,698	11,491	3,236	2,356	173	2,645	188	756	5,303
561	LOAD DISPATCHING	92,671	2,288	7,741	11,557	3,254	2,370	174	2,660	189	761	5,334
562	STATION EXPENSES	161,100	3,968	13,428	20,048	5,645	4,111	301	4,614	328	1,320	9,252
563	OVERHEAD LINE EXPENSES	11,349	279	946	1,412	398	290	21	325	23	93	652
565	TRANSMISSION OF ELECTRICITY BY OTHERS	419,531	10,328	34,968	52,209	14,701	10,706	785	12,016	855	3,436	24,094
566	MISC. TRANSMISSION EXPENSES	486,197	11,970	40,625	60,606	17,038	12,407	909	13,925	991	3,982	27,923
567	RENTS	2,935	72	245	365	103	75	5	84	6	24	169
568	MAINTENACE SUPERVISION AND ENG	0	0	0	0	0	0	0	0	0	0	0
569	STRUCTURES	3,970	98	331	494	139	101	7	114	8	33	228
570	MAINT OF STATION EQUIPMENT	130,064	3,202	10,841	16,186	4,558	3,319	243	3,725	265	1,065	7,470
571	MAINT OF OVERHEAD LINES	101,369	2,496	8,449	12,615	3,552	2,587	190	2,903	207	830	5,822
572	UNDERGROUND LINES	0	0	0	0	0	0	0	0	0	0	0
573	MISC PLANT	318	8	26	39	11	8	1	9	1	3	18
575	MARKET FACILITATION, MONITORING AND COMPLIANCE	983	24	82	122	34	25	2	28	2	8	56
	Sub-total	1,503,023	37,003	125,279	187,046	52,670	38,354	2,811	43,046	3,064	12,311	86,320
	Distribution Expense - Operating											
580	OPERATION SUPERVISION AND ENGI	43,006	1,602	3,155	6,155	1,920	13,199	554	17,592	2,585	390	3,020
581	LOAD DISPATCHING	33,036	821	2,487	4,855	1,494	1,361	99	1,528	48	300	1,999
582	STATION EXPENSES	92,665	2,307	6,992	13,648	4,201	3,827	280	4,295	135	842	5,618
583	OVERHEAD LINE EXPENSES	223,590	6,579	16,826	32,840	10,110	28,342	816	35,050	711	2,037	15,583
584	UNDERGROUND LINE EXPENSES	27,392	834	2,062	4,025	1,239	2,209	99	2,641	64	249	1,963
585	STREET LIGHTING EXPENSE	0	0	0	0	0	7,752	0	10,744	0	0	0
586	METER EXPENSES	15,785	4,461	211	370	421	0	4,829	0	29,467	131	1,441
586	METER EXPENSES - LOAD MANAGEMENT											
587	CUSTOMER INSTALLATIONS EXPENSE	-9,598	-331	-721	-1,407	-434	-9,026	-48	-12,338	-86	-87	-742
588	MISCELLANEOUS DISTRIBUTION EXP	128,196	4,419	9,627	18,789	5,791	120,561	635	164,799	1,154	1,165	9,910
588	MISC DISTR EXP -- MAPPIN											
589	RENTS	613	21	46	90	28	577	3	789	6	6	47
590	MAINTENANCE SUPERVISION AND EN	505	15	38	74	23	148	2	195	2	5	36
591	STRUCTURES	78,894	1,960	5,940	11,595	3,569	3,251	237	3,649	115	716	4,773
592	MAINTENANCE OF STATION EQUIPME	72,195	1,794	5,436	10,610	3,266	2,975	217	3,339	105	655	4,368
593	MAINTENANCE OF OVERHEAD LINES	622,229	18,308	46,824	91,392	28,135	78,874	2,270	97,540	1,978	5,669	43,366
594	MAINTENANCE OF UNDERGROUND LIN	95,793	2,917	7,211	14,075	4,332	7,727	346	9,237	222	870	6,866
595	MAINTENANCE OF LINE TRANSFORME	0	330	0	0	0	1,002	31	1,233	26	0	656
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	0	0	0	0	0	332,352	0	460,604	0	0	0
597	MAINTENANCE OF METERS											
598	MISCELLANEOUS DISTRIBUTION EXPENSES	11,400	393	856	1,671	515	10,721	56	14,655	103	104	881
	Sub-total	1,435,901	46,432	106,989	208,784	64,611	605,852	10,428	815,552	36,632	13,050	99,786
	Customer Accounts Expense											
901	SUPERVISION/CUSTOMER ACCTS	1,359	384	30	30	30	4,813	19	6,271	116	4	47
902	METER READING EXPENSES	4,371	1,235	95	95	95	15,473	62	20,162	380	14	152
903	RECORDS AND COLLECTION	9,832	2,778	214	214	214	34,806	139	45,353	855	32	342

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Acct. No.	Account Description		LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
904	UNCOLLECTIBLE ACCOUNTS		1,752	495	38	38	38	6,204	25	8,084	152	6	61
905	MISC CUST ACCOUNTS		534	151	12	12	12	1,892	8	2,465	46	2	19
	Sub-total		17,848	5,044	388	388	388	63,187	252	82,338	1,552	58	621
	Customer Service & Information Expense												
907	SUPERVISION		18	4	0	0	0	1,410	40	1,837	243	1	11
908	CUSTOMER ASSISTANCE EXPENSES		467	132	10	10	10	42,390	1,198	55,231	7,309	30	325
908	CUSTOMER ASSISTANCE EXP-INCENTIVES												
909	INFORMATIONAL AND INSTRUCTIONA		37	10	1	1	1	3,352	95	4,367	578	2	26
909	INFORM AND INSTRUC -LOAD MGMT												
910	MISCELLANEOUS CUSTOMER SERVICE		72	20	2	2	2	6,550	185	8,535	1,129	5	50
911	DEMONSTRATION AND SELLING EXP												
912	DEMONSTRATION AND SELLING EXP												
913	ADVERTISING EXPENSES		6	2	0	0	0	576	16	750	99	0	4
915	MDSE-JOBBING-CONTRACT												
916	MISC SALES EXPENSE												
	Sub-total		598	169	13	13	13	54,276	1,534	70,720	9,358	39	416
	General Expenses												
920	ADMIN. & GEN. SALARIES-		1,409,318	36,040	115,757	174,161	49,107	73,890	3,635	90,876	7,235	11,488	81,287
921	OFFICE SUPPLIES AND EXPENSES		697,522	17,838	57,292	86,199	24,305	36,571	1,799	44,978	3,581	5,686	40,232
922	ADMINISTRATIVE EXPENSES TRANSFERRED		-202,184	-5,170	-16,607	-24,986	-7,045	-10,600	-521	-13,037	-1,038	-1,648	-11,662
923	OUTSIDE SERVICES EMPLOYED		473,826	12,117	38,919	58,555	16,510	24,843	1,222	30,553	2,432	3,862	27,330
924	PROPERTY INSURANCE		343,166	8,768	28,337	43,419	12,352	38,275	741	50,379	924	2,840	20,349
925	INJURIES AND DAMAGES - INSURAN		228,444	5,842	18,764	28,231	7,960	11,977	589	14,731	1,173	1,862	13,176
926	EMPLOYEE BENEFITS		2,345,969	59,993	192,690	289,911	81,744	122,999	6,051	151,274	12,043	19,123	135,312
927	FRANCHISE REQUIREMENTS		2,855	73	236	361	103	318	6	419	8	24	169
928	REGULATORY COMMISSION FEES		71,730	1,832	5,923	9,076	2,582	8,000	155	10,530	193	594	4,254
929	DUPLICATE CHARGES-CR		-3,468	-89	-285	-429	-121	-182	-9	-224	-18	-28	-200
930	MISCELLANEOUS GENERAL EXPENSES		97,450	2,492	8,004	12,043	3,396	5,109	251	6,284	500	794	5,621
931	RENTS AND LEASES		140,880	3,577	11,651	17,776	5,049	13,708	298	17,928	384	1,164	8,311
935	MAINTENANCE OF GENERAL PLANT		554,878	14,090	45,690	70,016	19,885	53,992	1,172	70,613	1,434	4,584	32,732
	Sub-total		6,160,387	157,401	506,571	764,333	215,827	378,900	15,389	475,304	28,831	50,343	356,911
	TOTAL O & M EXPENSES		78,634,424	1,933,859	6,459,989	9,415,402	2,607,114	3,115,202	175,155	3,703,250	223,096	627,407	4,406,645
	Depreciation Expense												
	Steam Production		7,528,769	185,351	627,531	936,928	263,827	182,118	14,082	215,630	15,347	61,668	432,385
	Hydraulic Production		91,717	2,258	7,645	11,414	3,214	2,340	172	2,627	187	751	5,267
	Other Production		968,985	23,855	80,766	120,587	33,956	24,726	1,812	27,753	1,975	7,937	55,650
	Transmission - Kentucky System Property		793,087	19,525	66,105	98,697	27,792	20,238	1,483	22,715	1,617	6,496	45,548
	Transmission - Virginia Property		0	0	0	0	0	0	0	0	0	0	0
	Distribution		1,125,493	38,800	84,516	164,958	50,840	1,058,456	5,575	1,446,845	10,129	10,230	87,002
	General & Common Plant		583,143	14,807	48,228	73,582	20,898	56,742	1,232	74,210	1,607	4,818	34,400
	Intangible Plant		571,785	14,611	47,211	72,355	20,586	64,168	1,237	84,483	1,543	4,732	33,915
	TOTAL DEPRECIATION EXPENSES		$11,662,978	$299,208	$982,001	$1,478,521	$421,113	$1,418,789	$26,594	$1,874,262	$32,305	$96,632	$694,167
	Other Expenses												
	Regulatory Credits	-$1,558,535											
	Production		-200,921	-4,946	-16,747	-25,004	-7,041	-5,127	-376	-5,755	-410	-1,646	-11,539

Louisville Gas and Electric
Electric Cost of Service Study
(Expenses)

Acct. No.	Account Description		LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
	Transmission		-261	-6	-22	-32	-9	-7	0	-7	-1	-2	-15
	Distribution		-658	-23	-49	-97	-30	-619	-3	-848	-6	-6	-51
	Accretion Expense	$1,389,410											
	Production		170,179	4,411	14,935	22,298	6,279	4,672	335	5,132	365	1,468	10,290
	Transmission		238	6	20	30	8	6	0	7	0	2	14
	Distribution		642	22	48	94	29	604	3	826	6	6	50
	Property Taxes & Other		1,942,862	49,632	160,431	245,822	69,933	216,694	4,197	285,223	5,232	16,078	115,210
	Amortization of Investment Tax Credit		429,195	10,964	35,441	54,304	15,449	47,870	927	63,008	1,156	3,552	25,451
	Gain on Disposition of Allowances		-50,237	-1,282	-4,147	-6,343	-1,803	-5,601	-109	-7,372	-137	-415	-2,974
	Interest		5,033,672	128,484	415,549	635,513	180,614	561,203	10,918	738,630	13,721	41,596	297,954
	Other Deductions												
	Total Other Expenses		$7,333,712	$187,261	$805,458	$926,586	$263,429	$819,598	$15,893	$1,078,845	$19,927	$60,632	$434,390
	TOTAL EXPENSES		$97,631,114	$2,420,328	$8,027,447	$11,820,509	$3,291,657	$5,353,587	$216,642	$8,656,357	$275,328	$784,670	$5,535,202
	Assignment of Innteruptible Credit		-3,875,488										
	Allocation of Innteruptible Credit		591,298	15,850	19,999	81,236	12,015	0	0	0	1,078	5,933	41,880
	Calculation of Taxable Income and Allocation of Income Taxes:												
	Total Operating Revenue		$100,266,170	$2,830,994	$7,781,860	$11,613,636	$3,075,165	$6,222,827	$207,196	$8,619,655	$280,300	$802,735	$5,941,047
	Operating Expenses		$89,515,092	$2,312,770	$7,648,716	$11,291,365	$3,130,138	$4,798,137	$206,103	$5,924,336	$263,102	$750,662	$5,290,733
	Interest Expense		$5,033,672	$128,484	$415,549	$635,513	$180,614	$561,203	$10,918	$738,630	$13,721	$41,596	$297,954
	Taxable Income		$5,717,405	$389,740	-$282,405	-$313,342	-$235,586	$863,487	-$9,825	$1,956,689	$3,478	$10,477	$352,360
	Income Taxes												
	State & Federal Income Taxes		1,773,538	120,897	-87,602	-97,199	-73,079	267,853	-3,048	606,964	1,079	3,250	109,302

Louisville Gas and Electric
Electric Cost of Service Study
(Salaries and Wages)

Acct. No. Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP-Pri	LP-Sec	LP-TOD Trans
Labor O & M Expenses										
Labor Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	$1,077,777	403,947	131,130	12,978	178,987	26,960	27,798	8,935	46,627	42,832
501 FUEL	$2,704,814	970,634	324,190	33,179	455,563	69,201	71,453	23,178	119,957	114,050
502 STEAM EXPENSES	$11,190,363	4,224,653	1,384,985	134,314	1,853,876	278,834	287,425	92,242	482,041	440,073
505 ELECTRIC EXPENSES	$526,289	198,688	64,195	6,317	87,169	13,114	13,518	4,338	22,671	20,697
506 MISC. STEAM POWER EXPENSES	$4,082,740	1,541,341	498,000	49,004	678,376	101,731	104,865	33,654	175,870	160,558
507 RENTS	$0	0	0	0	0	0	0	0	0	0
Total Steam Power Operation Expenses	$19,581,983	$7,339,264	$2,382,480	$235,792	$3,251,991	$489,840	$505,059	$162,346	$847,166	$778,210
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	$1,482,893	533,182	177,853	18,176	249,606	37,902	39,133	12,688	65,695	62,369
511 MAINTENANCE OF STRUCTURES	$291,815	110,168	35,595	3,503	48,344	7,271	7,495	2,405	12,570	11,476
512 MAINTENANCE OF BOILER PLANT	$5,821,256	2,088,983	697,716	71,408	980,456	148,934	153,780	49,879	258,170	245,456
513 MAINTENANCE OF ELECTRIC PLANT	$1,610,447	577,916	193,023	19,755	271,243	41,203	42,543	13,799	71,423	67,905
514 MAINTENANCE OF MISC STEAM PLANT	$52,464	18,827	6,288	644	8,836	1,342	1,386	450	2,327	2,212
Total Steam Power Generation Maintenance Expense	$9,258,874	$3,329,076	$1,110,474	$113,485	$1,558,485	$236,652	$244,338	$79,222	$410,184	$389,418
Total Steam Power Generation Expense	$28,840,857	$10,668,339	$3,492,954	$349,276	$4,810,476	$726,492	$749,397	$241,568	$1,257,350	$1,167,627
Hydraulic Power Generation Operation Expenses										
535 OPERATION SUPERVISION & ENGINEERING	$41,501	15,668	5,062	498	6,875	1,034	1,066	342	1,788	1,632
536 WATER FOR POWER	$0	0	0	0	0	0	0	0	0	0
537 HYDRAULIC EXPENSES	$0	0	0	0	0	0	0	0	0	0
538 ELECTRIC EXPENSES	$133,065	50,235	16,231	1,597	22,044	3,316	3,418	1,097	5,732	5,233
539 MISC. HYDRAULIC POWER EXPENSES	$10,772	4,067	1,314	129	1,785	268	277	89	464	424
540 RENTS	$0	0	0	0	0	0	0	0	0	0
Total Hydraulic Power Operation Expenses	$185,338	$69,970	$22,607	$2,225	$30,704	$4,618	$4,760	$1,528	$7,984	$7,289
Hydraulic Power Generation Maintenance Expenses										
541 MAINTENANCE SUPERVISION & ENGINEERING	$3,574	1,307	431	43	598	91	93	30	157	147
542 MAINTENANCE OF STRUCTURES	$28,335	10,697	3,456	340	4,694	706	728	234	1,221	1,114
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	$45,458	17,162	5,545	546	7,531	1,133	1,168	375	1,958	1,788
544 MAINTENANCE OF ELECTRIC PLANT	$126,469	45,384	15,158	1,551	21,301	3,236	3,341	1,084	5,609	5,333
545 MAINTENANCE OF MISC HYDRAULIC PLANT	$0	0	0	0	0	0	0	0	0	0
Total Hydraulic Power Generation Maint. Expense	$203,838	$74,550	$24,590	$2,481	$34,124	$5,165	$5,330	$1,722	$8,944	$8,382
Total Hydraulic Power Generation Expense	$389,175	$144,520	$47,197	$4,705	$64,829	$9,783	$10,090	$3,250	$16,928	$15,670
Other Power Generation Operation Expense										
546 OPERATION SUPERVISION & ENGINEERING	$20,122	7,596	2,454	242	3,334	501	517	166	867	791
547 FUEL	$0	0	0	0	0	0	0	0	0	0
548 GENERATION EXPENSE	$183,969	69,453	22,440	2,208	30,478	4,584	4,725	1,516	7,925	7,235
549 MISC OTHER POWER GENERATION	$0	0	0	0	0	0	0	0	0	0

Louisville Gas and Electric
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Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
550	RENTS	$0	0	0	0	0	0	0	0	0	0
	Total Other Power Generation Expenses	$204,091	$77,050	$24,894	$2,450	$33,811	$5,085	$5,242	$1,682	$8,791	$8,026
	Other Power Generation Maintenance Expense										
551	MAINTENANCE SUPERVISION & ENGINEERING	$15,085	5,695	1,840	181	2,499	376	387	124	650	593
552	MAINTENANCE OF STRUCTURES	$45,406	17,142	5,538	545	7,522	1,131	1,166	374	1,956	1,786
553	MAINTENANCE OF GENERATING & ELEC PLANT	$268,788	101,474	32,788	3,226	44,529	6,697	6,904	2,216	11,578	10,570
554	MAINTENANCE OF MISC OTHER POWER GEN PLT	$33,195	12,532	4,049	398	5,499	827	853	274	1,430	1,305
	Total Other Power Generation Maintenance Expense	$362,474	$136,843	$44,213	$4,351	$60,050	$9,032	$9,310	$2,988	$15,614	$14,255
	Total Other Power Generation Expense	$566,564	$213,893	$69,108	$6,800	$93,861	$14,117	$14,552	$4,670	$24,406	$22,281
	Total Production Expense	$29,796,596	$11,026,752	$3,609,259	$360,782	$4,969,165	$750,392	$774,039	$249,488	$1,298,684	$1,205,578
	Purchased Power										
555	PURCHASED POWER	$0									
556	SYSTEM CONTROL AND LOAD DISPATCH	710,294	268,154	86,639	8,525	117,672	17,699	18,244	5,855	30,597	27,933
557	OTHER EXPENSES	265	100	32	3	44	7	7	2	11	10
	Total Purchased Power Labor	$710,558	$268,254	$86,672	$8,529	$117,716	$17,705	$18,251	$5,857	$30,608	$27,943
	Transmission Labor Expenses										
560	OPERATION SUPERVISION AND ENG	$474,328	179,071	57,857	5,693	78,581	11,819	12,183	3,910	20,432	18,653
561	LOAD DISPATCHING	536,971	202,721	65,498	6,445	88,958	13,380	13,792	4,426	23,131	21,117
562	STATION EXPENSES	559,972	211,404	68,304	6,721	92,769	13,953	14,383	4,616	24,122	22,022
563	OVERHEAD LINE EXPENSES	7,204	2,720	879	86	1,193	179	185	59	310	283
566	MISC. TRANSMISSION EXPENSES	142,661	53,858	17,401	1,712	23,634	3,555	3,664	1,176	6,145	5,610
569	MAINTENACE OF STRUCTURES	3,759	1,419	458	45	623	94	97	31	162	148
570	MAINT OF STATION EQUIPMENT	223,429	84,350	27,253	2,682	37,015	5,567	5,739	1,842	9,625	8,787
571	MAINT OF OVERHEAD LINES	5,995	2,263	731	72	993	149	154	49	258	236
573	MAINT OF MISC. TRANSMISSION PLANT	745	281	91	9	123	19	19	6	32	29
	Total Transmission Labor Expenses	$1,955,063	$738,087	$238,473	$23,466	$323,890	$48,715	$50,216	$16,116	$84,217	$76,885
	Distribution Operation Labor Expense										
580	OPERATION SUPERVISION AND ENGI	$772,745	492,999	138,683	2,909	51,308	6,161	6,472	2,254	13,612	91
581	LOAD DISPATCHING	251,408	122,222	32,477	2,663	36,195	5,259	5,251	1,850	9,277	0
582	STATION EXPENSES	194,629	94,619	25,143	2,061	28,021	4,071	4,065	1,432	7,182	0
583	OVERHEAD LINE EXPENSES	2,089,509	1,375,239	252,788	11,132	178,603	21,646	24,657	7,749	44,856	8
584	UNDERGROUND LINE EXPENSES	93,338	55,824	11,951	622	10,195	1,225	1,443	432	2,582	0
585	STREET LIGHTING EXPENSE	7,108	0	0	0	0	0	0	0	0	0
586	METER EXPENSES	2,224,315	1,514,790	613,402	830	46,307	4,065	1,337	2,320	17,083	679
586	METER EXPENSES - LOAD MANAGEMENT	0									
587	CUSTOMER INSTALLATIONS EXPENSE	0									
588	MISCELLANEOUS DISTRIBUTION EXP	1,116,394	650,350	136,707	5,190	97,504	10,289	13,007	3,649	24,300	17
589	RENTS	0									
	Total Distribution Operation Labor Expense	$6,749,446	$4,306,043	$1,211,132	$25,407	$448,130	$53,816	$56,533	$19,687	$118,693	$796

Louisville Gas and Electric
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Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP- Pri	LP-Sec	LP-TOD Trans
	Distribution Maintenance Labor Expense										
590	MAINTENANCE SUPERVISION AND EN	$2,889	1,819	349	16	260	31	36	11	65	0
591	MAINTENANCE OF STRUCTURES	10,923	5,310	1,411	116	1,573	228	228	80	403	0
592	MAINTENANCE OF STATION EQUIPME	153,675	74,709	19,852	1,628	22,124	3,214	3,210	1,131	5,671	0
593	MAINTENANCE OF OVERHEAD LINES	1,888,160	1,229,555	226,009	9,953	159,683	18,531	22,313	6,928	40,104	7
594	MAINTENANCE OF UNDERGROUND LIN	276,603	165,431	35,417	1,843	30,212	3,631	4,277	1,282	7,652	1
595	MAINTENANCE OF LINE TRANSFORME	116,235	85,807	16,394	0	8,967	0	1,167	0	2,195	0
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	50,878	0	0	0	0	0	0	0	0	0
597	MAINTENANCE OF METERS	0									
598	MAINTENANCE OF MISC DISTR PLANT	42,413	24,708	5,194	197	3,704	391	494	139	923	1
	Total Distribution Maintenance Labor Expense	$2,521,775	$1,587,338	$304,626	$13,752	$226,522	$27,027	$31,726	$9,571	$57,014	$8
	Total Distribution Operation and Maintenance Labor Expenses	9,271,223	5,893,381	1,515,758	39,159	674,652	80,843	88,259	29,258	175,907	804
	Transmission and Distribution Labor Expenses	11,226,288	8,631,468	1,754,230	62,625	998,542	129,558	138,474	45,373	260,124	77,689
	Production, Transmission and Distribution Labor Expenses	$41,733,441	$17,926,474	$5,450,161	$431,936	$6,085,424	$897,658	$930,784	$300,718	$1,589,416	$1,311,211
	Customer Accounts Expense										
901	SUPERVISION/CUSTOMER ACCTS	$463,272	372,613	47,780	520	27,838	291	1,081	457	3,388	104
902	METER READING EXPENSES	215,848	173,808	22,262	242	12,970	138	504	213	1,569	48
903	RECORDS AND COLLECTION	1,902,071	1,529,649	196,173	2,134	114,296	1,195	4,439	1,878	13,828	427
904	UNCOLLECTIBLE ACCOUNTS	0									
905	MISC CUST ACCOUNTS	96,696	77,773	9,973	108	5,811	61	226	95	703	22
	Total Customer Accounts Labor Expense	$2,677,887	$2,153,843	$276,188	$3,004	$160,915	$1,682	$6,249	$2,644	$19,468	$601
	Customer Service Expense										
907	SUPERVISION	$75,987	65,798	7,670	9	492	3	10	8	59	1
908	CUSTOMER ASSISTANCE EXPENSES	80,721	69,868	8,148	10	522	3	10	9	63	1
908	CUSTOMER ASSISTANCE EXP-LOAD MGMT	0									
909	INFORMATIONAL AND INSTRUCTIONA	1,150	995	116	0	7	0	0	0	1	0
909	INFORM AND INSTRUC -LOAD MGMT	0									
910	MISCELLANEOUS CUSTOMER SERVICE	15,640	13,543	1,579	2	101	1	2	2	12	0
911	DEMONSTRATION AND SELLING EXP	0									
912	DEMONSTRATION AND SELLING EXP	0									
913	WATER HEATER - HEAT PUMP PROGRAM	0									
915	MDSE-JOBBING-CONTRACT	0									
916	MISC SALES EXPENSE	0									
	Total Customer Service Labor Expense	$173,497	$150,234	$17,513	$21	$1,122	$8	$22	$18	$136	$2
	Sub-Total Labor Exp	44,584,824	20,230,551	5,743,862	434,961	6,247,461	899,344	937,035	303,381	1,609,020	1,311,814

Louisville Gas and Electric
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Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP-Pri	LP-Sec	LP-TOD Trans
Administrative and General Expense											
920	ADMIN. & GEN. SALARIES-	$10,137,273	4,599,830	1,305,985	93,897	1,420,488	204,484	213,054	68,680	365,844	298,268
921	OFFICE SUPPLIES AND EXPENSES	$0									
922	ADMIN. EXPENSES TRANSFERRED - CREDIT	-1,068,560	-484,863	-137,663	-10,425	-149,732	-21,554	-22,458	-7,271	-38,563	-31,440
923	OUTSIDE SERVICES EMPLOYED	0									
924	PROPERTY INSURANCE	0									
925	INJURIES AND DAMAGES - INSURAN	45,353	20,579	5,843	442	6,355	915	953	309	1,637	1,334
926	EMPLOYEE BENEFITS	0									
928	REGULATORY COMMISSION FEES	0									
929	DUPLICATE CHARGES-CR	0									
930	MISCELLANEOUS GENERAL EXPENSES	0									
931	RENTS AND LEASES	0									
935	MAINTENANCE OF GENERAL PLANT	2,117,540	888,084	258,497	22,236	316,935	45,974	48,320	15,304	82,001	66,275
	Total Administrative and General Expense	$11,231,606	$5,023,630	$1,432,662	$111,151	$1,594,046	$229,818	$239,870	$77,321	$410,918	$334,437
	Total Operation and Maintenance Expenses	$55,816,431	$25,254,181	$7,176,525	$546,112	$7,841,507	$1,129,162	$1,176,905	$380,702	$2,019,939	$1,646,251
	Operation and Maintenance Expenses Less Purchase Power	$55,816,431	$25,254,181	$7,176,525	$546,112	$7,841,507	$1,129,162	$1,176,905	$380,702	$2,019,939	$1,646,251

Louisville Gas and Electric
Electric Cost of Service Study
(Salaries and Wages)

Acct. No. Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
Labor O & M Expenses											
Labor Expenses											
Steam Power Generation Operation Expenses											
500 OPERATION SUPERVISION & ENGINEERING	142,121	3,490	11,819	17,544	4,922	3,699	271	4,152	290	1,158	8,115
501 FUEL	377,846	9,156	31,039	44,571	12,236	10,883	798	12,215	782	2,985	20,897
502 STEAM EXPENSES	1,460,620	35,959	121,744	181,769	51,184	37,272	2,732	41,833	2,977	11,964	83,685
505 ELECTRIC EXPENSES	68,694	1,691	5,726	8,549	2,407	1,753	128	1,967	140	563	3,945
506 MISC. STEAM POWER EXPENSES	532,899	13,119	44,416	66,317	18,674	13,598	997	15,263	1,086	4,365	30,605
507 RENTS	0	0	0	0	0	0	0	0	0	0	0
Total Steam Power Operation Expenses	$2,582,181	$63,416	$214,748	$318,750	$89,423	$67,205	$4,926	$76,430	$5,277	$21,034	$147,448
Steam Power Generation Maintenance Expenses											
510 MAINTENANCE SUPERVISION & ENGINEERING	206,641	5,010	16,984	24,423	6,711	5,928	435	6,653	428	1,634	11,444
511 MAINTENANCE OF STRUCTURES	38,089	938	3,175	4,740	1,335	972	71	1,091	78	312	2,187
512 MAINTENANCE OF BOILER PLANT	813,195	19,708	66,802	95,925	26,335	23,422	1,717	26,289	1,684	6,424	44,975
513 MAINTENANCE OF ELECTRIC PLANT	224,970	5,452	18,481	26,538	7,285	6,480	475	7,273	466	1,777	12,442
514 MAINTENANCE OF MISC STEAM PLANT	7,329	178	602	865	237	211	15	237	15	58	405
Total Steam Power Generation Maintenance Expense	$1,290,224	$31,283	$106,043	$152,490	$41,903	$37,013	$2,713	$41,543	$2,670	$10,205	$71,454
Total Steam Power Generation Expense	$3,872,405	$94,699	$320,789	$471,240	$131,326	$104,218	$7,639	$116,973	$7,946	$31,240	$218,902
Hydraulic Power Generation Operation Expenses											
535 OPERATION SUPERVISION & ENGINEERING	5,417	133	452	674	190	138	10	155	11	44	311
536 WATER FOR POWER	0	0	0	0	0	0	0	0	0	0	0
537 HYDRAULIC EXPENSES	0	0	0	0	0	0	0	0	0	0	0
538 ELECTRIC EXPENSES	17,368	428	1,448	2,161	609	443	32	497	35	142	997
539 MISC. HYDRAULIC POWER EXPENSES	1,406	35	117	175	49	36	3	40	3	12	81
540 RENTS	0	0	0	0	0	0	0	0	0	0	0
Total Hydraulic Power Operation Expenses	$24,191	$598	$2,016	$3,011	$848	$617	$45	$693	$49	$198	$1,389
Hydraulic Power Generation Maintenance Expenses											
541 MAINTENANCE SUPERVISION & ENGINEERING	487	12	40	59	16	13	1	15	1	4	27
542 MAINTENANCE OF STRUCTURES	3,698	91	308	460	130	94	7	108	8	30	212
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	5,933	146	495	738	208	151	11	170	12	49	341
544 MAINTENANCE OF ELECTRIC PLANT	17,667	428	1,451	2,084	572	509	37	571	37	140	977
545 MAINTENANCE OF MISC HYDRAULIC PLANT	0	0	0	0	0	0	0	0	0	0	0
Total Hydraulic Power Generation Maint. Expense	$27,786	$677	$2,294	$3,341	$926	$768	$56	$862	$57	$222	$1,558
Total Hydraulic Power Generation Expense	$51,977	$1,273	$4,311	$6,352	$1,774	$1,385	$102	$1,555	$107	$421	$2,947
Other Power Generation Operation Expense											
546 OPERATION SUPERVISION & ENGINEERING	2,626	65	219	327	92	67	5	75	5	22	151
547 FUEL	0	0	0	0	0	0	0	0	0	0	0
548 GENERATION EXPENSE	24,013	591	2,001	2,988	841	613	45	688	49	197	1,379
549 MISC OTHER POWER GENERATION	0	0	0	0	0	0	0	0	0	0	0

Louisville Gas and Electric
Electric Cost of Service Study
(Salaries and Wages)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
550	RENTS	0	0	0	0	0	0	0	0	0	0	0
	Total Other Power Generation Expenses	$26,639	$656	$2,220	$3,315	$933	$680	$50	$763	$54	$218	$1,530
	Other Power Generation Maintenance Expense											
551	MAINTENANCE SUPERVISION & ENGINEERING	1,969	48	164	245	69	50	4	56	4	16	113
552	MAINTENANCE OF STRUCTURES	5,927	146	494	738	208	151	11	170	12	49	340
553	MAINTENANCE OF GENERATING & ELEC PLANT	35,083	864	2,924	4,366	1,229	895	66	1,005	72	287	2,015
554	MAINTENANCE OF MISC OTHER POWER GEN PLT	4,333	107	361	539	152	111	8	124	9	35	249
	Total Other Power Generation Maintenance Expense	$47,312	$1,165	$3,943	$5,888	$1,658	$1,207	$88	$1,355	$96	$388	$2,717
	Total Other Power Generation Expense	$73,951	$1,821	$6,164	$9,203	$2,591	$1,887	$138	$2,118	$151	$606	$4,247
	Total Production Expense	$3,998,333	$97,782	$331,264	$486,795	$135,691	$107,491	$7,879	$120,646	$8,204	$32,266	$226,096
	Purchased Power											
555	*PURCHASED POWER*											
556	SYSTEM CONTROL AND LOAD DISPATCH	92,711	2,282	7,728	11,538	3,249	2,366	173	2,655	189	759	5,324
557	OTHER EXPENSES	35	1	3	4	1	1	0	1	0	0	2
	Total Purchased Power Labor	$92,746	$2,283	$7,730	$11,542	$3,250	$2,367	$173	$2,656	$189	$760	$5,326
	Transmission Labor Expenses											
560	OPERATION SUPERVISION AND ENG	61,912	1,524	5,160	7,705	2,170	1,580	116	1,773	126	507	3,558
561	LOAD DISPATCHING	70,088	1,726	5,842	8,722	2,456	1,789	131	2,007	143	574	4,025
562	STATION EXPENSES	73,090	1,799	6,092	9,096	2,561	1,865	137	2,093	149	599	4,198
563	OVERHEAD LINE EXPENSES	940	23	78	117	33	24	2	27	2	8	54
566	MISC. TRANSMISSION EXPENSES	18,621	458	1,552	2,317	653	475	35	533	38	153	1,069
569	MAINTENACE OF STRUCTURES	491	12	41	61	17	13	1	14	1	4	28
570	MAINT OF STATION EQUIPMENT	29,163	718	2,431	3,629	1,022	744	55	835	59	239	1,675
571	MAINT OF OVERHEAD LINES	782	19	65	97	27	20	1	22	2	6	45
573	MAINT OF MISC. TRANSMISSION PLANT	97	2	8	12	3	2	0	3	0	1	6
	Total Transmission Labor Expenses	$255,184	$6,282	$21,270	$31,757	$8,942	$6,512	$477	$7,309	$520	$2,090	$14,655
	Distribution Operation Labor Expense											
580	OPERATION SUPERVISION AND ENGI	26,697	1,002	1,973	3,850	1,201	8,255	347	11,003	1,616	244	1,889
581	LOAD DISPATCHING	24,909	819	1,675	3,661	1,127	1,026	75	1,152	36	226	1,507
582	STATION EXPENSES	19,284	479	1,452	2,834	872	795	58	892	28	175	1,167
583	OVERHEAD LINE EXPENSES	103,445	3,044	7,784	15,194	4,677	13,113	377	16,216	329	942	7,209
584	UNDERGROUND LINE EXPENSES	5,803	177	437	853	262	468	21	560	13	53	416
585	*STREET LIGHTING EXPENSE*	0	0	0	0	0	2,979	0	4,129	0	0	0
586	METER EXPENSES	6,247	1,765	83	147	167	0	1,911	0	11,661	52	570
586	METER EXPENSES - LOAD MANAGEMENT											
587	CUSTOMER INSTALLATIONS EXPENSE											
588	MISCELLANEOUS DISTRIBUTION EXP	48,348	1,667	3,630	7,086	2,184	45,467	239	62,150	435	439	3,737
589	RENTS											
	Total Distribution Operation Labor Expense	$234,931	$8,753	$17,236	$33,624	$10,491	$72,103	$3,029	$96,101	$14,119	$2,131	$16,495

Louisville Gas and Electric
Electric Cost of Service Study
(Salaries and Wages)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
	Distribution Maintenance Labor Expense											
590	MAINTENANCE SUPERVISION AND EN	147	4	11	22	7	43	1	57	0	1	10
591	MAINTENANCE OF STRUCTURES	1,062	27	81	159	49	45	3	50	2	10	65
592	MAINTENANCE OF STATION EQUIPME	15,226	378	1,146	2,238	688	627	46	704	22	138	921
593	MAINTENANCE OF OVERHEAD LINES	92,487	2,721	6,960	13,584	4,182	11,724	337	14,498	294	843	6,446
594	MAINTENANCE OF UNDERGROUND LIN	17,198	524	1,295	2,527	778	1,387	82	1,658	40	156	1,233
595	MAINTENANCE OF LINE TRANSFORME	0	172	0	0	0	521	18	641	13	0	341
596	MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	0	0	0	0	0	21,325	0	29,554	0	0	0
597	MAINTENANCE OF METERS											
598	MAINTENANCE OF MISC DISTR PLANT	1,837	63	138	269	63	1,727	9	2,361	17	17	142
	Total Distribution Maintenance Labor Expense	$127,978	$3,690	$9,631	$18,799	$5,787	$37,399	$475	$49,523	$388	$1,165	$9,159
	Total Distribution Operation and Maintenance Labor Expenses	362,907	12,642	26,867	52,422	16,278	109,502	3,503	145,624	14,507	3,296	25,654
	Transmission and Distribution Labor Expenses	618,092	18,925	48,137	84,179	25,220	116,013	3,980	152,933	15,027	5,386	40,310
	Production, Transmission and Distribution Labor Expenses	$4,709,170	$119,000	$387,131	$582,516	$164,161	$225,871	$12,033	$276,235	$23,420	$38,412	$271,732
	Customer Accounts Expense											
901	SUPERVISION/CUSTOMER ACCTS	956	270	21	21	21	3,386	14	4,412	83	3	33
902	METER READING EXPENSES	448	128	10	10	10	1,577	8	2,055	39	1	15
903	RECORDS AND COLLECTION	3,927	1,110	85	85	85	13,901	55	18,113	341	13	137
904	UNCOLLECTIBLE ACCOUNTS											
905	MISC CUST ACCOUNTS	200	56	4	4	4	707	3	921	17	1	7
	Total Customer Accounts Labor Expense	$5,528	$1,562	$120	$120	$120	$19,571	$78	$25,501	$481	$18	$192
	Customer Service Expense											
907	SUPERVISION	8	2	0	0	0	767	22	899	132	1	6
908	CUSTOMER ASSISTANCE EXPENSES	9	3	0	0	0	814	23	1,061	140	1	6
908	CUSTOMER ASSISTANCE EXP-LOAD MGMT											
909	INFORMATIONAL AND INSTRUCTIONA	0	0	0	0	0	12	0	15	2	0	0
909	INFORM AND INSTRUC -LOAD MGMT											
910	MISCELLANEOUS CUSTOMER SERVICE	2	0	0	0	0	158	4	206	27	0	1
911	DEMONSTRATION AND SELLING EXP											
912	DEMONSTRATION AND SELLING EXP											
913	WATER HEATER - HEAT PUMP PROGRAM											
915	MDSE-JOBBING-CONTRACT											
916	MISC SALES EXPENSE											
	Total Customer Service Labor Expense	$19	$5	$0	$0	$0	$1,750	$49	$2,280	$302	$1	$13
	Sub-Total Labor Exp	4,714,717	120,568	387,252	582,636	164,282	247,192	12,161	304,017	24,202	38,431	271,937

Louisville Gas and Electric
Electric Cost of Service Study
(Salaries and Wages)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
	Administrative and General Expense											
920	ADMIN. & GEN. SALARIES-	1,071,988	27,414	88,050	132,474	37,353	58,204	2,765	69,124	5,503	8,738	61,831
921	OFFICE SUPPLIES AND EXPENSES											
922	ADMIN. EXPENSES TRANSFERRED - CREDIT	-112,997	-2,890	-9,281	-13,964	-3,937	-5,924	-291	-7,286	-580	-921	-6,517
923	OUTSIDE SERVICES EMPLOYED											
924	PROPERTY INSURANCE											
925	INJURIES AND DAMAGES - INSURAN	4,796	123	394	593	167	251	12	309	25	39	277
926	EMPLOYEE BENEFITS											
928	REGULATORY COMMISSION FEES											
929	DUPLICATE CHARGES-CR											
930	MISCELLANEOUS GENERAL EXPENSES											
931	RENTS AND LEASES											
935	MAINTENANCE OF GENERAL PLANT	238,675	6,081	19,739	30,116	8,553	23,224	504	30,373	617	1,972	14,079
	Total Administrative and General Expense	$1,202,461	$30,707	$98,901	$149,219	$42,136	$73,755	$2,990	$92,521	$5,584	$9,828	$69,669
	Total Operation and Maintenance Expenses	$5,917,179	$151,276	$486,153	$731,856	$206,418	$320,947	$15,151	$398,537	$29,767	$48,259	$341,606
	Operation and Maintenance Expenses Less Purchase Power	$5,917,179	$151,275	$486,153	$731,856	$206,418	$320,947	$15,151	$398,537	$29,767	$48,259	$341,608

Louisville Gas and Electric
Electric Cost of Service Study
(Revenue)

Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP-Pri	LP-Sec	LP-TOD Trans
REVENUE											
	Sales to Ultimate Consumers	$780,783,699	314,219,675	113,886,416	8,326,142	127,291,267	16,194,022	18,050,768	5,977,441	32,185,764	23,067,091
	Rate Refunds	-$9,763,357	-3,929,179	-1,424,100	-104,115	-1,591,720	-202,499	-225,717	-74,745	-402,469	-288,444
	Intercompany Sales	$88,772,853	31,856,530	10,640,015	1,088,955	14,951,741	2,271,212	2,345,117	780,650	3,937,034	3,743,143
	Off-System Sales	$67,472,720	27,017,882	8,396,321	771,186	11,398,017	1,571,223	1,841,257	522,420	2,893,085	2,373,039
	Brokered Sales	-$2,000,584	-717,919	-239,783	-24,541	-336,952	-51,184	-52,850	-17,142	-88,725	-84,355
	Forfeited Discounts	$2,744,200	2,268,501	308,711	3,272	49,789	6,368	7,074	8,518	46,034	33,040
	Misc Service Revenues	$863,121	741,297	121,824	0	0	0	0	0	0	0
	Rent From Electric Property	$3,037,655	1,429,853	376,091	28,061	437,807	56,466	60,210	18,833	109,167	74,995
	Other Electric Revenue	$1,071,355	438,437	150,265	11,396	171,783	22,443	24,639	8,111	43,613	32,757
	Unbilled Revenue.	$785,000	315,916	114,501	8,371	127,979	16,281	18,148	6,010	32,360	23,192
	Merger Surcredit Amortization	-$1,382,146							-130,596		-397,436
	TOTAL REVENUE	$932,384,516	373,638,974	$132,330,260	$10,108,726	$152,499,710	$19,884,331	$21,868,647	$7,079,501	$38,755,862	$28,577,022

Louisville Gas and Electric
Electric Cost of Service Study
(Revenue)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
REVENUE												
	Sales to Ultimate Consumers	81,308,569	2351093	6,497,749	9236472	2474679	5750822	172123	8099488	240932	641268	4811908
	Rate Refunds	-1,016,728	-29399	-81,251	-115498	-30945	-71912	-2152	-101281	-3013	-8019	-60171
	Intercompany Sales	12,401,040	300,507	1,018,714	1,462,840	401,596	357,185	26,182	400,898	25,675	97,963	685,856
	Off-System Sales	8,035,718	202,656	520,343	1,004,081	225,338	148,146	10,859	166,276	15,927	69,651	489,318
	Brokered Sales	-279,470	-6,772	-22,958	-32,967	-9,050	-8,050	-590	-9,036	-579	-2,208	-15,456
	Forfeited Discounts	14,892	0	0	0	0	0	0	0	0	0	0
	Misc Service Revenues	0	0	0	0	0	0	0	0	0	0	0
	Rent From Electric Property	278,302	7,357	15,912	38,167	7,589	33,754	368	45,363	797	2,526	18,038
	Other Electric Revenue	114,060	3,188	8,969	13,153	3,472	7,100	233	9,782	318	909	6,716
	Unbilled Revenue	81,748	2,364	6,533	9,286	2,488	5,782	173	8,143	242	645	4,838
	Merger Surcredit Amortization	-671,962		-182,152								
	TOTAL REVENUE	$100,268,170	$2,830,994	$7,781,860	$11,613,536	$3,076,165	$6,222,827	$207,196	$8,619,655	$280,300	$802,735	$5,941,047

Louisville Gas and Electric
Electric Cost of Service Study
(Allocator Amounts)

Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP-Pri	LP-Sec	LP-TOD Trans
1	Energy loss adjusted	$13,418,258,759	$4,815,200,674	$1,608,268,956	$164,598,454	$2,259,998,003	$343,299,768	$354,470,845	$114,974,363	$595,093,351	$585,786,147
2	Energy @ meter	$12,671,329,647	$4,518,362,813	$1,509,123,731	$157,715,440	$2,120,670,289	$328,944,000	$332,818,135	$110,186,480	$558,408,228	$552,768,000
3	Monthly Bills	$5,890,568	$4,301,388	$501,420	$600	$32,136	$168	$624	$528	$3,888	$60
4	Average Customers (Bills/12)	$490,889	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
5	Average Customers (Lighting = Lights)	$490,889	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
6 Cust05	Weighted Average Customers (Lighting = 9 Lights)	$445,602	$358,449	$45,964	$500	$26,780	$280	$1,040	$440	$3,240	$100
7 Cust04	Street Lighting	$57,069,712									
8 Cust01	Average Customers	$490,889	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
9 Cust06	Average Customers (Lighting = 9 Lights Per Customer)	$413,953	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
10 Cust07	Average Secondary Customers	$413,043	$358,449	$41,788	$0	$2,678	$0	$52	$0	$324	$0
11 Cust08	Average Primary Customers	$413,203	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$0
12	Year End Customers	$490,889	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
13	Year End Customers (Lighting = Lights)	$490,889	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
14 YECust05	Weighted Year End Customers (Lighting =9 Lights Per Customer)	$446,327	$358,449	$45,964	$500	$26,780	$280	$1,040	$440	$3,240	$100
15 YECust04	Street Lighting (Plant-in-Service balance)	$67,121,503			$0						
16 YECust01	Year End Customers	$490,889	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
17 YECust06	Year End Customers (Lighting = 9 Lights per Customer)	$413,208	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
18 YECust07	Year End Secondary Customers	$413,043	$358,449	$41,785	$0	$2,678	$0	$52		$324	
19 YECust08	Year End Primary Customers	$413,208	$358,449	$41,785	$50	$2,678	$14	$52	$44	$324	$5
20 NCP	Maximum Class Non-Coincident Peak Demands	$2,961,081	$1,400,180	$372,056	$30,505	$414,648	$60,243	$60,158	$21,104	$106,278	$80,077
21 C01	Primary Distribution Plant -- Average Number of Customers	1.00000000	0.86748863	0.10112460	0.00012101	0.00648107	0.00003388	0.00012585	0.00010649	0.00078412	0.00000000
22 C02	Customer Services -- Weighted cost of Services	1.00000000	0.73202800	0.11577400	0.00000000	0.12669100	0.00000000	0.00244700	0.00000000	0.02087800	0.00000000
23 C03	Meter Costs -- Weighted Cost of Meters	1.00000000	0.08101428	0.27577133	0.00037300	0.02081846	0.00223108	0.00060092	0.00104301	0.00788024	0.00030524
24 C04	Lighting Systems -- Lighting Customers	1.00000000	0.00000000	0.00000000	0.00000000	0.00000000	0.00000000	0.00000000	0.00000000	0.00000000	0.00000000
25 C05	Meter Reading and Billing -- Weighted Cost	1.00000000	0.80430706	0.10313537	0.00112193	0.06009040	0.00062828	0.00233361	0.00098730	0.00727009	0.00022439
26 C06	Marketing/Economic Development	1.00000000	0.86591715	0.10094141	0.00012079	0.00646933	0.00003382	0.00012562	0.00010629	0.00078270	0.00001208
27 R01	Rev	780783699	314219675	113888416	6328142	127291267	16194022	18050768	5977441	32185764	23067091
28 NCPP	Maximum Class Demands (Primary)	$2,880,104	$1,400,160	$372,056	$30,505	$414,646	$60,243	$60,158	$21,104	$106,278	$0
29 SICD	Sum of the Individual Customer Demands (Secondary)	$4,760,839	$3,306,511	$742,883		$480,284		$55,042		$121,385	
30 SCP	Summer Peak Period Demand Allocator	$2,681,053	$1,252,814	$354,353	$28,778	$408,693	$58,205	$59,428	$17,905	$99,082	$68,841
31 WCP	Winter Peak Period Demand Allocator	$2,259,111	$992,116	$290,238	$23,087	$408,693	$44,604	$48,746	$15,359	$99,082	$62,104
32 BDEM	Base Demand Allocator	$1,527,581	$548,179	$183,091	$18,738	$257,288	$39,082	$40,354	$13,089	$67,747	$64,411
33 PPWDRA	Production Residual Winter Demand Allocator	$2,259,111	$992,115	$290,238	$23,087	$408,583	$44,604	$48,745	$15,359	$99,082	$62,104
34 PPWDA	Production Winter Demand Allocator	$38,437,616	$16,001,960	$4,681,269	$372,373	$6,590,253	$719,424	$788,215	$247,727	$1,698,107	$1,001,684
35 PPSDRA	Production Residual Summer Demand Allocator	$2,681,053	$1,252,814	$354,353	$28,776	$408,693	$58,205	$59,428	$17,905	$99,082	$68,841
36 PPSDA	Production Summer Demand Allocator	$24,112,391	$11,267,342	$3,186,919	$258,801	$3,674,733	$523,474	$534,473	$161,031	$891,107	$619,130
37 PPBDRA	Production Residual Base Demand Allocator	$1,527,579	$548,179	$183,091	$16,738	$257,286	$39,082	$40,354	$13,089	$67,747	$64,411
38 PPBDA	Production Base Demand Allocator	$30,612,263	$10,985,342	$3,669,081	$376,613	$5,165,928	$783,200	$808,686	$262,301	$1,357,639	$1,290,778
39 SDALL	Distribution O&M	$706,478,040	$409,324,850	$83,751,489	$2,833,143	$50,387,823	$5,152,496	$6,503,894	$1,834,633	$12,233,612	$2,808
40 OREV	Total Other Revenue allocator	$7,476,653	$3,059,718	$1,048,651	$79,528	$1,158,818	$156,619	$171,949	$56,607	$304,361	$228,601
41 FDIS	Forfeited Discounts	$2,744,186	$2,266,489	$308,710	$3,272	$49,769	$6,368	$7,074	$8,618	$48,034	$33,040
42 MISCR	Misc Revenue Allocator	$863,121	$741,297	$121,824	$0	$0	$0	$0	$0	$0	$0
43 OSSALL	Off-System Sales Allocator	$154,244,989	$61,763,773	$19,194,281	$1,762,957	$29,056,263	$3,591,889	$3,751,870	$1,194,271	$8,613,692	$5,424,851
44 INTCRE	Interruptible Credit Allocator (Winter & Summer Peak Prod Plant)	$1,548,745,217	$607,494,096	$201,252,982	$16,144,187	$262,557,773	$31,790,844	$33,780,555	$10,455,219	$63,069,102	$41,457,181
45 OMLF	O&M less fuel	$167,759,263	$88,840,199	$21,639,929	$1,328,428	$21,165,384	$2,658,766	$2,822,608	$900,072	$5,201,947	$3,378,813
46	Base Rate Revenue at Current Rates	$741,330,322	$299,726,700	$109,984,799	$7,840,189	$121,065,621	$15,241,445	$17,124,072	$5,684,983	$30,757,406	$20,696,994
47 VDTREV	VDT Revenue	-$7,376,617	-$2,969,742	-$1,075,676	-$77,677	-$1,203,468	-$152,191	-$171,164	-$56,169	-$304,077	-$216,032
48 MSCREV	Merger Surcredit Revenue	-$18,092,633	-$7,938,693	-$2,871,018	-$208,059	-$3,207,612	-$406,085	-$455,288	-$149,741	-$810,438	-$106,689
49 ECRREV	ECR Revenue	$10,161,263	$4,122,618	$1,483,566	$106,496	$1,655,625	$207,581	$230,515	$77,342	$416,589	$292,151
50 DSMREV	DSM revenue	$4,404,262	$3,792,723	$298,627	$14,075	$169,320	$49,967	$49,580	$0	$0	$0
51	Gross Production Plant	2,204,761,687	832,354,954	288,929,937	26,453,001	365,256,561	54,938,690	56,629,327	18,173,889	94,973,256	86,704,615
52	Gross Transmission Plant	255,091,069	96,303,622	31,116,211	3,061,771	42,260,209	6,356,178	6,552,017	2,102,720	10,988,412	10,031,729
53	Gross Distribution Plant	776,183,225	452,161,550	85,047,071	3,608,668	67,790,181	7,153,761	9,043,153	2,536,807	16,894,967	11,929
54	Gross Prod., Trans, Dist. Plant	3,236,035,980	1,380,820,026	385,092,219	33,133,439	475,306,950	68,448,630	72,224,496	22,813,416	122,856,634	96,748,273
55	Dist. Overhead Lines Gross Plant	288,850,108	180,110,612	34,645,005	1,538,870	24,689,782	3,019,897	3,449,975	1,071,256	6,200,824	1,130
56	Gross Intangible Plant	21,719,246	9,267,626	2,651,734	222,381	3,190,109	459,392	484,748	153,116	824,575	649,344
57	Gross Total Plant In Service	3,411,422,531	1,454,534,813	416,502,798	34,969,477	501,496,610	72,242,287	78,215,779	24,077,102	129,831,943	102,207,128
58	Dist. Underground Lines Gross Plant	157,900,818	94,437,435	20,217,823	1,052,206	17,248,665	2,072,845	2,441,618	731,601	4,368,395	302
59	Gross General Plant	153,667,305	64,447,181	18,758,844	1,613,657	22,999,550	3,336,265	3,506,635	1,110,670	5,950,714	4,809,611
60	Labor Accts 501-507	$18,504,206	$6,935,316	$2,251,350	$222,614	$3,073,004	$462,679	$477,261	$153,411	$800,539	$735,378
61	Labor Accts 511-514	$7,775,961	$2,795,694	$932,622	$95,309	$1,308,879	$198,750	$205,205	$66,534	$344,490	$327,049
62	Labor Accts 536-540	$143,837	$54,302	$17,545	$1,726	$23,029	$3,584	$3,694	$1,186	$6,196	$5,657
63	Labor Accts 542-545	$200,262	$73,243	$24,159	$2,437	$33,626	$5,074	$5,236	$1,692	$8,788	$8,235
64	Labor Accts 581-588	5,976,702	3,813,043	1,072,469	22,498	390,624	47,655	50,000	17,433	105,281	704
65	Labor Accts 591-598	2,518,606	1,585,519	304,277	13,737	229,283	26,996	31,690	9,560	56,848	8

Louisville Gas and Electric
Electric Cost of Service Study
(Allocator Amounts)

Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP-Pri	LP-Sec	LP-TOD Trans
66	Labor Accts 500-918	44,584,824	20,230,551	5,743,602	434,961	8,247,481	899,344	937,035	303,381	1,606,020	1,311,814
67	O&M less Purchased Power	538,090,930	213,906,187	65,523,255	6,011,313	83,794,964	12,494,602	12,947,454	4,194,580	21,890,230	19,727,998
68	Dist. Lines Gross Plant	446,750,928	284,548,047	56,162,928	2,591,076	41,938,427	6,092,742	5,891,794	1,802,857	10,669,218	1,431
69	Rate Base	1,826,018,111	778,897,465	222,937,770	18,746,124	288,739,655	38,737,284	40,856,615	12,914,556	69,489,563	55,048,323
70	Gross Transformer Plant	108,478,013	80,081,096	15,300,324	0	8,388,181	0	1,089,073	0	2,048,254	0
71	Dpreciation Expense	108,263,300	48,673,705	13,210,132	1,091,385	16,719,160	2,253,340	2,383,613	751,645	4,060,589	3,145,181
72	Total Labor	55,816,431	25,254,181	7,176,525	548,112	7,841,507	1,129,162	1,176,905	380,702	2,018,939	1,646,251
73	Distribution O&M	32,779,090	20,333,051	4,855,573	154,858	2,559,838	313,407	344,326	112,478	659,769	1,978
74	Sales Revenue	780,783,699	314,219,675	113,886,418	8,328,142	127,291,267	16,194,022	18,050,768	5,977,441	32,185,784	23,067,091
75	Distribution Poles, Lines, Transform & Services	579,769,920	382,808,473	73,300,776	2,591,076	53,416,273	6,092,742	7,040,967	1,802,857	13,130,208	1,431

Louisville Gas and Electric
Electric Cost of Service Study
(Allocator Amounts)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
1	Energy loss adjusted	$1,874,450,757	$45,422,475	$153,981,442	$221,112,251	$80,702,392	$53,989,416	$3,957,427	$60,590,772	$3,880,869	$14,607,401	$103,666,978
2	Energy @ meter	$1,796,066,850	$42,622,361	$147,542,400	$211,866,000	$58,184,000	$50,661,164	$3,713,467	$56,861,223	$3,641,648	$14,188,200	$97,278,200
3	Monthly Bills	$550	$156	$12	$12	$12	$450,964	$1,416	$587,652	$8,640	$38	$384
4	Average Customers (Bills/12)	$46	$13	$1	$1	$1	$37,582	$118	$48,971	$720	$3	$32
5	Average Customers (Lighting = Lights)	$46	$13	$1	$1	$1	$37,582	$118	$48,971	$720	$3	$32
6 Cust05	Weighted Average Customers (Lighting = 9 Lights)	$920	$260	$20	$20	$20	$3,257	$13	$4,244	$80	$3	$32
7 Cust04	Street Lighting						$23,919,848		$33,150,068			
8 Cust01	Average Customers	$46	$13	$1	$1	$1	$37,582	$118	$48,971	$720	$3	$32
9 Cust06	Average Customers (Lighting = 9 Lights Per Customer)	$46	$13	$1	$1	$1	$4,176	$118	$5,441	$720	$3	$32
10 Cust07	Average Secondary Customers	$0	$13	$0	$0	$0	$4,176	$13	$5,441	$80	$0	$32
11 Cust08	Average Primary Customers	$46	$13	$1	$1	$1	$4,176	$13	$5,441	$80	$3	$32
12	Year End Customers	$46	$13	$1	$1	$1	$37,582	$118	$48,971	$720	$3	$32
13	Year End Customers (Lighting = Lights)	$46	$13	$1	$1	$1	$37,582	$118	$48,971	$720	$3	$32
14 YECust05	Weighted Year End Customers (Lighting =9 Lights Per Customer)	$920	$260	$20	$20	$20	$3,257	$13	$4,244	$80	$60	$640
15 YECust04	Street Lighting (Plant-in-Service balance)						$28,132,650	$0	$38,968,647			
16 YECust01	Year End Customers	$46	$13	$1	$1	$1	$37,582	$118	$48,971	$720	$3	$32
17 YECust06	Year End Customers (Lighting = 9 Lights per Customer)	$46	$13	$1	$1	$1	$4,176	$13	$5,441	$80	$3	$32
18 YECust07	Year End Secondary Customers		$13				$4,176	$13	$5,441	$80	$0	$32
19 YECust08	Year End Primary Customers	$46	$13	$1	$1	$1	$4,176	$13	$5,441	$80	$3	$32
20 NCP	Maximum Class Non-Coincident Peak Demands	$285,359	$7,090	$21,485	$41,939	$12,908	$11,759	$859	$13,198	$415	$2,588	$17,264
21 C01	Primary Distribution Plant -- Average Number of Customers	0.00011133	0.00003146	0.00000242	0.00000242	0.00000242	0.01010587	0.00003173	0.01316840	0.00019361	0.00000726	0.00007744
22 C02	Customer Services -- Weighted cost of Services	0.00000000	0.00073000	0.00000000	0.00000000	0.00000000	0.00000000	0.00023800	0.00000000	0.00113300	0.00000000	0.00008300
23 C03	Meter Costs -- Weighted Cost of Meters	0.00280831	0.00079385	0.00003745	0.00006589	0.00007493	0.00000000	0.00085911	0.00000000	0.00524245	0.00002332	0.00025645
24 C04	Lighting Systems -- Lighting Customers	0.00000000	0.00000000	0.00000000	0.00000000	0.00000000	0.41913031	0.00000000	0.58086969	0.00000000	0.00000000	0.00000000
25 C05	Meter Reading and Billing -- Weighted Cost	0.00206435	0.00058340	0.00004486	0.00004488	0.00004486	0.00730647	0.00002942	0.00952326	0.00017951	0.00000673	0.00007180
26 C06	Marketing/Economic Development	0.00011112	0.00003140	0.00000242	0.00000242	0.00000242	0.01008756	0.00028506	0.01314454	0.00173933	0.00000725	0.00007730
27 R01	Rev	81308569	2351093	6497749	9236472	2474679	5750622	172123	8099498	240932	641288	4811908
28 NCPP	Maximum Class Demands (Primary)	$285,359	$7,090	$21,485	$41,939	$12,908	$11,759	$859	$13,198	$415	$2,588	$17,264
29 SICD	Sum of the Individual Customer Demands (Secondary)		$9,550				$11,759	$859	$13,198	$415	$0	$16,953
30 SCP	Summer Peak Period Demand Allocator	$231,768	$6,402	$21,485	$40,519	$12,908	$0	$0	$0	$415	$2,423	$17,136
31 WCP	Winter Peak Period Demand Allocator	$224,978	$5,985	$0	$26,070	$0	$0	$0	$0	$415	$2,203	$15,533
32 BDEM	Base Demand Allocator	$213,394	$5,171	$17,530	$25,172	$8,911	$6,148	$451	$6,899	$442	$1,686	$11,802
33 PPWDRA	Production Residual Winter Demand Allocator	$224,978	$5,985	$0	$26,070	$0	$0	$0	$0	$415	$2,203	$15,533
34 PPWDA	Production Winter Demand Allocator	$3,628,701	$96,533	$0	$420,487	$0	$0	$0	$0	$6,694	$35,532	$250,534
35 PPSDRA	Production Residual Summer Demand Allocator	$231,768	$6,402	$21,485	$40,519	$12,908	$0	$0	$0	$416	$2,423	$17,136
36 PPSDA	Production Summer Demand Allocator	$2,084,435	$57,577	$193,228	$364,413	$116,090	$0	$0	$0	$3,732	$21,792	$154,115
37 PPBDRA	Production Residual Base Demand Allocator	$213,394	$5,171	$17,530	$25,172	$8,911	$6,148	$451	$8,899	$442	$1,686	$11,802
38 PPBDA	Production Base Demand Allocator	$4,278,350	$103,626	$351,291	$504,443	$138,488	$123,171	$9,028	$138,245	$8,854	$33,781	$238,509
39 SDALL	Distribution O&M	$24,394,934	$620,093	$1,635,339	$3,582,071	$1,102,860	$4,690,221	$106,983	$5,868,964	$138,874	$222,695	$1,670,256
40 OREV	Total Other Revenue allocator	$795,990	$22,245	$62,694	$91,792	$24,227	$49,552	$1,627	$68,337	$2,222	$6,344	$46,668
41 FDIS	Forfeited Discounts	$14,892	$0									
42 MISCR	Misc Revenue Allocator	$0	$0									
43 OSSALL	Off-System Sales Allocator	$18,369,931	$463,279	$1,169,522	$2,285,365	$516,126	$338,666	$24,624	$380,113	$36,410	$159,220	$1,118,599
44 INTCRE	Interruptible Credit Allocator (Winter & Summer Peak Prod Plant)	$146,130,576	$3,941,627	$4,942,387	$20,076,154	$2,969,343	$0	$0	$0	$256,675	$1,466,234	$10,350,103
45 OMLF	O&M less fuel	$12,066,220	$352,168	$732,888	$1,692,102	$356,986	$1,150,297	$25,353	$1,513,607	$87,022	$118,148	$830,729
46	Base Rate Revenue at Current Rates	$75,025,769	$2,233,997	$5,830,932	$8,594,227	$2,293,972	$5,677,317	$161,029	$8,049,296	$226,798	$598,933	$4,517,788
47 VDTREV	VDT Revenue	-$768,922	-$22,776	-$61,488	-$87,255	-$23,360	-$54,246	-$1,625	-$76,416	-$2,275	-$5,936	-$44,922
48 MSCREV	Merger Surcredit Revenue	-$1,090,885	-$59,145	$0	-$232,828	-$62,152	-$144,419	-$4,323	-$203,852	-$6,043	-$15,828	-$119,755
49 ECRREV	ECR Revenue	$1,041,986	$30,821	$83,520	$122,061	$32,105	$72,673	$2,182	$103,526	$3,077	$8,173	$62,058
50 DSMREV	DSM revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,268	$8,684
51	Gross Production Plant	287,778,193	7,064,775	23,086,446	35,812,708	10,084,398	7,343,441	538,276	8,242,149	586,832	2,357,165	16,527,276
52	Gross Transmission Plant	33,293,724	819,709	2,775,233	4,143,533	1,166,766	849,637	62,278	953,617	67,873	272,724	1,912,207
53	Gross Distribution Plant	33,813,115	1,158,784	2,524,081	4,926,518	1,518,363	31,611,034	160,512	43,210,354	302,499	305,512	2,598,348
54	Gross Prod., Trans, Dist. Plant	354,885,032	9,083,268	29,285,760	44,882,758	12,769,526	39,804,111	767,065	52,406,120	957,004	2,935,402	21,037,831
55	Dist. Overhead Lines Gross Plant	14,300,056	420,750	1,078,111	2,100,367	648,608	1,812,688	52,176	2,241,659	45,461	130,275	998,626
56	Gross Intangible Plant	2,380,533	60,830	196,657	301,239	85,705	267,153	5,146	351,733	6,423	19,701	141,199
57	Gross Total Plant in Service	374,385,916	9,583,601	30,914,763	47,389,511	13,475,945	41,758,806	808,601	54,982,005	1,008,194	3,098,194	22,200,759
58	Dist. Underground Lines Gross Plant	9,817,425	298,995	739,018	1,442,512	444,019	791,887	35,413	946,710	22,772	89,193	703,688
59	Gross General Plant	17,320,353	439,903	1,432,448	2,185,515	620,714	1,685,342	36,587	2,204,152	44,767	143,091	1,021,729
60	Labor Accts 501-507	$2,440,060	$59,926	$202,927	$301,206	$84,501	$63,506	$4,655	$71,276	$4,986	$19,876	$139,332
61	Labor Accts 511-514	$1,083,583	$26,273	$89,059	$128,068	$35,192	$31,085	$2,279	$34,889	$2,242	$8,571	$60,010
62	Labor Accts 536-540	$18,774	$462	$1,565	$2,336	$658	$479	$35	$538	$38	$154	$1,076
63	Labor Accts 542-545	$27,299	$665	$2,254	$3,283	$910	$765	$56	$847	$56	$218	$1,530
64	Labor Accts 581-588	208,034	7,750	15,262	29,774	9,290	63,848	2,682	65,098	12,503	1,687	14,607
65	Labor Accts 591-598	127,829	3,885	9,620	18,777	5,780	37,356	474	49,457	388	1,163	9,148

Louisville Gas and Electric
Electric Cost of Service Study
(Allocator Amounts)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
66	Labor Accts 500-916	4,714,717	120,568	387,252	582,636	184,282	247,182	12,181	304,017	24,202	38,431	271,937
67	O&M less Purchased Power	67,305,797	1,658,796	5,527,680	8,069,857	2,236,514	2,793,519	151,578	3,342,199	199,686	537,508	3,777,118
68	Dist. Lines Gross Plant	24,117,481	719,745	1,815,127	3,542,879	1,090,627	2,604,573	87,689	3,188,360	68,233	219,468	1,700,316
69	Rate Base	201,059,368	5,132,028	16,598,206	25,384,220	7,214,231	22,418,070	436,111	29,502,991	548,040	1,661,445	11,901,156
70	Gross Transformer Plant	0	160,279	0	0	0	486,331	15,239	598,221	12,483	0	318,522
71	Oprecinlon Expense	11,662,978	299,208	962,001	1,478,521	421,113	1,418,789	25,594	1,874,262	32,305	96,632	694,167
72	Total Labor	5,917,179	161,275	486,153	731,858	206,418	320,947	15,151	398,537	29,767	48,259	341,606
73	Distribution O&M	1,435,931	48,432	106,989	206,784	64,811	605,852	10,428	815,552	38,632	13,050	99,786
74	Sales Revenue	81,308,569	2,351,093	8,497,749	9,230,472	2,474,579	5,750,822	172,123	8,099,498	240,932	641,288	4,811,908
75	Distribution Poles, Lines, Transform & Services	24,117,481	897,954	1,815,127	3,542,879	1,090,627	3,090,904	108,673	3,786,589	108,544	219,468	2,020,877

Louisville Gas and Electric
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Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP-Pri	LP-Sec	LP-TOD Trans
1	Energy loss adjusted	100.0000%	35.8854%	11.8857%	1.2267%	18.8427%	2.5585%	2.8417%	0.8569%	4.4350%	4.2165%
2	Energy @ meter	100.0000%	35.6582%	11.9098%	1.2447%	18.7360%	2.5960%	2.6250%	0.8894%	4.4059%	4.3619%
3	Monthly Bills	100.0000%	73.0204%	8.5121%	0.0102%	0.5455%	0.0029%	0.0106%	0.0090%	0.0660%	0.0010%
4	Average Customers (Bills/12)	100.0000%	73.0204%	8.5121%	0.0102%	0.5455%	0.0029%	0.0106%	0.0090%	0.0660%	0.0010%
5	Average Customers (Lighting = Lights)	100.0000%	73.0204%	8.5121%	0.0102%	0.5455%	0.0029%	0.0106%	0.0090%	0.0660%	0.0010%
6 Cust05	Weighted Average Customers (Lighting = 9 Lights)	100.0000%	80.4307%	10.3136%	0.1122%	6.0090%	0.0628%	0.2334%	0.0987%	0.7270%	0.0224%
7 Cust04	Street Lighting	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
8 Cust01	Average Customers	100.0000%	73.0204%	8.5121%	0.0102%	0.5458%	0.0029%	0.0106%	0.0090%	0.0660%	0.0010%
9 Cust06	Average Customers (Lighting = 9 Lights Per Customer)	100.0000%	86.5917%	10.0941%	0.0121%	0.6469%	0.0034%	0.0126%	0.0105%	0.0783%	0.0012%
10 Cust07	Average Secondary Customers	100.0000%	86.7825%	10.1184%	0.0000%	0.6484%	0.0000%	0.0126%	0.0000%	0.0784%	0.0000%
11 Cust08	Average Primary Customers	100.0000%	86.7489%	10.1125%	0.0121%	0.6481%	0.0034%	0.0126%	0.0106%	0.0784%	0.0000%
12	Year End Customers	100.0000%	73.0204%	8.5121%	0.0102%	0.5455%	0.0029%	0.0106%	0.0090%	0.0660%	0.0010%
13	Year End Customers (Lighting = Lights)	100.0000%	73.0204%	8.5121%	0.0102%	0.5455%	0.0029%	0.0106%	0.0090%	0.0660%	0.0010%
14 YECust05	Weighted Year End Customers (Lighting =9 Lights Per Customer)	100.0000%	80.3106%	10.2983%	0.1120%	6.0001%	0.0627%	0.2330%	0.0986%	0.7259%	0.0224%
15 YECust04	Street Lighting (Plant-in-Service balance)	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
16 YECust01	Year End Customers	100.0000%	73.0204%	8.5121%	0.0102%	0.5455%	0.0029%	0.0106%	0.0090%	0.0660%	0.0010%
17 YECust06	Year End Customers (Lighting = 9 Lights per Customer)	100.0000%	86.7478%	10.1123%	0.0121%	0.6481%	0.0034%	0.0126%	0.0106%	0.0784%	0.0012%
18 YECust07	Year End Secondary Customers	100.0000%	86.7825%	10.1184%	0.0000%	0.6484%	0.0000%	0.0126%	0.0000%	0.0784%	0.0000%
19 YECust08	Year End Primary Customers	100.0000%	86.7470%	10.1123%	0.0121%	0.6481%	0.0034%	0.0126%	0.0106%	0.0784%	0.0012%
20 NCP	Maximum Class Non-Coincident Peak Demands	100.0000%	47.2854%	12.5649%	1.0302%	14.0032%	2.0345%	2.0316%	0.7158%	3.6892%	2.7347%
21 C01	Primary Distribution Plant -- Average Number of Customers	100.0000%	86.7489%	10.1125%	0.0121%	0.6481%	0.0034%	0.0126%	0.0106%	0.0784%	0.0000%
22 C02	Customer Services -- Weighted cost of Services	100.0000%	73.2028%	11.5774%	0.0000%	12.6891%	0.0000%	0.2447%	0.0000%	2.0876%	0.0000%
23 C03	Meter Costs -- Weighted Cost of Meters	100.0000%	68.1014%	27.5771%	0.0373%	2.0618%	0.2232%	0.0501%	0.1043%	0.7680%	0.0305%
24 C04	Lighting Systems -- Lighting Customers	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
25 C05	Meter Reading and Billing -- Weighted Cost	100.0000%	80.4307%	10.3135%	0.1122%	6.0090%	0.0628%	0.2334%	0.0987%	0.7270%	0.0224%
26 C06	Marketing/Economic Development	100.0000%	86.5917%	10.0941%	0.0121%	0.6460%	0.0034%	0.0126%	0.0106%	0.0783%	0.0012%
27 R01	Rev	100.0000%	40.2441%	14.5862%	1.0664%	18.3030%	2.0741%	2.3119%	0.7656%	4.1222%	2.9544%
28 NCPP	Maximum Class Demands (Primary)	100.0000%	48.6149%	12.9181%	1.0592%	14.3969%	2.0917%	2.0887%	0.7359%	3.6901%	0.0000%
29 SICD	Sum of the Individual Customer Demands (Secondary)	100.0000%	69.1617%	15.5388%	0.0000%	10.2552%	0.0000%	1.3605%	0.0000%	2.5390%	0.0000%
30 SCP	Summer Peak Period Demand Allocator	100.0000%	40.7284%	13.2169%	1.0733%	15.2400%	2.1710%	2.2166%	0.6678%	3.8956%	2.5677%
31 WCP	Winter Peak Period Demand Allocator	100.0000%	43.9182%	12.6474%	1.0220%	18.0865%	1.9744%	2.1577%	0.6799%	4.3859%	2.7490%
32 BDEM	Base Demand Allocator	100.0000%	35.8854%	11.9857%	1.2266%	18.8427%	2.5584%	2.8417%	0.8568%	4.4349%	4.2165%
33 PPWDRA	Production Residual Winter Demand Allocator	100.0000%	43.9182%	12.6474%	1.0220%	18.0865%	1.9744%	2.1577%	0.6799%	4.3859%	2.7490%
34 PPWDA	Production Winter Demand Allocator	100.0000%	43.9182%	12.6474%	1.0220%	18.0865%	1.9744%	2.1577%	0.6799%	4.3859%	2.7490%
35 PPSDRA	Production Residual Summer Demand Allocator	100.0000%	46.7284%	13.2169%	1.0733%	15.2400%	2.1710%	2.2166%	0.6678%	3.8956%	2.5677%
36 PPSDA	Production Summer Demand Allocator	100.0000%	46.7284%	13.2169%	1.0733%	15.2400%	2.1710%	2.2166%	0.6678%	3.8956%	2.5677%
37 PPBDRA	Production Residual Base Demand Allocator	100.0000%	35.8854%	11.9857%	1.2267%	18.8427%	2.5585%	2.6417%	0.8569%	4.4350%	4.2165%
38 PPBDA	Production Base Demand Allocator	100.0000%	35.8854%	11.9857%	1.2267%	18.8427%	2.5585%	2.6417%	0.8560%	4.4350%	4.2165%
39 BDALL	Distribution O&M	100.0000%	70.6780%	11.6548%	0.3727%	7.1323%	0.7293%	0.9206%	0.2597%	1.7316%	0.0004%
40 OREV	Total Other Revenue allocator	100.0000%	40.9236%	14.0257%	1.0637%	18.0342%	2.0948%	2.2998%	0.7571%	4.0708%	3.0575%
41 FDIS	Forfeited Discounts	100.0000%	82.6924%	11.2496%	0.1192%	1.6144%	0.2320%	0.2578%	0.3104%	1.6775%	1.2040%
42 MISCR	Misc Revenue Allocator	100.0000%	85.8856%	14.1144%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
43 OSSALL	Off-System Sales Allocator	100.0000%	40.0426%	12.4440%	1.1430%	18.8928%	2.3267%	2.4325%	0.7743%	4.2878%	3.5170%
44 INTCRE	Interruptible Credit Allocator (Winter & Summer Peak Prod Plant)	100.0000%	45.0381%	12.9948%	1.0424%	18.9529%	2.0527%	2.1012%	0.6751%	4.1110%	2.6768%
45 OMLF	O&M less fuel	100.0000%	52.9570%	12.8994%	0.7919%	12.6106%	1.5849%	1.6825%	0.5365%	3.1008%	2.0129%
46	Base Rate Revenue at Current Rates	100.0000%	40.4309%	14.8361%	1.0578%	16.3309%	2.0580%	2.3099%	0.7669%	4.1469%	2.7919%
47 VDTREV	VDT Revenue	100.0000%	40.2643%	14.5842%	1.0559%	16.3168%	2.0634%	2.3207%	0.7618%	4.1227%	2.9290%
48 MSCREV	Merger Surcredit Revenue	100.0000%	43.8783%	15.8885%	1.1500%	17.7300%	2.2445%	2.5219%	0.8276%	4.4794%	0.5842%
49 ECRREV	ECR Revenue	100.0000%	40.5719%	14.6002%	1.0481%	16.2955%	2.0488%	2.3276%	0.7611%	4.0998%	2.8751%
50 DSMREV	DSM revenue	100.0000%	80.1148%	0.7804%	0.3155%	4.2986%	1.1350%	1.1257%	0.0000%	0.0000%	0.0000%
51	Gross Production Plant	100.0000%	37.7526%	12.1977%	1.2003%	18.5687%	2.4917%	2.5685%	0.8243%	4.3076%	3.9326%
52	Gross Transmission Plant	100.0000%	37.7526%	12.1977%	1.2003%	18.5687%	2.4917%	2.5685%	0.8243%	4.3076%	3.9326%
53	Gross Distribution Plant	100.0000%	58.2545%	12.2454%	0.4849%	8.7338%	0.9217%	1.1651%	0.3268%	2.1767%	0.0015%
54	Gross Prod., Trans, Dist. Plant	100.0000%	42.6701%	12.2091%	1.0239%	14.6879%	2.1151%	2.2319%	0.7050%	3.7965%	2.9897%
55	Dist. Overhead Lines Gross Plant	100.0000%	65.8184%	12.0980%	0.5326%	8.5478%	1.0455%	1.1944%	0.3709%	2.1467%	0.0004%
56	Gross Intangible Plant	100.0000%	42.6701%	12.2091%	1.0239%	14.6879%	2.1151%	2.2319%	0.7050%	3.7965%	2.9897%
57	Gross Total Plant in Service	100.0000%	42.6372%	12.2091%	1.0251%	14.7005%	2.1177%	2.2341%	0.7058%	3.7999%	2.9960%
58	Dist. Underground Lines Gross Plant	100.0000%	69.6081%	12.8042%	0.6664%	10.9225%	1.3128%	1.5464%	0.4833%	2.7665%	0.0002%
59	Gross General Plant	100.0000%	41.9394%	12.2074%	1.0501%	14.9071%	2.1711%	2.2819%	0.7227%	3.8725%	3.1298%
60	Labor Accts 501-507	100.0000%	37.4797%	12.1667%	1.2041%	18.6071%	2.5016%	2.5792%	0.8291%	4.3263%	3.9741%
61	Labor Accts 511-514	100.0000%	35.9555%	11.9936%	1.2257%	18.8323%	2.5559%	2.5390%	0.8556%	4.4302%	4.2059%
62	Labor Accts 536-540	100.0000%	37.7526%	12.1977%	1.2003%	18.5687%	2.4917%	2.5685%	0.8243%	4.3076%	3.9326%
63	Labor Accts 542-545	100.0000%	36.5735%	12.0638%	1.2169%	16.7410%	2.5339%	2.8147%	0.8449%	4.3860%	4.1119%
64	Labor Accts 581-588	100.0000%	63.7984%	17.9442%	0.3784%	6.8395%	0.7973%	0.8376%	0.2917%	1.7615%	0.0118%

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Acct. No.	Account Description	Total	R	GS	LC Pri	LC Sec	LC-TOD Pri	LC-TOD Sec	LP-Pri	LP-Sec	LP-TOD Trans
65	Labor Accts 591-598	100.0000%	62.9452%	12.0798%	0.5453%	8.9826%	1.0718%	1.2581%	0.3795%	2.2609%	0.0003%
66	Labor Accts 500-916	100.0000%	45.3754%	12.8830%	0.9756%	14.0125%	2.0172%	2.1017%	0.6805%	3.6089%	2.9423%
67	O&M less Purchased Power	100.0000%	39.9011%	12.2224%	1.1213%	16.6307%	2.3307%	2.4152%	0.7824%	4.0833%	3.6800%
68	Dist. Lines Gross Plant	100.0000%	63.6928%	12.3476%	0.6800%	9.3870%	1.1400%	1.3188%	0.4035%	2.3658%	0.0003%
69	Rate Base	100.0000%	42.5350%	12.2090%	1.0266%	14.7172%	2.1214%	2.2374%	0.7073%	3.8055%	3.0146%
70	Gross Transformer Plant	100.0000%	73.6224%	14.1045%	0.0000%	7.7142%	0.0000%	1.0040%	0.0000%	1.6882%	0.0000%
71	Dpreciation Expense	100.0000%	43.1113%	12.2102%	1.0061%	14.5194%	2.0814%	2.2017%	0.6943%	3.7507%	2.9051%
72	Total Labor	100.0000%	45.2451%	12.8574%	0.9784%	14.0487%	2.0230%	2.1085%	0.6821%	3.6169%	2.9484%
73	Distribution O&M	100.0000%	62.0306%	14.8130%	0.4718%	7.8094%	0.9581%	1.0504%	0.3431%	2.0123%	0.0060%
74	Sales Revenue	100.0000%	40.2441%	14.5862%	1.0684%	18.3030%	2.0741%	2.3118%	0.7658%	4.1222%	2.9544%
75	Distribution Poles, Lines, Transform & Services	100.0000%	65.9909%	12.6437%	0.4469%	9.2130%	0.8784%	1.2144%	0.3109%	2.2640%	0.0002%

Louisville Gas and Electric
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Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
1	Energy loss adjusted	13.9694%	0.3385%	1.1476%	1.6478%	0.4524%	0.4024%	0.0295%	0.4516%	0.0289%	0.1104%	0.7726%
2	Energy @ meter	14.1743%	0.3384%	1.1644%	1.6720%	0.4590%	0.3998%	0.0293%	0.4487%	0.0287%	0.1120%	0.7677%
3	Monthly Bills	0.0093%	0.0026%	0.0002%	0.0002%	0.0002%	7.6559%	0.0240%	9.9760%	0.1467%	0.0006%	0.0065%
4	Average Customers (Bills/12)	0.0094%	0.0026%	0.0002%	0.0002%	0.0002%	7.6559%	0.0240%	9.9760%	0.1467%	0.0006%	0.0065%
5	Average Customers (Lighting = Lights)	0.0094%	0.0026%	0.0002%	0.0002%	0.0002%	7.6559%	0.0240%	9.9760%	0.1467%	0.0006%	0.0065%
6 Cust05	Weighted Average Customers (Lighting = 9 Lights)	0.2064%	0.0583%	0.0045%	0.0045%	0.0045%	0.7308%	0.0029%	0.9523%	0.0180%	0.0007%	0.0072%
7 Cust04	Street Lighting	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	41.9130%	0.0000%	68.0870%	0.0000%	0.0000%	0.0000%
8 Cust01	Average Customers	0.0094%	0.0026%	0.0002%	0.0002%	0.0002%	7.6559%	0.0240%	9.9760%	0.1467%	0.0006%	0.0065%
9 Cust06	Average Customers (Lighting = 9 Lights Per Customer)	0.0111%	0.0031%	0.0002%	0.0002%	0.0002%	1.0068%	0.0285%	1.3144%	0.1739%	0.0007%	0.0077%
10 Cust07	Average Secondary Customers	0.0000%	0.0031%	0.0000%	0.0000%	0.0000%	1.0110%	0.0031%	1.3173%	0.0194%	0.0000%	0.0077%
11 Cust08	Average Primary Customers	0.0111%	0.0031%	0.0002%	0.0002%	0.0002%	1.0106%	0.0031%	1.3168%	0.0194%	0.0007%	0.0077%
12	Year End Customers	0.0094%	0.0026%	0.0002%	0.0002%	0.0002%	7.6559%	0.0240%	9.9760%	0.1467%	0.0006%	0.0065%
13	Year End Customers (Lighting = Lights)	0.0094%	0.0026%	0.0002%	0.0002%	0.0002%	7.6559%	0.0240%	9.9760%	0.1467%	0.0006%	0.0065%
14 YECust05	Weighted Year End Customers (Lighting =9 Lights Per Customer)	0.2061%	0.0583%	0.0045%	0.0045%	0.0045%	0.7297%	0.0029%	0.9509%	0.0179%	0.0134%	0.1434%
15 YECust04	Street Lighting (Plant-In-Service balance)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	41.9130%	0.0000%	68.0870%	0.0000%	0.0000%	0.0000%
16 YECust01	Year End Customers	0.0094%	0.0026%	0.0002%	0.0002%	0.0002%	7.6559%	0.0240%	9.9760%	0.1467%	0.0006%	0.0065%
17 YECust06	Year End Customers (Lighting = 9 Lights per Customer)	0.0111%	0.0031%	0.0002%	0.0002%	0.0002%	1.0106%	0.0031%	1.3168%	0.0194%	0.0007%	0.0077%
18 YECust07	Year End Secondary Customers	0.0000%	0.0031%	0.0000%	0.0000%	0.0000%	1.0110%	0.0031%	1.3173%	0.0194%	0.0000%	0.0077%
19 YECust08	Year End Primary Customers	0.0111%	0.0031%	0.0002%	0.0002%	0.0002%	1.0106%	0.0031%	1.3168%	0.0194%	0.0007%	0.0077%
20 NCP	Maximum Class Non-Coincident Peak Demands	9.6370%	0.2394%	0.7256%	1.4163%	0.4359%	0.3971%	0.0250%	0.4457%	0.0140%	0.0874%	0.5830%
21 C01	Primary Distribution Plant -- Average Number of Customers	0.0111%	0.0031%	0.0002%	0.0002%	0.0002%	1.0106%	0.0032%	1.3168%	0.0194%	0.0007%	0.0077%
22 C02	Customer Services -- Weighted cost of Services	0.0000%	0.0730%	0.0000%	0.0000%	0.0000%	0.0000%	0.0238%	0.0000%	0.1133%	0.0000%	0.0083%
23 C03	Meter Costs -- Weighted Cost of Meters	0.2809%	0.0794%	0.0037%	0.0068%	0.0075%	0.0000%	0.0859%	0.0000%	0.5242%	0.0023%	0.0256%
24 C04	Lighting Systems -- Lighting Customers	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	41.9130%	0.0000%	68.0870%	0.0000%	0.0000%	0.0000%
25 C05	Meter Reading and Billing -- Weighted Cost	0.2064%	0.0583%	0.0045%	0.0045%	0.0045%	0.7308%	0.0029%	0.9523%	0.0180%	0.0007%	0.0072%
26 C06	Marketing/Economic Development	0.0111%	0.0031%	0.0002%	0.0002%	0.0002%	1.0068%	0.0285%	1.3145%	0.1739%	0.0007%	0.0077%
27 R01	Rev	10.4137%	0.3011%	0.8322%	1.1830%	0.3169%	0.7365%	0.0220%	1.0374%	0.0309%	0.0821%	0.6183%
28 NCPP	Maximum Class Demands (Primary)	9.6078%	0.2462%	0.7480%	1.4562%	0.4482%	0.4083%	0.0258%	0.4582%	0.0144%	0.0899%	0.5094%
29 SICD	Sum of the Individual Customer Demands (Secondary)	0.0000%	0.1998%	0.0000%	0.0000%	0.0000%	0.2460%	0.0160%	0.2781%	0.0087%	0.0000%	0.3964%
30 SCP	Summer Peak Period Demand Allocator	8.6447%	0.2388%	0.8014%	1.5113%	0.4815%	0.0000%	0.0000%	0.0000%	0.0155%	0.0904%	0.6392%
31 WCP	Winter Peak Period Demand Allocator	9.9587%	0.2649%	0.0000%	1.1540%	0.0000%	0.0000%	0.0000%	0.0000%	0.0184%	0.0975%	0.6876%
32 BDEM	Base Demand Allocator	13.9894%	0.3385%	1.1476%	1.6478%	0.4524%	0.4023%	0.0295%	0.4516%	0.0289%	0.1104%	0.7726%
33 PPWDRA	Production Residual Winter Demand Allocator	9.9587%	0.2649%	0.0000%	1.1540%	0.0000%	0.0000%	0.0000%	0.0000%	0.0184%	0.0975%	0.6876%
34 PPWDA	Production Winter Demand Allocator	9.9587%	0.2649%	0.0000%	1.1540%	0.0000%	0.0000%	0.0000%	0.0000%	0.0184%	0.0975%	0.6876%
35 PPSDRA	Production Residual Summer Demand Allocator	8.6447%	0.2388%	0.8014%	1.5113%	0.4815%	0.0000%	0.0000%	0.0000%	0.0155%	0.0904%	0.6392%
36 PPSDA	Production Summer Demand Allocator	8.6447%	0.2388%	0.8014%	1.5113%	0.4815%	0.0000%	0.0000%	0.0000%	0.0155%	0.0904%	0.6392%
37 PPBDRA	Production Residual Base Demand Allocator	13.9894%	0.3385%	1.1476%	1.6478%	0.4524%	0.4024%	0.0295%	0.4516%	0.0289%	0.1104%	0.7726%
38 PPBDA	Production Base Demand Allocator	13.9894%	0.3385%	1.1476%	1.6478%	0.4524%	0.4024%	0.0295%	0.4516%	0.0289%	0.1104%	0.7726%
39 SDALL	Distribution O&M	3.4530%	0.1161%	0.2598%	0.5070%	0.1581%	0.6639%	0.0161%	0.8336%	0.0197%	0.0315%	0.2647%
40 OREV	Total Other Revenue allocator	10.6483%	0.2975%	0.8372%	1.2277%	0.3240%	0.8826%	0.0218%	0.9140%	0.0287%	0.0849%	0.6269%
41 FDIS	Forfeited Discounts	0.5427%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
42 MISCR	Misc Revenue Allocator	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
43 OSSALL	Off-System Sales Allocator	11.9096%	0.3004%	0.7712%	1.4881%	0.3340%	0.2198%	0.0161%	0.2484%	0.0236%	0.1032%	0.7252%
44 INTCRE	Interruptible Credit Allocator (Winter & Summer Peak Prod Plant)	9.4354%	0.2545%	0.3191%	1.2963%	0.1917%	0.0000%	0.0000%	0.0000%	0.0172%	0.0947%	0.6683%
45 OMLF	O&M less fuel	7.7291%	0.2099%	0.4365%	1.0087%	0.2128%	0.6857%	0.0151%	0.9022%	0.0522%	0.0704%	0.5006%
46	Base Rate Revenue at Current Rates	10.1204%	0.3013%	0.7868%	1.1593%	0.3094%	0.7658%	0.0217%	1.0858%	0.0306%	0.0805%	0.6094%
47 VDTREV	VDT Revenue	10.4252%	0.3068%	0.8334%	1.1830%	0.3187%	0.7355%	0.0220%	1.0381%	0.0308%	0.0805%	0.6091%
48 MSCREV	Merger Surcredit Revenue	6.0278%	0.3260%	0.0000%	1.2669%	0.3435%	0.7982%	0.0239%	1.1256%	0.0334%	0.0875%	0.6610%
49 ECRREV	ECR Revenue	10.2545%	0.3033%	0.8218%	1.2012%	0.3160%	0.7152%	0.0215%	1.0188%	0.0303%	0.0604%	0.6107%
50 DSMREV	DSM revenue	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0268%	0.1872%
51	Gross Production Plant	13.0525%	0.3213%	1.0879%	1.6243%	0.4574%	0.3331%	0.0244%	0.3738%	0.0266%	0.1069%	0.7496%
52	Gross Transmission Plant	13.0525%	0.3213%	1.0879%	1.6243%	0.4574%	0.3331%	0.0244%	0.3738%	0.0266%	0.1069%	0.7496%
53	Gross Distribution Plant	4.3308%	0.1493%	0.3252%	0.6347%	0.1956%	4.0725%	0.0215%	5.5670%	0.0390%	0.0394%	0.3349%
54	Gross Prod., Trans, Dist. Plant	10.9805%	0.2801%	0.9050%	1.3870%	0.3946%	1.2300%	0.0237%	1.0165%	0.0296%	0.0907%	0.6501%
55	Dist. Overhead Lines Gross Plant	4.9507%	0.1457%	0.3725%	0.7271%	0.2239%	0.6278%	0.0181%	0.7781%	0.0157%	0.0451%	0.3450%
56	Gross Intangible Plant	10.9805%	0.2801%	0.9050%	1.3870%	0.3946%	1.2300%	0.0237%	1.6195%	0.0296%	0.0907%	0.6501%
57	Gross Total Plant in Service	10.9745%	0.2803%	0.9062%	1.3886%	0.3950%	1.2240%	0.0237%	1.6111%	0.0296%	0.0908%	0.6508%
58	Dist. Underground Lines Gross Plant	8.2175%	0.1894%	0.4880%	0.9136%	0.2812%	0.5015%	0.0224%	0.5896%	0.0144%	0.0565%	0.4457%
59	Gross General Plant	11.2713%	0.2862%	0.9322%	1.4222%	0.4039%	1.0967%	0.0238%	1.4344%	0.0291%	0.0931%	0.6849%
60	Labor Accts 501-507	13.1865%	0.3238%	1.0967%	1.6278%	0.4567%	0.3432%	0.0252%	0.3852%	0.0269%	0.1074%	0.7530%
61	Labor Accts 511-514	13.9350%	0.3379%	1.1463%	1.6470%	0.4528%	0.3996%	0.0293%	0.4487%	0.0260%	0.1102%	0.7717%
62	Labor Accts 535-540	13.0525%	0.3213%	1.0879%	1.6243%	0.4574%	0.3331%	0.0244%	0.3738%	0.0266%	0.1069%	0.7496%
63	Labor Accts 542-545	13.6315%	0.3322%	1.1256%	1.6392%	0.4542%	0.3768%	0.0276%	0.4229%	0.0281%	0.1091%	0.7641%
64	Labor Accts 581-588	3.4808%	0.1297%	0.2554%	0.4982%	0.1554%	1.0683%	0.0449%	1.4238%	0.2092%	0.0316%	0.2444%

Louisville Gas and Electric
Electric Cost of Service Study
(Allocator Percents)

Acct. No.	Account Description	LP-TOD Pri	LP-TOD Sec	Special Contracts-A	Special Contracts-B	Special Contracts-C	PSL	SLE	OL	TLE	STOD-Pri	STOD-Sec
65	Labor Accts 591-598	5.0748%	0.1542%	0.3819%	0.7459%	0.2295%	1.4830%	0.0188%	1.9638%	0.0164%	0.0452%	0.3632%
66	Labor Accts 500-918	10.5747%	0.2704%	0.6686%	1.3068%	0.3885%	0.6544%	0.0273%	0.6819%	0.0543%	0.0862%	0.6098%
67	O&M less Purchased Power	12.5549%	0.3084%	1.0311%	1.5063%	0.4172%	0.6211%	0.0293%	0.6234%	0.0372%	0.1003%	0.7046%
68	Dist. Lines Gross Plant	5.3984%	0.1611%	0.4063%	0.7930%	0.2441%	0.5830%	0.0186%	0.7137%	0.0153%	0.0491%	0.3806%
69	Rate Base	11.0108%	0.2611%	0.9090%	1.3901%	0.3951%	1.2276%	0.0235%	1.6157%	0.0300%	0.0910%	0.8518%
70	Gross Transformer Plant	0.0000%	0.1478%	0.0000%	0.0000%	0.0000%	0.4483%	0.0140%	0.5516%	0.0115%	0.0000%	0.2936%
71	Dpreciation Expense	10.7728%	0.2784%	0.8868%	1.3657%	0.3890%	1.3105%	0.0236%	1.7312%	0.0298%	0.0893%	0.5412%
72	Total Labor	10.6011%	0.2710%	0.8710%	1.3112%	0.3698%	0.5750%	0.0271%	0.7104%	0.0533%	0.0885%	0.6120%
73	Distribution O&M	4.3605%	0.1417%	0.3284%	0.6369%	0.1971%	1.8483%	0.0318%	2.4880%	0.1118%	0.0396%	0.3044%
74	Sales Revenue	10.4137%	0.3011%	0.8322%	1.1830%	0.3169%	0.7365%	0.0220%	1.0374%	0.0309%	0.0821%	0.6163%
75	Distribution Poles, Lines, Transform & Services	4.1597%	0.1549%	0.3131%	0.6111%	0.1881%	0.5331%	0.0187%	0.6531%	0.0187%	0.0378%	0.3486%

LG&E
OAG Proposed Revenue Distribution

Class	Total Revenue @ Current rates 1/	LG&E Proposed: ROR @ Current Rates	LG&E Proposed: Indexed ROR	LG&E Proposed: Increase Amount 1/	LG&E Proposed: Increase Percent	LG&E Proposed: Percent Of System Average	OAG Proposed: ROR @ Current Rates	OAG Proposed: Indexed ROR	OAG Proposed: Increase Amount	OAG Proposed: Increase Percent	OAG Proposed: Percent Of System Average
R	$358,721,834	5.45%	70%	$13,673,276	3.81%	230%	7.22%	93%	$6,987,615	1.95%	118%
GS	$127,902,362	13.17%	169%	$228,601	0.18%	11%	13.61%	175%	$1,059,478	0.83%	50%
LC Pri	$9,970,639	9.89%	127%	$0	0.00%	0%	8.07%	104%	$165,183	1.66%	100%
LC Sec	$145,907,390	10.42%	134%	$0	0.00%	0%	9.99%	129%	$1,812,934	1.24%	75%
LC-TOD Pri	$18,799,071	7.47%	96%	$0	0.00%	0%	5.17%	67%	$389,305	2.07%	125%
LC-TOD Sec	$20,799,838	9.58%	123%	$0	0.00%	0%	7.26%	93%	$344,591	1.66%	100%
LP- Pri	$7,200,364	11.38%	146%	$0	0.00%	0%	9.15%	118%	$89,466	1.24%	75%
LP-Sec	$36,414,465	9.89%	127%	$0	0.00%	0%	8.62%	111%	$452,458	1.24%	75%
LP-TOD Trans	$26,234,221	8.39%	108%	($8,461)	-0.03%	-2%	4.66%	60%	$543,277	2.07%	125%
LP-TOD Pri	$93,343,802	7.16%	92%	$0	0.00%	0%	3.95%	51%	$1,933,032	2.07%	125%
LP-TOD Sec	$2,701,998	10.94%	141%	$0	0.00%	0%	7.99%	103%	$44,764	1.66%	100%
Special Contracts-A	$7,116,358	8.71%	112%	($145,782)	-2.05%	-124%	0.17%	2%	$176,845	2.49%	150%
Special Contracts-B	$10,901,714	3.67%	47%	$0	0.00%	0%	1.50%	19%	$270,913	2.49%	150%
Special Contracts-C	$2,878,344	6.36%	82%	$0	0.00%	0%	0.03%	0%	$71,528	2.49%	150%
PSL	$5,863,941	6.02%	77%	$199,009	3.39%	205%	4.29%	55%	$121,435	2.07%	125%
SLE	$193,369	11.75%	151%	$0	0.00%	0%	0.72%	9%	$4,805	2.49%	150%
OL	$9,026,923	8.71%	112%	$462,434	5.12%	309%	7.51%	97%	$149,549	1.66%	100%
TLE	$227,327	2.07%	27%	$9,376	4.12%	249%	-0.57%	-7%	$5,649	2.49%	150%
STOD-Pri	$754,388	4.24%	55%	$45,334	6.01%	363%	2.84%	37%	$15,622	2.07%	125%
STOD-Sec	$5,466,489	5.68%	73%	$287,867	5.27%	318%	3.99%	51%	$113,204	2.07%	125%
Total Company	$890,424,838	7.77%	100%	$14,751,654	1.66%	100%	7.77%	100%	$14,751,654	1.66%	100%

1/ Per Seelye Exhibit 27.

Louisville Gas and Electric
Electric Customer Cost Analysis

		Residential
Gross Plant		
	369 Services	$17,979,330
	370 Meters	$23,419,433
	Total Gross Plant	$41,398,763
Depreciation Reserve		
	Services (OVHD & UNGD)	9,168,030
	Meters	11,942,050
	Total Depreciation Reserve	$21,110,080
Total Net Plant		$20,288,682
Operation & Maintenance Expenses		
	Dist Oper - Meter	$3.827,846
	Dist Oper - Cust Installations	-$129,111
	Meter Reading	$1,702,884
	Records & Collections	$3,830,537
	Dist Maint - Meters	$0
	Total O & M Expenses	$9,232,156
Depreciation Expense		
	Services	$602,015
	Meters	$764,171
	Total Depreciation Expense	$1,366,186
Revenue Requirement		
	Interest	$497,073
	Equity return	$1.064,750
	Income Tax	$642,949
	Revenue For Return	2.204,771
	O & M Expenses	$9,232.156
	Depreciation Expense	$1,366,186
	Total Customer Revenue Rei	$12,823,113
	Number of Bills	4,301,386
	Monthly Cost	$2.98

	PCT	Cost	WGHT Cost
Debt	47.52%	5.16%	2.45%
Common	52.48%	10.00%	5.25%
Total	100.00%		7.70%

Louisville Gas and Electric
Gas CCOSS
(Summary)

Account Description	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Operating Revenues							
Sales and Transportation	$ 93,106,470	$ 64,534,283	$ 21,745,208	$ 1,649,829	$ 200,259	$ 3,701,009	$ 1,275,882
Forfeited Discounts	$ 1,838,323	$ 1,540,850	$ 276,629	$ 20,844	$ -	$ -	$ -
Miscellaneous Revenue	$ 595,857	$ 81,937	$ 413,779	$ -	$ -	$ 100,140	$ -
Total Operating Revenues	$ 95,540,650	$ 66,157,070	$ 22,435,616	$ 1,670,673	$ 200,259	$ 3,801,149	$ 1,275,882
Pro-Forma Adjustments to Revenues							
VDT Amortization and Surcredit	$ 1,903,311	$ 1,234,925	$ 582,431	$ 57,181	$ 16,785	$ 5,272	$ 6,716
Temperature Normalization	$ 1,645,733	$ 1,218,161	$ 312,553	$ 41,506	$ 4,958	$ 44,251	$ 24,304
Year-End Customer Adjustment	$ 526,355	$ 319,390	$ 143,149	$ -	$ -	$ 63,816	$ -
Rate Switching	$ (29,168)	$ -	$ (42,032)	$ 12,864	$ -	$ -	$ -
Adjustment for special contract to electric generation	$ 4,221,720	$ 2,438,338	$ 1,024,067	$ 78,972	$ 26,112	$ 358,648	$ 295,583
Adjustment to eliminate unbilled revenues	$ (1,203,000)	$ (804,000)	$ (404,000)	$ 5,000	$ -	$ -	$ -
Eliminate VDT from rate refund acct.	$ (352,260)	$ (228,557)	$ (107,795)	$ (10,583)	$ (3,107)	$ (976)	$ (1,243)
Removal of DSM Revenues	$ (1,453,819)	$ (1,466,446)	$ 11,951	$ -	$ 131	$ 545	$ -
Total Revenue Adjustments	$ 5,258,872	$ 2,711,811	$ 1,520,324	$ 184,941	$ 44,879	$ 471,557	$ 325,360
Total Adjusted Revenue	$100,799,522	$ 68,868,881	$ 23,955,941	$ 1,855,614	$ 245,138	$ 4,272,706	$ 1,601,242
Expenses							
Operation and Maintenance Expenses	$ 52,256,676	$ 37,683,234	$ 10,481,642	$ 847,177	$ 105,796	$ 2,082,786	$ 1,056,040
Depreciation and Amortization Expenses	$ 19,232,812	$ 14,196,984	$ 3,558,330	$ 247,583	$ 44,789	$ 801,980	$ 383,147
Other Expenses (ITC amortization, Reg Credits, Accretion)	$ (171,937)	$ (121,408)	$ (35,085)	$ (2,592)	$ (454)	$ (6,385)	$ (4,012)
Other Taxes	$ 5,674,634	$ 3,978,512	$ 1,176,565	$ 89,565	$ 14,854	$ 279,591	$ 135,547
Total Operating Expenses	$ 76,992,185	$ 55,737,321	$ 15,181,452	$ 1,181,732	$ 164,984	$ 3,155,972	$ 1,570,723
Pro-Forma Adjustments to Expenses							
Eliminate DSM Expenses	(1,921,602)	$ (1,938,292)	$ 15,797	$ -	$ 173	$ 720	$ -
Year-End Customer Adjustment	190,929	115855	51926	0	0	23148	0
Depreciation Expenses	3,488,855	$ 2,575,350	$ 645,485	$ 44,912	$ 8,125	$ 145,480	$ 69,503
Labor Adjustment	733,940	$ 511,914	$ 155,493	$ 12,764	$ 1,742	$ 34,533	$ 17,493
Pensions/Post Retirement Benefits Adjmt. *(see Funct Assig)*							
Eliminate Advertising Expenses *(see Func Assign)*							
Rate Case Expenses	123,722	$ 89,218	$ 24,816	$ 2,006	$ 250	$ 4,931	$ 2,500
Eliminate Amort. One-Utility Costs *(see Func Assign))*							
Normalize 925 Injuries/Damages Adjmt. *(See Func Assign)*							
Adjustment for new credit facilities bank fees	617,418	$ 430,385	$ 132,860	$ 10,041	$ 1,545	$ 28,785	$ 13,803
Adjustment to annualize vehicle fuel costs	55,636	$ 40,120	$ 11,159	$ 902	$ 113	$ 2,217	$ 1,124
Total Expense Adjustments	$ 3,288,898	$ 1,824,550	$ 1,037,537	$ 70,624	$ 11,948	$ 239,816	$ 104,424
Net Income Before Income Taxes	$ 20,518,440	$ 11,307,010	$ 7,736,952	$ 603,257	$ 68,206	$ 876,918	$ (73,904)
Income Taxes	$ 3,486,533	$ 513,074	$ 1,675,527	$ 163,729	$ 42,295	$ 800,300	$ 291,608

Louisville Gas and Electric
Gas CCOSS
(Summary)

Account Description	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Net Operating Income (Pro-Forma)	$ 17,031,907	$ 10,793,936	$ 6,061,425	$ 439,529	$ 25,911	$ 78,618	$ (365,512)
Unadjusted Net Cost Rate Base	$441,457,053	$307,727,146	$ 94,995,404	$ 7,179,082	$ 1,104,796	$ 20,581,634	$ 9,868,990
Depreciation Adjustment	$ (3,488,855)	$ (2,575,350)	$ (645,485)	$ (44,912)	$ (8,125)	$ (145,480)	$ (69,503)
Cash Woking Capital Adjustment	$ 517,847	$ 373,429	$ 103,870	$ 8,395	$ 1,048	$ 20,640	$ 10,465
Net Cost Rate Base	$438,486,045	$305,525,225	$ 94,453,789	$ 7,142,566	$ 1,097,719	$ 20,456,794	$ 9,809,952
Rate of Return -- Pro-Forma	3.88%	3.53%	6.42%	6.15%	2.36%	0.37%	-3.73%

Louisville Gas and Electric
Gas CCOSS
(Rate Base)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Plant-in-Service									
	Underground Storage Plant								
350-357	Underground Storage Plant		$ 61,770,449	$ 41,045,197	$ 19,155,076	$ 1,570,176	$ -	$ -	$ -
358	Asset Retire Obligations Gas Plant		$ 541,132	$ 359,571	$ 167,806	$ 13,755	$ -	$ -	$ -
	Sub-total		$ 62,311,581	$ 41,404,768	$ 19,322,882	$ 1,583,931	$ -	$ -	$ -
	Transmission Plant								
365-371	Transmission	$ 12,901,908							
	Demand		$ 12,901,908	$ 8,573,053	$ 4,000,894	$ 327,960	$ -	$ -	$ -
	Customer		$ -						
	Sub-total		$ 12,901,908	$ 8,573,053	$ 4,000,894	$ 327,960	$ -	$ -	$ -
	Distribution Plant								
374	Land and Land Rights		$ 133,743	$ 73,806	$ 34,090	$ 2,683	$ 889	$ 12,211	$ 10,065
375	Structures and Improvements		$ 729,373	$ 402,502	$ 185,913	$ 14,631	$ 4,846	$ 66,591	$ 54,891
376	Mains	$279,586,446							
	L/M Pressure								
	Demand		$208,340,477	$116,618,842	$ 55,471,558	$ 4,879,308	$ 966,334	$ 21,138,257	$ 9,266,178
	Customer		$ 36,241,631	$ 33,389,038	$ 2,827,574	$ 22,795	$ 445	$ 1,779	$ -
	H Pressure								
	Demand		$ 32,565,757	$ 17,971,308	$ 8,300,806	$ 653,242	$ 216,387	$ 2,973,210	$ 2,450,803
	Customer		$ 2,438,581	$ 2,246,136	$ 190,231	$ 1,556	$ 120	$ 516	$ 22
378	Meas. & Reg. Station Equip.- Gen.		$ 8,254,321	$ 4,555,120	$ 2,103,974	$ 165,575	$ 54,847	$ 753,608	$ 621,196
379	Meas. & Reg. Station Equip.- City Gate		$ 3,864,491	$ 2,132,607	$ 985,034	$ 77,519	$ 25,678	$ 352,823	$ 290,830
380	Services		$137,878,756	$126,896,285	$ 10,761,244	$ 100,238	$ 33,780	$ 81,431	$ 5,777
381	Meters		$ 22,084,789	$ 17,068,163	$ 3,978,641	$ 224,448	$ 75,773	$ 697,261	$ 40,504
382	Meter Installations		$ 9,381,447	$ 7,250,423	$ 1,690,096	$ 95,344	$ 32,188	$ 296,191	$ 17,206
383	House Regulators		$ 4,941,391	$ 3,818,939	$ 890,208	$ 50,219	$ 16,954	$ 156,010	$ 9,063
384	House Regulators Installations		$ 5,298,054	$ 4,094,585	$ 954,460	$ 53,844	$ 18,178	$ 167,270	$ 9,717
385	Indust. Meas. & Reg. Station Equip.		$ 159,362	$ 123,162	$ 28,710	$ 1,620	$ 547	$ 5,031	$ 292
387	Other Equipment		$ 51,112	$ 39,502	$ 9,208	$ 519	$ 175	$ 1,614	$ 94
388	Asset Retire Obligations Gas Plant - City Gate		$ 1,063	$ 587	$ 271	$ 21	$ 7	$ 97	$ 80
388	Asset Retire Obligations Gas Plant - Mains	$ 29,707							
	L/M Pressure								
	Demand		$ 22,137	$ 12,391	$ 5,894	$ 518	$ 103	$ 2,246	$ 985
	Customer		$ 3,851	$ 3,548	$ 300	$ 2	$ 0	$ 0	$ -
	H Pressure								
	Demand		$ 3,460	$ 1,909	$ 882	$ 69	$ 23	$ 316	$ 260
	Customer		$ 259	$ 239	$ 20	$ 0	$ 0	$ 0	$ 0
	Sub-total		$472,394,055	$336,699,093	$ 88,419,113	$ 6,344,151	$ 1,447,273	$ 26,706,462	$ 12,777,962

Louisville Gas and Electric
Gas CCOSS
(Rate Base)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
	Other Plant-In-Service								
117	Gas Stored Underground/Non-Current		$ 2,139,990	$ 1,421,979	$ 663,613	$ 54,398	$ -	$ -	$ -
301-303	Intangible Plant		$ 1,187	$ 839	$ 242	$ 18	$ 3	$ 58	$ 28
389-399	General Plant		$ 9,038,473	$ 6,382,251	$ 1,844,359	$ 136,269	$ 23,888	$ 440,800	$ 210,905
	Common Utility Plant		$ 46,796,536	$ 33,043,993	$ 9,649,138	$ 705,531	$ 123,679	$ 2,282,236	$ 1,091,958
	Sub-total		$ 57,976,186	$ 40,849,062	$ 12,057,353	$ 896,216	$ 147,570	$ 2,723,095	$ 1,302,891
	TOTAL PLANT-IN-SERVICE		$605,583,729	$427,525,977	$123,800,242	$ 9,152,259	$ 1,594,842	$ 29,429,557	$ 14,080,853
	Construction Work In Progress								
	Underground Storage		$ 5,807,802	$ 3,859,165	$ 1,801,005	$ 147,632	$ -	$ -	$ -
	Transmission		$ 937,105	$ 622,687	$ 290,597	$ 23,821	$ -	$ -	$ -
	Distribution Mains	$ 25,956,033							
	L/M Pressure								
	Demand		$ 19,341,754	$ 10,826,571	$ 5,149,826	$ 452,981	$ 89,712	$ 1,962,417	$ 860,246
	Customer		$ 3,364,573	$ 3,099,746	$ 262,504	$ 2,116	$ 41	$ 165	$ -
	H Pressure								
	Demand		$ 3,023,315	$ 1,668,407	$ 770,624	$ 60,645	$ 20,089	$ 276,025	$ 227,526
	Customer		$ 226,391	$ 208,525	$ 17,660	$ 144	$ 11	$ 48	$ 2
	Other Distribution		$ 29,497,248	$ 21,024,178	$ 5,521,070	$ 396,142	$ 90,371	$ 1,667,606	$ 797,882
	General		$ 502,110	$ 354,550	$ 102,459	$ 7,570	$ 1,327	$ 24,488	$ 11,716
	Common		$ 9,331,195	$ 6,588,948	$ 1,904,091	$ 140,682	$ 24,661	$ 455,076	$ 217,736
	Sub-total		$ 72,031,493	$ 48,252,777	$ 15,819,837	$ 1,231,734	$ 226,212	$ 4,385,825	$ 2,115,108
	TOTAL GAS PLANT AT ORIGINAL COST		$677,615,222	$475,778,754	$139,620,079	$ 10,383,993	$ 1,821,055	$ 33,815,381	$ 16,195,961
	LESS								
	Depreciation Reserve								
	Underground Storage		$ 33,664,748	$ 22,369,535	$ 10,439,471	$ 855,742	$ -	$ -	$ -
	Transmission		$ 12,066,636	$ 8,018,032	$ 3,741,876	$ 306,728	$ -	$ -	$ -
	Distribution		$159,528,317	$113,703,886	$ 29,859,293	$ 2,142,431	$ 488,747	$ 9,018,820	$ 4,315,141
	General and Intangible		$ 5,750,062	$ 4,060,237	$ 1,173,338	$ 86,691	$ 15,197	$ 280,427	$ 134,173
	Common		$ 21,838,804	$ 15,420,827	$ 4,456,350	$ 329,254	$ 57,718	$ 1,065,064	$ 509,590
	Sub-total		$232,848,567	$163,572,517	$ 49,670,327	$ 3,720,847	$ 561,661	$ 10,364,311	$ 4,958,904
	Other Rate Base Items								
	Customer Advances for Construction		$ 8,042,634	$ 5,724,167	$ 1,494,059	$ 108,987	$ 23,447	$ 468,130	$ 225,844
	Accum. Deferred Income Taxes		$ 51,050,223	$ 36,047,609	$ 10,417,131	$ 769,662	$ 134,921	$ 2,489,686	$ 1,191,214
	FAS 109 Deferred Income Taxes		$ 4,502,012	$ 3,178,963	$ 918,665	$ 67,875	$ 11,898	$ 219,560	$ 105,051
	Asset Retirement Obligation - Net Assets		$ 149,250	$ 104,846	$ 31,837	$ 2,385	$ 360	$ 6,643	$ 3,179
	Asset Retirement Obligation - Liabilities		$ (7,928,279)	$ (5,569,493)	$ (1,691,229)	$ (126,691)	$ (19,124)	$ (352,895)	$ (168,846)

Louisville Gas and Electric
Gas CCOSS
(Rate Base)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
	Asset Retirement Obligation - Regulatory Assets		$ 5,354,546	$ 3,761,486	$ 1,142,210	$ 85,564	$ 12,916	$ 238,336	$ 114,034
	Asset Retirement Obligation - Regulatory Liabilities		$ (128,566)	$ (90,316)	$ (27,425)	$ (2,054)	$ (310)	$ (5,723)	$ (2,738)
	Accum Depr. Reclassification		$ 2,424,396	$ 1,711,916	$ 494,714	$ 36,552	$ 6,407	$ 118,236	$ 56,571
PLUS									
	Materials and Supplies		$ 51,524	$ 36,382	$ 10,514	$ 777	$ 136	$ 2,513	$ 1,202
	Prepayments		$ 817,525	$ 577,271	$ 166,821	$ 12,325	$ 2,161	$ 39,870	$ 19,076
	Gas Stored Underground		$ 52,559,620	$ 34,924,790	$ 16,298,789	$ 1,336,041	$ -	$ -	$ -
	Cash Working Capital		$ 6,727,945	$ 4,851,643	$ 1,349,491	$ 109,072	$ 13,621	$ 268,155	$ 135,963
ADJUSTMENTS									
	Unamortized Debt		$ -						
	Regulatory		$ -						
	Customer Advances for Construction		$ -						
	Depreciation Adjustment		$ -						
NET COST RATE BASE			$441,457,053	$307,727,146	$ 94,995,404	$ 7,179,082	$ 1,104,796	$ 20,581,634	$ 9,868,990

Louisville Gas and Electric
Gas COOSS
(Expenses)

Acct. No.	Account Description		Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
O & M Expenses									
	Labor Expenses								
807-813	Procurement Expenses	$ 588,875							
	Demand		$ 69,134	$ 38,151	$ 17,622	$ 1,387	$ 459	$ 6,312	$ 5,203
	Commodity		$ 519,741	$ 238,453	$ 122,254	$ 13,455	$ 4,180	$ 94,397	$ 47,003
	Sub-total		$ 588,875	$ 276,604	$ 139,875	$ 14,841	$ 4,640	$ 100,708	$ 52,206
	Storage Operating Expenses								
814	Operations Supervision and Engineer	$ 506,600							
	Demand		$ 141,741	$ 94,184	$ 43,954	$ 3,603	$ -	$ -	$ -
	Commodity		$ 364,859	$ 235,156	$ 114,444	$ 10,480	$ (335)	$ 3,172	$ 1,943
815	Maps and Records		$ -						
816	Well Expenses		$ 465,962	$ 309,622	$ 144,495	$ 11,845	$ -	$ -	$ -
817	Lines Expenses		$ 568,150	$ 377,524	$ 176,184	$ 14,442	$ -	$ -	$ -
818	Compressor Station Exp - Payroll		$ 1,183,131	$ 762,542	$ 371,107	$ 33,982	$ (1,065)	$ 10,284	$ 6,300
819	Compressor Station Fuel and Power		$ 785,264	$ 506,112	$ 246,310	$ 22,555	$ (720)	$ 6,826	$ 4,181
820	Measurement and Regulator Station		$ -						
821	Purification of Natural Gas		$ 1,666,277	$ 1,073,935	$ 522,653	$ 47,860	$ (1,528)	$ 14,484	$ 8,873
823	Gas losses		$ -						
824	Other Expenses		$ (1,031)	$ (665)	$ (323)	$ (30)	$ 1	$ (9)	$ (5)
825	Storage Well Royalties		$ 44,077	$ 29,285	$ 13,668	$ 1,120	$ -	$ -	$ -
826	Rents		$ 40,158	$ 26,684	$ 12,453	$ 1,021	$ -	$ -	$ -
	Sub-total		$ 5,256,587	$ 3,414,382	$ 1,644,945	$ 140,876	$ (3,656)	$ 34,757	$ 21,292
	Storage Maintenance Expenses								
830	Maintenance Super and Eng.	$ 317,059							
	Demand		$ 124,335	$ 82,676	$ 38,558	$ 3,101	$ -	$ -	$ -
	Commodity		$ 192,724	$ 124,213	$ 60,451	$ 5,536	$ (177)	$ 1,675	$ 1,026
831	Maintenance of Structures		$ -						
832	Maintenance of Reservoirs		$ 483,560	$ 321,316	$ 149,953	$ 12,292	$ -	$ -	$ -
833	Maintenance of Lines		$ 114,376	$ 76,001	$ 35,468	$ 2,907	$ -	$ -	$ -
834	Main of Compressor Station Equipment		$ 895,766	$ 577,345	$ 280,977	$ 25,728	$ (821)	$ 7,767	$ 4,770
835	Main of Meas and Reg Sta. Equip		$ 63,792	$ 42,388	$ 19,782	$ 1,622	$ -	$ -	$ -
836	Main of Purification Equip		$ 296,274	$ 190,952	$ 92,931	$ 8,510	$ (272)	$ 2,575	$ 1,578
837	Main of Other Equipment		$ 92,217	$ 61,276	$ 28,597	$ 2,344	$ -	$ -	$ -
	Sub-total		$ 2,263,065	$ 1,470,109	$ 706,715	$ 62,100	$ (1,270)	$ 12,037	$ 7,374
	Transmission Expense								
850-867	Transmission Expense		$ 1,234,372	$ 820,215	$ 382,780	$ 31,377	$ -	$ -	$ -
	Sub-total		$ 1,234,372	$ 820,215	$ 382,780	$ 31,377	$ -	$ -	$ -
	Distribution Expense								
870	Operation Supr and Engr		$ -						
871	Dist Load Dispatching		$ 354,548	$ 162,664	$ 83,397	$ 9,178	$ 2,852	$ 64,394	$ 32,064
872	Compr. Station Labor and Exp.		$ -						
873	Compr. Station Fuel and Power		$ -						
874.01	Other Mains/Serv. Expenses		$ 3,417,868	$ 2,432,592	$ 634,928	$ 40,316	$ 8,964	$ 198,091	$ 95,977
874.02	Leak Survey-Mains		$ -						
874.03	Leak Survey - Service		$ -						
874.04	Locate Main per Request		$ -						
874.05	Check Stop Box Access		$ -						
874.06	Patrolling Mains		$ -						
874.07	Check/Grease Valves		$ -						
874.08	Opr. Odor Equipment		$ -						
874.09	Locate and Inspect Valve Boxes		$ -						

Louisville Gas and Electric
Gas CCOSS
(Expenses)

Acct. No.	Account Description		Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
874.1	Cut Grass - Right of Way		$ -						
875	Meas and Reg Station Exp.- General		$ 620,859	$ 347,478	$ 160,406	$ 12,630	$ 4,184	$ 57,487	$ 47,380
876	Meas and Reg Station Exp.- Industrial		$ 318,886	$ 244,904	$ 57,088	$ 3,221	$ 1,087	$ 10,005	$ 581
877	Meas and Reg Station Exp. - City Gate		$ 161,563	$ 89,158	$ 41,181	$ 3,241	$ 1,074	$ 14,750	$ 12,159
878	Meter and House Reg. Expense		$ 18,921	$ 14,823	$ 3,409	$ 192	$ 65	$ 597	$ 35
879	Customer Installation Expense		$ 221,770	$ 171,394	$ 39,952	$ 2,254	$ 781	$ 7,002	$ 407
880	Other Expenses		$ 3,190,567	$ 2,278,355	$ 598,309	$ 42,929	$ 9,793	$ 160,716	$ 88,465
881	Rents		$ 9,859	$ 6,885	$ 1,808	$ 130	$ 30	$ 646	$ 291
	Sub-total		$ 8,327,441	$ 5,748,049	$ 1,620,569	$ 120,091	$ 29,609	$ 533,588	$ 275,335
	Distribution Maintenance Expenses								
885	Maintenance Supr and Engr		$.						
886	Maintenance Structures		$ 536,206	$ 205,904	$ 138,676	$ 10,758	$ 3,563	$ 48,955	$ 40,353
887	Maintenance Mains	$ 6,326,382							
	L/M Pressure								
	Demand		$ 4,714,254	$ 2,636,810	$ 1,255,191	$ 110,407	$ 21,666	$ 476,309	$ 209,872
	Customer		$ 620,063	$ 755,516	$ 63,981	$ 518	$ 10	$ 40	$ -
	H Pressure								
	Demand		$ 738,880	$ 406,048	$ 187,828	$ 14,781	$ 4,896	$ 67,277	$ 55,456
	Customer		$ 55,179	$ 50,824	$ 4,304	$ 35	$ 3	$ 12	$ 1
888	Maintenance Comp. Station Equip.		$ -						
889	Maintenance Meas and Reg. General		$ 64,371	$ 35,523	$ 18,408	$ 1,291	$ 428	$ 5,877	$ 4,844
890	Maintenance Meas and Reg - Industrial		$ 98,086	$ 75,805	$ 17,670	$ 997	$ 337	$ 3,097	$ 180
891	Maintenance Meas and Reg.-City Gate		$ 264,782	$ 148,108	$ 67,486	$ 5,311	$ 1,759	$ 24,172	$ 19,025
892	Maintenance Services		$ 2,105,216	$ 2,020,381	$ 171,334	$ 1,590	$ 538	$ 1,298	$ 92
893	Maintenance Meters and House Reg.		$.						
894	Maintenance Other Equipment		$ 255,307	$ 181,970	$ 47,786	$ 3,429	$ 782	$ 14,434	$ 6,906
	Sub-total		$ 9,740,330	$ 6,607,488	$ 1,968,884	$ 149,119	$ 34,181	$ 643,469	$ 337,420
Total O&M Expense			$ 52,258,676	$ 37,683,234	$ 10,481,842	$ 847,177	$ 105,790	$ 2,082,760	$ 1,056,040
Customer Accounts Expense									
901	Supervision		$ 538,800	$ 486,802	$ 45,924	$ 3,026	$ 323	$ 2,235	$ 89
902	Meter Reading		$ 1,732,200	$ 1,564,441	$ 147,848	$ 11,665	$ 1,038	$ 7,168	$ 285
903	Customer Records and Collection		$ 3,896,904	$ 3,519,377	$ 332,145	$ 26,241	$ 2,335	$ 16,168	$ 640
904	Uncollectible Accounts		$ 645,241	$ 582,731	$ 54,998	$ 4,345	$ 387	$ 2,677	$ 106
905	Misc. Cust Accounts Expense		$ 167,812	$ 151,555	$ 14,303	$ 1,130	$ 101	$ 890	$ 28
	Sub-total		$ 6,981,017	$ 6,304,706	$ 595,014	$ 47,009	$ 4,182	$ 28,980	$ 1,147
Customer Service & Information Expenses									
907-910	Customer Service		$ 2,677,108	$ 2,423,021	$ 224,525	$ 16,600	$ 1,292	$ 10,985	$ 485
	Sub-total		$ 2,677,108	$ 2,423,021	$ 224,525	$ 16,600	$ 1,292	$ 10,985	$ 485
Sales Expenses									
911-916	Sales Expenses		$ 29,965	$ 27,121	$ 2,513	$ 186	$ 14	$ 123	$ 5
	Sub-total		$ 29,965	$ 27,121	$ 2,513	$ 186	$ 14	$ 123	$ 5
Total - Customer Accounts - Services			$ 9,688,090	$ 8,754,847	$ 822,052	$ 63,897	$ 5,483	$ 40,057	$ 1,637
Administrative & General Expenses									
	Labor-Related		$ 3,438,447	$ 2,398,771	$ 729,833	$ 60,202	$ 8,114	$ 161,487	$ 82,040
920	Admin and General Salaries		$ 1,771,717	$ 1,234,976	$ 376,059	$ 31,020	$ 4,181	$ 83,209	$ 42,273
921	Office Supplies and Expense		$ (327,510)	$ (226,291)	$ (69,616)	$ (5,734)	$ (773)	$ (15,382)	$ (7,814)
922	Admin. Expenses Transferred		$ 1,997,549	$ 1,392,253	$ 423,951	$ 34,970	$ 4,713	$ 93,806	$ 47,858
923	Outside Services Employed		$ 208,312	$ 148,264	$ 42,922	$ 3,192	$ 560	$ 10,396	$ 4,979
924	Property Insurance		$ 579,206	$ 403,738	$ 122,940	$ 10,141	$ 1,367	$ 27,203	$ 13,820
925	Injuries and Damages		$ 5,706,590	$ 3,977,781	$ 1,211,262	$ 92,913	$ 13,460	$ 268,011	$ 130,157
926	Employee Pensions and Benefits		$ 518,055	$ 363,746	$ 106,743	$ 7,939	$ 1,392	$ 25,853	$ 12,382
927	Franchise Requirement		$ 78,843	$ 55,359	$ 18,245	$ 1,208	$ 212	$ 3,935	$ 1,884
928	Regulatory Commission Fee		$ (899,875)	$ (627,258)	$ (191,004)	$ (15,755)	$ (2,123)	$ (42,263)	$ (21,471)
929	Duplicate Charges -Credit		$ (29,965)	$ (21,039)	$ (6,174)	$ (459)	$ (81)	$ (1,495)	$ (716)
930.1	General Advertising Expense		$ 69,065	$ 48,142	$ 14,660	$ 1,200	$ 163	$ 3,244	$ 1,648
930.2	Misc. General Expense		$ 345,372	$ 242,499	$ 71,163	$ 5,293	$ 928	$ 17,235	$ 8,255
931	Rents								

Louisville Gas and Electric
Gas CCOSS
(Expenses)

Acct. No.	Account Description		Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
935	Maintenance of General Plant		1,700,338	1,200,822	340,959	25,635	4,494	82,823	39,675
	Sub-total		15,155,910	10,585,559	3,196,042	258,774	36,612	718,160	360,768
Depreciation Expense									
	Underground Storage Plant								
350-357	Underground Storage Plant		1,362,711	905,494	422,578	34,639	-	-	-
358	Asset Retire Obligations Gas Plant		9,054	6,016	2,808	230	-	-	-
	Sub-total		1,371,765	911,510	425,386	34,870	-	-	-
	Transmission Plant								
365-371	Transmission		216,806	144,064	67,232	5,511	-	-	-
	Sub-total		216,806	144,064	67,232	5,511	-	-	-
	Distribution Plant								
374	Land and Land Rights		2,184	1,205	557	44	15	199	164
375	Structures and Improvements		24,023	13,754	6,353	500	168	2,275	1,878
376	Mains	$ 6,050,220							
	L/M Pressure								
	Demand		4,508,485	2,523,619	1,200,398	105,588	20,911	457,430	200,519
	Customer		784,205	722,535	61,188	493	10	30	-
	H Pressure								
	Demand		704,719	386,897	179,028	14,136	4,665	84,340	53,055
	Customer		52,771	48,606	4,117	34	3	11	0
378	Meas. & Reg. Station Equip.- Gen.		258,001	142,377	65,763	5,175	1,714	23,555	19,416
379	Meas. & Reg. Station Equip.- City Gate		122,383	67,628	31,190	2,455	813	11,172	9,209
380	Services		5,852,940	6,388,735	456,814	4,235	1,434	3,457	245
381	Meters		673,531	520,538	121,339	6,845	2,311	21,265	1,235
382	Meter Installations		290,691	224,660	52,389	2,954	997	9,178	533
383	House Regulators		116,500	90,037	20,986	1,184	400	3,678	214
384	House Regulators Installations		111,104	85,868	20,018	1,129	381	3,508	204
385	Indust. Meas. & Reg. Station Equip.		6,760	4,459	1,030	69	20	182	11
387	Other Equipment		1,208	932	217	12	4	38	2
388	Asset Retire Obligations Gas Plant - City Gate		2	1	1	0	0	0	0
388	Asset Retire Obligations Gas Plant - Mains	$ 63							
	L/M Pressure								
	Demand		47	20	13	1	0	5	2
	Customer		8	7	1	0	0	0	-
	H Pressure								
	Demand		7	4	2	0	0	1	1
	Customer		1	1	0	0	0	0	0
	Sub-total		13,509,497	10,221,784	2,221,991	144,884	33,801	800,332	258,668
	Other Plant-In-Service								
117	Gas Stored Underground/Non-Current		-						
301-303	Intangible Plant		1,851,569	1,307,431	377,825	27,915	4,894	90,300	43,205
389-399	General Plant		414,205	292,470	84,521	6,245	1,095	20,201	9,665
	Common Utility Plant		1,858,008	1,319,717	381,375	28,178	4,939	91,148	43,611
	Sub-total		4,134,742	2,919,626	843,721	62,336	10,928	201,649	96,481
TOTAL DEPRECIATION ESPENSE			19,232,812	14,196,984	3,558,330	247,583	44,789	801,980	383,147
Regulatory Credits and Accretion									
	Regulatory Credits		(438,274)	(308,082)	(89,025)	(6,578)	(1,153)	(21,277)	(10,180)
	Accretion		427,171	301,634	87,167	6,440	1,129	20,833	9,968
	Amortization of Income Tax Credits		(162,834)	(114,980)	(33,227)	(2,455)	(430)	(7,941)	(3,800)
	Sub-total		(171,937)	(121,408)	(35,085)	(2,592)	(454)	(8,385)	(4,012)
Taxes Other Than Income									
	Property Taxes		3,776,543	2,653,056	778,655	57,904	10,155	188,563	90,313
	Unemployment Insurance		32,504	22,871	6,886	565	77	1,529	775
	Federal Old Age & Survivor Insurance		1,227,755	856,344	260,114	21,352	2,914	57,769	29,263
	Public Service Commission Fee		681,570	478,556	140,435	10,445	1,832	34,013	18,290
	Miscellaneous		(45,738)	(32,114)	(9,424)	(701)	(123)	(2,282)	(1,093)
	Sub-total		5,674,634	3,978,512	1,176,585	89,585	14,654	279,591	135,547
	Interest Expense		10,397,327	7,300,349	2,142,330	159,332	27,942	518,863	248,511

Louisville Gas and Electric
Gas CCOSS
(Revenue)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Operating Revenues									
	Sales and Transportation	REVUC	$ 93,106,470	$ 64,534,283	$ 21,745,208	$ 1,649,829	$ 200,259	$ 3,701,009	$ 1,275,882
	Forfeited Discounts	REVFD	$ 1,838,323	$ 1,540,850	$ 276,629	$ 20,844	$ -	$ -	$ -
	Miscellaneous Revenue	REVMISC	$ 595,857	$ 81,937	$ 413,779	$ -	$ -	$ 100,140	$ -
Total Operating Revenues			$ 95,540,650	$ 66,157,070	$ 22,435,616	$ 1,670,673	$ 200,259	$ 3,801,149	$ 1,275,882
Pro-Forma Adjustments to Revenues									
	VDT Amortization and Surcredit	REVVDT	$ 1,903,311	$ 1,234,925	$ 582,431	$ 57,181	$ 16,785	$ 5,272	$ 6,716
	Temperature Normalization	REVADJ1	$ 1,645,733	$ 1,218,161	$ 312,553	$ 41,506	$ 4,958	$ 44,251	$ 24,304
	Year-End Customer Adjustment	REVADJ2	$ 526,355	$ 319,390	$ 143,149	$ -	$ -	$ 63,816	$ -
	Rate Switching	REVADJ3	$ (29,168)	$ -	$ (42,032)	$ 12,864	$ -	$ -	$ -
	Adjustment for special contract to electric generatioi	RBTHP	$ 4,221,720	$ 2,438,338	$ 1,024,067	$ 78,972	$ 26,112	$ 358,648	$ 295,583
	Adjustment to eliminate unbilled revenues	REVUB	$ (1,203,000)	$ (804,000)	$ (404,000)	$ 5,000	$ -	$ -	$ -
	Eliminate VDT from rate refund acct.	REVVDT	$ (352,260)	$ (228,557)	$ (107,795)	$ (10,583)	$ (3,107)	$ (976)	$ (1,243)
	Removal of DSM Revenues	REVADJ4	$ (1,453,819)	$ (1,466,446)	$ 11,951	$ -	$ 131	$ 545	$ -
Total Revenue Adjustments			$ 5,258,872	$ 2,711,811	$ 1,520,324	$ 184,941	$ 44,879	$ 471,557	$ 325,360
Total Adjusted Revenue			$100,799,522	$ 68,868,881	$ 23,955,941	$ 1,855,614	$ 245,138	$ 4,272,706	$ 1,601,242

Louisville Gas and Electric
Gas CCOSS
(Allocation Amount)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
1	Procurement Expenses		$ 44,604,231	$ 20,464,024	$ 10,491,813	$ 1,154,680	$ 358,749	$ 8,101,129	$ 4,033,837
2	Storage		$ 24,047,389	$ 15,498,824	$ 7,542,835	$ 690,700	$ (22,051)	$ 209,030	$ 128,050
3	Transmission		$ 24,047,389	$ 15,498,824	$ 7,542,835	$ 690,700	$ (22,051)	$ 208,030	$ 128,050
4	Distribution		$ 44,604,231	$ 20,464,024	$ 10,491,813	$ 1,154,680	$ 358,749	$ 8,101,129	$ 4,033,837
5	Adjusted Deliveries		$ 47,757,220	$ 22,405,080	$ 11,210,089	$ 1,182,410	$ 368,186	$ 8,343,343	$ 4,248,113
6	Procurement Expenses		$ 590,403	$ 325,812	$ 150,490	$ 11,843	$ 3,923	$ 53,903	$ 44,432
7	Storage		$ 12,340,000	$ 8,199,677	$ 3,826,646	$ 313,677	$ -	$ -	$ -
8	Transmission		$ 12,340,000	$ 8,199,677	$ 3,826,646	$ 313,677	$ -	$ -	$ -
9	Distribution Structures		$ 590,403	$ 325,812	$ 150,490	$ 11,843	$ 3,923	$ 53,903	$ 44,432
10	High Pressure Distribution Mains		$ 590,403	$ 325,812	$ 150,490	$ 11,843	$ 3,923	$ 53,903	$ 44,432
11	Low/Medium Pressure Distribution Mains		$ 500,974	$ 325,812	$ 149,179	$ 11,062	$ 785	$ 14,136	$ -
12	High Pressure Distrib Mains (yr-end cust.)		$ 326,002	$ 300,275	$ 25,431	$ 208	$ 16	$ 69	$ 3
13	Low/Med Pres. Distrib Mains (yr-end cust.)		$ 325,929	$ 300,275	$ 25,429	$ 205	$ 4	$ 16	$ -
14	Services		$151,937,410	$139,835,124	$ 11,858,502	$ 110,458	$ 37,225	$ 89,734	$ 6,366
15	Meters		$ 46,190,089	$ 35,697,872	$ 8,321,283	$ 469,430	$ 158,478	$ 1,458,313	$ 84,713
16	Customer Count (Average)		$ 325,556	$ 299,990	$ 25,271	$ 208	$ 16	$ 68	$ 3
17	Customer Accounts		$ 6,981,017	$ 6,304,706	$ 595,014	$ 47,009	$ 4,182	$ 28,960	$ 1,147
18	Customer Service		$ 331,448	$ 299,990	$ 27,798	$ 2,080	$ 160	$ 1,360	$ 60
19	Forfeited Discounts		$ 1,838,323	$ 1,540,850	$ 276,629	$ 20,844	$ -	$ -	$ -
20	Net Income Before Income Tax		$ 20,518,438	$ 9,354,252	$ 7,048,147	$ 618,538	$ 134,681	$ 2,474,619	$ 888,201
21	Interest Expense		$ 10,397,327	$ 7,669,742	$ 2,270,850	$ 153,873	$ 15,421	$ 220,256	$ 67,185
22	Interest Adjustment		$ 330,392	$ 243,719	$ 72,160	$ 4,890	$ 490	$ 6,999	$ 2,135
23	Taxable Income		$ 9,790,719	$ 1,440,791	$ 4,705,137	$ 459,775	$ 118,770	$ 2,247,364	$ 818,881
24	Total Distribution Expense		$ 26,974,573	$ 19,453,189	$ 5,778,232	$ 391,076	$ 60,005	$ 906,068	$ 386,004
25	Meter Cost		$ 46,190,089	$ 35,697,872	$ 8,321,283	$ 469,430	$ 158,478	$ 1,458,313	$ 84,713
26	Number of Customers		$ 326,002	$ 300,275	$ 25,431	$ 208	$ 16	$ 69	$ 3
27	Services Cost		$151,937,410	$139,835,124	$ 11,858,502	$ 110,458	$ 37,225	$ 89,734	$ 6,366
28	Actual Revenue		$ 93,106,470	$ 64,534,283	$ 21,745,208	$ 1,649,829	$ 200,259	$ 3,701,009	$ 1,275,882
29	DSM Allocation		$ 1,008,572	$ 1,017,332	$ (8,291)	$ -	$ (91)	$ (378)	$ -
30	Miscellaneous Revenue Allocation		$ 595,857	$ 81,937	$ 413,779	$ -	$ -	$ 100,140	$ -
31	VDT Revenue		$ (1,876,111)	$ (1,217,277)	$ (574,108)	$ (56,364)	$ (16,545)	$ (5,197)	$ (6,620)
32	High Pressure System		$ 26,909,794	$ 15,542,281	$ 6,527,535	$ 503,380	$ 166,441	$ 2,286,070	$ 1,884,087
33	PTD Plant		$547,607,544	$386,676,915	$111,742,889	$ 8,256,043	$ 1,447,273	$ 26,706,462	$ 12,777,962
34	Dist Plant		$472,394,055	$336,699,093	$ 88,419,113	$ 6,344,151	$ 1,447,273	$ 26,706,462	$ 12,777,962
35	Mains + Services		$417,465,202	$297,121,610	$ 77,551,413	$ 5,657,139	$ 1,217,066	$ 24,195,193	$ 11,722,781
36	Depreciation Reserve		$232,848,567	$163,572,517	$ 49,670,327	$ 3,720,847	$ 561,661	$ 10,364,311	$ 4,958,904
37	O&M Expense		$ 52,256,676	$ 37,683,234	$ 10,481,642	$ 847,177	$ 105,796	$ 2,082,786	$ 1,056,040
38	Labor Excl. A&G		$ 12,166,046	$ 8,480,347	$ 2,582,324	$ 213,008	$ 28,708	$ 571,380	$ 290,278

Louisville Gas and Electric
Gas CCOSS
(Allocation Amount)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
39	PTD Plant + CWIP		$677,615,222	$475,778,754	$139,620,079	$ 10,383,993	$ 1,821,055	$ 33,815,381	$ 16,195,961
40	Total Labor		$ 15,313,282	$ 10,680,829	$ 3,244,289	$ 266,315	$ 36,344	$ 720,523	$ 364,981
41	Depreciation Expenses		$ 19,232,812	$ 14,196,984	$ 3,558,330	$ 247,583	$ 44,789	$ 801,980	$ 383,147
42	Rate Base		$441,457,053	$307,727,146	$ 94,995,404	$ 7,179,082	$ 1,104,796	$ 20,581,634	$ 9,868,990
43	Peak & Avg.		100.0000%	55.9751%	26.6254%	2.3420%	0.4638%	10.1460%	4.4476%

Louisville Gas and Electric
Gas CCOSS
(Allocation Percent)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
1	Procurement Expenses		100.0000%	45.8791%	23.5220%	2.5887%	0.8043%	18.1622%	9.0436%
2	Storage		100.0000%	64.4512%	31.3665%	2.8722%	-0.0917%	0.8692%	0.5325%
3	Transmission		100.0000%	64.4512%	31.3665%	2.8722%	-0.0917%	0.8692%	0.5325%
4	Distribution		100.0000%	45.8791%	23.5220%	2.5887%	0.8043%	18.1622%	9.0436%
5	Adjusted Deliveries		100.0000%	46.9145%	23.4731%	2.4759%	0.7710%	17.4703%	8.8952%
6	Procurement Expenses		100.0000%	55.1847%	25.4894%	2.0059%	0.6645%	9.1299%	7.5257%
7	Storage		100.0000%	66.4479%	31.0101%	2.5420%	0.0000%	0.0000%	0.0000%
8	Transmission		100.0000%	66.4479%	31.0101%	2.5420%	0.0000%	0.0000%	0.0000%
9	Distribution Structures		100.0000%	55.1847%	25.4894%	2.0059%	0.6645%	9.1299%	7.5257%
10	High Pressure Distribution Mains		100.0000%	55.1847%	25.4894%	2.0059%	0.6645%	9.1299%	7.5257%
11	Low/Medium Pressure Distribution Mains		100.0000%	65.0357%	29.7778%	2.2081%	0.1567%	2.8217%	0.0000%
12	High Pressure Distrib Mains (yr-end cust.)		100.0000%	92.1083%	7.8009%	0.0638%	0.0049%	0.0212%	0.0009%
13	Low/Med Pres. Distrib Mains (yr-end cust.)		100.0000%	92.1290%	7.8020%	0.0629%	0.0012%	0.0049%	0.0000%
14	Services		100.0000%	92.0347%	7.8049%	0.0727%	0.0245%	0.0591%	0.0042%
15	Meters		100.0000%	77.2847%	18.0153%	1.0163%	0.3431%	3.1572%	0.1834%
16	Customer Count (Average)		100.0000%	92.1470%	7.7624%	0.0639%	0.0049%	0.0209%	0.0009%
17	Customer Accounts		100.0000%	90.3121%	8.5233%	0.6734%	0.0599%	0.4148%	0.0164%
18	Customer Service		100.0000%	90.5089%	8.3869%	0.6275%	0.0483%	0.4103%	0.0181%
19	Forfeited Discounts		100.0000%	83.8182%	15.0479%	1.1339%	0.0000%	0.0000%	0.0000%
20	Net Income Before Income Tax		100.0000%	45.5895%	34.3503%	3.0145%	0.6564%	12.0605%	4.3288%
21	Interest Expense		100.0000%	73.7665%	21.8407%	1.4799%	0.1483%	2.1184%	0.6462%
22	Interest Adjustment		100.0000%	73.7665%	21.8407%	1.4799%	0.1483%	2.1184%	0.6462%
23	Taxable Income		100.0000%	14.7159%	48.0571%	4.6960%	1.2131%	22.9540%	8.3638%
24	Total Distribution Expense		100.0000%	72.1168%	21.4210%	1.4498%	0.2225%	3.3590%	1.4310%
25	Meter Cost		100.0000%	77.2847%	18.0153%	1.0163%	0.3431%	3.1572%	0.1834%
26	Number of Customers		100.0000%	92.1083%	7.8009%	0.0638%	0.0049%	0.0212%	0.0009%
27	Services Cost		100.0000%	92.0347%	7.8049%	0.0727%	0.0245%	0.0591%	0.0042%
28	Actual Revenue		100.0000%	69.3124%	23.3552%	1.7720%	0.2151%	3.9750%	1.3703%
29	DSM Allocation		100.0000%	100.8686%	-0.8221%	0.0000%	-0.0090%	-0.0375%	0.0000%
30	Miscellaneous Revenue Allocation		100.0000%	13.7512%	69.4427%	0.0000%	0.0000%	16.8061%	0.0000%
31	VDT Revenue		100.0000%	64.8830%	30.6010%	3.0043%	0.8819%	0.2770%	0.3529%
32	High Pressure System		100.0000%	57.7570%	24.2571%	1.8706%	0.6185%	8.4953%	7.0015%
33	PTD Plant		100.0000%	70.6121%	20.4057%	1.5077%	0.2643%	4.8769%	2.3334%
34	Dist Plant		100.0000%	71.2750%	18.7172%	1.3430%	0.3064%	5.6534%	2.7049%
35	Mains + Services		100.0000%	71.1728%	18.5767%	1.3551%	0.2915%	5.7957%	2.8081%
36	Depreciation Reserve		100.0000%	70.2485%	21.3316%	1.5980%	0.2412%	4.4511%	2.1297%
37	O&M Expense		100.0000%	72.1118%	20.0580%	1.6212%	0.2025%	3.9857%	2.0209%
38	Labor Excl. A&G		100.0000%	69.7050%	21.2257%	1.7508%	0.2360%	4.6965%	2.3860%

Louisville Gas and Electric
Gas CCOSS
(Allocation Percent)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
39	PTD Plant + CWIP		100.0000%	70.2137%	20.6046%	1.5324%	0.2687%	4.9904%	2.3901%
40	Total Labor		100.0000%	69.7488%	21.1861%	1.7391%	0.2373%	4.7052%	2.3834%
41	Depreciation Expenses		100.0000%	73.8165%	18.5013%	1.2873%	0.2329%	4.1699%	1.9922%
42	Rate Base		100.0000%	69.7072%	21.5186%	1.6262%	0.2503%	4.6622%	2.2355%
43	Peak & Avg.		100.0000%	55.9751%	26.6254%	2.3420%	0.4638%	10.1460%	4.4476%

Louisville Gas and Electric
Gas CCOSS
(Salaries and Wages)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Labor Expenses									
807-813	Procurement Expenses	$ 481,886							
	Demand		$ 56,573	$ 31,220	$ 14,420	$ 1,135	$ 376	$ 5,165	$ 4,258
	Commodity		$ 425,313	$ 195,130	$ 100,042	$ 11,010	$ 3,421	$ 77,246	$ 38,464
	Sub-total		$ 481,886	$ 226,349	$ 114,462	$ 12,145	$ 3,797	$ 82,411	$ 42,721
Storage Expenses									
Operation									
814	Operations Supervision and Engineer	$ 303,331							
	Demand		$ 84,868	$ 56,393	$ 26,318	$ 2,157	$ -	$ -	$ -
	Commodity		$ 218,463	$ 140,802	$ 68,524	$ 6,275	$ (200)	$ 1,899	$ 1,163
815	Maps and Records		$ -						
816	Well Expenses		$ 15,841	$ 10,526	$ 4,912	$ 403	$ -	$ -	$ -
817	Lines Expenses		$ 315,936	$ 209,933	$ 97,972	$ 8,031	$ -	$ -	$ -
818	Compressor Station Exp - Payroll		$ 369,233	$ 237,975	$ 115,816	$ 10,605	$ (339)	$ 3,210	$ 1,966
819	Compressor Station Fuel and Power		$ -						
820	Measurement and Regulator Station		$ -						
821	Purification of Natural Gas		$ 484,806	$ 312,463	$ 152,067	$ 13,925	$ (445)	$ 4,214	$ 2,582
823	Gas losses		$ -						
824	Other Expenses		$ -						
825	Storage Well Royalities		$ -						
826	Rents		$ -						
Total Storage Operation Labor			$ 1,489,148	$ 968,093	$ 465,609	$ 41,396	$ (983)	$ 9,323	$ 5,711
Storage Expense									
Maintenance									
830	Maintenance Super and Eng.	$ 223,206							
	Demand		$ 87,531	$ 58,163	$ 27,143	$ 2,225	$ -	$ -	$ -
	Commodity		$ 135,675	$ 87,444	$ 42,557	$ 3,897	$ (124)	$ 1,179	$ 722
831	Maintenance of Structures		$ -						
832	Maintenance of Resevoirs		$ 167,523	$ 111,316	$ 51,949	$ 4,258	$ -	$ -	$ -
834	Main of Compressor Station Equipment		$ 384,777	$ 247,993	$ 120,691	$ 11,052	$ (353)	$ 3,345	$ 2,049
835	Main of Meas and Reg Sta. Equip		$ 43,610	$ 28,978	$ 13,523	$ 1,109	$ -	$ -	$ -
836	Main of Purification Equip		$ 122,286	$ 78,815	$ 38,357	$ 3,512	$ (112)	$ 1,063	$ 651
837	Main of Other Equipment		$ 58,500	$ 38,872	$ 18,141	$ 1,487	$ -	$ -	$ -
Total Maintenance Labor			$ 1,057,401	$ 692,181	$ 324,095	$ 28,407	$ (437)	$ 8,391	$ 4,764
Total Storage Labor			$ 2,546,548	$ 1,660,274	$ 789,704	$ 69,803	$ (1,421)	$ 17,714	$ 10,475

Louisville Gas and Electric
Gas CCOSS
(Salaries and Wages)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Transmission									
850-867	Transmission Expenses		$ 483,796	$ 321,473	$ 150,026	$ 12,298	$ -	$ -	$ -
Distribution Expenses									
Operation									
870	Operation Supr and Engr		$ -						
871	Dist Load Dispatching		$ 278,731	$ 127,879	$ 65,563	$ 7,216	$ 2,242	$ 50,624	$ 25,207
872	Compr. Station Labor and Exp.		$ -						
873	Compr. Station Fuel and Power		$ -						
874.01	Other Mains/Serv. Expenses		$ 445,647	$ 317,180	$ 82,787	$ 6,039	$ 1,299	$ 25,829	$ 12,514
874.02	Leak Survey-Mains		$ -						
874.03	Leak Survey - Service		$ -						
874.04	Locate Main per Request		$ -						
874.05	Check Stop Box Access		$ -						
874.06	Patrolling Mains		-						
874.07	Check/Grease Valves		$ -						
874.08	Opr. Odor Equipment		$ -						
874.09	Locate and Inspect Valve Boxes		$ -						
874.1	Cut Grass - Right of Way		$ -						
875	Meas and Reg Station Exp.- General		$ 372,198	$ 205,396	$ 94,871	$ 7,466	$ 2,473	$ 33,981	$ 28,011
876	Meas and Reg Station Exp.- Industrial		$ 213,534	$ 165,029	$ 38,469	$ 2,170	$ 733	$ 6,742	$ 392
877	Meas and Reg Station Exp. - City Gate		$ 27,338	$ 15,086	$ 6,968	$ 548	$ 182	$ 2,496	$ 2,057
878	Meter and House Reg. Expense		$ 5,262	$ 4,066	$ 948	$ 53	$ 18	$ 166	$ 10
879	Customer Installation Expense		$ 132,415	$ 102,337	$ 23,855	$ 1,346	$ 454	$ 4,181	$ 243
880	Other Expenses		$ 1,173,513	$ 836,422	$ 219,649	$ 15,760	$ 3,595	$ 66,344	$ 31,743
881	Rents		$ -						
Total Operations Distribution Labor			$ 2,648,638	$ 1,773,396	$ 533,110	$ 40,598	$ 10,996	$ 190,362	$ 100,176
Total Operations Transmission and Distribution Labor			$ 3,132,434	$ 2,094,868	$ 683,136	$ 52,896	$ 10,996	$ 190,362	$ 100,176
Maintenance Expense – Distribution									
885	Maintenance Supr and Engr		$ -						
886	Maintenance Structures		$ 24,283	$ 13,400	$ 6,189	$ 487	$ 161	$ 2,217	$ 1,827
887	Maintenance Mains	$ 2,849,128							
	L/M Pressure								
	Demand		$ 2,123,095	$ 1,188,405	$ 565,283	$ 49,723	$ 9,847	$ 215,410	$ 94,427
	Customer		$ 369,321	$ 340,252	$ 28,814	$ 232	$ 5	$ 18	$ -
	H Pressure								
	Demand		$ 331,862	$ 183,137	$ 84,590	$ 6,657	$ 2,205	$ 30,299	$ 24,975
	Customer		$ 24,850	$ 22,889	$ 1,939	$ 16	$ 1	$ 5	$ 0

Louisville Gas and Electric
Gas CCOSS
(Salaries and Wages)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
888	Maintenance Comp. Station Equip.		$ -						
889	Maintenance Meas and Reg. General		$ 33,209	$ 18,326	$ 8,465	$ 666	$ 221	$ 3,032	$ 2,499
890	Maintenance Meas and Reg - Industrial		$ 64,687	$ 49,916	$ 11,636	$ 656	$ 222	$ 2,039	$ 118
891	Maintenance Meas and Reg.-City Gate		$ 125,858	$ 69,454	$ 32,080	$ 2,525	$ 836	$ 11,491	$ 9,472
892	Maintenance Services		$ 521,123	$ 479,614	$ 40,673	$ 378	$ 128	$ 308	$ 22
893	Maintenance Meters and House Reg.		$ -						
894	Maintenance Other Equipment		$ 117,919	$ 84,047	$ 22,071	$ 1,584	$ 361	$ 6,666	$ 3,190
	Total Maintenance Labor		$ 3,736,107	$ 2,449,441	$ 801,740	$ 62,924	$ 13,987	$ 271,484	$ 136,531
	Total Transmission & Distribution Labor		$ 6,868,542	$ 4,544,309	$ 1,484,876	$ 115,821	$ 24,983	$ 461,846	$ 236,707
	Customer Accounts Expense								
901	Supervision		$ 379,040	$ 342,320	$ 32,307	$ 2,552	$ 227	$ 1,572	$ 62
902	Meter Reading		$ 176,603	$ 159,494	$ 15,052	$ 1,189	$ 106	$ 733	$ 29
903	Customer Records and Collections		$ 1,556,484	$ 1,405,694	$ 132,664	$ 10,481	$ 933	$ 6,457	$ 256
904	Uncollectible Accounts		$ -						
905	Misc. Cust Account Expenses		$ 70,905	$ 64,036	$ 6,043	$ 477	$ 42	$ 294	$ 12
	Total Customer Accounts Labor		$ 2,183,033	$ 1,971,544	$ 186,067	$ 14,700	$ 1,308	$ 9,056	$ 359
	Customer Service Expenses								
907-910	Customer Service		$ 86,037	$ 77,871	$ 7,216	$ 540	$ 42	$ 353	$ 16
	Sales Expenses								
911-916	Sales Expenses		$ -						
	Administrative & General								
920	Admin and General Salaries		$ 2,616,333	$ 1,823,716	$ 555,334	$ 45,808	$ 6,174	$ 122,877	$ 62,425
921	Office Supplies and Expense		$ -						
922	Admin. Expenses Transferred		$ (214,389)	$ (149,440)	$ (45,506)	$ (3,754)	$ (506)	$ (10,069)	$ (5,115)
923	Outside Services Employed		$ -						
924	Property Insurance		$ -						
925	Injuries and Damages		$ 6,657	$ 4,640	$ 1,413	$ 117	$ 16	$ 313	$ 159
926	Employee Pensions and Benefits		$ -						
927	Franchise Requirement		$ -						
928	Regulatory Commission Fee		$ -						
929	Duplicate Charges -Credit		$ -						
930.1	General Advertising Expense		$ -						
930.2	Misc. General Expense		$ -						
931	Rents		$ -						

Louisville Gas and Electric
Gas CCOSS
(Salaries and Wages)

Acct. No.	Account Description	Alloc	Total	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
935	Maintenance of General Plant		$ 738,636	$ 521,566	$ 150,724	$ 11,136	$ 1,952	$ 36,023	$ 17,235
Total Administrative and General Labor			$ 3,147,237	$ 2,200,482	$ 661,965	$ 53,307	$ 7,636	$ 149,143	$ 74,704
Total Labor Expense			$ 16,313,282	$ 10,680,829	$ 3,244,289	$ 266,315	$ 38,344	$ 720,523	$ 364,981

Louisville Gas and Electric
Gas Customer Cost Analysis

		Residential
Gross Plant		
380 Services	$	126,898,285
381 Meters	$	17,068,163
382 Meter Installations	$	7,250,423
383 House Regulators	$	3,818,939
384 House Regulators Installations	$	4,094,586
Total Gross Plant		$159,128,398
Depreciation Reserve		
380 Services		42,853,102
381 Meters		5,763,949
382 Meter Installations		2,448,481
383 House Regulators		1,289,663
384 House Regulators Installations		1,382,749
Total Depreciation Reserve		$53,737,944
Total Net Plant		$105,390,452
Operation & Maintenance Expenses		
878 Meter and House Reg. Expense		$14,623
879 Customer Installation Expense		$171,394
892 Maintenance Services		$2,020,361
893 Maintenance Meters and House Reg.		$0
902 Meter Reading		$1,564,441
903 Customer Records and Collection		$3,519,377
Total O&M Expenses		$7,290,195
Depreciation Expense		
380 Services		5,386,735
381 Meters		520,536
382 Meter Installations		224,660
383 House Regulators		90,037
384 House Regulators Installations		85,868
Total Depreciation Reserve		$6,307,834
Revenue Requirement		
Interest		$2,582,066.07
Equity return		$5,530,890.92
Income Tax		$3,339,824
Revenue For Return		$11,452,781.25
O & M Expenses		$7,290,195
Depreciation Expense		$6,307,834
Total Customer Revenue Requirement		$25,050,811.08
Number of Bills		3,599,880
Monthly Cost		$6.96

	PCT	Cost	WGHT Cost
Debt	47.52%	5.16%	2.45%
Common	52.48%	10.00%	5.25%
Total	100.00%		7.70%

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY, INC. FOR AN	)	CASE NO. 2008-00252
ADJUSTMENT OF ITS ELECTRIC AND GAS	)	C/W
BASE RATES	)	CASE NO. 2007-00564

AFFIDAVIT OF GLENN A. WATKINS

Commonwealth of Virginia)
)
)

Glenn A. Watkins, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Glenn A. Watkins

SUBSCRIBED AND SWORN to before me this 28th day of October, 2008.

NOTARY PUBLIC

My Commission Expires: 03/31/10
Registration # 270986