COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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

VOLUME 4 OF 7

TESTIMONY

Filed: December 29, 2003

Louisville Gas and Electric Company
Case No. 2003-00433
Historical Test Year Filing Requirements

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Mr. Stalneri

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY OF
VICTOR A. STAFFIERI
CHAIRMAN OF THE BOARD
CHIEF EXECUTIVE OFFICER AND PRESIDENT
LG&E ENERGY CORP.
LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

December 29, 2003

Filed: December 29, 2003

Q. Please state your name and business address.

A. My name is Victor A. Staffieri. My business address is 220 West Main Street, Louisville, KY 40202.

Q. Where are you employed, and what is your position?

A. I am employed by LG&E Energy Services, Inc., a service company subsidiary wholly-owned by LG&E Energy Corp. ("LG&E Energy"). I am Chairman of the Board, Chief Executive Officer and President of LG&E Energy and its subsidiaries, Louisville Gas and Electric Company ("LG&E" or "the Company") and Kentucky Utilities Company ("KU").

Q. Please describe your employment history, education, and civic involvement.

A. I joined LG&E Energy in March 1992 as Senior Vice President, General Counsel, and Corporate Secretary. Since then, I have served in a number of positions at LG&E Energy, LG&E, and KU. I assumed my current position on May 1, 2001. Descriptions of my employment history, educational background, and civic involvement are attached to this testimony as Exhibit A.

Q. Have you testified before this Commission on other occasions?

A. Yes. I testified before this Commission in Case No. 2001-104, *In the Matter of: Joint Application of E.ON AG, Powergen plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company For Approval of an Acquisition*. Prior to that, I testified in Case No. 2000-095, *In the Matter of: Joint Application of Powergen plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company For Approval of a Merger*. I also testified in Case Nos. 98-426 and 98-474, concerning the Applications of LG&E and KU, respectively, for approval of an alternative method of regulation, which proceedings resulted in the development and implementation of LG&E's current Earnings Sharing Mechanism ("ESM"). Finally, I testified in Case No. 97-300 concerning the merger of KU Energy Corporation into LG&E Energy, and the resulting change in the ownership of and control over LG&E and KU.

Q. Please identify the other witnesses offering direct testimony on behalf of the Company in this case, and generally describe the subject matter of each such testimony.

A. LG&E is offering direct testimony from the following witnesses:

- Paul Thompson – Mr. Thompson will describe, from a generation and transmission function perspective, how the Company has been able to provide safe and reliable service to its customers for years without having to seek a base rate increase, and explain why a rate increase is needed at this time;
- Chris Hermann – Mr. Hermann will describe how LG&E has been able to effectively manage costs while providing reliable, safe service for our retail operations and electric and gas distribution businesses, and will explain why a rate increase is needed at this;
- S. Bradford Rives – Mr. Rives will describe why the financial condition of the Company requires the requested increase in base rates, present the financial exhibits to LG&E's application, discuss the Company's accounting records, describe the calculation of LG&E's adjusted net operating income for the twelve month period ended September 30, 2003, and support the different valuations of the Company's property;

- Valerie L. Scott – Ms. Scott will support certain pro forma adjustments to the Company's operating income for the twelve months ended September 30, 2003, demonstrate that those adjustments are known, measurable and reasonable, and support certain reference schedules supporting the Company's application;
- Earl M. Robinson – Mr. Robinson will present the results of his depreciation study and his recommendations for new depreciation rates and depreciation expense related to the Company's plant in service;
- Robert G. Rosenberg – Mr. Rosenberg will present the results of his analysis of the cost of equity for the Company, discuss his conclusion that the cost of equity for our electric operations should be in the 10.75-11.25 percent range, with 11.25 percent recommended as the return that should be allowed in this proceeding, and discuss his conclusion that the cost of equity for the Company's gas operations should be in the 11.0-11.5 percent range, with 11.5 percent recommended as the return that should be allowed in this proceeding;
- Michael S. Beer – Mr. Beer will support certain exhibits required by the Commission's regulations, identify the revenue effect of the proposed rates, present the Company's recommendation for the allocation of the proposed increase in revenues among the customer classes, discuss the effect of various billing mechanisms on the requested rate increase, and present the Company's position on the expenses it has incurred for its membership in Midwest Independent Transmission System Operator, Inc. ("MISO");
- Clay Murphy – Mr. Murphy will discuss the increasingly competitive nature of the natural gas industry and some of LG&E's competitive challenges, address certain

specific changes that LG&E is proposing to its natural gas transportation services and certain sales services, describe the services that LG&E proposes to modify, and discuss those proposed modifications;

- W. Steven Seelye – Mr. Seelye will support certain pro forma adjustments to the Company's operating income for the twelve months ended September 30, 2003, demonstrate that those adjustments are known, measurable and reasonable, support certain reference schedules supporting the Company's application, present the results of his cost-of-service study, and recommend rate structures and rates; and
- Sidney L. "Butch" Cockerill – Mr. Cockerill will describe and support the proposed revisions to the Company's terms and conditions for furnishing electric and gas services, discuss the proposed changes to some of LG&E's nonrecurring charges, and review the Company's efforts to assist its low-income customers.

Q. What is the purpose of your testimony?

A. I will explain why LG&E's proposed adjustment to its base rates should be approved. I will describe some of the significant changes that have occurred since LG&E last requested an increase in base rates, and will explain why the proposed increase is necessary to allow LG&E to earn a fair, just and reasonable return while continuing to provide low cost, safe and reliable energy service. Finally, I will discuss LG&E's ongoing commitment to the community and low income customers.

Q. Please describe LG&E's proposed increase in base rates.

A. LG&E has not had a base electric rate increase for nearly fourteen years, and in fact had a reduction in electric base rates in 2000. During that time, we have kept our costs down and have passed along substantial savings, generated by integration and best practice initiatives, to our customers. With respect to its gas operations, LG&E's base gas rates were increased in 2000 at the Commission's direction to discontinue prior subsidies of the gas business by the electric business. LG&E stated in that proceeding that another increase in base rates would likely be necessary in approximately three years, and this filing is consistent with that statement.

LG&E understands that no customer wants higher prices. However, LG&E's cost of doing business has risen to the point that an increase in its base rates is necessary to allow the Company to continue to provide reliable, high quality service and at the same time earn a fair and reasonable return. For these reasons, and the reasons set forth in LG&E's application, LG&E is requesting an 11.34%, or $63.8 million a year, increase in its electric base rates, and a 5.42%, or $19.1 million a year, increase in its gas base rates. The monthly residential electric bill will increase by 10.70%, or approximately $6.00, for a customer using 1000 Kwh of electricity. The monthly residential gas bill will increase by 6.50%, or approximately $5.50, for a customer using 90 Ccf of gas.

The testimonies of Mr. Rives, Ms. Scott, Mr. Seelye, and Mr. Robinson provide a detailed explanation of the calculation of LG&E's revenue requirement. The testimony of Mr. Rosenberg supports LG&E's proposed rate of return on equity through an extensive cost of capital analysis. The testimonies of these witnesses demonstrate that LG&E is not presently earning a fair and reasonable return.

Q. What steps has LG&E taken to control its costs since its last request for a base rate increase?

A. LG&E has made every effort to offset or absorb increased costs since seeking its last electric and gas base rate increases in 1990 and 2000, respectively. As discussed in the testimonies of Mr. Thompson and Mr. Hermann, LG&E has undertaken numerous initiatives to create efficiencies and, in turn, optimize savings in the face of rising costs. LG&E has a long track record of operating very efficiently and avoiding price increases, and we have been able to extend this price performance since the merger of KU and LG&E by taking advantage of synergies, combined work practices, lower overheads and administrative staff expenses, and other economies of scale.

Q. Why is LG&E now seeking an increase in its electric rates?

A. As noted above, the Company's cost of doing business has increased to the point that it is not presently earning a fair and reasonable return. For example, since December 31, 1998, the end of the test year used in Case No. 98-426, LG&E has increased its net investment in plant for electric operations by over $400 million. And, comparing the twelve months ended September 30, 2003 with the test year used in Case No. 98-426, the Company has incurred approximately $24 million in additional depreciation expense, on a pro forma basis, associated with those net investments in plant. During that same time period, on the electric side of the business, LG&E's employee pension and post-retirement expenses have increased about $10 million, on a pro forma basis, as a result of the decline in financial market performance, and the Company has seen an approximately $4 million rise in property insurance costs. LG&E has also incurred approximately $3 million in MISO Schedule 10 administrative costs, which are not currently being recovered, and has experienced significant increases in its operating expenses for electric operations, such as higher wage rates, due in part to inflation.

Q. Why is LG&E seeking an increase in its gas rates?

A. Again, the Company's cost of doing business has increased to the point that it is not presently earning a fair and reasonable return. For example, since December 31, 1999, the end of the test year used in Case No. 2000-080, LG&E has increased its net investment in plant for gas operations by over $47 million. And, comparing the twelve months ended September 30, 2003 with the test year used in Case No. 2000-080, the Company has incurred approximately $5 million in additional depreciation expense, on a pro forma basis, associated with those net investments in plant. During that same time period, on the gas side of the business, LG&E's employee pension and post-retirement expenses have increased about $4 million, on a pro forma basis, as a result of the decline in financial market performance. And, LG&E has experienced significant increases in its operating expenses for gas operations, such as higher wage rates, due in part to inflation.

Q. What efforts has LG&E made to ensure the continued reliability of its system?

A. To ensure reliability of service to native load, LG&E has, among other things, made substantial investments in its utility infrastructure during the last several years, including transmission and distribution systems and electric generation. In the latter regard, LG&E has added 366 megawatts of generation capacity in the form of six combustion turbines. The Company has also spent more than $24 million in its gas operations as part of an ongoing large-scale gas main replacement project since its last gas base rate increase.

Q. Why did the Company wait so long to seek another combined base rate adjustment?

A. Providing safe, reliable and affordable service to our customers has been the cornerstone of LG&E's retail business for many years. We are very proud of the fact that our rates are among the lowest in the nation, and we have carried out many programs over the years to keep them that way. Much like any utility or other business, we have faced rising costs for things such as materials, labor, pension and post-retirement benefits, and insurance. Nevertheless, we have been able to mitigate or offset many of those cost increases through efficiency initiatives and debt refinancing.

And, importantly, our efficiency-driven initiatives have not unduly affected our service quality or performance. Throughout the last several years, LG&E has achieved a standard of excellence in overall customer satisfaction very nearly unsurpassed in the industry. In fact, in both 2002 and 2003, J.D. Power & Associates, an international marketing information firm widely recognized as the "voice of the customer," ranked LG&E, together with its sister utility KU, *first in the nation* among investor-owned utilities in overall satisfaction among residential electric customers. Those rankings are not arbitrary – they are based on thousands of interviews with customers throughout the country in several categories. To win, a company has to earn high rankings in such key areas as price/value, power quality and reliability, billing and payment, customer service and overall company image.

Q. Given LG&E's success over the last several years in maintaining high quality service without raising rates, what prompted the Company's application at this time?

A. LG&E, like any responsible utility, has sought to balance between providing a high level of service at the most affordable price and aggressively controlling costs without eroding our commitment to safe and reliable service. However, we have now exhausted all prudent means of reducing costs internally, and must seek a reasonable rate adjustment to preserve our financial integrity and, in turn, our ability to sustain the high quality of service our customers have come to expect. It is not in the public interest to have a financially weakened utility. A rate increase will allow the Company to continue to provide the safe and reliable service its customers have come to expect, while also having the opportunity to earn a fair and reasonable return.

Q. After LG&E's requested rate adjustment becomes effective, will customers still receive a good value for the service received?

A. Yes. LG&E recognizes that its proposed rate adjustment will result in an average increase of approximately $11.50 to the monthly combined electric and gas bill of a residential customer who uses 1000 Kwh of electricity and 90 Ccf of gas. We do not take lightly the effect of any increase on our customers, but this needed increase will ensure that our customers continue to receive a high level of service while also still enjoying among the lowest rates in the nation.

Q. Please describe LG&E's commitment to the community.

A. We are proud of our employees, who give freely of their time and talents, actively volunteering, from boardrooms and classrooms to Little League fields and soup kitchens, to improve the quality of life in the communities where they work and live. LG&E and KU help to maintain LG&E Energy's firm commitment to the community by contributing resources, talent and ideas that support community heritage and economic growth.

In addition, the LG&E Energy Foundation is a self-sufficient, non-profit business entity established to support education, community outreach, environment, and arts in the communities served by LG&E Energy and its subsidiaries. Caring about people and being a good neighbor are much more than a corporate obligation to LG&E Energy. Social responsibility is deeply rooted in our culture. We develop valuable relationships with our employees, customers and fellow citizens in order to enrich lives and build better places to live. We simply see it as the right thing to do.

Since the inception of the LG&E Energy Foundation in 1994, the Foundation has awarded more than $11.3 million in grants in order to proactively support philanthropic initiatives to strengthen communities across the Commonwealth. Not one dollar of these donations is paid by our customers. Instead, the gifts are funded solely by our shareholders. Despite lower returns on, and decline in, the market value of its investments, the Foundation is on track to contribute approximately $1.7 million to worthy causes in 2003.

Q. What steps has LG&E taken to assist low-income customers with their energy bills?

A. Over the years, LG&E has developed a number of programs to assist our low-income customers. The Company's Helping Hands brochure is a quick reference guide of assistance programs, and the Community Winterhelp program allows us to partner with our customers to help those that need assistance in paying their bills from time to time. Project Warm draws on volunteers from the community, especially from LG&E, to weatherize the homes of low-income, elderly and handicapped persons in our service area. We have retained a community liaison who works with low-income customers, advocates and ministries to ensure that those customers receive all the aid for which they qualify.

Q. Do you have any final comments?

A. In closing, let me reiterate that LG&E's commitment to provide low-cost, reliable service to its customers is as strong as ever. Although no utility enjoys implementing rate increases, we take great pride in how long we were able to go before asking for this increase. The rate adjustments LG&E has proposed in this case *are* necessary, and will allow LG&E to continue to live up to the standard of excellence the Company and its customers expect.

Q. Does this complete your testimony?

A. Yes, it does.

280022.21

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Victor A. Staffieri**, being duly sworn, deposes and says he is Chairman of the Board, Chief Executive Officer and President of LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

VICTOR A. STAFFIERI

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Melody L. Hubel (SEAL)
Notary Public

My Commission Expires:
November 26, 2007

Appendix A

Victor A. Staffieri

Chairman, Chief Executive Officer, and President
LG&E Energy Corp., Louisville, Gas & Electric Company and Kentucky Utilities
220 West Main Street
Louisville, KY 40202
Phone: (502) 627-3912
Board member Powergen plc.

Education

Fordham University School of Law, J.D. -- 1980
Yale University, B.A. – 1977

Previous Positions

LG&E Energy Corp., Louisville KY
March 1999 - April 2001 -- President and Chief Operating Officer
May 1997 - February 1999 -- Chief Financial Officer
December 1995 - May 1997 -- President, Distribution Services Division
December 1993 - May 1997 -- President, Louisville Gas and Electric Company
December 1992 - December 1993 -- Senior Vice President - Public Policy, and General Counsel
March 1992 - November 1992 -- Senior Vice President, General Counsel and Corporate Secretary

Long Island Lighting Company, Hicksville, NY
1989-1992 -- General Counsel and Secretary
1988-1989 -- Deputy General Counsel
1986-1988 -- Assistant General Counsel
1985-1986 -- Managing Attorney
1984-1985 -- Senior Attorney
1980-1984 – Attorney

Industry Affiliations

Edison Electric Institute, Washington, DC - Board of Directors -- June 2001 - May 2004
Electric Power Research Institute, Palo Alto, CA - Board of Directors -- May 2001 - April 2002

Civic Activities

Boards

Metro United Way -- Board of Directors -- 1998 - 2004
MidAmerica Bancorp -- Board of Directors -- 2000 - 2003
Kentucky Country Day -- Board of Directors -- 1996 – 2002

Civic Activities, Continued

Boards, Continued

Bellarmine University - Board of Trustees -- 1995 - 1998, 2000 - 2003
Executive Committee -- 1997 - 1998
Finance Committee -- 1995 - 1997, 2000 - 2003
Strategic Planning Committee -- 1997
Jefferson County/Louisville Area Chamber of Commerce Family Business Partnership
Co-Chair -- 1996-1997
Louisville Area Chamber of Commerce -- Board of Directors -- 1994-1997; 2000-2006

Other

Louisville Area Chamber of Commerce -- Chair -- 1997
Louisville Area Chamber of Commerce -- African-American Affairs Committee -- 1996-1997
Louisville Area Chamber of Commerce -- Vice Chairman, Finance and Administration
Steering Committee -- 1995
The National Conference - Dinner Chair -- 1997
Chairman of the Coordination Council for Economic Development Activities
-- Regional Economic Development Strategy -- 1997
Metro United Way -- Chair of Community Campaign -- 2002
Metro United Way - Cabinet Member -- 1995 and 2000 Campaigns
Boy Scouts of America -- 1996 Annual Explorer Campaign

Mr. Thompson

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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

TESTIMONY OF
PAUL W. THOMPSON

SENIOR VICE PRESIDENT, ENERGY SERVICES
LG&E ENERGY CORP.
LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

December 29, 2003

Filed: December 29, 2003

Q. Please state your name, employer, position and business address.

A. My name is Paul W. Thompson. I am employed by LG&E Energy Services, Inc. I am the Senior Vice President, Energy Services for LG&E Energy Corp. ("LG&E Energy"), Louisville Gas and Electric Company ("LG&E" or "the Company"), and Kentucky Utilities Company ("KU"). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

A. I received a Bachelor of Science degree in Mechanical Engineering from the Massachusetts Institute of Technology in 1979 and a Master of Business Administration from the University of Chicago in Finance and Accounting in 1981. Before joining LG&E Energy in 1991, I acquired eleven years of experience in the oil, gas and energy-related industries in positions of financial management, general management and sales. A complete statement of my work experience and education is contained in the Appendix hereto.

Q. Please describe your duties and responsibilities as Senior Vice President, Energy Services.

A. I am responsible for both regulated and unregulated power generation functions, regulated electric transmission, and regulated and unregulated fuels and energy marketing activities. For purposes of this testimony, I will refer to the above regulated functions collectively as "Energy Services."

Q. Have you previously testified before this Commission?

A. Yes. I testified in the merger proceedings of LG&E and KU before the Kentucky Public Service Commission in Case No. 97-300, *In the Matter of: Application of Louisville Gas* *and Electric Company and Kentucky Utilities Company for Approval of a Merger under KRS 278.020.* I also filed testimony in the Commission's investigation of LG&E's and KU's membership in the Midwest Independent Transmission System Operator, Inc., *In the Matter of: Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.,* Case No. 2003-00266.

Q. Please provide an overview of your testimony, and comment on the Company's request for a base rate increase in this case.

A. In this testimony, I will describe certain notable efficiency initiatives that Energy Services has undertaken over the last several years to manage the increasing costs of doing business, while at the same time preserving service reliability and workforce safety. LG&E has always strived to offer its customers an exceptional value in electric service by striking a balance between two key attributes: low price and high reliability. The Company's success in achieving this balance to date – measured at least in part by LG&E's ability to avoid an electric base rate increase for 13 years, despite national and industry-specific cost pressures – is a credit to the Company's innovation and initiative.

The innovative steps taken to this point, however, are no longer sufficient to offset the increasing cost of meeting the Company's service obligations and commitments. As demonstrated in my testimony and the testimonies of Bradford Rives and Chris Hermann, the Company is at a point where it must implement a base rate increase to reflect fully the costs of providing reliable service to its customers, thereby allowing LG&E to maintain an optimum balance between price and reliability.

Q. In general, what is Energy Services' major corporate objective?

A. Energy Services has three major, and overlapping, objectives: (i) to maximize the performance and investment life of the Company's electric generation and transmission assets; (ii) to maintain sound operating and maintenance practices that promote reliable operations, high efficiency, and a safe working environment; and (iii) to continue to provide high value electric service to LG&E's customers.

Q. Please describe LG&E's generation and transmission systems.

A. LG&E's generation system consists primarily of three coal-fired generating stations – Cane Run, Mill Creek, and Trimble County. All of these stations are equipped with scrubbers to reduce sulfur dioxide, allowing the units to burn lower-cost, higher-sulfur content coal. LG&E also owns and operates multiple natural gas-fired combustion turbines, which supplement the system during peak periods, and the Ohio Falls hydroelectric station, which provides baseload supply, subject to river flow constraints.

LG&E owns and operates approximately 2,900 MW of generating capacity with a net book value of more than $1 billion. The Company serves approximately 386,000 electricity customers over a transmission and distribution network extending approximately 700 square miles in 16 counties. LG&E's transmission plant covers more than 950 circuit miles, and has a net book value of approximately $100 million. The Company provides its customers with some of the lowest-cost energy in the nation.

Q. What efforts has Energy Services undertaken in the last several years to create efficiencies and manage costs?

A. Energy Services has undertaken a number of initiatives over the last several years aimed at managing costs through enhanced efficiencies and productivity. These initiatives, which focus largely on asset management, employ improved system analysis techniques, best practices, and technological advances designed to optimize the performance of LG&E's assets and eliminate costly duplication and other inefficiencies in operations and administration.

Q. Please describe what is meant by the phrase "asset management."

A. As used by Energy Services, the term "asset management" refers broadly to a business discipline for managing the lifecycle of long-term generation and transmission assets to maximize the performance of these assets, from both an efficiency and reliability perspective, in the most cost-effective manner possible.

Q. Can you offer some specific examples of LG&E's asset management initiatives?

A. Yes. On the generation side, Energy Services has implemented a system-wide initiative to enhance long-term boiler circuit availability and, in turn, generating unit performance. Among other things, this initiative is designed to promote more rapid detection of, and more accurate analysis of, boiler circuit failures and failure trends, with the aim of significantly reducing boiler-related availability losses. Additionally, LG&E has installed digital control technology (Distributed Control Systems or DCS) across much of its generation fleet, allowing the Company to more accurately control the interrelated operation of various generating unit components and the coordination of various processes integral to power production. This technology not only improves operational efficiencies, but also enhances the real-time diagnostic capabilities of LG&E's operating and maintenance staff.

Further, and again on the generation side, LG&E has transitioned from a more rigid, time-based preventive maintenance approach to a predictive, reliability-centered maintenance process, allowing LG&E to efficiently prioritize and allocate maintenance activities and resources consistent with the actual needs of its equipment, as determined by the Company consistent with prudent utility practice. Under LG&E's reliability-based maintenance model, equipment within a generating unit (motors, pumps, etc.) is routinely tested to measure equipment performance. If such tests (*e.g.*, vibration and lubricating analyses on rotating equipment) show performance degradation warranting repair, repairs can be made timely and efficiently, as both the equipment and the problem are effectively isolated through the testing process. Should testing reveal more minor performance variations, tests can be undertaken on a more frequent basis, facilitating the timely discovery of equipment problems warranting repair and, in turn, mitigating the risk of major repair or outage-related costs.

Q. Has LG&E implemented any technological initiatives to support its reliability-centered maintenance process?

A. Yes. LG&E utilizes MAXIMO®, a computerized maintenance management system that complements and supports LG&E's reliability-centered maintenance process. The MAXIMO® system tracks anomalous test results, equipment operating problems, and equipment failure trends. MAXIMO® also stores replacement/spare part information and makes that information readily accessible; and tracks testing schedules and any corrective or preventative work undertaken, allowing LG&E to manage its resources as efficiently as possible over their respective lifecycles.

Q. Please provide an example of asset management as applied to LG&E's transmission operations.

A; LG&E has optimized the use of its transmission system assets through various means. First, Energy Services has adopted enhanced data collection and analysis capabilities similar to those offered by MAXIMO® on the generation side. Specifically, the Company has enhanced the real-time diagnostics capabilities of its Energy Management System ("EMS"), a computer-based network control system designed to continuously monitor (and store) various transmission data.

In addition, LG&E has begun using thermal-based transmission line ratings, as opposed to seasonal (static) ratings, to measure line capability. The use of thermal-based line ratings has, in my judgment, resulted in a measurable increase in the productivity of the Company's transmission assets. One indication of this productivity increase is the significant decrease in the number of Transmission Line Loading Relief ("TLR") directives called on LG&E's system by LG&E's regional transmission grid operator since the Company's adoption of a thermal-based rating approach.

Further, LG&E has increased its use of telemetry equipment, which allows dispatch centers to operate and monitor substation equipment remotely and on a real-time basis. Not only has this initiative created workforce efficiencies, it likewise has enhanced the system's reliability by affording dispatch centers continuous monitoring capabilities.

Q. In addition to the asset management initiatives you just described, has LG&E undertaken other operational or work process-related initiatives aimed at achieving efficiencies and managing costs?

A. Yes. In addition to the benefits of joint system dispatch and planning (commencing with the LG&E and KU merger), LG&E has increased its employee training and capabilities with respect to both its generation and transmission functions, thereby improving productivity. This has allowed the use of practices such as "multi-skilling" (*e.g.*, training employees to undertake a combination of power plant and scrubber operations), and the sharing of special services or expertise among plants across the fleet (*e.g.*, turbine overhaul specialists, continuous emission monitor testing services). In addition, similar to other utilities, Energy Services has continued its use of independent contractors, or a variable workforce, to perform maintenance and repairs on both its transmission and generation systems. The nature of a variable workforce (specialized and working only when needed) is particularly well-suited to the various needs of Energy Services.

Q. Please explain why the use of a variable workforce is well-suited to Energy Services.

A. With regard to transmission, work performed on the transmission system typically consists of sporadic, large-scale, projects. Such work calls for the periodic use of varying types of expensive, heavy equipment that, if separately owned by the utility, could sit idle for several months each year. Accordingly, it is more cost-effective to outsource most of this work to capable and qualified contractors. LG&E currently uses four transmission line contractors and two right-of-way clearing contractors to undertake transmission maintenance and repair projects, as applicable, throughout the year.

Similarly, with respect to generation, the Company uses a variable workforce primarily for periodic scheduled maintenance and other specific projects such as boiler retrofits, coal mill overhauls, duct work refurbishment, and cooling tower reconstruction. Again, the reasons are straightforward: the periodic nature of the work involved and the level of specialization required call for the use of specialists contracted on a project-by-project basis. Such practice is not only supported by economics, but it also, because of these contractors' specialized focus, fosters both reliability and safety in the repair of major system components.

Q. How has the reliability of LG&E's generation system fared over the last several years?

A. LG&E's generation system as a whole has been highly reliable historically, as evidenced both by capacity factor trends and actual system reliability performance, measured through systematic benchmarking. In the latter regard, Energy Services' combined system Equivalent Forced Outage Rate ("EFOR"), a measure commonly used in the industry to gauge the reliability of coal-fired generating units, has historically remained quite low; the system-wide EFOR for coal-fired units was 6.8 percent in calendar year 1999, 4.1 percent in calendar year 2000, 5.4 percent in calendar year 2001, 10.5 percent in calendar year 2002, and only 4.7 percent through November 2003. Although these numbers do show that Energy Services experienced difficulties in 2002, reliability performance has dramatically improved in 2003.

Q. Please describe the Company's capacity factor trend over the last several years.

A. LG&E's internal analyses show a relatively consistent upward trend in the steam capacity factor of the Company's coal-fired baseload generating units since 1991. In fact, as of November 2003, the year-to-date average steam capacity factor of the Company's coal-fired units was almost 81 percent.

Q. Would you explain in more detail how LG&E benchmarks the reliability of its generation assets to others in the industry?

A. Yes. LG&E and KU perform their reliability (again, as measured by an Equivalent Forced Outage Rate or "EFOR") benchmarking on a combined system basis (the combined system EFOR is determined by capacity weighting the average of each individual coal unit EFOR target) and on a similar unit basis. The benchmarking exercise is essentially a two-step process. First, LG&E and KU establish a "target" performance quartile for each unit, based on the Company's determination of the appropriate balance of reliability and cost. For example, LG&E has historically targeted second quartile performance for its baseload units at its Cane Run facility, in recognition of these units' lower capacity factors and age. It does not make economic sense to target top quartile performance for these units, given the incremental costs necessary to achieve such top quartile status.

Second, once a target performance quartile is established, LG&E and KU compare the actual EFORs of the units and the combined system EFOR to the EFORs of (i) baseload coal-fired units nationwide, and (ii) a more limited group of generating units with characteristics most comparable to LG&E's and KU's units. LG&E relies on EFOR data reported by other utilities to the North American Electric Reliability Council ("NERC").

Q. How does the EFOR of Energy Services' combined system generally compare to those of the benchmark groups described above?

A. The combined system EFOR compares favorably. In fact, based on a comparison to all coal-fired baseload units nationwide, LG&E's/KU's overall system EFOR (the capacity weighted average EFOR of all coal-fired generating units) consistently achieves top quartile performance. A comparison of the combined system EFOR to the more limited group of comparable units (the second benchmark group described above) shows that the overall system EFOR consistently achieves at least second quartile performance, and is trending towards top quartile performance levels.

Q. Has LG&E invested any capital in its generation system for reliability purposes over the last several years?

A. Yes. Most of the Company's coal-fired generating units were built before 1980. Only Mill Creek Unit 4 and Trimble County Unit 1 were built after 1980. Because of the corrosive and extremely high temperature, high pressure environments in which these units operate, LG&E has had to make significant incremental capital investment in its coal-fired units over the last several years to ensure their safe and reliable operation. Specifically, LG&E, among other things, has installed new distributed control systems, rebuilt cooling towers, replaced coal handling equipment and turbine blading, and refurbished boilers, precipitators and scrubbers across the fleet.

In addition, LG&E has added six new gas-fired combustion turbines for increased system capacity, particularly during peak periods. These units, jointly owned by LG&E and KU, are a product of the Companies' joint planning capabilities, which allow for the most efficient procurement and use of capacity system-wide. Specifically, LG&E has added approximately 366 MW of gas-fired combustion turbine capacity since the summer of 1999, at a cost of $138 million. Another 225 MW of combustion turbine capacity is scheduled to come on-line by the summer of 2004, at a cost through September 30, 2003 of $63 million. LG&E has long recognized the importance of maintaining an adequate reserve margin of capacity, and the volatile pricing in the late 1990's and the experience of California have only strengthened its resolve in this regard. For generation planning purposes, LG&E currently targets a reserve margin of 14 percent, within a range of 13 percent to 15 percent. The added combustion turbine capacity is of key importance in achieving this reserve margin target.

Q. Turning to transmission, how has the reliability of LG&E's transmission system fared over the last several years?

A. Like its generation system, LG&E's transmission system has historically been highly reliable, a consequence, at least in part, of the Company's commitment to, and membership in, the East Central Area Reliability Council, a regional member of NERC. It is incumbent on LG&E to take whatever prudent steps are necessary to comply fully with the relevant reliability standards set by NERC, whose mission is to ensure that the bulk power system is dependable, adequate and secure. LG&E takes its responsibilities seriously in this regard.

Apart from its commitment to meet the reliability criteria established by NERC, LG&E tracks, for internal purposes, the average duration of service interruptions related to transmission. Because LG&E's transmission system is integrated with the transmission system of its sister company, KU, LG&E tracks performance on a combined company basis. Although a duration of service interruption tracking measure is of limited value to transmission systems, LG&E uses this measure to gauge and trend its performance over time, and has historically fared well. In fact, on a combined-company basis, reliability performance has consistently surpassed performance targets on an annual basis.

Q. Has LG&E made any capital or other investments in its transmission system over the last several years?

A. Yes. LG&E invested approximately $30 million over the last four years to preserve the reliability of its transmission system. Among other things, the Company has increased transformer capacity in areas of high load growth and added transmission lines to serve as back-up circuits in the event primary circuits are interrupted.

Q. You indicated earlier that LG&E has a strong interest in promoting a safe working environment for its workforce. Please discuss LG&E's safety performance in the areas of generation and transmission.

A. LG&E has worked extremely hard to develop a higher level of trust and partnering among our employees to move towards our ultimate goal of zero injuries in the workplace. We have also performed better and more consistent hazard assessments to prevent the occurrence of injuries. In fact, based upon a comparison of recordable injuries for the years 2002 and 2003, there were approximately 50 percent fewer recordable employee injuries in the first 11 months of 2003, as compared to the same period in 2002; and approximately 50 percent fewer injuries in calendar year 2002, as compared to calendar year 2000. The trend is clearly encouraging.

Q. Does LG&E's use of independent contractors compromise LG&E's commitment to safety in any way?

A. Absolutely not. Based upon current contractor injury trends, our contractors have a safety rating that beats the most recent national benchmark by 17 percent. Although we are pleased with that performance, our goal is zero injuries, for both employees and contractors, and we will continue to focus on safety for our entire workforce.

Q. Do you have any closing thoughts?

A. Yes. As I stated at the outset of this testimony, Energy Services' mission is predicated on three fundamental, overlapping objectives: (i) maximizing the performance and investment life of the Company's electric generation and transmission assets; (ii) maintaining sound operating and maintenance practices that promote both reliable and efficient operations and a safe working environment; and (iii) providing high value electric service to LG&E's customers. Through the various initiatives described above and the commitment and dedication of its employees, Energy Services has achieved these objectives in the face of mounting cost pressures. Nonetheless, in my professional judgment the Company cannot continue to meet these goals without the ability to adequately recover its costs. A base rate increase now will allow LG&E to continue to provide the reliable service its customers have grown to expect, at rates still ranking among the lowest in the nation.

Q. Does this conclude your testimony?

A. Yes.

289992.21

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says he is SENIOR Vice President, Energy Services for LG&E Energy Corp., Louisville Gas and Electric Company, and Kentucky Utilities Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Paul W. Thompson

PAUL W. THOMPSON

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Melody A. Hulse (SEAL)
Notary Public

My Commission Expires:

November 24, 2007

APPENDIX A

Paul W. Thompson

Senior Vice President, Energy Services
LG&E Energy Corp.
220 West Main Street
Louisville, KY 40202
(502) 627-3861

Education

University of Chicago, MBA in Finance and Accounting -- 1981
Massachusetts Institute of Technology (MIT), BS in Mechanical Engineering -- 1979
Leadership Louisville -- 1997-98

Previous Positions

LG&E Energy Marketing, Louisville, KY
1998 - 1999 – Group Vice President

Louisville Gas and Electric Company, Louisville, KY
1996 - 1999 – Vice President, Retail Electric Business

LG&E Energy Corp., Louisville, KY
1994 - 1996 (Sept.) – Vice President, Business Development
1994 - 1994 (July) – Louisville Gas & Electric Company, Louisville, KY
General Manager, Gas Operations

1991 - 1993 – Director, Business Development

Koch Industries Inc.
1990 - 1991 – Koch Membrane Systems, Boston, MA
National Sales Manager, Americas
1989 - 1990 – John Zink Company, Tulsa, OK
Vice President, International

Lone Star Technologies (a former Northwest Industries subsidiary)
1988 - 1989 – John Zink Company, Tulsa, OK
Vice Chairman
1986 - 1988 – Hydro-Sonic Systems, Dallas, TX
General Manager
1986 – 1986 (July) — Ft. Collins Pipe, Dallas, TX, General Manager
1985 - 1986 – Lone Star Technologies, Dallas, TX
Assistant to Chairman
1980 - 1985 – Northwest Industries, Chicago, IL
Manager, Financial Planning

Civic Activities

Friends of the Waterfront Board
Library Foundation Board
  Chair, Annual Appeal 2002
  Co-Chair Annual Children's Reading Appeal 1999, 2000, & 2001
March of Dimes 1997 & 1998 - Honorary Chair
Habitat for Humanity - Representing LG&E as co-sponsor

Mr. Hermann

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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

TESTIMONY OF
CHRIS HERMANN
SENIOR VICE PRESIDENT – ENERGY DELIVERY
LG&E ENERGY CORP.
LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

December 29, 2003

Filed: December 29, 2003

Q. Please state your name, position and business address.

A. My name is Chris Hermann. I am employed by LG&E Energy Services, Inc., a service company subsidiary wholly-owned by LG&E Energy Corp. ("LG&E Energy"). I am Senior Vice President – Energy Delivery for LG&E Energy, Louisville Gas & Electric Company ("LG&E" or "the Company") and Kentucky Utilities Company ("KU"). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

A. I received a B.S. degree in Mechanical Engineering from the University of Louisville in 1970. I joined LG&E that same year. In 1978, I began working for LG&E as the Plant Manager for the Cane Run generating station. I held a number of other positions before assuming my current duties in December 2000. A complete statement of my work experience and education is contained in the Appendix attached hereto.

Q. Please describe your duties and responsibilities as Senior Vice President, Energy Delivery and the mission of the Energy Delivery division.

A. As Senior Vice President, Energy Delivery, I am responsible for retail operations as well as the gas and electric distribution functions for KU and LG&E. Our mission is straightforward. We strive to provide safe, reliable, and low cost service to our customers while maintaining excellent customer satisfaction. As a constant backdrop to these objectives, we must also achieve sufficient earnings and earnings growth opportunities to continue to accomplish our customer-oriented goals.

Q. Have you previously appeared before this Commission?

A. Yes. I have appeared before this Commission in informal conferences and participated in the merger proceedings of LG&E and KU before the Kentucky Public Service

Commission in Case No. 97-300, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Merger*.

I. PURPOSE OF TESTIMONY AND DESCRIPTION OF BUSINESS

Q. What is the purpose of your testimony?

A. By effectively managing costs, LG&E has been able to provide reliable, safe service for years without having to seek base rate increases. My testimony will describe how LG&E has been able to accomplish this goal for our retail operations and electric and gas distribution businesses, and will explain why a rate increase is needed at this time.

Q. Why is LG&E now seeking a base rate increase?

A. Despite the cost management initiatives undertaken by the Company over the last several years, as discussed below and in the testimony of Paul W. Thompson, the Company is now at a point at which we must implement an increase in our gas and electric base rates in order to continue to provide the reliable, safe service our customers have come to expect while also being afforded the opportunity to earn a reasonable return on our investment. LG&E's base rates for gas and electric services must be adjusted to a level which will provide LG&E: (1) the ability to generate sufficient revenue to continue to provide safe and reliable service to its customers; (2) the ability to maintain its financial integrity; and (3) the ability to adequately compensate investors for the risks assumed with respect to its operations.

It has been thirteen years since LG&E's electric base rates were last increased, four years since its electric rates were reduced and reset in conjunction with the establishment of LG&E's Earnings Sharing Mechanism ("ESM") and three years since our last gas base rate case. As set out in detail in the testimonies of S. Bradford Rives, Valerie L. Scott and Robert G. Rosenberg, LG&E's current rates do not provide sufficient revenue to recover the costs of its gas and electric businesses, including a fair and reasonable return on investment.

Q. **Please describe LG&E's gas and electric distribution businesses.**

A. LG&E's distribution businesses serves about 386,000 electric customers and about 311,000 gas customers in 16 counties in and around Louisville and Jefferson County. The electric distribution assets we manage include over 80 substations and over 4,000 miles of electric lines. Our electricity is primarily produced by our coal-fired generating stations which are discussed in greater detail in the testimony of Mr. Thompson. The gas distribution assets we manage include over 4,200 miles of gas pipe and five underground gas storage fields.

Q. **How does the Energy Delivery division operate and maintain the distribution networks that serve LG&E's customers?**

A. In general, we oversee the delivery of electricity and natural gas to our customers by constructing, operating and maintaining the electric and gas distribution infrastructure. We take appropriate actions to ensure safety and to restore supply to our customers in the event of outages, emergencies, or damage to our distribution system. We also provide the associated retail and customer service functions to our residential, commercial, and industrial customers.

The cornerstone of our retail and distribution operations continues to be our commitment to low costs, excellence in safety, customer satisfaction, and reliability in the provision of energy services. We also provide energy conservation options to our customers, including innovative programs like Demand Conservation. And, of course, we strive to achieve award-winning levels of customer satisfaction.

II. EFFORTS TO ACHIEVE EFFICIENCIES

Q. Please describe LG&E's initiatives and efforts in recent years to manage costs from a retail and gas and electric distribution standpoint.

A. Over the past several years, we have undertaken a number of initiatives aimed at managing costs by increasing efficiencies and achieving synergies, while maintaining safety, reliability, and customer satisfaction. Following the merger of KU and LG&E, we implemented our "One Utility" initiative. That initiative was followed by our "Value Delivery" initiative.

Q. What are some the key business practices that LG&E uses to achieve efficiencies and maintain low operating costs?

A. LG&E has adopted process changes focusing on asset management, improved work practices, and new technologies that have helped achieve operating efficiencies and synergies, and, in turn, mitigate the increased costs of doing business. I will discuss each of these practices throughout my testimony.

Notwithstanding our constant focus on cost management and performance, we are now at the point where our revenues are insufficient to continue to meet customer demand, provide safe and reliable service, and position ourselves to meet the needs of our customers. We want to be able to continue to offer some of the lowest rates in the industry, and to also maintain reliable and safe energy delivery and high levels of customer service.

Q. Describe how asset management has changed the ways in which LG&E's distribution operation is managed.

A. Since the merger of LG&E and KU, we have created an asset management organization. Asset management relies in part upon improved system modeling and analysis techniques. Enhanced assessment capabilities support the development of optimum repair or replacement decisions as well as optimum identification and timing of system enhancement investments required to serve growing system loads. LG&E's asset management processes focus on three main areas: (1) operating policies and standards, (2) investment strategy, and (3) asset information.

Our operating policies and standards area focuses on the development of materials standards, design and construction standards, operating/maintenance standards, Reliability Centered Maintenance programs, practices and procedures for regulatory compliance, and benchmarking. These activities allow us to adopt uniform practices and material standards across all areas of LG&E's and KU's energy distribution activities, and to thereby better manage our costs.

Our investment strategy area allows KU and LG&E to better plan their short- and long-term investment activities to ensure compliance with regulatory guidelines and to optimize asset life cycles.

Our asset information area includes facility and equipment data, records management, and asset history data which will allow us to more readily determine the condition of our assets and their performance.

These functions are designed to give us more information to help us better assess the assets that we own. In turn, asset management functions help us to determine how best to manage and optimize asset life cycles in order to maintain operating and spending efficiencies.

Q. Can you provide an example of asset management as applied by LG&E and KU?

A. Yes. One example is the use of Reliability Centered Maintenance ("RCM") processes. The RCM process relies upon a condition-based diagnostic maintenance program supporting appropriate funding and prioritization of maintenance activities and resources. Equipment operation is now tested as a first step in the maintenance process. If the equipment test results show that it is operating within acceptable parameters, further maintenance can be avoided until the next scheduled test. Testing schedules can be time-based; they can be based on the number of equipment operations, or they can be based on other factors. Before we implemented RCM, LG&E practiced a time-based and invasive maintenance process on its substation equipment. Large substation equipment would be completely dismantled and overhauled regardless of current or historical equipment performance. Equipment overhauls are very time-consuming, and thus expensive. In some cases we were completing extensive, invasive maintenance on equipment that had experienced very few operations and was performing well within the prescribed parameters. The move to a condition-based diagnostic maintenance process has reduced maintenance costs by optimizing maintenance schedules and activities based on our risk analyses, testing results, and actual experience with equipment makes and models.

Q. In addition to asset management, has LG&E undertaken other new work processes and methods?

A. LG&E has implemented several important work process improvements, such as Contractor Performance Management and materials outsourcing.

Q. Please discuss how LG&E manages its use of contractors.

A. LG&E outsources a portion of its activities for two reasons: (1) to reduce costs (e.g., for substation maintenance); or (2) to provide for a variable workforce (e.g., for construction requirements driven by load growth). An important aspect of outsourcing is the selection of quality contractors and the efficient management of those contractors. LG&E solicits bids based upon specific criteria, such as safety records, cost structures, resource capabilities, and worker qualifications, when selecting its contractors in order to retain only high quality contractors. LG&E has instituted a Contractor Performance Management initiative, which has allowed us to more effectively manage our contractors. That initiative involves a focus on safety, cost management and quality of work. LG&E establishes measurements and controls designed to ensure the productivity, safety, and quality of the work performed by our contractors. We also provide contractors with reviews and feedback on their performance and, as a part of that process, establish targets for unit measures of the work to be performed. Many of LG&E's Contractor Performance Management processes incorporate the use of incentive mechanisms to increase productivity without diminishing reliability or safety.

Q. What is materials outsourcing and how has it helped achieve efficiencies?

A. Materials outsourcing allows us to shift the responsibility from LG&E to our suppliers for managing, handling and delivering both gas and electric materials. LG&E initiated this process for gas materials in late 1999. Electric materials were outsourced in mid-2002.

Under this process, materials orders are sent directly to the supplier's warehouse and the materials are delivered on a timely basis consistent with our work schedules.

This outsourced materials handling process has allowed the Company to reduce in-house inventory and materials handling costs.

Q. Please describe some of the recent information systems in which LG&E has invested.

A. LG&E has implemented new information technology such as GEMINI, MAXIMO®, IVRU, and SMILE. They are designed to help us to better serve our customers.

Q. Please describe GEMINI and some of the efficiencies it can help to create.

A. The Geospatial Enterprise Management Integration Network Initiative ("GEMINI") will allow LG&E and KU to obtain improved data, thus allowing us to better manage and optimize our work force to achieve efficiencies. Specifically, GEMINI will help the two companies through improved work order scheduling and improved response to customer requests for service through streamlined data access and management. Secondarily, but importantly, GEMINI also allows us to provide customers with better information on the status of service restoration and service installations. This system integrates a work management system, outage management system, geographic information system, and graphical work design system.

GEMINI will be utilized by both gas and electric distribution operations of KU and LG&E. The outage management component will improve crew management and dispatch functions during outages, by tracking incoming calls to assist in quickly identifying system protective devices (e.g., fuses) that have operated, thus improving dispatch efficiency. The work management function will keep track of planned gas and electric construction work and available internal and external construction personnel to enable effective and efficient use of these resources. The Geospatial Information System

("GIS") will overlay geographical data such as roads and other landmarks in order to more reliably and effectively locate our distribution facilities. We have spent a total of $27 million to date on our GEMINI technology, including costs for software, hardware, supporting infrastructure, and data conversion.

Q. Please describe MAXIMO® and some of the efficiencies it can help to create.

A. LG&E and KU have completed the installation of the MAXIMO® maintenance management system. The MAXIMO® system is designed to identify, analyze and maintain physical assets such as substations and gas compressor stations. The MAXIMO® maintenance management system tracks equipment condition, testing results, and maintenance/testing schedules. MAXIMO® can flag test results that are out of range, equipment operating levels triggering scheduled maintenance, regulatory compliance maintenance schedules, and testing schedules, in order to optimize maintenance activities. This innovative technology also helps achieve efficiencies by accurately tracking materials and their usage, thus allowing for the maintenance of appropriate inventory levels. It allows us to track maintenance work and testing performed on our assets so that we can optimize our resources and maintain productivity. MAXIMO® supports our ability to implement consistent maintenance practices throughout the distribution operations of LG&E and KU.

Q. Describe LG&E's efforts to achieve efficiencies in the provision of its retail call-center and other customer services.

A. One of the ways in which we have achieved operational efficiencies is through the integration of the LG&E and KU call centers. Those call centers, located in Louisville, Lexington and Pineville, operate together as a single virtual call center. The three center locations were integrated in 2001 so that calls can be answered by representatives in any location. It is only through new technology that these call centers can operate as if they were located in one physical location. These technologies are used to provide timely responses to customers by managing the call load among the three centers, allowing a customer to report an outage or request service without undue delay.

The Integrated Voice Response Unit ("IVRU"), which we implemented in late 1999, allows us to keep costs down, to handle larger volumes of calls, and to route calls more effectively to representatives with the most appropriate skills based upon the customer's stated reason for calling.

We have also engaged in specialized training of our representatives to better respond to customer inquiries, and have started utilizing bilingual staff to better serve and communicate with our growing number of Hispanic customers. Procedural changes, such as the use of an open queue, which eliminates busy signals, have also been implemented. As a result of procedural changes and streamlined operations, the average wait time to speak with a customer service representative has decreased from almost two minutes in 2000 to just over 30 seconds in 2003.

Q. Please describe the SMILE system and some of the efficiencies it can help to create.

A. One of our new information systems is called SMILE. SMILE is an acronym for "Service Makes It Look Easy." The SMILE system creates a common data presentation system for data drawn from both the LG&E and KU customer information systems. This single system manages the data in such a way as to assist KU and LG&E customer representatives to be trained more efficiently and effectively to respond to inquiries from either LG&E or KU customers. The use of the SMILE system has facilitated LG&E's

efforts to create a virtual call center, optimize call center personnel, and reduce training time.

III. MEETING CUSTOMER GROWTH AND OTHER CHALLENGES

Q. What have been some of LG&E's more significant challenges?

A. The replacement of our aging gas infrastructure and maintaining high levels of safety, reliability, and customer satisfaction with increased electric and gas customer growth have presented challenges for LG&E over the past several years.

Q. Describe the impact of customer growth on LG&E.

A. As a utility, we have a public service obligation to serve all customers in our gas and electric service areas. We make continuing investments in our utility infrastructure in order to meet the demands of new and existing customers.

The increased number of gas and electric customers over the past several years has been quite significant. In the time frame since LG&E's ESM was first placed into effect in 2000, our net electric customer count at LG&E has grown by more than 26,000 customers, and the Company has expended about $172 million in capital on its electric distribution business. The demand for gas services has also expanded by more than 16,000 net gas customers since LG&E's last gas rate case in 2000, and in that time the Company has expended about $94 million in capital on its gas business. These increases put additional strain on our system and require additional capacity. As noted, we have a public service obligation to serve these customers. On the electric side, new distribution facilities required to serve new customers account for almost 50% of the capital expended in LG&E's electric distribution system. On the gas side, new customers account for about 35% of the capital expended in our gas distribution business.

Q. Are there any challenges that are particular to LG&E's gas business?

A. Yes. LG&E has replaced 147 miles of main as a part of a large scale main replacement effort, including 95 miles since LG&E's last gas rate case. LG&E's main replacement program helps ensure continued safety, improved reliability, enhanced operating efficiencies, and lower operating costs. There are 413 miles yet to replace. LG&E believes that there are important safety and performance benefits associated with the replacement of older bare pipe in its system.

The replacement of these mains through large-scale projects, rather than piecemeal repair and replacement carried out through priority main replacement projects, is more efficient because of the economies of scale involved. The investment levels required to replace these mains have proven difficult to maintain given LG&E's current revenue levels and other expenditures which it must also make in order to continue to operate a sound system and, at the same time, maintain the viability and integrity of the gas business.

Q. Will LG&E's gas distribution business need to address additional regulatory requirements in the future?

A. Yes. There are regulatory changes that will affect our business operations. For example, LG&E must comply with federal directives on natural gas pipeline safety established in the Pipeline Safety Improvement Act of 2002. One of the requirements of the Act is that operators of gas transmission lines establish integrity management programs that include the continual assessment of the integrity of pipeline segments located in High

Consequence Areas ("HCAs"). As a result of this new requirement, LG&E will need to identify all HCAs along its gas transmission lines, conduct risk analyses of its pipeline segments, and complete pipeline integrity assessments on 50% of its highest risk segments within 5 years of the passage of the Act and on 100% of those segments within 10 years. After the initial assessment, each segment must be tested every 7 years thereafter. LG&E has taken the initial steps required to comply with these new federal regulations, and is developing cost estimates for compliance, but is not proposing a pro forma adjustment in this proceeding.

IV. <u>BENCHMARKING: SAFETY, RELIABILITY, AND COST MANAGEMENT</u>

Q. Discuss the role of benchmarking in LG&E's retail and distribution operations.

A. We continually benchmark our distribution and retail activities (both against others in the industry and against our own prior achievements) not merely to measure our performance, but also to better understand our performance. Our benchmarking activities focus on areas such as reliability, safety, and cost management. For example, as indicated below, we have a "No Compromise" policy in the area of safety, and benchmarking is one tool used to determine the effectiveness of our safety efforts.

Benchmarking enables us to identify areas of focus and to validate how we operate our retail and distribution businesses. We believe that benchmarking, in the appropriate context, is a valuable management tool.

Q. Please discuss the Company's commitment to safety and its overall safety performance.

A. We have a "No Compromise" policy on safety that emphasizes individual accountability. This policy begins with a top-down commitment and is based on modifying behaviors and attitudes in order to create an ownership and safety culture within our workforce. Our goal is a low-risk, safe work environment. Our "No Compromise" policy states that it is unacceptable for anyone to work in an unsafe manner. In order to ensure that the policy is operating as it should, we utilize such programs as random field audits, safety tailgates, and quarterly safety meetings.

By leveraging the synergies and resources available to both KU and LG&E, we have been able to move from an environment with different programs operating at different levels to a safety program for the whole of Energy Delivery which exceeds the mandates of both OSHA and the National Electrical Safety Code ("NESC"). We have also received numerous Governor's Safety and Health Awards; our OSHA recordable incident rates are significantly below the national average, and our OSHA recordable incident rates continue to decline. In fact, our benchmarking efforts, in terms of safety, demonstrate that we are a leader in the industry.

Q. How has LG&E performed in the area of electric reliability?

A. The reliability of our electric service is measured by tracking the system's average length of interruption and the system's average frequency of interruption. Our electric reliability measures for the duration and frequency of interruptions from 1999 through 2002 represent improvements from our 1998 performance measures. These post-merger measures represent solid performance when compared to the industry.

However, our measures indicate an upward trend in the duration and frequency of interruptions. We are concerned about that trend and, in response, are increasing our focus on reliability. Our focused efforts will help to target our reliability-related investments in order to reverse this trend.

Q. How has LG&E performed in the area of cost management?

A. One cost management benchmark on which we focus is cash cost per customer. Cash cost per customer measures the combination of operating/maintenance costs and capital costs expended on a per customer basis. In terms of cash cost per customer, LG&E is a low cost provider in the industry.

Benchmarking is one tool that helps us maintain the proper balance between cost and reliability. LG&E delivers reliable gas and electric service at a reasonable cost. We are seeking this increase in our revenues in order to continue to maintain the appropriate balance between cost and reliability.

V. CUSTOMER SATISFACTION AND FOCUS

Q. Describe LG&E's customer satisfaction levels.

A. LG&E continues to be nationally recognized for its strong customer focus and outstanding customer satisfaction. J.D. Power and Associates ranked LG&E Energy (LG&E and KU) first in the Midwest in its 2003 residential survey of the nation's 77 largest electric utilities. LG&E Energy also ranked highest nationally in customer satisfaction in J.D. Power's 2003 survey of midsize business customers. The J.D. Power electric studies focus on customer service, power quality and reliability, company image, price/value and billing. In total, we have earned eight J.D. Power awards for customer satisfaction since 1999.

In the J.D. Power and Associates 2003 Gas Utility Residential Customer Satisfaction Study released in October 2003, LG&E ranked second overall among gas utilities in the Midwest. This annual study measures customer satisfaction performance among 55 of the largest local gas distribution companies in the country.

Q. How has LG&E achieved such excellence in customer satisfaction?

A. The bedrock of excellence in customer satisfaction is the efforts of our hardworking employees. Not only have they formulated the initiatives discussed above, they have implemented them. In addition to those initiatives, LG&E has instituted a number of programs designed to improve customer service and satisfaction, including customer self-service through the Internet using electronic billing and payment. Customers participating in our electronic billing program receive an e-mail each month instead of a traditional paper bill. A special link in the e-mail allows members to view their bill and bill inserts, along with a detailed account of their usage and billing history. For added convenience, customers can also pay their bill through the Internet or by phone. This program is an easy, convenient way for customers to pay their bill quickly and at any time, day or night. It is safe and secure and offers customers freedom from writing checks, buying postage stamps and worrying about postal delays.

Still another option available to customers is our Automatic Bank Club ("ABC") program. Our ABC program eliminates the need for customers to write checks, pay for postage, and mail their payments. Instead, the amounts owed by customers are deducted automatically from the customer's checking account on the due date. The ABC program is also cost-effective for LG&E, because handling and process costs are reduced.

Customers may also receive a credit for helping the environment and mitigating peak load growth by signing up for the Demand Conservation program. As part of Demand Conservation, electric customers reduce energy demand by signing up for a program under which a device is connected to their central air conditioner which controls the cycling of the unit. Demand Conservation helps to reduce peak demand, enabling us to use our power plants more efficiently and delay the addition of new ones, which, in turn, benefits all of our electric customers. As a reward, a customer's utility billing is credited up to $20 annually, per central air conditioning unit.

VI. <u>CONCLUSION</u>

Q. Can you briefly summarize your testimony?

A. Yes. KU and LG&E have undertaken a number of efforts over the past few years in an effort to achieve efficiencies and maintain low operating costs, all the while striving to meet challenges arising from increased customer demands and increased costs. LG&E's current rates do not provide sufficient revenue to recover the expenses incurred to maintain safety, reliability and high levels of customer satisfaction and allow for a reasonable return. As a result, our electric and gas base rates must be increased.

Q. Does this conclude your testimony?

A. Yes.

289994.14

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Chris Hermann**, being duly sworn, deposes and says he is Senior Vice President – Energy Delivery for LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

C Hermann

CHRIS HERMANN

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Nancy L Kitchen (SEAL)
Notary Public

My Commission Expires:
Notary Public, State at Large, KY
My commission expires Nov. 5, 2006

Appendix A

Chris Hermann

Senior Vice President – Energy Delivery
LG&E Service Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-2703

Education

University of Louisville, B.S. in Mechanical Engineering -- 1970
Duke University – Program for Management Development
Harvard University – Program on Negotiations
Edison Electric Institute – Program on Senior Middle Management
E.ON Executive Program—Leading Corporate Transformation, Harvard University

Previous Positions

LG&E Service Company, Louisville, KY:
December 2000 – Present -- Senior Vice President Distribution Operations

Louisville Gas and Electric, Louisville, KY:
January 2000 – December 2000 -- Vice President Supply & Logistics
May 1999 – December 1999 -- Vice President Business Integration
June 1998 – April 1999 -- Vice President Power Generation & General Services
May 1997 -- May 1998 -- Vice President Business Integration
1993 -- May 1997 – V.P. and General Manager, Wholesale Electric Business
1992 -- 1993 -- General Manager, Wholesale Electric
1990 -- 1991 -- General Manager, Power Production
1984 -- 1990 -- Manager of Administration, Power Production
1978 -- 1984 -- Plant Manager, Cane Run
1977 – 1978 – Assistant Plant Manager, Cane Run
1974 – 1977 -- Efficiency Engineer, Cane Run
1970 – 1974 – Mechanical Engineer

Professional/Trade Memberships

American Management Association
American Society of Mechanical Engineers
Association for Quality Participation
Southern Gas Association Executive Council
American Gas Association Leadership Council

Previous Professional/Trade Memberships

OVEC (Ohio Valley Electric Corp) -- Board of Directors & Executive Committee
EEI Generation Subject Area Committee -- National Chair
EEI Prime Movers Committee
EEI Power Supply Technical Task Force
EEI Engineering, Operating and Standards Executive Advisory Committee
ECAR Executive Board and Executive Board Working Group

Present Civic Activities

Louisville Orchestra Development Committee --2001, 2002, 2003
University of Louisville Speed Scientific School:
Board of Industrial Advisors -- 1992 - current

Previous Civic Activities

Redeemer Lutheran Church:
President of Congregation -- 1984 – 1997, 1999 – 2002
Chairman Call Committee, 1999 -- 2000
Chairman of Building Committee -- 1985 – 1991
Fund for the Arts Corporate Campaign – 2002
Technology Network of Louisville:
Executive Committee Member – 2002
Founding Member -- 2001
Board Member -- 2001, 2002
Advanced Technology Council – Board Member – 1999, President – 2000
Leadership Louisville -- 1994
Bingham Fellows Class of 2000
LG&E Employees Credit Union:
Chairman of the Board -- 1984 - 1992
Board Member -- 1978 - 1992
University of Louisville: Board of Overseers' Mentor Program -- 1993 -- 1994
University of Louisville: Commissioner, Bicentennial Celebration
University of Louisville Speed Scientific School:
Elected Chairman Board of Industrial Advisors for 1993 - 1994
Friends of Scouting Campaign -- Vice Chair
Lincoln Heritage Council of Boy Scouts — Explorer Post Sponsor 1997 – 1998
United Way – Variety of positions
Volunteers of America – Major Gifts Vice Chair, 1999, 2000, 2001
Junior Achievement – Variety of positions

Mr. Rives

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:	)	
	)	
AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	))))	CASE NO: 2003-00433

TESTIMONY OF
S. BRADFORD RIVES
CHIEF FINANCIAL OFFICER
LOUISVILLE GAS AND ELECTRIC COMPANY

December 29, 2003

Filed: December 29, 2003

Q. Please state your name, position and business address.

A. My name is S. Bradford Rives. I am the Chief Financial Officer for LG&E Energy Corp. and Louisville Gas and Electric Company ("LG&E"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my professional history and education is attached as an appendix hereto.

Q. Have you previously testified before this Commission?

A. Yes. I have previously testified before this Commission in rate proceedings, administrative investigations and environmental surcharge proceedings.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe why the financial conditions of LG&E require the requested increase in base rates, present the Financial Exhibits to LG&E's application, review LG&E's accounting records, describe the calculation of LG&E's adjusted net operating income for the twelve month period ended September 30, 2003, and support the different valuations of LG&E's property.

LG&E's Current Financial Condition

Q. How would you describe LG&E's present financial circumstances?

A. As pointed out in the testimonies of Mr. Victor A. Staffieri, Mr. Paul Thompson and Mr. Chris Hermann, LG&E's operational performance remains strong, but its financial condition has substantially deteriorated. Even with ongoing initiatives to control costs and improve efficient operations described by Mr. Thompson and Mr. Hermann, LG&E's financial results for the twelve-month period ending September 30, 2003, are well below a reasonable level.

It is essential that LG&E achieve and maintain a strong financial condition to allow it to continue to provide safe, reliable service to its customers. Despite LG&E's substantial cost reductions and process improvements, LG&E's revenues must be adjusted to reflect its cost of providing service and to continue to effectively meet its service obligation both now and in the future. LG&E's weakened current financial condition is not in the best interest of its shareholders or its customers. Approval of this rate increase is imperative to improve the Company's financial health.

Q. Has LG&E's investment in electric utility plant increased since December 31, 1998, the test period used by the Commission in Case No. 98-426?

A. Yes. The following chart shows LG&E's investment in net electric utility plant has increased by approximately $412.7 million since December 31, 1998:

Net Electric Utility Plant

	December 31, 1998	September 30, 2003	Increase
Electric utility plant	$2,481,566,887	$3,232,386,289	$750,819,402
Accumulated depreciation	1,001,300,599	1,339,452,661	338,152,062
Net electric utility plant	$1,480,266,288	$1,892,933,628	$412,667,340

Q. Has LG&E's investment in gas utility plant increased since December 31, 1999, the test period used by the Commission in Case No. 2000-080?

The following chart shows LG&E's investment in net gas utility plant has increased by approximately $47.1 million since December 31, 1999:

Net Gas Utility Plant

	December 31, 1999	September 30, 2003	Increase
Gas utility plant	$436,334,493	$519,793,206	$83,458,713
Accumulated depreciation	147,012,854	183,372,937	36,360,083
Net gas utility plant	$289,321,639	$336,420,269	$47,098,630

Q. Did LG&E earn its authorized return on equity in 2002 or for the twelve months ended September 30, 2003?

A. No. The results of LG&E's annual earnings sharing mechanism for 2002 shows the Company earned a return on equity of 7.56% and a return on capital of 5.61% for its electric operations, well below the 11.5% return on common equity and the overall cost of capital of 8.47% approved by the Commission in Case No. 98-426. For the twelve months ended September 30, 2003, the return on equity has further declined to 5.96% and the return on capital has declined to 4.58% for electric operations. In 2002 LG&E earned a return on equity of 7.43% and a return on capital of 5.18% for its gas operations, also below Commission approved returns in Case No. 2000-080 of 11.25% for return on equity and 8.21% return on capital. For the twelve months ended September 30, 2003, the return on equity has further declined to 3.92% and the return on capital has declined to 3.60% for gas operations.

Based on the analyses presented in Mr. Robert G. Rosenberg's testimony, he has determined that the return on equity for LG&E's electric operations should be in the 10.75% – 11.25% range and has recommended the Commission adopt an 11.25% allowed electric rate of return on equity in this proceeding. Mr. Rosenberg has also determined the return on equity for LG&E's gas operations should be in the range of 11.00% - 11.50%, and has recommended 11.50% as the allowed return on equity for LG&E's gas operations. These equity returns are necessary for the Company to regain and preserve its financial health. However, as my testimony has shown, LG&E's earned returns on common equity for the twelve-month period ending September 30, 2003, for both its electric and gas operations fall well below these returns.

For the reasons described in my testimony, the Commission should approve LG&E's proposed adjustment to base rates to afford LG&E the opportunity to earn a reasonable return on common equity of 11.25% for its electric operations and 11.50% for its gas operations.

PSC Financial Exhibits

Q. Are you supporting the information required by Commission regulation 807 KAR 5:001, Section 6 – Financial Exhibit?

A. Yes. The Financial Exhibit required by this regulation was filed with LG&E's Application in this case and includes the required financial information for the twelve months ended September 30, 2003.

Q. Are you supporting the information required by Commission regulation 807 KAR 5:001, Section 10(6)(a)-(v) – The Historical Test Period?

A. Yes. I am sponsoring the following Schedules for the corresponding Filing Requirements:

• Description of Adjustments	Section 10(6)(a)	Tab 20
• Testimony (Revenues > $1.0 mm)	Section 10(6)(b)	Tab 21
• Testimony (Revenues < $1.0 mm)	Section 10(6)(c)	Tab 22

• Revenue Requirements Determination	Section 10(6)(h)	Tab 27
• Reconcile Rate Base & Capitalization	Section 10(6)(i)	Tab 28
• Annual Auditor's Opinion(s)	Section 10(6)(k)	Tab 30
• Stock or Bond Prospectuses	Section 10(6)(p)	Tab 35
• Annual Reports of Shareholders	Section 10(6)(q)	Tab 36
• SEC Reports (10Ks, 10Qs and 8Ks)	Section 10(6)(s)	Tab 38

Accounting Records

Q. Are the accounting records of LG&E kept in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission and adopted by the Kentucky Public Service Commission?

A. Yes. The records are kept in accordance with the Uniform System of Accounts prescribed for electric and gas public utilities.

Q. Does LG&E file monthly and annual operating reports presenting financial results with the Kentucky Public Service Commission?

A. Yes. They are also provided in LG&E's Application in Filing Requirements Tabs 32 and 37 and are supported by the testimony of Ms. Valerie L. Scott in this case.

Q. Is an audit of the financial statements of LG&E performed annually by independent public accountants?

A. Yes. PricewaterhouseCoopers audits LG&E's financial statements annually. The most recent opinion of our external auditor is provided in Filing Requirements Tab 30.

Net Operating Income

Q. Please describe Rives Exhibit 1 and its purpose.

A. Rives Exhibit 1 shows electric and gas operating revenues separately, and electric and gas operating expenses and net operating income per books separately for the twelve months ended September 30, 2003. Because the historical test year is used instead of a forecasted test year, it is necessary that the historical test year be adjusted to reflect changes in revenues and expenses that can be expected to occur during the period the proposed rates will be effective. This Exhibit sets forth adjustments for the known and measurable changes and eliminates unrepresentative conditions in order to "pro form" or make the test year suitable for use in determining the deficiency of current electric and gas revenues. A further description of, and support for, each adjustment is contained in supporting Reference Schedules 1.00 through 1.38 of this Exhibit.

<u>Electric Operations</u>

Q. Briefly describe the nature of the pro forma adjustments you have made to LG&E's electric operations for the test year ended September 30, 2003 shown on Rives Exhibit 1.

A. For the electric operations as reflected in the twelve month period ended September 30, 2003, LG&E has made adjustments which:

a) Eliminate the effect of unbilled revenues (Reference Schedule 1.00),

b) Remove the impact of items included in other rate mechanisms (Reference Schedules 1.01, 1.03, 1.05, 1.07, 1.08, 1.09, 1.20 and 1.22),

c) Annualize year end facts and circumstances and adjust for other known and measurable changes to revenues and expenses (Reference Schedules 1.02, 1.04, 1.10, 1.11, 1.12, 1.13, 1.16, 1.17, 1.24, and 1.37),

d) Adjust for other excludable unusual, non-recurring or out-of-test period items in the test year (Reference Schedules 1.06, 1.14, 1.15, 1.18, 1.19, 1.21, 1.23, 1.25, 1.26, 1.27, 1.28, 1.29, 1.30, 1.31, 1.32, and 1.38), and

e) Adjust for Federal and state income tax expenses for these pro-forma adjustments (Reference Schedules 1.36 and 1.39).

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.00 of Exhibit 1.

A. This adjustment has been made to eliminate the effect of unbilled revenues. This adjustment was prepared by Mr. W. Steven Seelye and will be explained in detail in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.01 of Exhibit 1.

A. This adjustment has been made to account for the timing mismatch in fuel cost expenses and revenues under the Fuel Adjustment Clause (FAC) for the twelve months ended September 30, 2003. This adjustment was prepared by Mr. Seelye and will be explained in detail in his testimony.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.02 of Exhibit 1.

A. Reference Schedule 1.02 presents the adjustment necessary to annualize the full twelve months of the test year for the FAC roll-in as directed by the Commission's April 23, 2003 Order in Case No. 2002-00434. This adjustment was prepared by Mr. Seelye and will be explained in detail in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.03 of Exhibit 1.

A. This adjustment removes environmental cost recovery revenues and expenses from net operating income because those revenues and expenses are addressed by a separate rate mechanism. This adjustment was prepared by Mr. Seelye and will be explained in detail in his testimony.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.04 of Exhibit 1.

A. This adjustment has been made to reflect a full year of the environmental cost recovery roll-in as required in the Commission's October 22, 2002 Order in Case No. 2002-00193. This adjustment was prepared by Mr. Seelye and will be explained in detail in his testimony.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.05 of Exhibit 1.

A. This adjustment includes the environmental compliance costs associated with off-system sales revenues. This adjustment is made in accordance with the methodology approved by the Commission in its June 1, 2000 Order in Case No. 98-426. It is also consistent with the Commission's determination in Case No. 94-332 that LG&E should assign eligible environmental compliance costs attributable to off-system sales that are otherwise eligible for environmental surcharge recovery. This adjustment was prepared by Mr. Seelye and will be explained in detail in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.06 of Exhibit 1.

A. This adjustment has been made to eliminate electric brokered sales revenues and expenses as directed by the Commission in Case No. 98-426. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.07 of Exhibit 1.

A. This adjustment is necessary to eliminate the impact of the Earnings Sharing Mechanism revenues collected during the test period and not included in Rate Refund Account 449. The impact of rate mechanisms like the Earnings Sharing Mechanism should be removed from the test year revenues when assessing the adequacy of base rates. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.08 of Exhibit 1.

A. This adjustment has been made to eliminate the impact of the revenues recorded in the test year associated with the Earnings Sharing Mechanism, Environmental Cost Recovery and Fuel Adjustment Clause from Rate Refund Account 449. The impact of rate mechanisms, such as these, should be removed from the test year revenues when assessing the adequacy of base rates. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.09 of Exhibit 1.

A. This adjustment has been made to remove the impact of the revenues and expenses associated with LG&E's demand-side management mechanism from the test year revenues and expenses. The impact of rate mechanisms, like the demand-side management mechanism, should be removed from the test year revenues when assessing the adequacy of base rates. This adjustment was prepared by Mr. Seelye and is discussed in his testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.10 of Exhibit 1.

A. This adjustment has been made to annualize revenues based on actual customers at September 30, 2003. This adjustment was prepared by Mr. Seelye and will be explained in detail in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.11 of Exhibit 1.

A. This adjustment has been made to reflect annualized depreciation expenses under the new rates proposed in this case as applied to plant-in-service as of September 30, 2003. The calculation of the adjustment was prepared by Ms. Scott and is discussed in her testimony. The proposed new rates are based on a depreciation study conducted by AUS Consultants. The justification for these new rates is covered in Mr. Earl Robinson's testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.12 of Exhibit 1.

A. This adjustment has been made to reflect increases in labor and labor-related costs as applied to the twelve months ended September 30, 2003, and includes specific adjustments for wages, payroll taxes and LG&E's 401(k) match. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.13 of Exhibit 1.

A. This adjustment is necessary to annualize pension and post-retirement medical benefit expenses. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.14 of Exhibit 1.

A. This adjustment has been made to reflect a normalized level of storm damage expenses. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.15 of Exhibit 1.

A. This adjustment eliminates advertising expenses, was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.16 of Exhibit 1.

A. This adjustment is necessary to include the expenses incurred in conjunction with this base rate case. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.17 of Exhibit 1.

A. This adjustment is necessary to reflect the expenses incurred by LG&E for the Earnings Sharing Mechanism audit. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.18 of Exhibit 1.

A. The adjustment is necessary to remove the amortization of One-Utility costs as a non-recurring expense because these costs were completely amortized by September 30, 2003. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.19 of Exhibit 1.

A. This adjustment is made to normalize the expense levels in Account 925 "Injuries and Damages." This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.20 of Exhibit 1.

A. This adjustment is to reflect the Value Delivery Team net savings to shareholders recognized by the Commission in its December 3, 2001 Order in Case No. 2001-169. The adjustment was prepared by Ms. Scott based on the values in the Value Delivery Surcredit Rider and is discussed in her testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.21 of Exhibit 1.

A. This adjustment is to true-up the Value Delivery Team customer surcredit and amortization of expenses approved by the Commission its December 3, 2001 Order in Case No. 2001-169. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.22 of Exhibit 1.

A. This adjustment is made to reflect the current customers' and shareholders' portions of the merger savings approved by the Commission in its October 16, 2003 Order in Case No. 2002-00430. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.23 of Exhibit 1.

A. This adjustment is necessary to reflect the elimination of merger amortization expenses from the LG&E Energy Corp. acquisition of KU Energy Corporation approved by the Commission in Case No. 97-300. The merger expenses were fully amortized by September 30, 2003. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.24 of Exhibit 1.

A. This adjustment is necessary to reverse MISO Schedule 10 expense credits received in the test year that are not ongoing after 2003. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.25 of Exhibit 1.

A. This adjustment is necessary to fairly reflect the adoption of SFAS 143, *Accounting for Asset Retirement Obligations*, for ratemaking purposes. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.26 of Exhibit 1.

A. This adjustment has been made to reflect the October 2003 reduction of 27 employees in the Information Technology department of LG&E Energy Services, Inc. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.27 of Exhibit 1.

A. This adjustment is necessary to remove expenses incurred by LG&E in connection with the Alstom combustion turbine litigation in the test year. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.28 of Exhibit 1.

A. This adjustment is made to reflect the rate schedule switch of one electric customer and two gas customers and the plant closing by another gas customer. This adjustment was prepared by Mr. Seelye and will be explained in detail in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.29 of Exhibit 1.

A. This adjustment reflects changes in LG&E's corporate office lease expenses. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.30 of Exhibit 1.

A. This adjustment is to remove the insurance proceeds received by LG&E during the test year for costs incurred prior to the test year related to the repair of Cane Run Unit No. 5. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.31 of Exhibit 1.

A. This adjustment is for steam plant inventory that LG&E charged-off its books during the test year because the parts had become obsolete. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.32 of Exhibit 1.

A. This adjustment relates to the write-off of a payment for carbide lime made by LG&E to Carbide Graphite for use at the Cane Run Power Station. The deposit was written off as a result of Carbide Graphite's bankruptcy. This adjustment was prepared by Ms. Scott and is discussed in her testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.36 of Exhibit 1.

A. This adjustment is for federal and state income taxes corresponding to the base revenue and expense adjustments discussed above. Reference Schedule 1.36 shows the calculation of a composite federal and state income tax rate using a federal corporate income tax rate of 35%, and a Kentucky corporate income tax rate of 8.25%. As shown on Reference Schedule 1.36, the composite federal and state income tax rate is 40.3625%.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.37 of Exhibit 1.

A. This adjustment is for federal and state income taxes corresponding to the annualization and adjustment of year-end interest expense. The Commission has traditionally recognized the income tax effects of adjustments to interest expense through an interest synchronization adjustment. This adjustment is calculated following the methodology used by the Commission in its order in Case No. 2000-080. The total capitalization amount for LG&E is taken from Rives Exhibit 2 and is multiplied by LG&E's weighted cost of debt, and that amount is then compared to LG&E's interest per books (excluding other interest) to arrive at the interest synchronization amount. The composite federal and state income tax rate has been applied to the interest synchronization amount.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.38 of Exhibit 1.

A. This adjustment is for income tax true-ups and adjustments made during the test year that relate to prior periods and is in accordance with the Commission's approval of this type of adjustment in Case No. 2000-080.

Gas Operations

Q. Briefly describe the nature of the pro forma adjustments you have made to LG&E's gas operations for the test year ended September 30, 2003, shown on Rives Exhibit 1.

A. For the gas operations as reflected in the twelve month period ended September 30, 2003, LG&E has made adjustments which:

a) Eliminate the effect of unbilled revenues (Reference Schedule 1.00),

b) Remove the impact of items included in other rate mechanisms (Reference Schedules 1.09, 1.20 and 1.33),

c) Annualize year end facts and circumstances and adjust for other know and measurable changes to revenues and expenses (Reference Schedules 1.10, 1.11, 1.12, 1.13, and 1.37),

d) Adjust for other excludable unusual or non-recurring items in the test year (Reference Schedules 1.15, 1.16, 1.18, 1.19, 1.21, 1.26, 1.28, 1.29, 1.34, 1.35, and 1.38), and

e) Adjust for Federal and state income tax expenses for these pro-forma adjustments (Reference Schedules 1.36 and 1.39).

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.00 through 1.29 of Exhibit 1.

A. These adjustments are for the same items and reasons previously described in my testimony for the electric rates. The will be covered in detail by the witnesses previously mentioned in my testimony for each adjustment.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.33 of Exhibit 1.

A. This adjustment has been made to eliminate the effect of gas supply cost recoveries and gas supply expenses for the test year ended September 30, 2003. This adjustment was prepared by Mr. Seelye and will be explained in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.34 of Exhibit 1.

A. This adjustment is to reflect current costs for storage field losses and purification expense. This adjustment was prepared by Mr. Seelye and will be explained in his testimony.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.35 of Exhibit 1.

A. This adjustment was necessary to adjust revenues for temperature normalization for the months *outside* of the period covered by the Weather Normalization Adjustment Clause. This adjustment was prepared by Mr. Seelye and is fully explained in his testimony.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.36 of Exhibit 1.

A. This adjustment is for federal and state income taxes corresponding to the base revenue and expense adjustments discussed above. Reference Schedule 1.36 shows the calculation of a composite federal and state income tax rate using a federal corporate income tax rate of 35%, and a Kentucky corporate income tax rate of 8.25%. As shown on Reference Schedule 1.36, the composite federal and state income tax rate is 40.3625%.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.37 of Exhibit 1.

A. This adjustment is for federal and state income taxes corresponding to the annualization and adjustment of year-end interest expense. The Commission has traditionally recognized the income tax effects of adjustments to interest expense through an interest synchronization adjustment. This adjustment is calculated following the methodology used by the Commission in its order in Case No. 2000-080. The total capitalization amount for LG&E is taken from Rives Exhibit 2 and is multiplied by LG&E's weighted cost of debt, and that amount is then compared to LG&E's interest per books (excluding other interest) to arrive at the interest synchronization amount. The composite federal and state income tax rate has been applied to the interest synchronization amount.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.38 of Exhibit 1.

A. This adjustment is for income tax true-ups and adjustments made during the test year that relate to prior periods, and is in accordance with the Commission's approval of this type of adjustment in Case No. 2000-080.

<u>Capitalization and Weighted Average Cost of Capital</u>

Q. Please explain the capital structure strategy of LG&E.

A. As I have expressed in previous testimony before the Commission in Case No. 2001-104, LG&E is firmly committed to maintaining the financial strength of the Company. The Company has a target capital structure of the midpoint of the range for "A" rated utilities published by Standard and Poor's.

Q. What is the current target capital structure?

A. The midpoint of the total debt to total capital range for utilities with a business position "4" (LG&E's current business position) is 46.25%. This midpoint was established by Standard and Poor's in an article entitled "Utility Financial Targets Are Revised" dated June 18, 1999. The range established by Standard and Poor's is 43% to 49.5%. This indicates an acceptable range for the equity component of capital of 50.5% to 57%. As shown on Rives Exhibit 2, the overall adjusted equity component (common and preferred) of capital is 51.6%, as of September 30, 2003.

Q. Can you explain what is contained in Rives Exhibit 2?

A. Yes, Rives Exhibit 2 calculates adjusted capitalization as of September 30, 2003, as well as the weighted average cost of capital to apply to the adjusted capitalization.

Q. Please explain the calculation of the adjusted capitalization.

A. Column 1, page 1 of Rives Exhibit 2 contains the components of capitalization as recorded on the Company's books and records as of the end of the test year September 30, 2003. Column 2, page 1 of Rives Exhibit 2 calculates the relative capitalization percentages of each component of capitalization to the total capitalization (e.g., line 1, column 1 divided by line 6, column 1 equals line 1, column 2). Column 3 of page 1 contains the allocation factors to split total capitalization between electric operations and gas operations. These factors were calculated based on electric and gas net original cost base as shown on Rives Exhibit 3. Column 4 calculates the relative electric and gas capitalization components by multiplying column 1 by the factors in column 3.

Q. Will you explain the adjustments to capitalization contained in column 5, page 1 of Rives Exhibit 2?

A. Yes. The adjustments in column 5, page 1 of Rives Exhibit 2 are shown in detail in columns 3 through 8 on page 2 of Rives Exhibit 2. The adjustments in columns 3 through 5 to remove the 25% portion of Trimble County Unit No. 1 inventories that represent IMEA's and IMPA's portion of these assets, to remove LG&E's equity investment in Ohio Valley Electric Corporation and to add the Job Development Tax Credit are consistent with the adjustments approved by the Commission in Case No. 90-158. The remaining three adjustments in columns 6 through 8 are to remove the reimbursed capital invested to repair the combustion turbines at Unit Nos. 6 and 7 at the

E. W. Brown Generating Station, to reverse the impact of LG&E's minimum pension liability adjustment to Other Comprehensive Income, and to remove LG&E's 2001 environmental surcharge plan. Column 9, page 2 of Rives Exhibit 2 summarizes the total capitalization adjustments by adding the separate adjustments listed in columns 3 through 8. This amount is then carried over to column 5, page 1. Finally, column 6, page 1 calculates adjusted capitalization by subtracting the capitalization adjustments in column 5 from column 4.

Q. Please explain the adjustment shown in Column 6 of page 2 of 2 of Exhibit 2 for the repairs to the E. W. Brown Power Station.

A. LG&E capitalized some of the repairs to the combustion turbines Nos. 6 and 7 at the E. W. Brown Power Station. In its settlement agreement with Alstom, LG&E will receive payments from Alstom in 2004 that reimburse the capitalized cost of these repairs. LG&E used its ownership percentage of the combustion turbines to allocate the settlement amounts. The adjustment to capital is necessary to remove the impact of the cost of the reimbursed repairs that are currently included in LG&E's capitalization and rate base.

Q. Please explain the minimum pension liability adjustment from Column 7 on Page 2 of 2, Exhibit 2.

A. The purpose of this adjustment is to address the impact of SFAS No. 130, *Reporting Comprehensive Income*. With the issuance of SFAS No. 130 the FASB established the Other Comprehensive Income ("OCI") component of shareholders' equity, which included the offsetting balance sheet accounting for a minimum pension liability. SFAS 130 defines Comprehensive Income to include, in addition to net income of the owners, other changes in a company's equity from transactions and other events and circumstances from non-owner sources. The stated purpose of OCI is to report a measure of all changes in equity, not just those included in the income statement that result from transactions and economic events currently reflected in the determination of net income. These other changes, that are not currently reflected in net income, are called OCI items. SFAS No. 130's list of OCI items includes, among other things, minimum pension liability. For OCI items like minimum pension liability, the liability is fully recognized on the balance sheet but not yet on the income statement, because the losses these unrealized changes in value may eventually cause have not yet been realized and, as such, have not yet been included in the income statement under Generally Accepted Accounting Principles ("GAAP") as required by SFAS 87, *Employers' Accounting for Pensions*.

With this adjustment, LG&E is proposing to record a regulatory asset to match the recognition of the adjustment to equity for the minimum unfunded pension liability to recognize the resultant increase in future periodic pension expense that will result from the unfunded pension obligation. The proper ratemaking treatment of a minimum pension liability OCI equity charge would allow recording of a regulatory asset and the recovery of that asset in base rates through pension expense as the charge is realized.

GAAP does not permit the Company to record the <u>entire</u> OCI minimum pension liability amount as a pension expense on the income statement in the year in which the liability arises and is recognized on the balance sheet. Rather, GAAP provides for recording a <u>portion</u> of the minimum pension liability in periodic pension expense over time, if necessary – if the stock market performs better and interest rates rise, the pension underfunding may well disappear. In fact, as of September 30, 2003, $26.4 million of the LG&E OCI adjustment would have been reversed had that been the end of the pension plan year. Thus, the OCI adjustment results in a reduction to common equity for something that has not yet been reflected on the income statement because it is not a change in value that has been actually realized – it is only a contingency. It is premature to reduce common equity for ratemaking purposes for contingent losses that may never be realized and have not been recognized as an expense under GAAP. Such contingent costs are not fixed, known or measurable and have not yet been recorded in pension expense. Importantly, the Company has not been provided with the opportunity to include such (contingent) costs in its cost of service, along with the concomitant opportunity to recover such (contingent) costs in rates.

If such costs are no longer contingent but become realized, it is highly likely, as I explain below, that the costs will <u>then</u> be recoverable in rates. Under those circumstances, the common equity will not, at that time, have to be reduced to reflect a loss. Therefore, reducing common equity <u>today</u> for a loss not yet recorded on the income statement would be an unfair regulatory policy. Regulation should try to reflect a representative level of costs in the test year. Reducing common equity for the entire contingent minimum pension liability in the period it is recognized as inconsistent with this objective, especially when this contingent liability may not ultimately be realized in future periodic pension expense and the cost of service.

When the average equity in LG&E's application is appropriately adjusted to remove the minimum pension liability from equity, GAAP will support recording a regulatory asset going forward in order to properly match LG&E's equity with its regulated revenues and in order to reflect the ratemaking process in LG&E's financial statements. LG&E submits that it would be preferable to record a regulatory asset up front when the minimum pension liability is initially recorded. This would bring the accounting in line with the expected and appropriate ratemaking and properly reflect the economics of the ratemaking for pension costs in LG&E's financial statements as required by SFAS 71.

SFAS 71 and FERC's USofA instructions for Account 182.3 Other Regulatory Assets require that to record a regulatory asset it must be probable of recovery. The fact that ERISA precludes taking away any of the pension benefits that participants of a pension plan have earned requires LG&E to provide for those benefits over the participants' working lives and should encourage the Commission to provide for the recovery of those benefit provisions which are clearly represented by a minimum unfunded pension liability. LG&E's obligation to provide reasonable pension benefits to its employees has always been recognized by this Commission, which has consistently provided for recovery of SFAS 87 pension costs. SFAS 87 periodic pension expense has been and will be a reasonable and appropriate recoverable cost of providing regulated utility service.

The minimum pension liability adjustment is shown in Column 7 on Page 2 of 2, Exhibit 2. The amount was calculated by Mercer and included in the books and records of LG&E in December 2002.

Q. Please explain the adjustment shown in Column 8 of page 2 of 2 of Exhibit 2 for the Environmental Surcharge 2001 Plan.

A. Removing the environmental surcharge rate base from the capital structure is necessary because LG&E is recovering a return on its investment through the environmental surcharge.

Q. Please explain how the weighted average cost of capital is calculated.

A. Column 7, page 1 of Rives Exhibit 2 calculates the respective capitalization percentages for the components of adjusted capitalization (e.g., line 1, column 6 divided by line 6, column 6 equals line 1, column 7). Column 8 includes the embedded costs of the components of capital except the return on equity. The annual rate used for Short Term Debt and the A/R Securitization is the actual rate as of September 30, 2003. At present, the Company anticipates the accounts receivable financing will be terminated in the first quarter of 2004. The annual cost rate for Long Term Debt is the embedded cost of the first mortgage bonds and intercompany loans outstanding as of September 30, 2003. The intercompany loans were approved by the Commission in its April 30, 2003 Order in Case No. 2003-00058. The annual cost rate for Preferred Stock is its embedded cost as of September 30, 2003. The cost of equity is the amount recommended by Mr. Rosenburg and supported in his testimony. Column 9 then calculates the weighted average cost of capital by multiplying column 7 by column 8, resulting in 7.12% for electric operations and 7.23% for gas operations.

Property Valuation

Q. What are the property valuation measures to be considered by the Commission for ratemaking purposes?

A. Section 278.290 of the Kentucky Revised Statutes requires the Commission to give due consideration to three quantifiable values: original cost, cost of reproduction as a going concern and capital structure. The Commission is also required to consider the history and development of the utility and its property and other elements of value recognized by the law of the land for ratemaking purposes.

Q Have you prepared an exhibit showing LG&E's net original cost rate base as of September 30, 2003?

A. Yes. Page 1 of Rives Exhibit 3 shows LG&E's net original cost rate base at September 30, 2003, using the same format LG&E has used in prior rate cases. Page 2 of Rives Exhibit 3 shows the calculation of the allowance for cash working capital. The 45-day (1/8) methodology was used in computing the allowance for cash working capital.

Q. Have you developed a reproduction cost rate base?

A. Yes. The reproduction cost rate base at September 30, 2003, is shown on Rives Exhibit 4. The calculation of the reproduction cost of plant less depreciation used in developing the reproduction cost rate base was calculated under my supervision and is shown on Rives Exhibit 5.

Q. Please explain Rives Exhibit 5.

A. Rives Exhibit 5 shows LG&E's estimated reproduction (or current) cost of utility plant and the appropriate accumulated depreciation on the reproduction cost of utility as of September 30, 2003. The estimated reproduction cost – net at September 30, 2003, is approximately $1.7 billion greater than the original historical cost – net as recorded on LG&E's books. The current costs were determined principally by indexing the surviving plant and equity by use of the Handy-Whitman Index of Public Utility Construction Costs and the Consumer Price Index.

Q. Have you prepared a calculation of the rate of return for the twelve months ended September 30, 2003 on capitalization, net original cost rate base and reproduction cost rate base?

A. Yes. As I previously stated the rate of return on electric capital for the twelve months ended September 30, 2003, was 5.96%. Rives Exhibit 6 shows the actual rate of return earned for the twelve months ended September 30, 2003, was 6.49% on net original cost rate base and 3.58% on reproduction cost rate base. Using the adjusted net operating income from Rives Exhibit 1 and the revenue increase in the application, results in a requested rate of return of 6.33% on net original cost rate base and 3.49% on reproduction cost rate base. As indicated on Exhibit 2 the requested rate of return on electric capital as of September 30, 2003, is 7.12%.

As I previously stated the rate of return on gas capital for the twelve months ended September 30, 2003 was 5.18%. Rives Exhibit 6 shows the actual rate of return earned for the twelve months ended September 30, 2003, was 5.29% on net original cost rate base and 2.55% on reproduction cost rate base. Using the adjusted net operating income from Rives Exhibit 1 and the revenue increase in the application, results in a requested rate of return of 7.16% on net original cost rate base and 3.45% on reproduction cost rate base. As indicated on Exhibit 2 the requested rate of return on gas capital as of September 30, 2003, is 7.23%

Q. Have you prepared an exhibit showing the overall revenue deficiency at September 30, 2003 for LG&E?

A. Yes. Rives Exhibit 7 shows the overall revenue deficiency at September 30, 2003, for LG&E to be $63,764,203 for electric operations and $19,106,269 for gas operations or total overall deficiency $82,870,472.

Q. What is LG&E's recommendation for the Commission in this proceeding?

A. Louisville Gas and Electric Company recommends that the Commission approve the recovery of these revenue deficiencies through an increase in its electric and gas base rates.

Q. Does this conclude your testimony?

A. Yes.

278701.11

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **S. Bradford Rives**, being duly sworn, deposes and says he is the Chief Financial Officer for Louisville Gas and Electric Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

SBRives

S. BRADFORD RIVES

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Melody L. Hulse (SEAL)
Notary Public

My Commission Expires:

November 26, 2007

APPENDIX A

S. Bradford Rives

Chief Financial Officer
LG&E Energy Corp.
220 West Main Street
Louisville, Kentucky 40202
(502) 627-3990

Education

University of Louisville School of Law, J.D. (cum laude) -- 1988
University of Kentucky, B.S. in Accounting -- 1980

Previous Positions

LG&E Energy Corp., Louisville, KY
Dec 2000 - Sep 2003 – Senior Vice President, Finance and Controller
Feb 1999 - Dec 2000 – Senior Vice President, Finance and Business Development
Mar 1996 - Feb 1999 – Vice President, Finance and Controller
Jan 1996 - Mar 1996 – Vice President, Finance, Non Utility Business
Mar 1995 - Dec 1995 – Vice President, Controller and Treasurer (LG&E Power)
Jun 1994 - Mar 1995 – Vice President and Treasurer (LG&E Power)
Jan 1994 - Jun 1994 – Associate General Counsel
Jan 1993 - Dec 1993 – Director, Business Development
Feb 1992 - Dec 1992 – Assistant Treasurer
Oct 1991 - Feb 1992 – Director, Corporate Finance

Louisville Gas and Electric Company, Louisville, KY
1990-1991 -- Director, Corporate Finance
1989-1990 -- Director, Corporate Tax
1985-1989 -- Manager, Tax Accounting
1983-1985 -- Assistant Manager, Tax Accounting

Arthur Andersen and Company, Louisville, KY
1982-1983 -- Audit Senior
1980-1982 -- Audit Staff

Professional/Trade Memberships

American Institute of Certified Public Accountants
Financial Executives Institute
Kentucky Bar Association
Kentucky Society of Certified Public Accountants
Louisville Bar Association

Civic Activities

African - American Venture Capital Fund – Investment Committee
Lincoln Heritage Council, Boy Scouts of America – Executive Board
Metro United Way of Louisville – Board of Directors
National Kidney Foundation of Kentucky Cadillac Invitational Golf Tournament - Chair
St. Patrick Parish

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustments to Electric and Gas Operating Revenues, Operating Expenses and Net Operating Income
For the Twelve Months Ended September 30, 2003

		Electric Department			Gas Department		
	Reference Schedule (1)	Operating Revenues (2)	Operating Expenses (3)	Net Operating Income (4)	Operating Revenues (5)	Operating Expenses (6)	Net Operating Income (7)
1. Amount per books		$768,525,784	$659,842,391	$108,683,393	$310,775,345	$294,051,365	$16,723,980
2. Adjustments for known changes and to eliminate unrepresentative conditions:							
3. Adjustment to eliminate unbilled revenues	1.00	(1,867,000)	-	(1,867,000)	(2,780,000)	-	(2,780,000)
4. To adjust mismatch in fuel cost recovery	1.01	(4,406,145)	(2,005,300)	(2,400,845)	-	-	-
5. To adjust base rates and FAC to reflect a full year of the FAC roll-in	1.02	547,244	-	547,244	-	-	-
6. Adjustment to eliminate Environmental Surcharge revenues and expenses	1.03	(11,228,429)	(1,766,344)	(9,462,085)	-	-	-
7. To adjust base rate revenues to reflect a full year of the ECR roll-in	1.04	723,260	-	723,260	-	-	-
8. Off-System sales revenue adjustment for the ECR calculation	1.05	(1,929,923)	-	(1,929,923)	-	-	-
9. To eliminate Electric Brokered Sales Revenues and Expenses	1.06	(5,389,000)	(7,811,321)	2,422,321	-	-	-
10. To eliminate electric ESM revenues collected	1.07	(6,974,780)	-	(6,974,780)	-	-	-
11. To eliminate ESM,ECR, and FAC in Rate Refund Account 449	1.08	(7,150,231)	-	(7,150,231)	-	-	-
12. Eliminate DSM revenue and expenses	1.09	(3,277,501)	(3,280,013)	2,512	(1,526,197)	(1,527,223)	1,026
13. Adjustment to annualize year-end customers	1.10	2,614,347	1,458,544	1,155,803	(56,581)	(16,901)	(39,680)
14. Adjustment to reflect annualized depreciation expenses under proposed rates	1.11	-	8,959,749	(8,959,749)	-	1,605,685	(1,605,685)
15. Adjustment to reflect increases in labor and labor related costs	1.12	-	918,580	(918,580)	-	241,612	(241,612)
16. To adjust for pension and post retirement	1.13	-	2,755,476	(2,755,476)	-	724,767	(724,767)
17. Adjustment to reflect normalized storm damage expense	1.14	-	70,492	(70,492)	-	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustments to Electric and Gas Operating Revenues, Operating Expenses and Net Operating Income
For the Twelve Months Ended September 30, 2003

		Electric Department			Gas Department		
	Reference Schedule (1)	Operating Revenues (2)	Operating Expenses (3)	Net Operating Income (4)	Operating Revenues (5)	Operating Expenses (6)	Net Operating Income (7)
18. Adjustment to eliminate advertising expenses pursuant to Commission Rule 807 KAR 5:016	1.15	-	(62,499)	62,499	-	(21,625)	21,625
19. Adjustment to reflect amortization of rate case expenses	1.16	-	333,580	(333,580)	-	217,131	(217,131)
20. Adjustment to reflect amortization of ESM audit expenses	1.17	-	58,333	(58,333)	-	-	-
21. Adjustment to remove One-Utility costs	1.18	-	(1,061,924)	1,061,924	-	(564,537)	564,537
22. Adjustment for Injuries and Damages FERC Account 925	1.19	-	501,449	(501,449)	-	293,513	(293,513)
23. Adjustment for VDT net savings to shareholders	1.20	-	5,640,000	(5,640,000)	-	1,515,000	(1,515,000)
24. Adjust VDT to settlement agreement	1.21	44,485	(224,718)	269,203	231,796	(141,372)	373,168
25. Adjustment for merger savings	1.22	(2,758,795)	19,427,401	(22,186,196)	-	-	-
26. Adjustment to eliminate LG&E/KU merger amortization expense	1.23	-	(2,722,005)	2,722,005	-	-	-
27. Adjustment for MISO Schedule 10 credits	1.24	-	709,577	(709,577)	-	-	-
28. Adjustment for cumulative effect of accounting change	1.25	-	5,280,909	(5,280,909)	-	-	-
29. Adjustment for IT staff reduction	1.26	-	(431,834)	431,834	-	(113,585)	113,585
30. To remove E.W. Brown legal expenses	1.27	-	(2,157,640)	2,157,640	-	-	-
31. To adjust for customer rate switching and customer plant closing	1.28	6,445	-	6,445	(41,331)		(41,331)
32. Adjustment for corporate office lease expense	1.29	-	1,798,420	(1,798,420)	-	478,061	(478,061)
33. To adjust for Cane Run repair refund	1.30	-	3,588,000	(3,588,000)	-	-	-
34. Adjustment for obsolete inventory write-off	1.31	-	(1,373,632)	1,373,632	-	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustments to Electric and Gas Operating Revenues, Operating Expenses and Net Operating Income
For the Twelve Months Ended September 30, 2003

		Reference Schedule (1)	Electric Department: Operating Revenues (2)	Electric Department: Operating Expenses (3)	Electric Department: Net Operating Income (4)	Gas Department: Operating Revenues (5)	Gas Department: Operating Expenses (6)	Gas Department: Net Operating Income (7)
35. Adjustment for carbide lime write-off		1.32	-	(1,416,711)	1,416,711	-	-	-
36. Adjustment to revenues and expenses to eliminate gas supply cost recoveries and gas supply expenses		1.33	-	-	-	(221,622,896)	(220,151,701)	(1,471,195)
37. Adjustment to reflect current costs for storage field losses and purification expense		1.34	-	-	-	-	426,754	(426,754)
38. Adjustment to revenues for temperature normalization		1.35	-	-	-	(13,022)	-	(13,022)
39. Total of above adjustments			$ (41,046,023)	$ 27,186,569	$ (68,232,592)	$ (225,808,231)	$ (217,034,421)	$ (8,773,810)
40. Federal and state income taxes corresponding to base revenue and expense adjustments and above adjustments -	40.3625 %	1.36		(27,540,380)	27,540,380		(3,541,329)	3,541,329
41. Federal and state income taxes corresponding to annualization and adjustment of year-end interest expense		1.37		39,556	(39,556)		(151,228)	151,228
42. Prior income tax true-ups and adjustments		1.38		(58,593)	58,593		392,702	(392,702)
43. Total rate case adjustments page 2 of 2			$ (41,046,023)	$ (372,848)	$ (40,673,175)	$ (225,808,231)	$ (220,334,276)	$ (5,473,955)
44. Adjusted Net Operating Income			$ 727,479,761	$659,469,543	$ 68,010,218	$ 84,967,114	$ 73,717,089	$ 11,250,025

Rives Exhibit 1
Reference Schedule 1.00
Sponsoring Witness: Steve Seelye

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Eliminate Unbilled Revenues

	Electric	Gas
1. Unbilled revenues at September 30, 2002	$ 21,028,000	$ 3,546,000
2. Unbilled revenues at September 30, 2003	(22,895,000)	(6,326,000)
3. Increase in book revenues due to unbilled revenues	$ (1,867,000)	$ (2,780,000)

Rives Exhibit 1
Reference Schedule 1.01
Sponsoring Witness: Steve Seelye

LOUISVILLE GAS AND ELECTRIC COMPANY

To Adjust Mismatch in Fuel Cost Recovery
For the Twelve Months Ended September 30, 2003

Expense Month	Electric Revenue Form A Page 4 of 5 Line 3	Electric Expense Form A* Page 4 of 5 Line 8
Oct-02	$ 1,144,083	$ 945,200
Nov-02	1,137,978	887,425
Dec-02	979,879	1,348,306
Jan-03	1,005,630	316,830
Feb-03	1,382,975	(1,814,647)
Mar-03	285,052	(638,034)
Apr-03	(1,686,216)	(217,553)
May-03	(700,415)	1,138,920
Jun-03	(235,672)	40,070
Jul-03	1,434,845	(416,817)
Aug-03	45,639	425,355
Sep-03	(387,633)	(9,755)
Total	$ 4,406,145	$ 2,005,300
Adjustment	$ (4,406,145)	$ (2,005,300)

* NOTE : Expenses are recovered in the second succeeding month. For example, January 2003 would be reflected in March 2003.

Rives Exhibit 1
Reference Schedule 1.02
Sponsoring Witness: Steve Seelye

LOUISVILLE GAS AND ELECTRIC COMPANY

To Adjust Base Rates and FAC to Reflect a Full Year of the FAC Roll-in
For the Twelve Months Ended September 30, 2003

		Electric
1. Adjustment to base rate revenues to reflect a full year of the FAC roll-in	$	10,782,944
2. Adjustment to FAC revenues to reflect a full year of the FAC roll-in		(10,235,700)
3. Net adjustment	$	547,244

Rives Exhibit 1
Reference Schedule 1.03
Sponsoring Witness: Steve Seelye

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Eliminate Environmental Surcharge Revenues and Expenses
For the Twelve Months Ended September 30, 2003

Expense Month	Electric Revenues All Plans	Electric Expenses Post '95 Plan	Net Electric
Oct-02	$ 1,324,353	$ 84,724	$ 1,239,629
Nov-02	1,374,437	82,779	1,291,658
Dec-02	788,218	81,038	707,180
Jan-03	1,233,142	90,072	1,143,070
Feb-03	1,334,901	136,075	1,198,826
Mar-03	752,114	136,090	616,024
Apr-03	1,094,014	137,028	956,986
May-03	43,715	136,143	(92,428)
Jun-03	167,814	215,266	(47,452)
Jul-03	688,743	288,726	400,017
Aug-03	654,457	182,730	471,727
Sep-03	1,772,521	195,673	1,576,848
Total	$ 11,228,429	$ 1,766,344	$ 9,462,085
Adjustment	$ (11,228,429)	$ (1,766,344)	$ (9,462,085)

Rives Exhibit 1
Reference Schedule 1.04
Sponsoring Witness: Steve Seelye

LOUISVILLE GAS AND ELECTRIC COMPANY

To Adjust Base Rate Revenues to Reflect a Full Year of the ECR Roll-In
For the Twelve Months Ended September 30, 2003

	Electric
1. Adjustment to base rate revenues to reflect a full year of the ECR roll-in	$ 723,260

Rives Exhibit 1
Reference Schedule 1.05
Sponsoring Witness: Steve Seelye

LOUISVILLE GAS AND ELECTRIC COMPANY

Off-System Sales Revenue Adjustment for the ECR Calculation
For the Twelve Months Ended September 30, 2003

	Electric					
	(1)	(2)	(3)	(4)	(5)	(6)
	LG&E Off-System Sales Revenue	LG&E Off-System Sales Intercompany Revenue	LG&E Off-System Sales Revenue Less Intercompany (Col. 1 - 2)	Monthly Environmental Surcharge Factor	Average Environmental Surcharge Factor	Off-System Sales Environmental Cost (Col. 3 * 5)
Oct-02	$ 12,445,174	$ 5,918,480	$ 6,526,694	1.97%	1.86%	$ 121,397
Nov-02	7,741,067	3,587,193	4,153,874	2.55%	1.86%	77,262
Dec-02	9,362,793	4,254,586	5,108,207	2.95%	1.86%	95,013
Jan-03	17,650,740	5,349,231	12,301,509	1.79%	1.86%	228,808
Feb-03	15,075,495	4,753,155	10,322,340	3.01%	1.86%	191,996
Mar-03	23,103,728	6,866,828	16,236,900	0.09%	1.86%	302,006
Apr-03	16,368,049	4,501,594	11,866,455	0.33%	1.86%	220,716
May-03	5,767,285	2,201,050	3,566,235	1.04%	1.86%	66,332
Jun-03	11,322,041	4,131,452	7,190,589	1.01%	1.86%	133,745
Jul-03	10,772,934	3,197,779	7,575,155	2.81%	1.86%	140,898
Aug-03	12,796,062	4,426,611	8,369,451	2.60%	1.86%	155,671
Sep-03	14,896,692	4,354,780	10,541,912	2.14%	1.86%	196,079
Total	$ 157,302,060	$ 53,542,739	$ 103,759,321			$ 1,929,923
Average				1.86%		
Adjustment						$ (1,929,923)

Rives Exhibit 1
Reference Schedule 1.06
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

To Eliminate Electric Brokered Sales Revenues and Expenses
For the Twelve Months Ended September 30, 2003

	Electric	
1. Brokered Sales	$ 22,608,445	
2. Brokered Expense recorded in revenues	17,219,445	
3. Net Brokered Sales Revenue	$ 5,389,000	
4. Net Brokered Sales Revenue adjustment	$ (5,389,000)	
5. Brokered Expense recorded in power purchased	$ 7,811,321	*
6. Brokered Expense adjustment	$ (7,811,321)	
7. Total adjustment (Line 4 - Line 6)	$ 2,422,321	

*NOTE: Includes 4% of total labor and labor related costs from off-system sales activities of $53,326.

Effective January 1, 2003, LG&E adopted EITF No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities". The EITF required LG&E to net brokered revenues and expenses together in the revenue section of the income statement. The brokered expenses from line 5 are amounts recorded in expense for October through December 2002, before the EITF was effective.

Rives Exhibit 1
Reference Schedule 1.07
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

To Eliminate Electric ESM Revenues Collected During the Twelve Months Ended September 30, 2003

	Electric
1. 2001 ESM settlement - refund	$ 440,557
2. 2002 final ESM revenues	(13,646,721)
3. 2001 ESM amounts collected in the test year (October 2002) before the December 2002 settlement	(83,819)
4. 2000 ESM adjustment in test year relating to pre-test year period	4,211
5. Difference in December 2002 actual refund and amount estimated in 2001 settlement filing	1,868
6. Difference in amount recorded and final 2002 ESM booked when Commission approval received November 2003	(37)
7. ESM amounts still to be collected - Reference Schedule 1.08	6,309,161
8. Actual ESM revenue collected	$ (6,974,780)

Rives Exhibit 1
Reference Schedule 1.08
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

To Eliminate ESM, ECR, and FAC in Rate Refund Account 449
For the Twelve Months Ended September 30, 2003

	Electric
1. ESM Revenue	$ (6,309,161)
2. ECR Revenue	(875,656)
3. FAC Revenue	34,586
4. Total	$ (7,150,231)

Rives Exhibit 1
Reference Schedule 1.09
Sponsoring Witness: Steve Seelye

LOUISVILLE GAS AND ELECTRIC COMPANY

Eliminate DSM Revenues and Expenses
For the Twelve Months Ended September 30, 2003

	Electric	Gas
1. DSM revenue adjustment	$ (3,277,501)	$ (1,526,197)
2. DSM expense adjustment	(3,280,013)	(1,527,223)
3. Total	$ 2,512	$ 1,026

Rives Exhibit 1
Reference Schedule 1.10
Sponsoring Witness: Steve Seelye

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Annualize Year-End Customers
At September 30, 2003

	Electric	Gas
1. Revenue adjustment	$ 2,614,347	$ (56,581)
2. Expense adjustment	1,458,544	(16,901)
3. Net adjustment	$ 1,155,803	$ (39,680)

Rives Exhibit 1
Reference Schedule 1.11
Sponsoring Witness: Earl Robinson/Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment To Reflect Annualized Depreciation Expenses Under Proposed Rates
At September 30, 2003

	Electric	Gas
1. Depreciation expense per books excluding ARO and post-1995 ECR	$ 94,422,021	$ 16,669,594
2. Annualized depreciation expense with new rates	103,381,770	18,275,279
3. Total increase	$ 8,959,749	$ 1,605,685

NOTE: Common depreciation was allocated 75% to electric and 25% to gas pursuant to common utility plant study.

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Reflect Increases in Labor and Labor-Related Costs
As Applied to the Twelve Months Ended September 30, 2003

	Electric (1)	Gas (2)	Total (3)
1. Wages (Page 2)	$ 837,128	$ 220,188	$ 1,057,316
2. Payroll Taxes (Page 3)	64,040	16,844	80,885
3. 401(k) (Page 4)	17,412	4,580	21,992
4. Total	$ 918,580	$ 241,612	$ 1,160,193

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Reflect Increases in Labor and Labor-Related Costs As Applied to the Twelve Months Ended September 30, 2003

		Operating	Construction/ Other	Total
1.	Test Year Labor:			
2.	Base	$ 34,253,649	$ 11,188,346	$ 45,441,995
3.	Overtime and Premium	6,897,367	1,494,198	8,391,564
4.	TIA	2,776,081	606,680	3,382,762
5.	Total Test Year Ended September 30, 2003	$ 43,927,097	$ 13,289,224	$ 57,216,321
6.	Total Operating and Construction/Other %	76.8%	23.2%	100.0%

			Employees	
7.	Annualized base labor at September 30, 2003:			
8.	Union		624	$ 30,257,053
9.	Exempt		186	12,847,228
10.	Non-Exempt		75	2,661,408
11.	Total Annualized Labor		885	45,765,689
12.	Union Wage Increase Effective November 10, 2003 (Line 8 x 3%)			907,712
13.	Union Overtime/Premiums (a)			8,126,258
14.	Union wage increase applied to union overtime/premiums (Line 13 x 3%)			243,788
15.	Non-Exempt overtime (a)			265,306
16.	TIA - Exempt/Non-Exempt/Bargaining Unit (a)			3,382,762
17.	Union wage increase applied to union TIA (Sum of Lines 8, 12, 13, 14 x 6% x 3%)			71,163
18.	Less additional TIA amount charged in test year to bring TIA levels to 100%			(169,171)
19.	Total Annualized Labor			$ 58,593,507
24.	Test Year Operating Labor			$ 43,927,097
25.	Operating Labor based on annualized labor $ 58,593,507 x	76.8%		44,984,414
26.	Labor Adjustment Total			$ 1,057,317
27.	Electric Department (a)	79%		$ 837,128
28.	Gas Department (a)	21%		220,188
29.	Total			$ 1,057,316

(a) Represents actual numbers taken from the Company's financial records for the 12 months ended September 30, 2003.

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustments to Reflect Increases in Payroll Taxes
As Applied to the Twelve Months Ended September 30, 2003

1. Operating Labor increase (Page 2 Line 26)		$ 1,057,317
2. Payroll Taxes - FICA		7.65%
3. Payroll Tax adjustment		$ 80,885
4. Electric Department	79%	$ 64,040
5. Gas Department	21%	16,844
6. Total		$ 80,885

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Reflect Increases in Company Match of 401(k)
As Applied to the Twelve Months Ended September 30, 2003

1. Direct total payroll for 12 months ended 09/30/03 (Page 2 Line 5)		$ 57,216,321
2. Total 401(k) Company Match for 12 months ended 09/30/03		$ 1,191,502
3. 401(k) Company Match as a percent of payroll		2.08%
4. Operating Labor increase (Page 2 Line 26)		1,057,317
5. 401(k) Company Match operating increase (Line 3 x Line 4)		$ 21,992
6. Electric Department	79%	$ 17,412
7. Gas Department	21%	4,580
8. Total		$ 21,992

Rives Exhibit 1
Reference Schedule 1.13
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

To Adjust for Pension and Post Retirement
For the Twelve Months Ended September 30, 2003

1. Pension and Post Retirement expenses in test year		$ 13,025,204
2. Pension and Post Retirement expenses annualized for 2003 per Mercer study		16,505,447
3. Total adjustment		$ 3,480,243
4. Electric Department (a)	79%	$ 2,755,476
5. Gas Department (a)	21%	724,767
6. Total adjustment		$ 3,480,243

(a) Percentages taken from Reference Schedule 1.12.

Rives Exhibit 1
Reference Schedule 1.14
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Reflect Normalized Storm Damage Expense
For the Twelve Months Ended September 30, 2003

	Electric
1. Storm damage provision based upon ten year average	$ 2,569,744
2. Storm damage expenses incurred during the 12 months ended September 30, 2003	2,499,252
3. Adjustment	$ 70,492

Year	Expense *	CPI-All Urban Consumers	Amount
2003	$ 2,499,252	1.0000	$ 2,499,252
2002	2,465,175	1.0160	2,504,618
2001	2,329,376	1.0440	2,431,869
2000	2,167,000	1.0780	2,336,026
1999	1,152,000	1.1000	1,267,200
1998	3,108,339	1.1160	3,468,906
1997	1,708,339	1.1380	1,944,090
1996	3,482,316	1.1680	4,067,345
1995	1,322,196	1.1960	1,581,346
1994	2,943,360	1.2220	3,596,786
Total			$ 25,697,438
Ten Year Average			$ 2,569,744

* NOTE: 2003 expenses are for the 12 months ended September 30, 2003.
All other years expenses are for the calendar year.

Rives Exhibit 1
Reference Schedule 1.15
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Eliminate Advertising Expenses
Pursuant to Commission Rule 807 KAR 5:016
For the Twelve Months Ended September 30, 2003

	Electric	Gas
1. Uniform System of Accounts - Account No. 930.1 General Advertising Expenses	$ 60,921	$ 20,306
2. Account No. 913 Advertising Expenses	1,578	1,319
3. Total	$ 62,499	$ 21,625
4. Adjustment	$ (62,499)	$ (21,625)

Rives Exhibit 1
Reference Schedule 1.16
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Reflect Amortization of Rate Case Expenses

	Electric	Gas
1. Total estimated cost of rate case	$ 1,000,739	$ 651,393
2. Amortization period in years	3	3
3. Annual amortization	333,580	217,131
4. Amortization included in test year	0	0
5. Net adjustment	$ 333,580	$ 217,131

Rives Exhibit 1
Reference Schedule 1.17
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Reflect Amortization of ESM Audit Expenses
For the Twelve Months Ended September 30, 2003

	Electric
1. Total estimated cost of ESM audit by Barrington-Wellesley Group	$ 175,000
2. Amortization period in years	3
3. Annual amortization	58,333
4. Amortization included in test year	0
5. Net adjustment	$ 58,333

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Remove One-Utility Costs
For the Twelve Months Ended September 30, 2003

	Electric	Gas
1. One-Utility amortization charged to Account 930.2	$ 1,061,924	$ 564,537
2. Adjustment	$(1,061,924)	$ (564,537)

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment for Injuries and Damages FERC Account 925
For the Twelve Months Ended September 30, 2003

	Electric	Gas
1. Injury/Damage provision based upon five year average	$ 2,006,340	$ 705,441
2. Injury/Damage expenses incurred during the 12 months ended September 30, 2003	1,504,891	411,928
3. Adjustment	$ 501,449	$ 293,513

Year	Electric	Gas	CPI-All Urban Consumers	Adjusted Electric	Adjusted Gas
2002	$ 3,369,044	$ 354,333	1.0160	$ 3,422,949	$ 360,002
2001	726,180	323,911	1.0440	758,132	338,163
2000	1,750,482	770,436	1.0780	1,887,019	830,530
1999	1,912,057	1,048,283	1.1000	2,103,262	1,153,111
1998	1,666,969	757,523	1.1160	1,860,337	845,396
Total				$10,031,699	$ 3,527,203
Five Year Average				$ 2,006,340	$ 705,441

Rives Exhibit 1
Reference Schedule 1.20
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment for VDT Net Savings to Shareholders
For the Twelve Months Ended September 30, 2003

	Electric	Gas
1. Adjustment for net VDT Savings to Shareholders	$ 5,640,000	$ 1,515,000

Electric:

2002 Shareholders portion of VDT Savings per Tariff (a)	$ 1,680,000	
October - December 2002 (25%)	420,000	$ 420,000
2003 Shareholders portion of VDT Savings per Tariff (a)	6,960,000	
January - September 2003 (75%)	5,220,000	5,220,000
		$ 5,640,000

Gas:

2002 Shareholders portion of VDT Savings per Tariff (b)	$ 480,000	
October - December 2002 (25%)	120,000	$ 120,000
2003 Shareholders portion of VDT Savings per Tariff (b)	1,860,000	
January - September 2003 (75%)	1,395,000	1,395,000
		$ 1,515,000

NOTE: (a) First revision of original sheet No. 23-Q dated January 21, 2002.
(b) Third revision of original sheet No. 11-F dated January 21, 2002.

Rives Exhibit 1
Reference Schedule 1.21
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjust VDT to Settlement Agreement
For the Twelve Months Ended September 30, 2003

	Electric	Gas
1. Actual VDT surcredit refunded	$ 3,804,485	$ 1,241,796
2. VDT surcredit per settlement	3,760,000	1,010,000
3. VDT revenue adjustment	$ 44,485	$ 231,796
4. Actual VDT costs	$ 24,124,718	$ 6,241,372
5. VDT settlement cost amortization	23,900,000	6,100,000
6. VDT cost adjustment	$ (224,718)	$ (141,372)
7. Total adjustment	$ 269,203	$ 373,168

Rives Exhibit 1
Reference Schedule 1.22
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment for Merger Savings
For the Twelve Months Ended September 30, 2003

	Electric
1. Customer portion of merger surcredit per agreement	$ 19,427,401
2. Revenue returned to customers through the merger surcredit for 12 months ended September 30, 2003	16,668,606
3. Additional savings due customers	$ (2,758,795)
4. Shareholder's portion of merger surcredit per agreement	$ 19,427,401

NOTE: Merger surcredit per Commission's order dated October 16, 2003 in Case No. 2002-00430.

Rives Exhibit 1
Reference Schedule 1.23
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Eliminate LG&E/KU Merger Amortization Expense
For the Twelve Months Ended September 30, 2003

	Electric
1. LG&E/KU Merger amortization expense Account 930.2	$ 2,722,005
2. Adjustment	$ (2,722,005)

Rives Exhibit 1
Reference Schedule 1.24
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment for MISO Schedule 10 Credits
For the Twelve Months Ended September 30, 2003

	Electric
1. MISO Schedule 10 credits received in test period	$ 709,577

Rives Exhibit 1
Reference Schedule 1.25
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment for Cumulative Effect of Accounting Change
For the Twelve Months Ended September 30, 2003

	Electric
1. Adjustment to move cumulative effect of accounting change to match regulatory credit that is above net operating income due to Asset Retirement Obligation, net of tax	$ 3,149,402
2. Grossed up by the composite income tax rate - Reference Schedule 1.36 (100% - 40.3625%)	59.6375%
3. Gross adjustment to offset net operating income impact of Asset Retirement Obligation regulatory credit	$ 5,280,909

Rives Exhibit 1
Reference Schedule 1.26
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment for IT Staff Reduction
For the Twelve Months Ended September 30, 2003

1.	Total LG&E operating labor reduction		$ (638,831)
2.	Payroll taxes		7.65%
3.	Payroll tax reduction		$ (48,871)
4.	Total LG&E operating labor reduction		$ (638,831)
5.	401(k) company match as a percent of payroll (a)		2.87%
6.	401(k) company match reduction		$ (18,334)
7.	Total estimated cost reduction (Line 1 + Line 3 + Line 6)		$ (706,036)
8.	Actual costs ($481,852 / 3 years amortization)		160,617
9.	Net cost reduction		$ (545,419)
10.	Electric Department (b)	79%	$ (431,834)
11.	Gas Department (b)	21%	(113,585)
12.	Net cost reduction		$ (545,419)

(a) LG&E Energy Services Company percentage:

LG&E Energy Services Company total labor	$ 81,832,370
LG&E Energy Services 401(k) match	2,346,149
LG&E Energy Services 401(k) match as percent of payroll	2.87%

(b) Percentages taken from Reference Schedule 1.12.

LOUISVILLE GAS AND ELECTRIC COMPANY

To Remove E.W. Brown Legal Expenses
For the Twelve Months Ended September 30, 2003

	Electric
1. E.W. Brown legal expenses included in the test year	$ 5,678,000
2. LG&E combustion turbine ownership percentage	38%
3. LG&E's portion of E.W. Brown legal expenses	$ 2,157,640
4. Adjustment	$(2,157,640)

Rives Exhibit 1
Reference Schedule 1.28
Sponsoring Witness: Steve Seelye

LOUISVILLE GAS AND ELECTRIC COMPANY

To Adjust for Customer Rate Switching and Customer Plant Closing
As Applied to the Twelve Months Ended September 30, 2003

	Electric	Gas
1. Rate switch - Carbide Graphite to LPTOD primary	$ 6,445	$ -
2. Rate switch - Pendennis Club	-	2,769
3. Rate switch - Purnell Sausage	-	(9,381)
4. Customer plant closing - National Linen Service	-	(34,719)
5. Adjustment	$ 6,445	$ (41,331)

Rives Exhibit 1
Reference Schedule 1.29
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment for Corporate Office Lease Expense
For the Twelve Months Ended September 30, 2003

1.	One time credit occurring in test year due to renegotiating of lease of LG&E building		$ 2,276,481
2.	Electric portion	79%	$ 1,798,420
3.	Gas portion	21%	478,061
4.	Total adjustment		$ 2,276,481

Rives Exhibit 1
Reference Schedule 1.30
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

To Adjust for Cane Run Repair Refund
For the Twelve Months Ended September 30, 2003

	Electric
1. Insurance recovery received in test year for repairs to Cane Run Station expensed prior to test year	$ 3,588,000

Rives Exhibit 1
Reference Schedule 1.31
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment for Obsolete Inventory Write-Off
As Applied to the Twelve Months Ended September 30, 2003

	Electric
1. Write-off of obsolete inventory	$ 2,060,448
2. Amortization period in years	3
3. Annual amortization	686,816
4. Amount included in test year	2,060,448
5. Adjustment to remove expenses from test year	$ (1,373,632)

Rives Exhibit 1
Reference Schedule 1.32
Sponsoring Witness: Valerie Scott

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment for Carbide Lime Write-Off
As Applied to the Twelve Months Ended September 30, 2003

	Electric
1. Write-off of carbide lime	$ 2,125,067
2. Amortization period in years	3
3. Annual amortization	708,356
4. Amount included in test year	2,125,067
5. Adjustment to remove expenses from test year	$ (1,416,711)

Rives Exhibit 1
Reference Schedule 1.33
Sponsoring Witness: Steve Seelye

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Revenues and Expenses to Eliminate Gas Supply Cost Recoveries and Gas Supply Expenses During the Twelve Months Ended September 30, 2003

		Gas
1. Cost recoveries in revenue for the 12 months ended September 30, 2003	$	(221,622,896)
2. Gas supply expenses for the 12 months ended September 30, 2003		(220,151,701)
3. Net adjustment	$	(1,471,195)

Rives Exhibit 1
Reference Schedule 1.34
Sponsoring Witness: Steve Seelye

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Reflect Current Costs for Storage Field Losses and Purification Expense
For the Twelve Months Ended September 30, 2003

	Mcf	Average Unit Cost	Cost of Gas Stored Underground As of 9/30/03	Gas
1. Purification expenses in the test year	103,103	$ 3.80		$ 391,419
2. Purification expenses adjusted for current costs	103,103		$ 5.38	554,210
3. Increase in purification expenses				$ 162,791
4. Storage field losses in the test year	260,502	$ 4.36		$1,136,313
5. Storage field losses adjusted for current costs	260,502		$ 5.38	1,400,276
6. Increase in storage field losses				$ 263,963
7. Total adjustment (Line 3 + Line 6)				$ 426,754

Rives Exhibit 1
Reference Schedule 1.35
Sponsoring Witness: Steve Seelye

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Revenues for Temperature Normalization
For the Twelve Months Ended September 30, 2003

	Gas
1. Revenues	$ (13,022)

Rives Exhibit 1
Reference Schedule 1.36
Sponsoring Witness: Brad Rives

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation of Composite Federal and Kentucky Income Tax Rate (Based on Law in Effect September 30, 2003)

1. Assume pre-tax income of	$ 100.0000
2. State income tax at 8.25%	8.2500
3. Taxable income for Federal income tax	91.7500
4. Federal income tax at 35% (Line 3 x 35%)	32.1125
5. Total State and Federal income taxes (Line 2 + Line 4)	$ 40.3625

6. Therefore, the composite rate is:

7.	Federal	32.1125%
8.	State	8.2500%
9.	Total	40.3625%

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation of Current Tax Adjustment Resulting From "Interest Synchronization"

	Electric	Gas
1. Adjusted Capitalization - Exhibit 2	$ 1,485,701,357	$ 312,142,752
2. Weighted Cost of Debt	1.63%	1.63%
3. "Interest Synchronization"	24,216,932	5,087,927
4. Interest per books (excluding other interest)	24,314,933	4,713,252
5. "Interest Synchronization" adjustment	98,001	(374,675)
6. Composite Federal and State tax rate	40.3625%	40.3625%
7. Current tax adjustment from "Interest Synchronization"	$ 39,556	$ (151,228)

Rives Exhibit 1
Reference Schedule 1.38
Sponsoring Witness: Brad Rives

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment for Prior Period Income Tax True-Ups and Adjustments
For the Twelve Months Ended September 30, 2003

	Electric	Gas
1. 2002 Income Tax True-up:		
2. Federal Tax (benefit)	$ (359,886)	$ (394,884)
3. State Tax (benefit)	(112,144)	(99,952)
4. Total 2002 Income Tax True-up in test year	$ (472,030)	$ (494,836)
5. 2002 Other Tax adjustments:		
6. Kentucky Recycle Credit	$ 453,700	$ -
7. Deloitte & Touche contingency fee on Research & Expenditure Credit work	92,162	-
8. Total 2002 Other Tax adjustments	$ 545,862	$ -
9. Total reduction/(increase) to expense (Line 4 + Line 8)	$ 73,832	$ (494,836)
10. Percentage of 2002 pre-tax income through September 30, 2002	79.36%	79.36%
11. Total 2002 Income Tax True-up and adjustments in test period	$ 58,593	$ (392,702)
12. Adjustment	$ (58,593)	$ 392,702

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation of Revenue Gross Up Factor
(Based on Law in Effect September 30, 2003)

1. Assume pre-tax income of	$	100.000000
2. Bad Debt at .49%		0.490000
3. PSC Assessment at .1823%		0.182300
4. Taxable income for State income tax		99.327700
5. State income tax at 8.25%		8.194535
6. Taxable income for Federal income tax		91.133165
7. Federal income tax at 35%		31.896609
8. Total Bad Debt, PSC Assessment, State and Federal income taxes (Line 2 + Line 3 + Line 5 + Line 7)		40.763444
9. Assume pre-tax income of	$	100.000000
10. Gross Up Revenue Factor	$	59.236556

NOTE: Bad debt percent is percent of net charge-offs to revenue for the 12 months ended September 30, 2003.

LOUISVILLE GAS AND ELECTRIC COMPANY

Capitalization at September 30, 2003

	Per Books 09-30-03 (1)	Capital Structure (2)	Rate Base Percentage (3)	Capitalization (Col 1 x Col 3) (4)	Adjustments to Capitalization (Col 9, Pg 2) (5)	Adjusted Capitalization (6)	Adjusted Capital Structure (7)	Annual Cost Rate (8)	Cost of Capital (Col 8 x Col 7) (9)
ELECTRIC									
1. Short Term Debt	$ 75,132,051	3.90%	84.13%	$ 63,208,595	$ (6,196,064)	$ 57,012,531	3.84%	1.06%	0.04%
2 A/R Securitization	74,800,000	3.89%	84.13%	62,929,240	(6,180,175)	56,749,065	3.82%	1.39%	0.05%
3. Long Term Debt	797,769,753	41.45%	84.13%	671,163,693	(65,853,036)	605,310,657	40.74%	3.77%	1.54%
4. Preferred Stock	70,424,594	3.66%	84.13%	59,248,211	(5,814,768)	53,433,443	3.60%	2.51%	0.09%
5. Common Equity	906,432,535	47.10%	84.13%	762,581,692	(49,386,031)	713,195,661	48.00%	11.25%	5.40%
6. Total Capitalization	$1,924,558,933	100.00%		$1,619,131,431	$ (133,430,074)	$1,485,701,357	100.00%		7.12%
GAS									
1. Short Term Debt	$ 75,132,051	3.90%	15.87%	$ 11,923,456	$ 74,712	$ 11,998,168	3.84%	1.06%	0.04%
2 A/R Securitization	74,800,000	3.89%	15.87%	11,870,760	74,521	11,945,281	3.83%	1.39%	0.05%
3. Long Term Debt	797,769,753	41.45%	15.87%	126,606,060	794,058	127,400,118	40.81%	3.77%	1.54%
4. Preferred Stock	70,424,594	3.66%	15.87%	11,176,383	70,115	11,246,498	3.60%	2.51%	0.09%
5. Common Equity	906,432,535	47.10%	15.87%	143,850,843	5,701,844	149,552,687	47.92%	11.50%	5.51%
6. Total Capitalization	$1,924,558,933	100.00%		$ 305,427,502	$ 6,715,250	$ 312,142,752	100.00%		7.23%

LOUISVILLE GAS AND ELECTRIC COMPANY

Capitalization at September 30, 2003

	Capitalization (Col 4, Pg 1) (1)	Capital Structure (2)	Trimble County Inventories (a) (Col 2 x Col 3 Line 6) (3)	Other Investments (b) (Col 2 x Col 4 Line 6) (4)	JDIC (Col 2 x Col 5 Line 6) (5)	E.W. Brown Repairs (c) (6)	Minimum Pension Liability (7)	Environmental Surcharge Post '95 Plan (Col 2 x Col 8 Line 6) (8)	Total Adjustments To Capital (9)
ELECTRIC									
1. Short Term Debt	$ 63,208,595	3.90%	$ (115,470)	$ (19,110)	$ 1,928,963	$ (130,727)	$ -	$ (7,859,720)	$ (6,196,064)
2 A/R Securitization	62,929,240	3.89%	(115,173)	(19,061)	1,924,017	(130,392)	-	(7,839,566)	(6,180,175)
3. Long Term Debt	671,163,693	41.45%	(1,227,234)	(203,105)	20,501,412	(1,389,396)	-	(83,534,713)	(65,853,036)
4. Preferred Stock	59,248,211	3.66%	(108,364)	(17,934)	1,810,257	(122,682)	-	(7,376,045)	(5,814,768)
5. Common Equity	762,581,692	47.10%	(1,394,517)	(230,790)	23,295,934	(1,578,783)	25,443,354	(94,921,229)	(49,386,031)
6. Total Capitalization	$1,619,131,431	100.00%	$ (2,960,758)	$ (490,000)	$ 49,460,583	$ (3,351,980)	$ 25,443,354	$(201,531,273)	$ (133,430,074)
GAS									
1. Short Term Debt	$ 11,923,456	3.90%	$ -	$ -	$ 74,712	$ -	$ -	$ -	$ 74,712
2 A/R Securitization	11,870,760	3.89%	-	-	74,521	-	-	-	74,521
3. Long Term Debt	126,606,060	41.45%	-	-	794,058	-	-	-	794,058
4. Preferred Stock	11,176,383	3.66%	-	-	70,115	-	-	-	70,115
5. Common Equity	143,850,843	47.10%	-	-	902,295	-	4,799,549	-	5,701,844
6. Total Capitalization	$ 305,427,502	100.00%	$ -	$ -	$ 1,915,701	$ -	$ 4,799,549	$ -	$ 6,715,250

(a) Trimble County Inventories @ 09/30/03

Stores	$ 3,251,229
Stores Expense	599,462
Coal	7,785,880
Limestone	58,351
Fuel Oil	148,109
Total Trimble County Inventories	$11,843,031
Multiplied by Disallowed Portion	25.00%
Trimble County Inv. Disallowed	$ 2,960,758

(b)

Other Investments @ 09/30/03	Electric	Gas	Total
OVEC	$ 490,000	$ -	$ 490,000
	$ 490,000	$ -	$ 490,000

(c)

E.W. Brown capital adjustment	$ 8,821,000
LG&E's combustion turbine ownership %	38%
LG&E's portion of E.W. Brown capital	$ 3,351,980

LOUISVILLE GAS AND ELECTRIC COMPANY

Net Original Cost Rate Base as of September 30, 2003

	Electric (1)	Gas (2)	Total (3)
1. Utility Plant at Original Cost (a)	$ 3,232,386,289	$ 519,793,206	$ 3,752,179,495
2. Deduct:			
3. Reserve for Depreciation (a)	1,339,452,661	183,372,937	1,522,825,598
4. Net Utility Plant	1,892,933,628	336,420,269	2,229,353,897
5. Deduct:			
6. Customer Advances for Construction	507,146	9,193,354	9,700,500
7. Accumulated Deferred Income Taxes (b)	291,450,446	53,930,878	345,381,324
8. FAS 109 Deferred Income Taxes	37,113,002	2,077,649	39,190,651
9. Investment Tax Credit (prior law)	3,943	-	3,943
10. Total Deductions	329,074,537	65,201,881	394,276,418
11. Net Plant Deductions	1,563,859,091	271,218,388	1,835,077,479
12. Add:			
13. Materials and Supplies (c)(e)(f)	55,832,046	104,925	55,936,971
14. Gas Stored Underground (c)	-	38,757,261	38,757,261
15. Prepayments (c)(d)	2,882,693	325,109	3,207,802
16. Cash Working Capital (page 2)	52,800,999	5,640,692	58,441,691
17. Total Additions	111,515,738	44,827,987	156,343,725
18. Total Net Original Cost Rate Base	$ 1,675,374,829	$ 316,046,375	$ 1,991,421,204
19. Electric and Gas Net Original Cost Rate Base Percentage	84.13%	15.87%	100.00%

(a) Common utility plant and the reserve for depreciation are allocated 75% to the Electric Department and 25% to the Gas Department.
(b) Excludes supplemental retirement-related deferred taxes.
(c) Average for 13 months.
(d) Excludes PSC fees.
(e) Excludes 25% of Trimble County inventories.
(f) Includes emission allowances.

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation of Cash Working Capital
As of September 30, 2003

	Electric (1)	Gas (2)	Total (3)
1. Operating expense and taxes for the 12 months ended September 30, 2003	$ 659,842,391	$ 294,051,365	$ 953,893,756
2. Deduct:			
3. Depreciation and Amortization	95,739,973	16,669,595	112,409,568
4. Depreciation for Asset Retirement	87,993	-	87,993
5. Regulatory Credits	(5,831,421)	-	(5,831,421)
6. Accretion Expense	462,519	-	462,519
7. Taxes			
8. Federal Income - current	16,169,414	(1,344,277)	14,825,137
9. State Income - current	7,717,776	(3,425)	7,714,351
10. Deferred Federal Income - net	26,424,972	7,488,535	33,913,507
11. Deferred State Income - net	4,685,298	1,649,839	6,335,137
12. Property and Other	12,603,252	3,888,055	16,491,307
13. Investment Tax Credit - net	(4,010,380)	(198,467)	(4,208,847)
14. Electric Power Purchased	83,608,926	-	83,608,926
15. Gain on Utility Property	(223,921)	-	(223,921)
16. Gas Supply Expenses	-	220,775,974	220,775,974
17. Total Deductions	$ 237,434,401	$ 248,925,829	$ 486,360,230
18. Remainder	$ 422,407,990	$ 45,125,536	$ 467,533,526
19. Cash Working Capital (12 1/2% of Line 18)	$ 52,800,999	$ 5,640,692	$ 58,441,691

LOUISVILLE GAS AND ELECTRIC COMPANY

Estimated Net Reproduction Cost Rate Base As of September 30, 2003

	Electric (1)	Gas (2)	Total (3)
1. Utility Plant Reproduction Cost (a)	$ 5,734,650,448	$ 1,047,501,116	$ 6,782,151,564
2. Deduct:			
3. Reserve for Depreciation (a)	2,480,933,993	371,676,959	2,852,610,952
4. Net Utility Plant	3,253,716,455	675,824,158	3,929,540,612
5. Deduct:			
6. Customer Advances for Construction	507,146	9,193,354	9,700,500
7. Accumulated Deferred Income Taxes (b)	291,450,446	53,930,878	345,381,324
8. FAS 109 Deferred Income Taxes	37,113,002	2,077,649	39,190,651
9. Investment Tax Credit (prior law)	3,943	-	3,943
10. Total Deductions	329,074,537	65,201,881	394,276,418
11. Net Plant Deductions	2,924,641,918	610,622,277	3,535,264,194
12. Add:			
13. Materials and Supplies (c)(e)(f)	55,832,046	104,925	55,936,971
14. Gas Stored Underground (c)	-	38,757,261	38,757,261
15. Prepayments (c)(d)	2,882,693	325,109	3,207,802
16. Cash Working Capital (Exhibit 3 page 2 of 2)	52,800,999	5,640,692	58,441,691
17. Total Additions	111,515,738	44,827,987	156,343,725
18. Total Net Reproduction Cost Rate Base	$ 3,036,157,656	$ 655,450,264	$ 3,691,607,919
19. Electric and Gas Net Reproduction Cost Rate Base Percentage	82.24%	17.76%	100.00%

(a) Common utility plant and the reserve for depreciation are allocated 75% to the Electric Department and 25% to the Gas Department.
(b) Excludes supplemental retirement related deferred taxes.
(c) Average for 13 months.
(d) Excludes PSC fees.
(e) Excludes 25% of Trimble County Inventories.
(f) Includes emission allowances.

LOUISVILLE GAS & ELECTRIC COMPANY

Estimated Reproduction (or Current) Cost of Utility Plant and Applicable Reserve for Depreciation at September 30, 2003

	Original Cost 9/30/2003 (1)	Effect of Changing Prices (a) (2)	At 9/30/2003 (3)
1. Plant in Service			
2. Electric Plant:			
3. Steam Production	$ 1,711,057,433	$ 1,434,217,261	$ 3,145,274,694
4. Hydraulic Production	9,802,252	152,848,670	162,650,922
5. Other Production	153,206,676	45,080,970	198,287,646
6. Transmission	219,996,119	276,601,732	496,597,851
7. Distribution	681,124,226	542,910,794	1,224,035,020
8. General	17,404,704	4,200,028	21,604,732
9. Intangible	2,340	44,147	46,487
10.	2,792,593,750	2,455,903,602	5,248,497,352
11. Gas Plant:			
12. Storage Underground	56,235,899	103,514,295	159,750,194
13. Transmission	12,719,541	31,032,186	43,751,727
14. Distribution	374,904,915	369,606,490	744,511,405
15. General	8,821,612	2,204,380	11,025,992
16. Intangible	553,233	2,143,055	2,696,288
17.	453,235,200	508,500,406	961,735,606
18. Common Plant:			
19. General	158,671,071	56,914,792	215,585,863
20. Intangible	32,337,034	4,158,773	36,495,807
21.	191,008,105	61,073,565	252,081,670
22. Total Plant in Service	3,436,837,055	3,025,477,573	6,462,314,628
23. Plant Held for Future Use			
24. Electric	696,772	555,383	1,252,155
25. Construction Work In Progress:			
26. Electric	289,114,064	-	289,114,064
27. Gas	14,424,115	-	14,424,115
28. Common	8,967,499	-	8,967,499
29.	312,505,678	-	312,505,678
30. Gas Stored Undg. - Non-Current	2,139,990	3,939,113	6,079,103
31. Total Utility Plant	3,752,179,495	3,029,972,069	6,782,151,564
32. Less Reserve for Depreciation:			
33. Electric	1,274,274,410	1,120,641,022	2,394,915,432
34. Gas	161,646,853	181,357,252	343,004,105
35. Common	86,904,335	27,787,080	114,691,415
36. Total Reserve for Depreciation	1,522,825,598	1,329,785,354	2,852,610,952
37. Total Utility Plant less Reserve for Depreciation	$ 2,229,353,897	$ 1,700,186,715	$ 3,929,540,612
38. By Departments			
39. Electric (Including 75% Common)	1,892,933,628	1,360,782,827	3,253,716,455
40. Gas (Including 25% Common)	336,420,269	339,403,888	675,824,157
41. Total Utility Plant less Reserve for Depreciation	$ 2,229,353,897	$ 1,700,186,715	$ 3,929,540,612

(a) Based on Handy -Whitman Index

LOUISVILLE GAS AND ELECTRIC COMPANY

Rates of Return - Actual and Requested
Pro-Formed for the Rate Increase
For the Twelve Months Ended September 30, 2003

		Electric (1)	Gas (2)	Total (3)
1. Net Original Cost Rate Base - Exhibit 3		$ 1,675,374,829	$ 316,046,375	$ 1,991,421,204
2. Reproduction Cost Rate Base - Exhibit 4		3,036,157,656	655,450,264	3,691,607,919
3. Net Operating Income - Actual - Exhibit 1		108,683,393	16,723,980	125,407,373
4. Rate of Return (Actual):				
5. On Net Original Cost Rate Base		6.49%	5.29%	6.30%
6. On Reproduction Cost Rate Base		3.58%	2.55%	3.40%
7. Adjusted Net Operating Income - Exhibit 1		$ 68,010,218	$ 11,250,025	$ 79,260,243
8. Revenue Increase Applied For - Exhibit 7		63,764,203	19,106,269	82,870,472
9. Income Taxes - Exhibit 1, Reference Schedule 1.36	40.3625 %	(25,736,826)	(7,711,768)	(33,448,594)
10. Adjusted Net Operating Income Pro-formed for Rate Increase		106,037,595	22,644,526	128,682,121
11. Requested Rate of Return (Pro-forma):				
12. On Net Original Cost Rate Base		6.33%	7.16%	6.46%
13. On Reproduction Cost Rate Base		3.49%	3.45%	3.49%

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation of Overall Revenue Deficiency at September 30, 2003

	Electric (1)	Gas (2)	Total (3)
1. Net Operating Income Found Reasonable	$ 105,781,937	$ 22,567,921	$ 128,349,858
2. Pro-forma Net Operating Income	68,010,218	11,250,025	79,260,243
3. Net Operating Income Deficiency	$ 37,771,718	$ 11,317,896	$ 49,089,614
4. Gross Up Revenue Factor - Exhibit 1, Reference Schedule 1.39	0.59236556	0.59236556	0.59236556
5. Overall Revenue Deficiency	$ 63,764,203	$ 19,106,269	$ 82,870,472

Ms. Scott

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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

TESTIMONY OF
VALERIE L. SCOTT
DIRECTOR, FINANCIAL PLANNING AND ACCOUNTING – UTILITY OPERATIONS
LOUISVILLE GAS AND ELECTRIC COMPANY

December 29, 2003

Filed: December 29, 2003

Q. Please state your name, position and business address.

A. My name is Valerie L. Scott. I am Director of Financial Planning and Accounting – Utility Operations for Louisville Gas and Electric Company ("LG&E"). My business address is 220 West Main Street, Louisville, Kentucky.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support certain pro forma adjustments to LG&E's operating income for the twelve months ended September 30, 2003. The pro forma adjustments are described on the Reference Schedules attached to Rives Exhibit 1. My testimony demonstrates that these adjustments are known and measurable and, therefore, reasonable. My testimony also supports certain Schedules supporting LG&E's application.

Q. Are you supporting the information required by Commission regulation 807 KAR 5:001, Section 10(6)(a)-(v) – The Historical Test Period?

A. Yes. I am sponsoring the following Schedules for the corresponding Filing Requirements:

• Current Chart of Accounts	Section 10(6)(j)	Tab 29
• FERC Audit Reports	Section 10(6)(l)	Tab 31
• FERC Forms 1 and 2	Section 10(6)(m)	Tab 32
• Depreciation Study	Section 10(6)((n)	Tab 33
• Computer Software, Hardware, etc.	Section 10(6)(o)	Tab 34
• Monthly Management Reports	Section 10(6)(r)	Tab 37
• Affiliate, et. al., Allocations/Charges	Section 10(6)(t)	Tab 39

Q. Are you supporting the information required by Commission regulation 807 KAR 5:001, Section 10(7)(a) – (d) – Pro Forma Adjustments?

A. Yes. I am sponsoring the following Schedules for the corresponding Filing Requirements:

• Financial Statements with Adjustments	Section 10(7)(a)	Tab 42
• Capital Construction Budget	Section 10(7)(b)	Tab 43
• Pro Forma Adjustments – Plant Additions	Section 10(7)(c)	Tab 44
• Pro Forma Adjustments – Operating Budget	Section 10(7)(d)	Tab 45

Electric Operations

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.06 of Exhibit 1.

A. This adjustment has been made to eliminate brokered electric sales revenues and expenses. Brokered transactions do not utilize company generation or transmission assets; accordingly, the related revenues and expenses are eliminated in determining base rates. It is calculated in accordance with the Commission's determination in its Order of January 7, 2000 in Case No. 98-426.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.07 of Exhibit 1.

A. This adjustment is necessary to eliminate the Earnings Sharing Mechanism revenues collected during the test period that are included in the ultimate consumer revenue classes and are not included in Rate Refund Account 449. The impact of rate mechanisms like the Earnings Sharing Mechanism should be removed from the test year revenues when assessing the adequacy of base rates.

Q. Please explain the adjustment to operating revenues shown in Reference Schedule 1.08 of Exhibit 1.

A. This adjustment has been made to eliminate the impact of the revenues recorded in the test year associated with the Earnings Sharing Mechanism, Environmental Cost Recovery and Fuel Adjustment Clause from Rate Refund Account 449. The impact of rate mechanisms, such as these, should be removed from the test year revenues when assessing the adequacy of base rates.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.11 of Exhibit 1.

A. This adjustment has been made to reflect annualized depreciation expenses. The purpose of this adjustment is to reflect a full year's depreciation expense on net plant in service as of September 30, 2003, using proposed depreciation rates recommended by LG&E's expert, Earl M. Robinson with AUS Consultants, in the study he prepared for LG&E and filed in this proceeding. Mr. Robinson's testimony explains the changes in depreciation rates and the analysis supporting the changes. The adjustment is calculated in accordance with the methodology approved by the Commission in Case No. 2000-080.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.12 of Exhibit 1.

A. This adjustment has been made to reflect increases in labor and labor-related costs as applied to the twelve months ended September 30, 2003, and includes specific adjustments for wages, payroll taxes and LG&E 401(k) match. Page 1 of 4 presents an overview of the adjustment.

Page 2 of 4 of Reference Schedule 1.12 of Exhibit 1 shows the adjustment for wage expenses. The adjustment reflects the annualized base labor of all LG&E employees at September 2003, and it includes new union contract rates effective November 10, 2003.

Under the terms of the current contract, beginning November 10, 2003, union employees received a three percent wage increase, a three percent increase in overtime wages and, effective January 2003, those employees began participating in LG&E's Team Incentive Award ("TIA"). An adjustment has been made to increase union overtime for twelve months of the test year to recognize the impact of the November 10, 2003, contract increase. The adjustment also reduces the non-union TIA by an amount guaranteed by E.ON as part of the acquisition of Powergen. As part of that transaction, E.ON guaranteed all eligible employees 100 percent of their payouts under the TIA program for 2002. For the 2002 TIA payment made in March 2003, only non-union employees were eligible. LG&E has reduced the adjustment to remove the amount guaranteed by E.ON to the extent that it exceeded what employees would have been paid in March 2003, without the guarantee.

Page 3 of 4 of Reference Schedule 1.12 of Exhibit 1 shows the calculation of the component of the labor adjustment to reflect the increases in the Federal Insurance Contributions Act ("FICA") employer payroll taxes due to the increase in wages.

Finally, page 4 of Reference Schedule 1.12 of Exhibit 1 shows the calculation of the component of the labor adjustment to reflect the resulting increases in LG&E's match of 401(k) contributions as applied to the twelve months ended September 30, 2003, due to the adjustments to the increases in wages.

The labor adjustment follows the methodology approved by the Commission for this type of adjustment in Case No. 2000-080.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.13 of Exhibit 1.

A. This adjustment is necessary to annualize the pension and post-retirement medical benefit expenses for the test period. The adjustment is the difference in the net periodic cost calculated by Mercer for 2003 and the amount included in the test period.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.14 of Exhibit 1.

A. This adjustment has been made to reflect a normalized level of storm damage expenses based upon a ten-year average adjusted for inflation. This adjustment is calculated in accordance with the methodology approved by the Commission in Case No. 90-158.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.15 of Exhibit 1.

A. This adjustment eliminates advertising expenses. Commission regulation 807 KAR 5:016, Section 2(1) provides that a utility will be allowed to recover, for ratemaking purposes, only those advertising expenses which produce a "material benefit" to its ratepayers. The advertising expenses eliminated by this adjustment are primarily institutional and promotional in nature.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.16 of Exhibit 1.

A. This adjustment is necessary to include the expenses incurred in conjunction with this electric base rate case in operating expenses. LG&E estimates the total electric rate case expense to be $1,000,739. The adjustment has been amortized over three years at a rate of $333,580 per year. The adjustment will be trued-up as actual expenditures are incurred. The Commission approved the recovery of rate case expenses in Case No. 2000-080.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.17 of Exhibit 1.

A. This adjustment is necessary to reflect the amortization of expenses deferred by LG&E for the Earnings Sharing Mechanism audit in operating expenses. The amount of the adjustment is based on expenses incurred and projected to be incurred through the end of the Commission's investigation. The amount is then amortized over three years at a rate of $58,333 per year.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.18 of Exhibit 1.

A. The adjustment is necessary to remove the amortization of One-Utility costs as a non-recurring expense because these costs were completely amortized by September 30, 2003. The remaining amount of the related regulatory asset was amortized during the test year. The Commission approved the establishment of the regulatory asset and the amortization of the One-Utility costs in Case No. 2000-080.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.19 of Exhibit 1.

A. This adjustment is made to normalize the expense levels in Account 925 "Injuries and Damages." The normalization is based on five years. The adjustment is calculated consistent with the adjustment used in Case No. 2000-080. The amount was then adjusted for inflation to be consistent with the methodology used to calculate the storm damage normalization adjustment.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.20 of Exhibit 1.

A. This adjustment is to recognize the Value Delivery Team net savings to shareholders recognized by the Commission in its Order of December 3, 2001 in Case No. 2001-169. In its December 3, 2001 Order in Case No. 2001-169, the Commission approved LG&E's Value Delivery Surcredit Rider as part of the Settlement Agreement in that proceeding. Under the terms of the Settlement Agreement, the net savings from the Value Delivery Team initiative are shared 40 percent with the customers and 60 percent with the shareholders. The customers' share of the savings is distributed through the Value Delivery Surcredit Rider that took effect in December 2001. Since the end of 2001, LG&E's electric customers have received a total of $6,840,000 in bill credits and will receive an additional $5,640,000 in bill credits in 2004. LG&E and Kentucky Utilities Company ("KU") have achieved substantial savings under the VDT initiative reviewed by the Commission in Case No. 2001-169. Absent such savings, the needed increase in rates would have been larger than the Company is actually requesting in this proceeding. Thus, although the adjustment to recognize the shareholder portion of savings under the VDT initiative results in an upward adjustment of operating expenses, the overall effect of the VDT program has been to lower customers' bills, with the benefit to be shared by customers and shareholders, as per the Commission Order. The $5,640,000 adjustment to operating expenses of LG&E's electric operations shown in Reference Schedule 1.20 of Exhibit 1 is necessary to reflect the shareholders' portion of the net savings from the Value Delivery Team initiative for the test year. The adjustment to expenses is consistent with the ratemaking treatment of the shareholders' portion of the merger surcredit savings in Case No. 98-426.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.21 of Exhibit 1.

A. This adjustment is to true-up the Value Delivery Team customer surcredit and amortization of expenses recorded in the test year to the amount approved by the Commission in its December 3, 2001 Order in Case No. 2001-169.

Q. Please explain the adjustment to operating revenues and expenses shown in Reference Schedule 1.22 of Exhibit 1.

A. This adjustment is made to reflect the customers' and shareholders' portions of the merger savings in accordance with the Settlement Agreement approved by the Commission's October 16, 2003 Order in Case No. 2002-00430. The customers' portion of the savings is trued-up to the amount attributed to the shareholder to reflect the 50/50 saving split per the Settlement Agreement. Absent this adjustment, shareholders would lose their share of such savings that were approved by the Commission in its Order.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.23 of Exhibit 1.

A. This adjustment is necessary to reflect the elimination of merger amortization expenses from the LG&E Energy Corp. acquisition of KU Energy Corporation. The merger expenses were fully amortized by September 30, 2003, with the remaining amount of the related regulatory asset amortized during the test year. The amount amortized during the test year will not be a recurring expense. The Commission approved the establishment of the regulatory asset and the amortization of the merger expense amount in Case No. 97-300.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.24 of Exhibit 1.

A. As a member of the Midwest Independent Transmission System Operator, Inc. ("MISO"), LG&E received monthly credits during a portion of the test year pursuant to an agreement with MISO to defer increased demand charges until 2007. These credits were applied to billings of MISO's Schedule 10 administrative costs. The credits are reversed from the test year to restate MISO Schedule 10 expenses to actual since the credits will not continue after 2003 when MISO begins charging the higher demand charges.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.25 of Exhibit 1.

A. In June of 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. Under SFAS No. 143, entities are required to recognize and account for certain asset retirement obligations in a manner different from the way that LG&E and other public utilities have traditionally recognized and accounted for such costs. Specifically, if a legally enforceable asset retirement obligation ("ARO"), as defined by SFAS No. 143, is deemed to exist, an entity must measure and record the liability for the ARO on its books. The liability must be recorded at fair market value in the period during which the liability is incurred. SFAS No. 143 defines "fair market value" as the amount that the entity would be required to pay in an active market to settle the ARO. SFAS No. 143 also provides that if market prices are not available, estimates of their fair value can be calculated by discounting the estimated cash flows associated with the ARO to their present value at the date the liability is to be recorded. The value of the liability is accreted over the life of the asset to account for the time value of money, so that at the time of retirement the recorded ARO liability will be sufficient to provide the cash required to meet the legal obligation.

Under SFAS No. 143, at the time the liability is recorded, a corresponding and equivalent ARO asset is also recorded on the entity's books to recognize the cost of removal as an integral part of the cost of the associated tangible asset. The ARO asset is then depreciated over the life of the asset, similar to the depreciation of other assets.

In addition to the forward-looking requirements of SFAS No. 143, entities are required to recognize the cumulative impact on their financial statements resulting from the implementation of SFAS No. 143. This cumulative impact amounts to a transition entry on the entity's books. The cumulative effect impact represents the ARO asset depreciation and ARO liability accretion that would have been recorded had the asset and liability been recorded by the company when the original asset was placed in service. SFAS No. 143 recognized that many rate-regulated entities provide for costs related to retirement of certain long-lived assets and recover those amounts in rates charged to their customers. Where the timing of cost recognition under SFAS No. 143 and under rate recovery methods differ, this statement indicates a regulatory asset or liability shall be recorded for the difference subject to the provisions of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation.*

For ratemaking purposes, the impact of implementing SFAS No. 143 overstates LG&E's above-the-line income at a level that is not representative of its operations. The cumulative effect adjustments are recorded below-the-line in FERC USofA Account No. 435, while the corresponding amount of regulatory credit is recorded above-the-line in Account No. 407. While this accounting is required for the transition of implementing SFAS No. 143 in 2003, it overstates LG&E's net operating income for the test year ended September 30, 2003, for ratemaking purposes since the offsetting charge is recorded below-the-line.

On October 30, 2002, the Federal Energy Regulatory Commission ("FERC") issued a *Notice of Proposed Rulemaking to Revise Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, Docket No. RM02-7-000. Following the receipt and consideration of comments in response to this notice, on April 9, 2003, the FERC issued a final rule in Docket No. RM02-7-000, Order No. 631, Final Rule (Issued April 9, 2003) ("FERC Order No. 631"). Under FERC Order No. 631, a utility must recognize a liability for the fair value of an ARO, calculated on a net present value basis, at the time the asset is constructed, acquired, or when a change in law creates a legal obligation to perform the retirement activities. FERC Order No. 631 generally adopted the requirements of SFAS No. 143.

Reference Schedule 1.25 of Exhibit 1 shows the adjustment necessary to net the cumulative effect of this accounting change against the corresponding regulatory credit in the test year.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.26 of Exhibit 1.

A. This adjustment has been made to reflect the October 2003 reduction of 27 employees in the Information Technology department of LG&E Energy Services, Inc. The adjustment to expense reflects the labor and labor-related expenses charged to LG&E in the test year reduced by one-third of the costs to achieve the savings in order to effectively amortize those costs over a three-year period.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.27 of Exhibit 1.

A. This adjustment is necessary to remove legal expenses incurred by LG&E in the test year associated with the litigation against the supplier of two combustion turbines located at KU's E.W. Brown Power Station. The adjustment is necessary to remove LG&E's share of non-recurring legal expenses. LG&E owns a 38 percent interest in both of the combustion turbines.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.29 of Exhibit 1.

A. This adjustment reflects certain changes in LG&E's corporate office lease expenses. During 2002, LG&E negotiated a more favorable lease for its corporate offices at 220 West Main Street in Louisville, Kentucky. LG&E had recorded rent expense on a normalized basis over the term of the former lease normalizing accelerated payments that would have been due in the later years of the lease in conformity with SFAS 13, *Accounting for Leases*. The difference between the actual amounts paid and the normalized amount expensed until cancellation resulted in an accrual for future lease payments that would no longer be made with the cancellation of the lease. During the test year LG&E reversed this accrual. This adjustment removes the credit to expense and establishes the rent expense at the actual annual amount under the new lease.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.30 of Exhibit 1.

A. This adjustment is to remove the insurance proceeds received by LG&E during the test year for costs incurred prior to the test year related to the repair of Cane Run Unit No. 5. The insurance reimbursement is a non-recurring item and therefore must be removed from the test year.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.31 of Exhibit 1.

A. This adjustment is for inventory for steam plants that LG&E charged-off its books because the parts had become obsolete. The original costs were prudent business expenditures at the time of purchase in order to maintain adequate inventory to provide reliable customer service. The obsolete inventory write-down is not expected to be a recurring annual expense, although charges of this nature will occur from time to time. Therefore LG&E proposes to amortize this expense over a three-year period.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.32 of Exhibit 1.

A. This adjustment is for a payment for carbide lime made by LG&E to Carbide Graphite for use at the Cane Run Power Station. On October 1, 1988, LG&E entered into a contract with Carbide Graphite for the supply of carbide lime to be used in the pollution control facilities at the Cane Run Power Station. LG&E paid $4 million at that date for 1,000,000 net dry tons of carbide lime to be delivered to the Cane Run station as called upon by LG&E. Carbide Graphite delivered approximately 535,462 net dry tons to LG&E, but on September 1, 2001, Carbide Graphite filed bankruptcy and, on November

14, 2002, the contract was rejected by the bankruptcy court. As a result, LG&E was forced to record a loss for the remaining portion of the contract payment. The write-off of this payment is not expected to be a recurring annual expense, but it was incurred to benefit customers by securing carbide lime needed in the scrubber process. LG&E proposes to amortize this expense over a three-year period.

Gas Operations

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.11 of Exhibit 1.

A. This adjustment has been made to reflect annualized depreciation expenses. The purpose of this adjustment is to reflect a full year's depreciation expense in net plant in service as of September 30, 2003, using proposed depreciation rates recommended by Mr. Robinson in the study he prepared for LG&E and filed in this proceeding. Mr. Robinson's testimony explains the changes in depreciation rates and the analysis supporting the changes. This adjustment is calculated in accordance with the methodology approved by the Commission in Case No. 2000-080.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.12 of Exhibit 1.

A. This adjustment has been made to reflect increases in labor and labor related costs as applied to the twelve months ended September 30, 2003, and includes specific adjustments for wages, payroll taxes and LG&E 401(k) match. Page 1 of 4 presents an overview of the adjustment.

Page 2 of 4 of Reference Schedule 1.12 of Exhibit 1 shows the adjustment for wage expenses. The adjustment reflects the annualized base labor of all LG&E

employees at September 2003, and it includes new union contract rates effective November 10, 2003.

Under the terms of the current contract, beginning November 10, 2003, union employees received a three percent wage increase, a three percent increase in overtime wages and, effective January 2003, those employees began participating in LG&E's Team Incentive Award ("TIA"). An adjustment has been made to increase union overtime for twelve months of the test year to recognize the impact of the November 10, 2003, contract increase. The adjustment also reduces the non-union TIA by an amount guaranteed by E.ON as part of the acquisition of Powergen. As part of that transaction, E.ON guaranteed all eligible employees 100 percent of their payouts under the TIA program for 2002. For the 2002 TIA payment made in March 2003, only non-union employees were eligible. LG&E has reduced the adjustment to remove the amount guaranteed by E.ON to the extent that it exceeded what employees would have been paid in March 2003, without the guarantee.

Page 3 of 4 of Reference Schedule 1.12 of Exhibit 1 shows the calculation of the component of the labor adjustment to reflect the increases in the Federal Insurance Contributions Act ("FICA") employer payroll taxes due to the increase in wages.

Finally, page 4 of Reference Schedule 1.12 of Exhibit 1 shows the calculation of the component of the labor adjustment to reflect the resulting increases in LG&E's match of 401(k) contributions as applied to the twelve months ended September 30, 2003, due to the adjustments to the increases in wages.

The labor adjustment follows the methodology approved by the Commission for this type of adjustment in Case No. 2000-080.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.13 of Exhibit 1.

A. This adjustment is necessary to annualize the pension and post-retirement medical benefit expenses for the test period. The adjustment is the difference in the net periodic cost calculated by Mercer for 2003 and the amount included in the test period.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.15 of Exhibit 1.

A. This adjustment eliminates advertising expenses. Commission regulation 807 KAR 5:016, Section 2(1) provides that a utility will be allowed to recover, for ratemaking purposes, only those advertising expenses which produce a "material benefit" to its ratepayers. The advertising expenses eliminated by this adjustment are primarily institutional and promotional in nature.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.16 of Exhibit 1.

A. This adjustment is necessary to include the expenses incurred in conjunction with this gas base rate case in operating expenses. LG&E estimates the total gas rate case expense to be $651,393. The adjustment has been amortized over three years at a rate of $217,131 per year. The adjustment will be trued-up as actual expenditures are incurred. The Commission approved the recovery of rate case expenses in Case No. 2000-080.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.18 of Exhibit 1.

A. The adjustment is necessary to remove amortization of One-Utility Costs. The remaining amount of the related regulatory asset was amortized during the test year and therefore will not be an ongoing expense. The Commission approved the establishment of the regulatory asset and the amortization of the One-Utility Costs in Case No. 2000-080.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.19 of Exhibit 1.

A. This adjustment is made to normalize the expense levels in Account 925 "Injuries and Damages." The normalization is based on five years. The adjustment is calculated consistent with the adjustment used in Case No. 2000-080. The amount was then adjusted for inflation to be consistent with the methodology used to calculate the storm damage normalization adjustment.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.20 of Exhibit 1.

A. This adjustment is to recognize the Value Delivery Team net savings to shareholders recognized by the Commission in its Order of December 3, 2001 in Case No. 2001-169. In its December 3, 2001 Order in Case No. 2001-169, the Commission approved LG&E's Value Delivery Surcredit Rider as part of the Settlement Agreement in that proceeding. Under the terms of the Settlement Agreement, the net savings from the Value Delivery Team initiative are shared 40 percent with the customers and 60 percent with the shareholders. The customers' share of the savings is distributed through the Value Delivery Surcredit Rider that took effect in December 2001. Since the end of 2001, LG&E's gas customers have received a total of $1,680,000 in bill credits and will receive and additional $1,520,000 in bill credits in 2004. LG&E and KU have achieved substantial savings under the VDT initiative reviewed by the Commission in Case No. 2001-169. Absent such savings, the needed increase in rates would have been larger than the Company is actually requesting in this proceeding. Thus, although the adjustment to recognize the shareholder portion of savings under the VDT initiative results in an upward adjustment of operating expenses, the overall effect of the VDT program has been to lower customers' bills, with the benefit to be shared by customers and shareholders, as per the Commission Order. The $1,515,000 adjustment to operating expenses of LG&E's gas operations shown in Reference Schedule 1.20 of Exhibit 1 are necessary to reflect the shareholders' portion of the net savings from the Value Delivery Team initiative for the test year. The adjustment to expenses is consistent with the ratemaking treatment of the shareholders' portion of the merger surcredit savings in Case No. 98-426.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.21 of Exhibit 1.

A. This adjustment is to true-up the Value Delivery Team customer surcredit and amortization of expenses recorded in the test year to the amount approved by the Commission in its December 3, 2001 Order in Case No. 2001-169.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.26 of Exhibit 1.

A. This adjustment has been made to reflect the October 2003 reduction of 27 employees in the Information Technology department of LG&E Energy Services, Inc. The adjustment to expense reflects the labor and labor-related expenses charged to LG&E in the test year reduced by one third of the costs to achieve the savings in order to effectively amortize those costs over a three-year period.

Q. Please explain the adjustment to operating expenses shown in Reference Schedule 1.29 of Exhibit 1.

A. This adjustment reflects certain changes in LG&E's corporate office lease expenses. During 2002, LG&E negotiated a more favorable lease for its corporate offices at 220 West Main Street in Louisville, Kentucky. LG&E had recorded rent expense on a normalized basis over the term of the former lease normalizing accelerated payments that would have been due in the later years of the lease in conformity with SFAS 13, *Accounting for Leases*. The difference between the actual amounts paid and the normalized amount expensed until cancellation resulted in an accrual for future lease payments that would no longer be made with the cancellation of the lease. During the test year LG&E reversed this accrual. This adjustment removes the credit to expense and establishes the rent expense at the actual annual amount under the new lease.

Q. Does this conclude your testimony?

A. Yes.

288508.06

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Valerie L. Scott**, being duly sworn, deposes and says she is Director of Financial Planning and Accounting – Utility Operations for Louisville Gas and Electric Company, that she has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Valerie L. Scott

VALERIE L. SCOTT

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Melody L. Hulsel (SEAL)
Notary Public

My Commission Expires:

November 26, 2007

APPENDIX A

Valerie L. Scott

Director, Financial Planning & Accounting – Utility Operations
LG&E Energy Corp.
220 West Main Street
Louisville, Kentucky 40202
(502) 627-3660

Professional Memberships:

American Institute of Certified Public Accountants (AICPA)
Kentucky Society of Certified Public Accountants (KSCPA)

Education:

University of Louisville, Masters of Business Administration (with high distinction), 1994
University of Louisville, Bachelor of Science in Commerce with a major in Accounting (with honors), 1978

Previous Positions with LG&E Energy Corp.:

- February 1999 – August 2002 – Director, Trading Controls & Energy Marketing Accounting
- May 1998 – February 1999 – Manager, Trading Controls and Manager, Financial Planning, Reporting and Special Projects
- July 1993 – May 1998 – Manager, Corporate Internal Auditing
- October 1991 – July 1993 – Senior Staff Accountant

Mr. Robinson

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY
OF
EARL M. ROBINSON
PRESIDENT AND CHIEF EXECUTIVE OFFICER
AUS CONSULTANTS -
WEBER FICK & WILSON DIVISION

Concerning
Depreciation Service Life Study

December 29, 2003

Filed: December 29, 2003

Q1. STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A1. My name is Earl M. Robinson. I am President and Chief Executive Officer of the Weber Fick & Wilson Division (WFW) of AUS Consultants - Utility Services. WFW is a public utility consulting firm specializing in the performance of various financial studies including depreciation, valuation, cost of service and other analysis for the utility industry and regulatory agencies. AUS Consultants provides a wide spectrum of consulting services through its various affiliated groups which include Utility Services, Valuation Services, ICR Survey Research, and Marketing Systems. The Weber Fick & Wilson Division is located at 1000 North Front Street, Suite 200, Wormleysburg, Pennsylvania 17043.

Q2. DO YOU HAVE AN APPENDIX WHICH CONTAINS YOUR QUALIFICATIONS, EXPERIENCE AND PRIOR APPEARANCES?

A2. Yes. Appendix A to my direct testimony contains a summary of all such information.

Q3. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A3. The purpose of my testimony is to set forth the results of my review and analysis of the plant in service of Louisville Gas & Electric - Electric, Gas and Common Plant (the Company) which was conducted in the process of conducting a depreciation studies and report(s) as of December 31, 2002. In completing the studies, my task included an investigation and analysis of the Company's historical data, together with an interpretation of past experience and future expectancy to determine the remaining lives of the Company's property. The studies also utilized the resulting remaining lives, the results of our salvage analysis, the Company's vintaged plant in service investment and depreciation reserve to develop recommended average remaining life depreciation rates, and depreciation expense related to the Company's plant in service.

Q4. WHAT IS YOUR PROFESSIONAL OPINION WITH REGARD TO THE COMPLETED DEPRECIATION STUDY RESULTS?

A4. In my opinion, the proposed depreciation rates resulting from the completion of the comprehensive depreciation study (s) are reasonable and appropriate given that they incorporate the life and net salvage parameters anticipated for each of the property group investments over their average remaining lives.

Q5. WHAT STEPS WERE INVOLVED IN PREPARING THE SERVICE LIFE AND SALVAGE DATA BASE?

A5. The completion of the comprehensive depreciation analysis through December 31, 2002 included a detailed analysis of the Company's fixed capital books and records. The Company's historical investment cost records for each account have been assembled into a depreciation data base upon which detailed service life and salvage analysis can be performed using standard depreciation procedures.

Q6. WHAT IS THE PURPOSE OF DEVELOPING THE HISTORICAL DATA BASE?

A6. The historical data is a basic depreciation study tool that is assembled to enable the preparation of a depreciation study. The historical data base is a source from which to prepare historical analysis. These analytical results are used to make assessments and judgements concerning the life and salvage factors being achieved, and (along with information relative to current and prospective factors) to benchmark the estimated future lives over which to recover the Company's depreciable fixed capital investments. In utilizing this standard depreciation process, the Company's developed depreciation database compiled through December 31, 2002 was used to develop observed life tables upon which historical analysis was performed. Likewise, the net salvage database was used as a basis to identify historical experience and trends and to determine each property group's recommended net salvage factors.

Q7. IN THE PREPARATION OF THIS AND OTHER DEPRECIATION STUDIES, DO YOU DRAW INFORMATION FROM ADDITIONAL SOURCES WHEN ESTIMATING SERVICE LIFE AND SALVAGE PARAMETERS?

A7. Yes, in addition to the historical data obtained from the Company's books and records, information is obtained from Company personnel relative to current operations and future expectations. I also incorporated professional knowledge obtained from my more than thirty (30) years of utility industry depreciation experience, along with depreciation data assembled from other operating companies.

Q8. DO YOU HAVE DEPRECIATION STUDY REPORTS WHICH SUMMARIZE THE RECOMMENDATIONS RESULTING FROM THE DEPRECIATION SERVICE LIFE AND SALVAGE STUDIES?

A8. Yes, the results are included in separately bound volumes (Appendix C, D, and E) entitled "Louisville Gas and Electric - Electric Division Depreciation Study as of December 31, 2002", "Louisville Gas and Electric - Gas Division Depreciation Study as of December 31, 2002", and "Louisville Gas and Electric - Common Plant

Depreciation Study as of December 31, 2002" respectively, which summarize the results of my service life and salvage analysis of each entity.

Q9. DO YOU HAVE A SUMMARY OF THE DEPRECIATION RATES THAT YOU DEVELOPED AND ARE PROPOSING FOR EACH OF THE COMPANY'S DEPRECIABLE PROPERTY GROUPS?

A9. Yes, Appendix B-LG&E contains an account level summary of the present and proposed depreciation rates which are also set forth in detail in Section 2 of the depreciation study report(s).

Q10. RELATIVE TO THE COMPANY'S GENERATING STATION INVESTMENTS, HAVE YOU DEVELOPED DEPRECIATION RATES APPLICABLE TO EACH INDIVIDUAL PLANT SITE?

A10. Yes, Table 1-Plant Site, within Section 2 of the electric depreciation study report, contains depreciation rates for each plant site.

Q11. COULD YOU PLEASE BRIEFLY DESCRIBE THE INFORMATION INCLUDED WITH THE DEPRECIATION REPORT(S).

A11. The report(s) are segregated into seven (7) sections. Two (2) key areas of the report are Section 2 and Section 4. Section 2 includes the summary schedules listing the present and proposed depreciation rates for each depreciable property group and other following the letter of transmittal lists the complete contents of the report. In addition, Section 1 contains a brief narrative summary or overview of the entire report.

Q12. WHAT WAS THE SOURCE OF THE DATA WHICH WAS UTILIZED AS A BASIS FOR THE DEPRECIATION RATES?

A12. As previously discussed, all of the Company's historical data utilized in the course of performing the detailed service life and salvage study were obtained from the Company's books and records. The historical vintaged data (additions, retirements, adjustments, and balances), were obtained for each depreciable property group.

Q13. ARE THERE STANDARD METHODS UTILIZED TO COMPLETE THE SERVICE LIFE ANALYSIS OF A COMPANY'S HISTORICAL PROPERTY INVESTMENTS?

A13. Yes. As discussed in Section 3 of the depreciation study report(s) (Appendix C, D, and E) as well as later in this testimony, the two most common methods are the Retirement Rate Method and the Simulated Record Method.

Q14. WAS THE STUDY PREPARED UTILIZING THOSE ACCEPTED STANDARD METHODS?

A14. Yes. Those methods were utilized in the performance of the comprehensive depreciation study of the Company's property.

Q15. WHAT METHOD, PROCEDURE, AND TECHNIQUE WAS UTILIZED TO DEVELOP THE DEPRECIATION RATES FOR THE COMPANY'S PROPERTY?

A15. Inherent with all depreciation calculations, there is an overall method, such as the Straight Line Method, to depreciate property. Secondly, the property is grouped in a certain manner, such as by sub-groups of vintages to develop applicable service lives. Finally, the investment needs to be recovered over a period, such as the Whole Life or Remaining Life segment of the property. The depreciation rates set forth in my depreciation study report(s) (Appendix C, D, and E) were developed by utilizing the Straight Line Method, the Broad Group Procedure, and the Average Remaining Life Technique.

Q16. WHY WAS THE INDICATED DEPRECIATION APPROACH UTILIZED?

A16. The Company, like any other business, includes as an annual operating expense an amount which reflects a portion of the capital investment which was consumed in providing service during the accounting period. The straight line method is widely understood, recognized, and utilized almost exclusively for depreciating utility property. The broad group procedure recovers the Company's investments over the average period of time in which the property is providing service to the Company's customers, and was the utilized depreciation procedure. Lastly, the annual depreciation amount utilized needs to be based upon the productive life over which the undepreciated capital investment is recovered. The Company's utilization of the applicable annual depreciation over the average remaining life assures that the Company's property investment is fully recovered over the useful life of the property, and inter-generational inequities are avoided. The determination of the productive remaining life for each property group includes a study of both past experience and future expectations. Finally, the approach is consistent with depreciation methods and procedures generally utilized and accepted by this Commission in the Company's rate Order at KPSC Case No. 2001-141 dated December 3, 2001.

Q17. PLEASE EXPLAIN THE UTILIZATION OF GROUP DEPRECIATION PROCEDURES.

A17. Group depreciation procedures are utilized to depreciate property when more than one item of property is being depreciated. Such an approach is appropriate because all of the items within a specific group typically do not have identical service lives, but have lives which are dispersed over a range of time. Utilizing a group depreciation procedure allows for a condensed application of depreciation rates to groups of similar property in lieu of extensive depreciation calculations on an item by item basis. The two more common group depreciation procedures are the Broad Group (BG) and Equal Life Group (ELG) approach.

The Broad Group Procedure recovers the investment within the asset group over the average service life of the property group. Given that there is dispersion within each property group there are variations of retirement ages for the many investments within each property group. That is, some properties retire early (before average service life) while others retire at older ages (after average service life) with the weighted average retirement age of the total property group being the attained average service life. The Broad Group Procedure was used consistent with the historic and current practice.

By comparison, the ELG Procedure allocates the capital cost of a group property to annual expense in accordance with the consumption of the property group providing service to customers. In this regard, the company's customers are charged with the cost of the property consumed in providing them service during the applicable service period. The more timely return of plant cost is accomplished by fully accruing each unit's cost during its service life, thereby, reducing the risk of incomplete cost recovery.

Q18. WHAT TECHNIQUE DID YOU UTILIZE AND WHY DID YOU USE IT?

A18. I utilized the Average Remaining Life Technique because it incorporates all the Company's fixed capital cost components thereby better assuring full recovery of the Company's embedded net plant investment. The average remaining life technique gives consideration to not only the average service life and survival characteristic plus the net salvage component but also recognizes the level of depreciation which has been accrued to date in developing the proposed depreciation rate. The Average Remaining Life Technique is used by regulated companies and regulatory agencies because it allows full recovery by the end of the property's useful life -- no more and no less. Furthermore, the average remaining life technique is widely used by the electric, gas, water, and telephone industries throughout the nation as a basis for developing annual depreciation rates and expense. As previously noted, this is also the technique utilized in developing the Company's current depreciation rates.

Q19. WHAT FACTORS INFLUENCE THE DETERMINATION OF THE RECOMMENDED ANNUAL DEPRECIATION RATES INCLUDED IN THE COMPANY'S DEPRECIATION REPORTS (APPENDIX C, D, and E)?

A19. The depreciation rates reflect four (4) principal factors, namely (1) the plant in service by vintage, (2) the book depreciation reserve, (3) the future net salvage, and (4) the composite remaining life from the property group. Related factors to be considered in arriving at the service life are the average age, realized life and the survival characteristics. The net salvage estimate is influenced by both past experience and future estimates of cost of removal and gross salvage amounts.

Q20. WOULD YOU PLEASE EXPLAIN THE PRINCIPAL ASSUMPTIONS CONSIDERED WHEN UTILIZING THE COMPANY'S AUTHORIZED DEPRECIATION APPROACH?

A20. Through the utilization of the Company's depreciation approach, the Company will recover the undepreciated fixed capital investment via amounts of annual depreciation expense in each year throughout the useful life of the property. That is, the Average Remaining Life Technique incorporates the related future life expectancy of the property, the vintaged surviving plant in service, the survival characteristics, together with the book depreciation reserve balance and future net salvage in developing the amounts for each property account. Accordingly, Average Remaining Life depreciation meets the objective of providing a Straight Line recovery of the Company's fixed capital property investments.

Q21. IS THE COMPANY'S DEPRECIATION CALCULATION A UNIT OR GROUP DEPRECIATION APPROACH?

A21. The Company's depreciation calculation, as applied in this study, is a group depreciation approach. The "group" refers to the method of calculating annual depreciation on the summation of the investment in any one plant group rather than calculating depreciation for each individual unit. In theory, each unit achieves average service life by the time of retirement, accordingly, the full cost of the investment is credited to plant in service when the retirement occurs and likewise the depreciation reserve is debited with an equal retirement cost. No gain or loss is recognized at the time of property retirement because of the assumption that the retired property was at average service life.

Q22. WHAT ARE THE NET SALVAGE FACTORS THAT ARE INCLUDED IN THE DETERMINATION OF DEPRECIATION RATES?

A22. Net salvage is the difference between gross salvage, or what is received when an asset is disposed of, and the cost of removing it from service. Net salvage is said to be positive if gross salvage exceeds the cost of removal, but if cost of removal exceeds gross salvage the result is then negative salvage. Many retired assets generate little, if any positive salvage. Conversely, numerous of the Company's asset groups generate negative net salvage at end of their life from the cost of removal.

The cost of removal includes such costs as demolishing, dismantling, tearing down, disconnecting or otherwise retiring/removing plant, as well as any environmental clean up costs associated with the property. Salvage includes proceeds received for any sale of plant.

Net salvage experience is studied for a period of years to determine the trends which have occurred in the past. These trends are considered together with any changes that are anticipated in the future to determine the future net salvage factor for remaining life depreciation purposes. The net salvage percentage is determined by relating the total net positive or negative salvage to the book cost of the property investment retired.

The method used to estimate the retirement cost is a standard analysis approach which is used to identify a company's historical experience with regard to what the end of life cost will be relative to the cost of the plant when first placed into service. This information, along with knowledge about the average age of the historical retirements that have occurred to date, enables the depreciation professional to estimate the level of retirement cost that will be experienced by the Company at the end of each property group's useful life. The study methodology utilized has been extensively set forth in depreciation textbooks and has been the accepted practice by depreciation professionals for many decades. Furthermore, the cost of removal analysis approach is the current standard practice used for mass assets by essentially all depreciation professionals in estimating future net salvage for the purpose of identifying the applicable depreciation for a property group. There is a direct relationship to the installation of specific plant in service and its corresponding removal in that the installation is its beginning of life cost while the removal is its end of life cost. Also, it is important to note that average remaining life based depreciation rates incorporate future net salvage which is routinely more representative of recent versus long-term past average net salvage.

The Company's historical net salvage experience was analyzed to identify the historical net salvage factor for each applicable property group. This analysis routinely identifies that historical retirements have occurred at average ages significantly prior to the property group's average service life. This occurrence of historical retirements, at an age which is significantly younger than the average service life of the property category, clearly demonstrates that the historical data does not appropriately recognize the true level of retirement cost at the end of the property's useful life. An additional level of cost to retire will occur due to the passage of time until all the current in service plant is retired at end of life. That is, the level of retirement costs will increase over time until the average service life is attained. The estimated additional inflation, within the estimate of retirement cost, is related to those additional year's cost increases (primarily higher labor costs over time) that will occur prior to the end of the property group's average life.

To provide an additional explanation of the issue, several general principles surrounding property retirements and related net salvage need to be highlighted. Those are that as property continues to age, the retirement of assets, if generating positive salvage when retired, will typically generate a lower percent of positive salvage. By comparison, if the class of property is one that typically generates negative net salvage (cost of removal), with increasing age at retirement the negative percentage as related to original cost will typically be greater. This situation is routinely driven by the higher labor cost with the passage of time.

Next, a simple example will aid in a better understanding of the above discussed net salvage analysis and the required adjustment to the historical analysis results. Assume the following scenario. A company has two (2) cars, Car #1 and Car #2, each purchased for $20,000. Car #1 is retired after 2 years and Car #2, is retired after 10 years. Accordingly, the average life of the two cars is six (6) years (2 Yrs. Plus

10 Yrs./2). Car #1 generates 75% salvage or $15,000 when retired and Car #2 generates 5% salvage or $1,000 when retired.

Unit	Cost	Ret. Age (Yrs)	% Salv.	Salvage Amount
Car #1	$20,000	2	75%	$15,000
Car #2	20,000	10	5%	1,000
Total	40,000	6	40%	16,000

Assume an analysis of the experienced net salvage at year three (3). Based upon the Car #1 retirement, which was retired at a young age (2 Yrs.) as compared to the average six (6) year life of the property group, the analysis indicates that the property group would generate 75% salvage. This analysis indication is incorrect and is the result of basing the estimate on incomplete data. That is, the estimate is based upon the salvage generated from a retirement that occurred at an average age which is far less than the average service life of the property group. The actual total net salvage, that occurred over the average life of the assets (which experienced a six (6) year average life for the property group) is 40% as opposed to the initial incorrect estimate of 75%.

This is exactly the situation with the majority of the Company's historical net salvage data except that most of the Company's plant property groups routinely experience negative net salvage (cost of removal) as opposed to positive salvage.

Q23. **PLEASE EXPLAIN WHAT FACTORS AFFECT THE LENGTH OF THE AVERAGE SERVICE LIFE THAT THE COMPANY'S PROPERTY MAY ACHIEVE.**

A23. Several factors contribute to the length of time or average service life which the property achieves. The three major categories under which these factors fall are: (1) physical; (2) functional; and, (3) contingent casualties.

The physical category includes such things as deterioration, wear and tear and the action of the natural elements. The functional category includes inadequacy, obsolescence and requirements of governmental authorities. Obsolescence occurs when it is no longer economically feasible to use the property to provide service to customers or when technological advances have provided a substitute of superior performance. The remaining factor of contingent casualties relates to retirements caused by accidental damage or construction activity of one type or another.

In performing the life analysis for any property being studied, both past experience and future expectations must be considered in order to fully evaluate the circumstances that may have a bearing on the remaining life of the property. This ensures the selection of an average service life which best represents the expected life of each property investment.

Q24. WHAT STUDY PROCEDURES WERE UTILIZED TO DETERMINE DEPRECIATION RATES FOR THE COMPANY'S PROPERTY?

A24. Several study procedures were used to determine the prospective service lives recommended for the Company's plant in service. These include the review and analysis of historical, as well as anticipated retirements, current and future construction technology, historical experience and future expectations of salvage and cost of removal as related to plant investment.

Service lives are affected by many different factors, some of which can be obtained from studying past experience, others of which may rely heavily on future expectations. When physical aspects are the controlling factor in determining the service life of property, historical experience is a useful tool in selecting service lives. In cases where there are changes in technology, regulatory requirements, Company policy or a less costly alternative develops, historical experience is of lesser or little value. However, even when considering physical factors, the future lives of various properties may vary from that experienced in the recent past.

While various methods are available to study historical data, the two (2) most commonly used methods utilized to determine average service lives for a Company's property are the Retirement Rate Method and the Simulated Plant Record Method. Given that the Company maintains vintaged investment records, for the majority of its plant accounts, the Retirement Rate Method was the method utilized to analyze those historical data. For the remaining property groups for which aged retirement data was not available, the Simulated Plant Record Method was utilized for life analysis.

Q25. PLEASE EXPLAIN THE USE OF THE RETIREMENT RATE METHOD.

A25. In this method of analysis, the Company's actuarial service life data, which is identified by age, is used to develop a survivor curve (observed life table). This survivor curve is the basis upon which smooth curves are fitted to subsequently determine the average service life being experienced by the account under study. Computer processing provides the opportunity to review various experience bands throughout the life of the account to observe trends and changes. For each experience band analysis, an "observed life table" is constructed using the exposure and retirement experience within the selected band of years. In some cases, the total life cycle of the property has not been achieved and the experienced life table, when plotted, results in a "stub curve." It is this "stub curve" or total life curve, if achieved, which is matched or fitted to the standard Iowa curves. The matching process is performed both by computer analysis, using a least squares technique, and by plotting the observed life tables to the selected smooth curves for visual reference. The fitted smooth curve is a benchmark which provides a basis to determine the estimated average service life for the property group under study.

Q26. DOES SECTION 5 OF THE DEPRECIATION STUDIES CONTAIN ANY CHARTS, ETC. WHICH COMPARE THE ANALYSIS OF THE COMPANY'S ACTUAL HISTORICAL DATA TO THE SERVICE LIFE PARAMETERS YOU ARE PROPOSING AS A BASIS FOR YOUR RECOMMENDED ANNUAL DEPRECIATION RATES?

A26. For the majority of the Company's plant account the Company's records included vintaged retirement data and were studied via the Retirement Rate Method. The resulting observed life tables and plottings of the selected Iowa curves are contained in the depreciation study reports included in Section 5 of Appendix C, D, and E. Likewise, the accounts for which the Simulated Plant Record Method was used, for analysis, and plottings of the actual versus simulated balances, are contained in Section 5.

Q27. IN DESCRIBING THE RETIREMENT RATE METHOD, YOU REFERRED TO THE USE OF THE IOWA OR SMOOTH SURVIVOR CURVES. COULD YOU GENERALLY DESCRIBE THE CURVES AND THE PURPOSE FOR THEIR USE?

A27. The preparation of a depreciation study or theoretical depreciation reserve typically incorporates smooth curves to represent the experienced or estimated survival characteristics of the property. The "smoothed" or standard survivor curves generally used are the "Iowa" family of curves developed at Iowa State University which are widely used and accepted throughout the utility industry. The shape of the curves within the Iowa family are dependent upon whether the maximum rate of retirement occurs before, during or after the average service life. If the maximum retirement rate occurs earlier in life, it is a left (L) mode curve; if occurring at average life, it is a symmetrical (S) mode curve; if it occurs after average life, it is a right (R) mode curve. In addition, there is the origin (O) mode curve for plant which has heavy retirements at the beginning of life.

Many times, actual Company plant has not completed its life cycle; therefore, the survivor table generated from the Company is not complete. This situation requires an estimate be made with regard to the incomplete segment of the property group's life experience. Further, actual Company experience often varies, making its utilization for average service estimation difficult. Accordingly, the Iowa curves are used to both extend Company experience to zero percent surviving as well as to smooth actual Company data.

Q28. WHAT IS THE PRINCIPAL REASON FOR COMPLETING THE DETAILED HISTORIC LIFE AND SALVAGE ANALYSIS?

A28. The detailed historical analysis is prepared and used as a tool from which to make informed assessments as to the appropriate service life and salvage parameters over which to recover the Company's investment. In addition to the available historic data, consideration must be given to current events, the Company's ongoing operations, management's future plans, and general industry events which are anticipated to impact the life to be achieved by the plant in service.

Q29. WHAT IS THE BASIS OF THE COMPANY'S CURRENT DEPRECIATION?

A29. The depreciation rates are based upon depreciation parameters set forth in a study completed using investment data through December 31, 1999 for Louisville Gas and Electric together with the Broad Group Procedure applied on an Average Remaining Life basis. The current account level depreciation rates for Louisville Gas and Electric - Electric Division, Gas Division, and Common Plant composite to an equivalent annual depreciation rate of 2.96%, 2.80%, and 2.86% percent, respectively, when applied to each of the December 31, 2002 account balances.

Q30. WHAT ARE THE MOST NOTABLE CHANGES IN ANNUAL DEPRECIATION RATES AND EXPENSE BETWEEN THE PRESENT AND PROPOSED DEPRECIATION AS PER SECTION 2 OF THE DEPRECIATION REPORT (APPENDIX C)?

A30. With regard to Louisville Gas and Electric - Electric Division's plant in service (Appendix C) several of the accounts did reflect marked changes (as outlined in

Section 4 of this report) from the previously utilized depreciation rates. Those accounts for which the most notable depreciation expense changes occurred in comparison to the present depreciation rates include Account 311 - Structures and Improvements, Account 312 - Boiler Plant Equipment, Account 314 - Turbogenerator Units, Account 344 - Generators, Account 353.10 - Station Equipment, Account 364 - Poles, Towers & Fixtures, and Account 365 - Overhead Conductors and Devices.

The proposed depreciation rate for Account 312 - Boiler Plant Equipment, increased from 3.07 percent to 3.73 percent. Similar to Kentucky Utilities generating facilities, the basic factors influencing the proposed annual depreciation rate for this, and several other generating accounts is the developed interim retirement rate, the probable retirement years, the estimated interim and terminal net salvage factors, the mandated pollution control (NOX Projects) cost and the current level of accrued depreciation reserve. The interim retirement rates were developed based upon a detailed analysis of the historically experienced retirements, and are designed to recognize the level of interim retirements that are anticipated to occur from the study date until the probable retirement date of each facility. The estimated terminal/probable retirement years for each of the Company's operating units were developed by the Company's engineering staff after considering all factors affecting the current and prospective operation of the facilities as well as full production requirements. The probable retirement data for each of the facilities, while having been modified to reflect the latest available data, are generally consistent with those underlying the Company's current depreciation rates.

The interim net salvage was based upon an analysis of the Company's historical experience, while the terminal net salvage is based upon detailed calculations using underlying information obtained from the Company's experience in decommissioning KU's Pineville plant which was retired in place. Likewise, it is the Company's expressed intent to continually retire its other existing generating facilities in place, as it has done in the past. By comparison, based upon information obtained from decommissioning cost data relative to totally dismantling plants, the Company's historical experience and future estimates are very modest. The detailed account level decommissioning study cost was used to distribute the Company's experienced cost relative to Steam Production facilities to the individual FERC account level.

Like Kentucky Utilities, the incorporation of the mandated pollution control (NOX Projects) cost for LG&E - Electric Division is consistent with the inclusion of prior cost estimates into the present depreciation rates. These projects and the related costs are federally mandated and beyond the Company's managerial control. Finally, the current level of accrued depreciation directly impacts the prospective recovery levels given that the current unrecovered costs need to be rateably recovered over the average remaining life of each of the operating plants.

The depreciation rate for Account 344 - Generators, increased from 2.59 percent to 3.84 percent. The drivers for the depreciation rate change for this account are consistent with those described above for Account 312 - Boiler Plant Equipment, with the exception that the resulting depreciation rates were not impacted by future NOX related expenditures.

The depreciation rate for Account 364 - Poles, Towers & Fixtures increased from 3.55 percent to 3.92 percent. The proposed depreciation rate is the product of the application of the estimated applicable service life (which was revised from forty (40) years to forty-five (45) years) and the estimated future net salvage (which was revised from negative forty-five (45) to negative seventy-five (75) percent).

The depreciation rate for Account 365 - Overhead Conductors and Devices increased from 3.82 percent to 4.29 percent. The depreciation rate increase is being driven by an increase of the underlying negative net salvage parameters from negative twenty-five (25) to negative fifty (50) percent. Conversely, however, the underlying average service life was increased from thirty-two (32) to thirty-five (35) years. The estimated service life parameters and net salvage for the proposed depreciation rate are more representative of that currently being experienced by the property group.

Conversely, several of the property groups experienced depreciation rate decreases from the current levels.

The composite depreciation rate for Account 311 - Structures and Improvements declined from 2.56 percent to 2.21 percent, and Account 314 - Turbogenerator Units declined from 2.64 percent to 2.46 percent. The decrease of the depreciation rate for these property groups is a composite of applying the applicable life span and net salvage parameters as compared to those underlying the present depreciation rates. The decrease is consistent with the changes occurring within Account 312, except that the resulting rates are not impacted by the NOX expenditures.

The depreciation rate relative to Account 353.10 - Station Equipment declined from 2.10 percent to 1.85 percent. This depreciation expense reduction is the product of incorporating the estimated average service life (increased from forty-four (44) to fifty (50) years) and net salvage factors (increased from zero (0) percent to negative ten (10) percent) identified through an in depth analysis of the Company's historical experience and future expectations.

Q31. WHAT ARE THE MOST NOTABLE CHANGES IN ANNUAL DEPRECIATION RATES AND EXPENSE BETWEEN THE PRESENT AND PROPOSED DEPRECIATION AS PER SECTION 2 THE DEPRECIATION REPORT (APPENDIX D)?

A31. With regard to Louisville Gas and Electric - Gas Division's plant in service (Appendix D) several of the accounts did reflect marked changes (as outlined in Section 4 of this report) from the previously utilized depreciation rates. Those accounts for which the most notable depreciation expense changes occurred in comparison to the present depreciation rates include Account 376 - Mains, Account 380 - Services, and Account 381 - Meters.

The proposed depreciation rate for Account 376 - Mains increased from 2.23 percent to 2.54 percent. The proposed depreciation rate is the product of the application of the estimated future net salvage (which was revised from negative twenty (20) to negative thirty-five (35) percent), plus the fact that the current book depreciation reserve is lower than required when considering the current estimated depreciation parameters.

The depreciation rate for Account 380 - Services increased from 4.25 percent to 4.62 percent. The depreciation rate increase is being driven by a reduction in the underlying service life parameters from forty-two (42) years to thirty-five (35) years. Conversely, the negative net salvage factor declined from negative seventy-five (75) to negative fifty-five (55) percent The estimated service life and salvage parameters for the proposed depreciation rate are more representative of those currently being experienced by the property group.

The depreciation rate for Account 381 - Meters increased from 3.11 percent to 3.69 percent. The proposed depreciation rate is the product of the application of the estimated applicable service life (which was revised from thirty-five (35) years to thirty-one (31) years) and conversely, the estimated future negative net salvage (which was reduced from negative five (5) to zero (0) percent).

Q32. WHAT ARE THE MOST NOTABLE CHANGES IN ANNUAL DEPRECIATION RATES AND EXPENSE BETWEEN THE PRESENT AND PROPOSED DEPRECIATION AS PER SECTION 2 THE DEPRECIATION REPORT (APPENDIX E)?

A32. With regard to Louisville Gas and Electric - Common Plant's plant in service (Appendix E) several of the accounts did reflect marked changes (as outlined in Section 4 of this report) from the previously utilized depreciation rates. Those accounts for which the most notable depreciation expense changes occurred in comparison to the present depreciation rates include Account 390.10 - Structures & Improvements-GO, Account 397.00 - Communication, and Account 397.10 - Communication Equipment-

Computer. The proposed depreciation rate for Account 390.10 - Structures & Improvements increased from 2.18 percent to 3.10 percent. The proposed depreciation rate is the product of the application of the estimated life spans and interim retirement rate to each of the property locations along with the anticipated level of future net salvage.

The depreciation rate for Account 397.00 - Communication Equipment increased from 3.72 percent to 6.56 percent. The depreciation rate increase is being driven by a reduction in the underlying service life parameters from twenty-five (25) years to fifteen (15) years to reflect ongoing technologically changes. Communication Equipment is a property group which has been and will continue to be impacted by rapid technological change.

The depreciation rate for Account 397.10 - Communication Equipment-Computer increased from 3.74 percent to 10.12 percent. The proposed depreciation rate is the product of the application of the estimated applicable service life (which was revised from twenty-five (25) years to ten (10) years) which is more reflective of the assets contained within this property group.

Q33. WHAT IS THE NET CHANGE IN ANNUAL DEPRECIATION EXPENSE UNDER THE PROPOSED RATES AS APPOSED TO PRESENT DEPRECIATION RATES?

A33. The change in annual depreciation rates results in a net increase in annualized depreciation expense for Louisville Gas and Electric - Electric Division's plant in service of $8,681,141, (Table1, Section 2, page 2-2 of Appendix C), for Louisville Gas and Electric - Gas Division's plant in service of $812,832 (Table1, Section 2, page 2-1 of Appendix D), and for Louisville Gas and Electric - Common Plant's plant in service of $1,428,511 (Table 1, Section 2, Page 2-1 of Appendix E) in comparison to the depreciation amount produced by the current depreciation rates when applied to the Company's plant in service investment as of December 31, 2002.

Q34. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A34. It is my recommendation that the proposed depreciation rates set forth in my depreciation studies (Appendix C, D, and E) should be uniformly and prospectively adopted by this Commission for regulatory purposes as well as by the Company for accounting purposes.

Q35. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A35. Yes, it does.

293272.04

VERIFICATION

STATE OF Pennsylvania)
) **SS:**
COUNTY OF Cumberland)

The undersigned, **Earl M. Robinson**, being duly sworn, deposes and says he is President and Chief Executive Officer of AUS Consultants – Weber Fick & Wilson Division, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Earl M Robinson

EARL M. ROBINSON

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Susan M. Danner (SEAL)
Notary Public

My Commission Expires:

NOV. 28, 2005

Notarial Seal
Susan M. Danner, Notary Public
Wormleysburg Boro, Cumberland County
My Commission Expires Nov. 28, 2005

Mr. Rosenberg

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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

TESTIMONY

OF

ROBERT G. ROSENBERG
EDGEWOOD CONSULTING, INC.

December 29, 2003

Filed: December 29, 2003

INDEX

I. INTRODUCTION

Q. Will you give your name, business address and occupation?

A. My name is Robert G. Rosenberg. My business address is 541 Bear Ladder Road, West Fulton, New York. I am an economist and principal of the firm of Edgewood Consulting, Inc. My qualifications are described in Appendix A to this testimony.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to determine the cost of equity capital for the electric and gas operations of Louisville Gas and Electric Company (hereinafter referred to as LG&E or the Company).

Q. Have you prepared an exhibit in conjunction with your testimony?

A. Yes. In support of my testimony, I have prepared RGR Exhibit 1, consisting of 6 Schedules.

Q. Were these schedules prepared by you or under your supervision?

A. Yes, they were.

II. EXECUTIVE SUMMARY

Q. What conclusions have you reached?

A. Based on the discussion and analyses presented in my testimony, I determine the cost of equity for the Company's electric operations to be in the 10.75-11.25 percent range and recommend 11.25 percent—the upper end of the range—as the return that should be allowed in this proceeding. I determine the cost of equity for the Company's gas operations to be in the 11.0-11.5 percent range and recommend 11.5 percent—the upper end of the range—as the return that should be allowed in this proceeding.

Q. Would you provide a summary of your testimony?

A. I first review the current economic and financial climate facing utilities—one where bond downratings far outnumber upratings and where the regulatory commitment to allowing adequate returns is being questioned. I then discuss how the assessment of utility risk and potential performance is in flux currently. This can lead to larger measurement error in estimating the cost of equity than when utilities were facing a more status quo situation. In part because of this consideration, I employ four separate approaches to estimate the cost of equity including: (1) a discounted cash flow (DCF) analysis; (2) a capital asset pricing model (CAPM); (3) two risk premium analyses; and (4) a comparable earnings analysis. I perform separate analyses to determine the cost of equity of LG&E's electric operations and LG&E's gas operations, using similar methodologies in both instances.

Summary of Cost of Equity Analyses for LG&E's Electric Operations

Since LG&E is not, itself, publicly traded, I employ a proxy group of electric utility companies similar in risk to LG&E's electric operations in my cost of equity analyses.

Turning first to the DCF approach, to recognize some of the more complex growth expectations which investors may possess today, I employ two-stage DCF analyses which produce a 10.00-10.75 percent cost of equity estimate for my comparison companies.

I perform CAPM calculations using two formulations of the CAPM method and two different estimates of the expected market risk premium. Employing historic data from Ibbotson Associates to estimate the expected market risk premium, I obtain CAPM cost of equity estimates in the range of 9.6-10.2 percent. Employing data for the S&P 500 to estimate the market risk premium, the CAPM cost of equity estimate is in the range of 11.3-12.2 percent. Research cited by the Ibbotson publication suggests that smaller companies, including many utilities, require higher returns than indicated by the basic CAPM formulation. To account for this phenomenon, I add a size premium of 60 basis points to the CAPM results reported above. Based on these analyses, I employed a CAPM cost of equity range of 10.75-11.50 percent in my further calculations.

I also perform two risk premium analyses directly on electric utilities. The first analysis uses the historic spread between Moody's electric utility common stock returns and utility bond yields. I obtain a cost of equity estimate of 10.8 percent using this approach. The second risk premium analysis measures the risk premium implied by allowed returns on equity since 1980. I perform a regression analysis wherein I calculate the risk premium as a function of the (lagged) level of interest rates. Under this approach I obtain a 10.9 percent cost of equity estimate.

My fourth calculation is a comparable earnings analysis. The Hope and Bluefield decisions stated, in part, that a fair rate of return to a regulated company is one that is equal to that earned in enterprises of similar risk. I gather a sample of companies of similar risk (i.e., a Safety Rank of 2) and find that recent historic and projected returns for these companies are in the 14.0-14.5 percent range.

Based on the above-described analyses, the cost of equity of the electric proxy group of companies is in the range of 10.75-11.25 percent. Given the difficulty of determining the cost of equity capital with exact precision, analysts and regulatory commissions often estimate a "range of reasonableness" for the return on equity and then use qualitative factors and judgment to determine where within this range a particular allowed return should be set. I recommend that the electric operations of LG&E be allowed a return of 11.25 percent—at the upper end of the 10.75-11.25 percent cost of equity range I have determined—to recognize LG&E's efficient operations and the current uncertain business climate for utilities.

Summary of Cost of Equity Analyses for LG&E's Gas Operations

Since LG&E is not, itself, publicly traded, I employ a proxy group of gas distribution comparison companies similar in risk to LG&E's gas operations in my cost of equity analyses.

Turning first to the DCF approach, I employ two-stage DCF analyses which produce a 10.90-11.25 percent cost of equity estimate for my comparison companies.

I perform CAPM calculations using two formulations of the CAPM method and two different estimates of the expected market risk premium. Employing historic data from Ibbotson Associates to estimate the expected market risk premium, I obtain CAPM cost of equity estimates in the range of 9.8-10.3 percent. Employing data for the S&P 500 to estimate the market risk premium, the CAPM cost of equity estimate is in the range of 11.6-12.4 percent. Research cited by the Ibbotson publication suggests that smaller companies, including many utilities, require higher returns than indicated by the basic CAPM formulation. To account for this phenomenon, I add a size premium of 90 basis points to the CAPM results reported above. Based on these analyses, I employed a CAPM cost of equity range of 11.00-11.75 percent in my further calculations.

I also perform two risk premium analyses directly on gas utilities. The first analysis uses the historic spread between Moody's gas utility common stock returns and utility bond yields. I obtain a cost of equity estimate of 10.50 percent using this approach. The second risk premium analysis measures the risk premium implied by gas distribution company allowed returns on equity since 1980. I perform a regression analysis wherein I calculate the risk premium as a function of the (lagged) level of interest rates. Under this approach I obtain a 10.75 percent cost of equity estimate.

My fourth calculation is a comparable earnings analysis. The Hope and Bluefield decisions stated, in part, that a fair rate of return to a regulated company is one that is equal to that earned in enterprises of similar risk. I gather a sample of companies of similar risk (i.e., a Safety Rank of 2) and find that recent historic and projected returns for these companies are in the 14.0-14.5 percent range.

Based on the above-described analyses, the cost of equity of the gas proxy group of companies is in the range of 11.0-11.5 percent. I recommend that the gas operations of LG&E be allowed a return of 11.5 percent—at the upper end of the 11.0-11.5 percent range—to recognize LG&E's efficient operations and the current uncertain business climate for utilities.

III. THE RATE OF RETURN IN CONTEXT

Q. Would you briefly discuss the importance of the level of rate of return in the current economic and financial climate?

A. The financial community has put the utility industry under more intense scrutiny of late. Utility bond downratings have far outnumbered bond upratings. S&P reported that for the year-to-date 2003, there had been 41 utility issuer credit rating downgrades compared with 8 upgrades (Standard & Poor's *Ratings Trends*, October 20, 2003). Similarly, for the twelve months ended June 31, 2003, Moody's had downgraded about one-third of the utilities it follows—significantly higher than the approximate 10 percent annual average downgrade rate for utilities over the past nineteen years (Moody's *Rating Actions and Reviews*, July 2003, p. 3). Clearly the bond rating agencies have become less tolerant of financial weakness in utility companies. Furthermore, the cost of financial weakness to companies has increased recently, given the widening spreads in bond yields between stronger and weaker entities.

The heightened negative attention given to utilities, along with substantial bond downratings, have made utility financing problematic in some instances. Standard & Poor's in its February 12, 2003 *CreditWeek* article entitled "U.S. Power Industry Experiences Precipitous Credit Decline in 2002; Negative Slope Likely to Continue" indicated that deterioration of creditworthiness in the industry could be traced, in part, to:

> Increasingly constrained capital market access as a result of investor skepticism over accounting practices and disclosure, more and more federal and state investigations and subpoenas, audits, and failing

> confidence in future financial performance that has created a liquidity crisis.

FERC Commissioner William Massey in a March 17, 2003 speech entitled "Current Issues 2003" echoed a similar theme:

> Sadly, the tsunami of the western energy crisis, coupled with the collapse of Enron, have left a devastating wake within the industry. Investor confidence has been shaken by these events, by a declining national economy, indictments of energy traders, accounting irregularities, downgrades by rating agencies, and continuing investigations by the FERC, CFTC, the SEC and the Justice Department. [These investigations] do have an impact on investor confidence and credit availability.... Many sources of funds have dried up, yet energy companies have billions in debt to refinance over the next two years.

Rate of return on equity plays a significant part in how the financial community regards a particular utility company. Standard & Poor's in its May 24, 2002 publication *Regulatory Support For U.S. Electric Utility Credit Continues To Disappoint*, indicated that:

> Standard & Poor's views the future rating trend of the electric industry to be decidedly negative, with insufficient regulated authorized returns and expanding nonregulated investments providing the most downward pressure.

Standard & Poor's in its *Corporate Ratings Criteria*, page 23, also stressed the importance of the level of return on capital:

> Profit potential is a critical determinant of credit protection. A company that generates higher operating margins and returns on capital has a greater ability to generate equity capital internally, attract capital externally, and withstand business adversity. Earnings power ultimately attests to the value of the firm's assets as well.

S&P in "Regulation and Credit Quality in the U.S. Utility Sector," February 19, 2003, noted that:

> A Standard & Poor's-sponsored survey of regulatory commissioners throughout the U.S. a year ago indicated that credit quality ranked low on their list of priorities.... Notably, commission attention to having a strong and financially vibrant utility has waned in recent years. Certainly, commissions still want their utilities rated highly, but will they provide the returns necessary to that end? It will be interesting to see what type of working relationship electric companies and regulators form going forward.

Standard & Poor's also indicated in its November 18, 2002 report entitled *Constructive Regulation for U.S. Utilities is More Important Than Ever* that:

> ...regulation in general will once again play the pivotal, if not far and away the most pivotal, role in determining credit quality in the utility sector.

Thus, the level of a utility's allowed rate of return cannot be regarded in isolation, but instead is a key ingredient in overall financial integrity.

IV. RATIONALE FOR USING SEVERAL EQUITY COSTING METHODOLOGIES

Q. Do you believe it is reasonable to employ several approaches for estimating the cost of equity?

A. Yes. The cost of equity is not directly observable in the marketplace. Therefore, to estimate the cost of equity, one must take cognizance of financial theory, the legal and regulatory framework for ratemaking and investor perceptions and judgments. There is no one approach that is now recognized, or should be recognized, as the way to determine the cost of equity. Moreover, I believe that currently there is the potential for more error of estimation than normal in determining the cost of equity of a utility.

Q. Why do you believe that presently there is a potential for large measurement error associated in determining the cost of equity for utilities?

A. While it was always good financial practice to employ several methods to estimate the cost of equity in order to reduce measurement error associated with any particular methodology, that notion has special relevance today. The assessment of utility risk and potential performance is in flux currently due to the uncertainties associated with regulatory restructuring, competitive developments and consolidation in the industry. *The Value Line Investment Survey* of July 6, 2001 stated regarding the electric utility industry that:

> The industry is in a state of flux and will probably remain so for some time to come.

Value Line of April 4, 2003 continued the same theme by stating:

> The industry is still in a state of flux.

The Standard & Poor's *Electric Utility Industry Survey* of August 8, 2002 indicated that:

> We expect the performance of both the electric utility sector and the individual companies within the sector to remain volatile over the next several years.

The S&P *Electric Utility Industry Survey* of February 20, 2003 stated:

> Utility stocks often benefit the most (as in 2000) when the broader market is in a state of decline and investors look for a "safe haven" for their investments. However, this haven is not as safe as it once was: utility stocks have become much more volatile in recent years, sometimes experiencing sharp swings—often in the opposite direction of the broader market—within a short period of time.

The gas distribution industry is also in a state of flux. *The Value Line Investment Survey*, in its December 21, 2001 writeup of the gas distribution industry stated that:

> It is important to consider, however, that the entire energy industry, spurred by deregulation, is undergoing rapid change.

Standard & Poor's, at page 3 of its November 29, 2001 *Natural Gas Distribution Industry Survey*, stated that:

> ...the natural gas industry is still in the midst of a significant transition. The change involves not only consolidation within the industry, but even more significantly, the ongoing convergence of the natural gas business and an equally transformed electric utility industry.

S&P indicated on page 7 of the same publication that:

> The natural gas industry has undergone substantial change over the past decade. Gas utilities, which were once tightly regulated monopolies, have slowly been opening to regional competition. As state and federal public utility commissions continue to restructure the regulatory environment, the natural gas distribution industry is likely to be further transformed over the next several years.

Standard & Poor's, at page 9 of its May 15, 2003 *Natural Gas Distribution Industry Survey*, noted that with:

> ...supply and demand now in a tight balance, natural gas prices are becoming much more volatile. This phenomenon has complicated the short-term operations and long-term investment planning for the entire industry, including regulated local distribution companies (LDCs).

S&P stated at page 14 of that publication that the standard deviation of average natural gas prices for the period since January 2000 is three times the level experienced in the prior six years. S&P, at page 9 of the same publication, indicated that:

> Following the deterioration of energy merchants and their unregulated power operations, rating agencies and investors have demanded that energy companies maintain higher levels of equity funding and short term liquidity, further complicating the operating environment within the natural gas industry. Even utility LDCs have to rethink their capitalization structures....

Therefore, when we attempt to estimate the cost of equity for a particular utility, this uncertainty is likely to lead to more estimation error than under circumstances where that company's more easily forecasted fundamentals are the prime determinant of its stock prices and where that company's risk seems clearly delineated to investors.

Q. What conclusion do you reach from the above discussion?

A. As I indicated above, in part because I believe that there is more error of estimation than normal in determining the cost of equity of a utility, I will employ several different analyses in this proceeding. Such an approach leads to a broader-based set of estimates and will prevent any spurious results from biasing the cost of equity determination.

Q. What methods do you use in this proceeding to estimate the cost of common equity capital?

A. I will employ four separate approaches including: (1) a discounted cash flow (DCF) analysis; (2) a capital asset pricing model (CAPM) analysis; (3) two risk premium analyses; and (4) a comparable earnings analysis.

V. ESTIMATION OF THE COST OF EQUITY OF LG&E'S ELECTRIC OPERATIONS

A. Use of Comparison Companies to Determine the Cost of Equity of LG&E's Electric Operations

Q. Why do you use comparison companies to estimate the cost of equity of LG&E's electric operations in this proceeding?

A. Louisville Gas and Electric Company is a subsidiary of LG&E Energy and therefore is not, itself, publicly traded. LG&E Energy is a subsidiary of E.ON AG. E.ON is not covered by *The Value Line Investment Survey*—an important source of data that I employ in my equity costing analyses. Because of these considerations, it is my judgment that it is appropriate to use a proxy—a group of comparison companies—to obtain an estimate of the cost of equity of LG&E.

Q. Would you indicate how you selected the group of proxy companies upon which you conducted your cost of equity analysis?

A. I started by considering companies that were listed in *The Value Line Investment Survey*'s Electric Utility category and applied several further selection criteria to these companies. The comparison company utility subsidiaries had to have an overall senior bond rating of Aa/A from Moody's and AA/A from Standard & Poor's. In past testimonies, I have used an A/A bond rating as one of the criteria to select proxy groups. However, given the consolidation of the industry through mergers and the increase in unregulated activities, there are fewer candidate companies than formerly that can be included in the proxy group. To expand possible candidates for the proxy group, I have, in addition to the A/A bond rating criterion, also considered companies with an Aa/AA bond rating for inclusion in the proxy group. Currently, LG&E has a senior debt bond rating of A1/A-. Since Aa/AA companies are, if anything, less risky than LG&E as indicated by the bond rating, this expansion of the bond rating selection criterion is conservative. The median senior bond rating of the group that I have selected is A1/A-. Thus, the risk of the comparison companies, as indicated by bond rating, is comparable to LG&E.

Companies were excluded from the proxy group if they are currently involved in any major merger activity. Removing companies with merger activity from the cost of equity calculation eliminates companies whose prices and evaluations may be based on short-term merger-related considerations, rather than the long-term prospects of the company. As I explain in more detail in the discussion of the DCF methodology, merger activity has the potential for biasing the DCF result in a potentially significant manner. Companies were also excluded from the proxy group if they had significant unregulated operations. Since unregulated operations have the potential for being of different risk than regulated utility operations, this criterion insures that the companies in the proxy group have predominantly regulated utility operations. I also excluded companies not paying a dividend or for whom a dividend cut was forecast by Value Line.

The list of companies in the proxy group is shown on Schedule 1.

B. DCF Analysis

Q. Before proceeding with the presentation of the DCF analysis for estimating the cost of equity, would you please give a general description of the DCF method?

A. This method produces an estimate of the market-required return based upon investor evaluation of a company's earnings and dividends, as reflected by the prices that investors pay in the stock market. Basic DCF theory is predicated on the notion that the price that is paid for a company's stock in the market represents the sum of the present value of all future expected dividends. Algebraically, this can be written as:

$$(1) \qquad P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \frac{D_4}{(1+k)^4} + \cdots$$

where: P_0 = the recent price of the stock

D = the expected dividend for the period specified

k = the investors' discount rate, or required rate of return (expressed in decimal form, *e.g.*, 0.15)

The dots at the end of this formula indicate that the equation continues to infinity—in other words, the next two terms would be $D_5/(1+k)^5$ and $D_6/(1+k)^6$, and so on. The above formula indicates that investors establish the price they are willing to pay for a stock based upon the expected future stream of dividends, discounted back to the present time.

Q. Do you believe that there is the potential for large measurement error associated with the DCF at the present time?

A. Yes, I do. To apply the DCF method, needed elements include the price that investors are paying for a stock in the marketplace and a reliable estimate of the growth expectations that led investors to bid the observed price. If investors' growth expectations have been correctly estimated, then such estimate is congruent with the market price. If all the factors influencing the market price are not reflected in the growth estimate used by an analyst, then measurement error is introduced into the DCF analysis and the resulting cost of equity estimate will be biased.

As can be seen from the formulation presented above, in order to correctly assess investors' required return in a DCF context, one must ascertain the dividend stream that investors are expecting over the long run. Analysts typically do this in a framework of estimating constant expected growth (if the future is expected to be relatively stable) or multiple stages of growth (if there is an expectation that growth may change in the future). It is my opinion that the DCF method is more prone to measurement error currently due to a lack of congruence between the market price and the growth estimate employed due to a lessening of the clarity of investor growth expectations. Many companies in the industry are in flux currently, transitioning to a restructured environment where the final rules have not yet been established.

Typically, investment analysts provide 5-year growth projections for the companies they cover and investors often employ these projections as their expected growth in the future. However, given the changes occurring in the industry, it is my opinion that these 5-year projections may not be good proxies for the long-term expected growth for utilities at the current time. Many utilities have been assuming a more conservative payout policy either due to the need for more internally generated cash flow or to help deal with the higher risk of earnings fluctuations.

Some utility companies are engaged in repurchases of their common stock. This near-term phenomenon of stock buybacks creates a short-term demand for the stock which raises stock prices above what they would have been, absent the buyback plan.[1]

Investors are also aware that mergers have occurred in the utility industry and more are possible in the near future. The potential for additional mergers could influence investor expectations in several ways. Mergers have generally occurred at a premium above the pre-merger-announcement market price, leading to capital gains for investors. Investors may see mergers as a win-win situation—offering both rate reductions to ratepayers and enhanced return prospects for stockholders. To the extent that there is speculation about future merger activity among utilities, such influence would be reflected in the price, but not in the growth projections made by analysts. The effect on the DCF of such speculation would be to bias the

1 This is simply because, in a rising market, the fact that a company, itself, is buying back stock, merely adds to the buying pressure already in effect from a buoyant market. If investors think that stock prices might decline, the fact that the company is likely to be a large-scale buyer in a weak market would certainly provide investors with a cushion. Given both of these effects, stock buybacks would raise the price of a utility's stock above what it would be otherwise. Stock buyback plans often are implemented over a number of years. Thus any accretion in growth resulting from the buyback will be expected to be phased in gradually over time.

cost of equity estimate downward (due to the mismatch between the merger-speculation-inflated price and business-as-usual growth estimates).

The recent change in the level of income tax that investors must pay on dividends also complicates the DCF analysis currently. This tax change was enacted **during** the pricing period that I employ in my DCF analysis, specifically on May 28, 2003. While companies and investors base their payout policy and investment strategy, respectively, on long-term considerations, the dividend tax reduction has a sunset provision (i.e., unless specifically reauthorized, the dividend tax reduction will expire at the end of 2008). This serves to confound estimation of **long-term** growth expectations of investors.

Therefore, due to the complex set of phenomena currently affecting utility stock prices, it is my opinion that a DCF estimate will have the potential for more measurement error than DCF calculations performed in the past under more stable circumstances where investor expectations were determined with more certainty.

Q. Given the difficulties you outline above, how will you proceed with implementing the DCF approach for determining the cost of equity for the comparison companies?

A. The use of the constant-growth DCF formulation (D/P + g) for a regulated utility often may have been a reasonable assumption in the past when the financial and regulatory environment in which regulated utilities operated was more stable than currently. During that time, trends could reasonably be expected to continue and long-term future growth could be predicted with substantial accuracy. However, as established earlier in this testimony, the utility industry currently is in a state of flux. In light of this, I will employ a two-stage DCF approach to estimate the cost of equity of the comparison companies.

Q. How did you determine the appropriate pricing period for your DCF analysis?

A. The price component of the DCF analysis should reflect recent data over a representative period of time that is neither so short as to merely represent the "luck of the draw" nor so long as to encompass stale data. The pricing period should be long enough to smooth out the effects of any temporary market fluctuations. In the DCF analysis, I will employ a pricing period encompassing the six months ending September 2003.

On Schedule 2, I show the average prices for the comparison companies over the 6-month period ending September 2003. Each month's price was calculated by averaging the monthly high and low prices. The six-month average price is also shown in Column (1) of pages 1-3 of Schedule 3, which provides the inputs to the DCF calculation. The dividend level (*i.e.*, the dividends paid during my pricing period, annualized) for each of the comparison companies is shown in Column (2) of pages 1-3 of Schedule 3.

Q. How do you determine the expected growth component of the DCF model for the comparison companies?

A. As noted above, given the regulatory, competitive, risk, payout policy, and other changes noted above, it is difficult to ascertain, with great clarity, investor growth expectations at the current time. I will employ a two-stage growth formulation of the DCF method to estimate investors' future growth expectations. For the determination of near-term (*i.e.*, first-stage) growth, I rely on an average of earnings projections made by Value Line and First Call, a unit of Thomson Financial. These projections for the comparison companies and the average of the two are shown in Columns (3)-(5) of pages 1-3 of Schedule 3.

The estimation of second-stage, long-term growth is more problematic. I am not aware of any specific projections that are made by financial analysts for this timeframe. However, I will employ three proxies for investors' expected long-term growth.

First, I will employ the long-term projected nominal GDP (Gross Domestic Product) growth as a proxy for expected long-term second-stage growth for an individual company.[2] The Energy Information Administration (EIA) of the Department of Energy published the *Annual Energy Outlook 2003* which contains data that can be used to derive a long-term projection of growth in nominal GDP. Using data from that source, I have calculated projected growth in GDP for the period 2008-2025 to be 5.91 percent.

For the second proxy for investors' expected long-term growth, I employ projected sustainable growth, calculated using Value Line projections.[3] The

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2 In the absence of a clear picture of long-term future growth specific to electric utilities, investors might employ a generalized measure of economy-wide growth as a proxy for expected utility growth.

3 Sustainable growth is comprised of two factors—growth from the retention of earnings (i.e., internal growth) and growth from the sale of common stock (i.e., external growth). Internal growth can be calculated as the product of "b" (the expected retention ratio) and "r" (the expected return on equity). External growth can be calculated as the product of "s" (the growth in aggregate common equity due to the issuance of new common stock) and "v" (a function of the price-book ratio reflecting the fraction of funds obtained from the sale of common stock that accrues to the existing stockholders).

projected sustainable growth rates are shown in Column (6) on page 2 of Schedule 3.

For the third estimate of investors' expected long-term growth, I employ a projection of expected industry growth. Given the competitive and regulatory uncertainties facing utilities, discussed above, investors might look at projected industry growth as a proxy for projected long-term growth for individual companies. Zacks, Value Line, S&P and First Call project growth for the industry to be 4.5, 5.9, 5.7 and 5.0 percent, respectively. As a proxy for projected industry growth, I will use a figure of 5.3 percent.

Q. Would you review the components of the two-stage DCF analyses for the comparison companies?

A. The DCF analyses using GDP growth, sustainable growth and industry growth are shown on Schedule 3, pages 1, 2 and 3, respectively. Columns (1) and (2) of pages 1-3 of Schedule 3 show the 6-month average price and the dividend for the comparison companies. Columns (3)-(5) show the Value Line, First Call and average projected earnings growth rates. Column (6) of page 1 of Schedule 3 shows the long-term projected growth in GDP, which is assumed to occur after the first-stage growth period. Column (7) of page 1 of Schedule 3 shows the DCF cost of equity estimate for each company calculated by an iterative process employing the internal rate of return. (For calculational purposes, I continue the second-stage growth for 200 years because any growth after that point has a negligible effect on any present value or internal rate of return calculation.)

Page 2 of Schedule 3 shows the two-stage DCF analysis employing projected sustainable growth for the long-term expected growth rate. Columns (1)-(5) show the same inputs as on page 1 of Schedule 3. Column (6) of page 2 of Schedule 3 shows the projected sustainable growth, which I employ as the long-term projected growth assumed to occur after the first-stage growth period. Column (7) of page 2 Schedule 3 shows the DCF cost of equity estimate for each company.[4] Page 3 of Schedule 3 shows the two-stage DCF analysis employing projected industry growth for the long-term expected growth rate. Columns (1)-(5) show the same inputs as on pages 1 and 2 of Schedule 3. Column (6) of page 3 of Schedule 3 shows the projected industry growth, which I employ as the long-term projected growth assumed to occur after the first-stage growth period. Column (7) of page 3 of Schedule 3 shows the DCF cost of equity estimate for each company.

Q. What are the results of your DCF calculations?

A. Below, I show a table summarizing the results of the DCF calculations described above:

[4] Note that the cost of equity estimate for CH Energy is 6.8 percent which is only about at the level of utility bond yields. (CH Energy has been discussed in the financial press as a potential acquisition target and its stock price may well include an acquisition premium.) Since it is nearly universally agreed that the cost of equity does, and should, exceed the cost of debt, when a cost of equity estimate is only about at the level of bond yields, this is clearly an understated estimate and should be discarded. For example, FERC in Opinion No. 445 re Southern California Edison Company, July 26, 2000, 92 FERC ¶ 61,070, deleted a cost of equity estimate even somewhat above the concurrent bond yield. FERC indicated at page 27 of that Opinion that: "Because investors generally cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case." FERC excluded this low figure from its calculation of the cost of equity. I will exclude this CH Energy estimate from further consideration in my DCF analysis using sustainable growth.

Long-Term Growth Rate	Schedule Page	Range	Midpoint of Range	Median	Average
GDP	Sch. 3, p.1	9.1 - 11.5	10.3	10.8	10.6
Sustainable	Sch. 3, p.2	8.2 - 15.8	12.0	9.8	10.7
Industry Avg.	Sch. 3, p.3	8.6 - 11.0	9.8	10.3	10.1

Based on the results and analysis presented above, I will use a DCF range of 10.00-10.75 percent in my further discussion of the determination of the cost of equity. However, noting the possibility of measurement error and understatement associated with the application of the DCF method currently, it is my opinion that these results should be considered in conjunction with the results of the other methods that I employ.

C. <u>CAPM Analysis</u>

Q. What is the basis of the CAPM approach you will employ?

A. Assuming rationality on the part of investors, the greater the risk of an investment, the higher the return that investors will demand of that investment. The yield on risk-free assets such as U.S. Treasury securities is readily determinable in the marketplace. Given that fact, if we know the risk premium that investors require to invest in the stock of the comparison companies rather than a U.S. Treasury security, we can determine the required rate of return, or cost of common equity, for the comparison companies. In this section of my testimony, I will employ the capital asset pricing model (CAPM) method to calculate this risk premium and the cost of equity for the comparison companies.

Q. Would you briefly outline the theory underlying the CAPM method?

A. In recent developments in financial theory, the total risk (variance) of an asset has been partitioned into two components: unsystematic risk and systematic risk. Unsystematic risk represents risk (*i.e.*, fluctuations in returns) due to events specific to the particular company in question (*e.g.*, a long strike at the company's plants; the loss of a large government contract; the release of a highly profitable motion picture, etc.). Unsystematic risk is company-specific and is unrelated to changes in the economy as a whole. Systematic risk, on the other hand, represents the variability in the returns on an investment due to the effect on the firm of economy-wide forces. The level of a firm's systematic risk is determined by the firm's sensitivity to the totality of macroeconomic forces in the economy.

Modern financial theory calls for the evaluation of an asset, not in isolation, but in the context of a well-diversified portfolio. If enough stocks are held in a well-diversified portfolio, the firm-specific (unsystematic) risks of the individual firms will tend to cancel each other out. The theory is that if there are enough assets in the portfolio from diverse industries, some of the assets will experience higher than expected returns while other assets will experience lower than expected returns, but <u>the portfolio</u> as a whole will yield the average expected return. Thus, the exposure of an investor to the risk related to firm-specific events (unsystematic risk) can be eliminated by holding a well-diversified portfolio. Systematic risk, on the other hand, <u>cannot</u> be diversified away in a portfolio context.

Since unsystematic risk can be eliminated in a well-diversified portfolio, according to CAPM theory the investor need only concern himself with the degree of systematic risk possessed by an asset. Beta is a measure of the systematic risk of an asset. The level of beta of an asset indicates the risk contribution of that asset to the overall risk of a well-diversified portfolio. The higher the expected risk (*i.e.*, beta) of an investment in an individual asset, the higher the risk contribution of that asset to the risk of a portfolio and, thus, the higher will be the return which an investor would require to be willing to make such an investment.

The beta value of all assets, on average, is equal to 1.0. If a particular asset has a beta of 1.0, this means that the variability in its returns due to macroeconomic events will be equal to, and in phase with, the variability of returns in the economy as a whole. An asset with a beta of, say, .5 is only half as responsive to economy-wide events as the market index. When the market index goes up 10 percent, the price of this stock will only go up 5 percent. If the market index declines 30 percent, the price of this investment will only decline 15 percent. An asset with a beta of 2.0 has twice the volatility of the market index. If the market index goes up 20 percent, the price of this asset will go up 40 percent. If the market index declines 5 percent, the price of this asset will decline 10 percent.

Under CAPM theory, the basic formula which can be used to determine the market-required rate of return for a company is:

$$R_i = R_f + b_i\,[E(RP)]$$

where:

R_i = required return on security i

R_f = current return on risk-free investments

b_i = beta for security i

$E(RP)$ = expected market risk premium, *i.e.*, the expected difference between the return in the market and the rate of return on a risk-free investment

In the above formulation, the required rate of return for a company is equal to the current return on a risk-free investment plus the product of that company's beta times the expected market risk premium. The market risk premium is that extra return that investors require for an investment in assets of the market as a whole as compared to the return on a risk-free investment.

In addition to the "traditional" formulation of the CAPM shown above, I will also employ an "empirical" formulation of the CAPM.[5] The empirical CAPM is used due to both empirical and theoretical concerns that the "traditional" CAPM may provide an understated required return estimate for utilities. Empirical tests in the academic literature show that the "traditional" CAPM understated the required return for companies with beta below 1.0 and overstated the required return for companies with beta above 1.0. The empirical version of the CAPM reflects considerations that no estimate of the market return—in particular just using a

[5] This formulation of the CAPM is also sometimes known as the two-factor CAPM, or zero-beta CAPM.

stock market proxy—can truly represent the whole range of investments and returns available to investors and that investors who borrow money incur a cost of funds that exceeds the risk-free rate. I will use an empirical formulation[6] that is designed to alleviate the biases that may be reflected in the "traditional" CAPM:

$$R_i = R_f + .75(b_i)(RP) + .25(RP).$$

Q. What data requirements are necessary to implement the CAPM approach?

A. In order to use the CAPM approach for the comparison companies, three parameters must be estimated—beta, the current risk-free rate and the expected market risk premium.

Q. How do you determine beta for the CAPM calculation?

A. The average beta of the comparison companies is 0.65, per *The Value Line Investment Survey*. I will employ a beta of 0.65 in the CAPM calculation.

Q. How do you determine the current risk-free rate of return?

A. Since we are trying to determine the cost of common equity capital for the comparison companies and equity capital is a long-term investment, it is my belief that the yield on long-term government bonds best reflects the risk-free rate in this context.

Common stock is a long-term investment—it has no maturity date.[7] In this context, it is interesting to note that the discounted cash flow (DCF) approach determines the cost of equity in terms of a long horizon—*i.e.*, dividends are discounted to infinity in the DCF calculation. Even if an investor sells his or her

[6] See Roger Morin, *Regulatory Finance*, pages 334-336.

[7] The common stock of a utility will remain outstanding unless a company merges or becomes defunct, or if an investor voluntarily sells his shares back to the company.

common stock after only a few years, the successor investor determines the price that the original investor can receive, and so on. Based on the above, equity capital should be considered as a long-term investment and, therefore, the yield on long-term Government bonds best reflects the risk-free rate in this context.

Under a long-term investment horizon, if one purchased, say, 3-month Treasury securities and then kept rolling over the proceeds each three months as the investment matures, there would be substantial uncertainty (risk) as to what return one would earn over a long horizon by just investing in 3-month Treasury bills. In contrast, in the context of a long horizon, if a long-term Treasury bond is held until maturity, then there is no uncertainty as to the expected return—the interest payments and principal are guaranteed in nominal terms. Thus, using a long-term Government bond more closely matches the long-term investment horizon of equity and is therefore appropriate to use in a CAPM analysis for estimating the cost of equity.

I note that short-term Treasury securities are used by the Federal Reserve to implement its policy objectives for credit tightening and expansion. Thus, short-term Treasury security yields are greatly influenced by short-term Federal Reserve policy moves. These short-term adjustments should not be used to measure the long-term risk and return evaluations of investors for common stock.

The average yields on long-term Treasury securities over the April-September 2003 period, per the *Federal Reserve Statistical Release*, were as follows:

	Average Yield
10-Year	3.9 %
20-Year	4.9
Long-Term*	5.0

* Bonds with at least 25 years or more remaining until maturity.

Recent long-term Treasury bond futures yields have been close to 5.5 percent. Based on all the above-described data, I believe it would be appropriate to use a risk-free rate of 5.0 percent in the CAPM calculation.

Q. How do you determine the expected market risk premium?

A. For the third parameter needed for the CAPM approach, we must estimate the expected market risk premium—*i.e.*, the expected difference between the market-required return on common stocks and the yield on long-term government bonds.

Expectational risk premium data are not directly observable in the marketplace. Therefore, to estimate the expected market risk premium, I follow two approaches. The first approach employs historic long-term risk premium data from Ibbotson Associates *Risk Premia Over Time Report: 2003*. In the second approach I calculate a current cost of equity estimate for the market, in general, using a DCF approach and then subtract the estimate of the risk-free rate from this figure in order to determine the expected market risk premium.

Q. Will you now describe how you will use historic data from the Ibbotson publication to estimate the expected market risk premium?

A. As I indicated earlier, expectational risk premium data are not directly observable in the marketplace. Therefore, one can use estimates of historic realized return spreads as proxies for expected risk premiums. This approach is reasonable since it is plausible to assume that investors use the historic experience as a guide when forming their expectations of risk premiums in the future.

Ibbotson Associates publishes the *Risk Premia Over Time Report: 2003* in which the returns on common stocks and long-term government bonds are reported for the 1926-2002 period. Based on these data, the spread between common stock returns and returns on long-term government bonds has been 7.0 percentage points on an historical basis. I will use this 7.0 percent figure as the expected market risk premium in this CAPM analysis.

In the above discussion, I have employed figures reflecting the arithmetic mean rather than the geometric mean of the data. I believe that a rational investor would employ the arithmetic mean and would not use the geometric mean, because that would provide an understatement of expected future return. (I note that Ibbotson Associates states that the arithmetic mean is the correct measure to use in estimating the cost of equity capital.) Since the explanation of why the arithmetic mean should be used is quite lengthy, I have included it in Appendix B to this testimony. Appendix B shows that the arithmetic mean is the appropriate figure to use when investors are making forecasts about the future and dealing with uncertainties inherent in making projections.

A simple example also shows that the arithmetic mean is the correct approach to use in this context. Let us assume that you are faced with the prospect of betting on a coin toss where you win 50 percent of your bet if the coin comes up heads, but lose 50 percent of the bet if the coin comes up tails.[8] Common sense indicates that because the coin is a fair coin (*i.e.*, a 50 percent chance of landing on heads and a 50 percent chance of landing on tails), the bettor would expect to only break even (*i.e.*, they would expect to lose 50 percent of their bet half the time and expect to win 50 percent of their bet half the time). The arithmetic average of the return prospects a bettor would face in these circumstances is zero. Thus, the common sense expectation of a bettor in this example reflects the arithmetic average of return possibilities. In sharp contrast, the geometric average of an equal prospect of two returns (one plus 50 percent and one minus 50 percent) is -13.4 percent. A rational bettor would not go into a coin toss of the type described above with the expectation of a loss of 13.4 percent over time—they would expect to break even, as reflected in the arithmetic mean of zero. Clearly, they would not use a geometric average of return possibilities as their expected value, but would, instead, use the arithmetic average.

Q. Can you explain why it is reasonable to assume that investors look at achieved return spread results of the past in formulating their risk premium expectations for the future?

A. I examined historical return spread data over the 1926-2002 period and the results represent 77 years of return experience. The data that I examined, which represents the experience of a large number of companies over a lengthy period of time,

[8] Implicit in this discussion is an assumption that the coin used is fair—it is not biased (*e.g.*, weighted) to land disproportionately on either heads or tails.

indicates what return spreads investors have actually achieved, on average, in the past. It is not unreasonable to assume that, given the very extensive return spread experience examined, that investors would use this historic experience in formulating their expected risk premium for the future. Put simply, they see what return spread has been achieved in the past and use that experience as an expectation of what might be achieved in the future. Because of this consideration, I believe that the average historic return spread is appropriate to use as the expected risk premium in a CAPM analysis.

The 2002 Ibbotson *Yearbook* states that:

> A proper estimate of the equity risk premium requires a data series long enough to give a reliable average without being unduly influenced by very good and very poor short-term returns.... Some analysts estimate the expected equity risk premium using a shorter, more recent time period on the basis that recent events are more likely to be repeated in the near future; furthermore, they believe that the 1920s, 1930s, and 1940s contain too many unusual events. This view is suspect because all periods contain "unusual" events. Some of the most unusual events of this century took place quite recently, including the inflation of the late 1970s and early 1980s, the October 1987 stock market crash, the collapse of the high-yield bond market, the major contraction and consolidation of the thrift industry, the collapse of the Soviet Union, and the development of the European Economic Community—all of these happened in the last 20 years.... The 76-year period starting with 1926 is representative of what can happen: it includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific events) tend to repeat themselves, long-run capital market return studies can reveal a great deal about the future. Investors probably expect "unusual"

> events to occur from time to time, and their return expectations reflect this.

I agree with the sentiments expressed above and think it is appropriate to assume that investors would use the full range of experience available to them.

It should be noted that in individual years in the period under study, realized return spreads fluctuated significantly and even were negative in some cases. However, the <u>expected</u> risk premium of investors in each year must be positive; if not, a rational investor would never be willing to purchase a risky asset. One must always keep in mind that the risk premium concept is expectational. While investor ex ante risk premium expectations will not be matched in every year by the achieved ex post return spreads, investors will look at the average achieved return spread over a long period to get a sense of what would be realistic to expect for the future. The realized return spreads that I analyzed reflect a body of historic experience based on which investors would reasonably form their return expectations for the future. Of course, it is those future expectations that we are trying to ascertain. Atypically high or low results in any given historic period are not indicative of investors' expectations. Moreover, a negative return spread in any particular historic year or period does not cause investors to expect that in the future they will only be able to achieve negative return premiums, on average. It is, therefore, my view that the average realized return spread over a long period is likely to be viewed by investors as a reasonable estimate of the expected risk premium.

Q. How do you specifically implement the CAPM approach for the comparison companies using the Ibbotson market risk premium?

A. The beta for the comparison companies, per Value Line, is 0.65. The expected market risk premium is 7.0 percent. The risk-free rate is 5.0 percent. Using these inputs, the average required return for the comparison companies is calculated below:

<u>Traditional CAPM</u>

$$R_i = 5.0 + 0.65(7.0) = 9.6\%$$

<u>Empirical CAPM</u>

$$R_i = 5.0 + 0.75(.65)(7.0) + .25(7.0) = 10.2\%$$

Q. Will you now describe how you use S&P 500 data to estimate the expected market risk premium?

A. I first calculate an estimate of the expected (required) return for the S&P 500 using the DCF method and then subtract the risk-free rate employed in my analysis in order to determine the expected market risk premium under this second approach.

The recent dividend yield for the S&P 500 has been about at the 1.75 percent level. According to First Call, projected earnings growth for the companies in the S&P 500 averages about 12.0 percent. Per S&P, the average projected earnings growth for the companies it covers is about 14.0 percent. Using 13.0 percent as the estimate of expected growth and a 1.75 percent dividend yield, the DCF estimate of the expected return for the S&P 500 is 14.75 percent. Using a risk-free rate of 5.0 percent, the expected market risk premium would be 9.75 percent (14.75– 5.0 = 9.75). Employing this expected market risk premium for the S&P 500, the average required return for the comparison companies is calculated below:

Traditional CAPM

$$R_i = 5.0 + 0.65(9.75) = 11.3\%$$

Empirical CAPM

$$R_i = 5.0 + 0.75(.65)(9.75) + .25(9.75) = 12.2\%$$

Q. Are there any other factors to consider that may not be captured by the CAPM calculations described above?

A. Yes, there are. Ibbotson Associates indicates that companies with market capitalization in the mid- or low-capitalization range (including many utilities) require higher returns than indicated by the CAPM formulation I have employed above. As a way to account for this phenomenon, a size premium can be added to the CAPM results.

According to the Ibbotson Associates *Risk Premium Over Time Report: 2003*, size premiums of 82 and 152 basis points are appropriate for mid- or low-capitalization companies, respectively. I will use a 60 basis point size premium for the comparison group to recognize that six of the companies (Alliant, NSTAR, Pinnacle West, SCANA, Vectren and Wisconsin Energy) are in the mid-capitalization range, two of the companies (CH Energy and MGE Energy) are in the low-capitalization range and five of the companies (Ameren, Consolidated Edison, DTE, Exelon and Southern Company) required no adjustment.

Q. Would you summarize the results of your CAPM analyses?

A. The CAPM results are summarized in the table below:

CAPM Formulation	Market Risk Premium Based on:	CAPM Result	CAPM Result + Size Premium
Traditional	Ibbotson	9.6 %	10.2 %
	S&P 500	11.3	11.9
Empirical	Ibbotson	10.2	10.8
	S&P 500	12.2	12.8

Based on the above analyses and results, I conclude that the CAPM estimate of the cost of equity is in the 10.75-11.50 percent range.

D. Risk Premium Analysis

Q. Would you provide an overview of your risk premium calculations?

A. I employ two risk premium approaches. The first analysis is based on the historic average spread between utility stocks and bonds. The second relies on a regression analysis to measure how utility risk premiums vary with the level of interest rates.

Q. Will you explain the rationale behind a risk premium analysis?

A. The higher the perceived risk of an investment, the higher will be the return that investors require from that investment. If two investments offer the same expected return but have differing risks, investors will prefer the investment with lesser risk. Investors do so because they are said to be risk averse—*i.e.*, they prefer to take on less risk, rather than more risk, other things being equal.

It is nearly universally agreed that investors require a higher rate of return for an investment in the common equity for a particular company than they do in its debt. This is so for two important reasons. First, if an enterprise fails, debtholders have priority over equityholders as to the remaining assets of the company. Second, for an ongoing business, debtholders must be paid their contractual level of interest before equityholders can receive anything. Because of this basic fact of financial life, companies may reduce their dividend payments to equityholders when under some financial strain. The cessation of payments to debtholders is a much rarer occurrence and will usually result in bankruptcy, unless corrected. In summary, debt is thought to be less risky than equity because debtholders have priority over equityholders as to: (1) distribution of assets in the case of dissolution of the company and (2) distribution of earnings in the case of everyday operations. Because equityholders "take second," they require a higher return than do debtholders. In order to be induced to choose a higher risk investment, an investor would have to be offered an expectation of some increment in return—a premium for incurring additional risk. This incremental return is often known as the "risk premium" and it reflects the additional return that investors require to invest in common equity rather than debt.

The cost of equity is not directly observable, but must be estimated using inferences and judgment. In contrast, a bond yield is observable and if we know, or can estimate, the risk premium that common equity investors require to invest in common equity rather than debt, we can employ the risk premium approach to estimate the cost of common equity. In the well-known *Hope* decision, the U.S. Supreme Court said:

> From the investor or company point of view, it is important that there be enough revenue not only for

> operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).]

While this decision speaks in terms of returns commensurate with those being earned on investments of comparable risk, implicitly a company must also earn a return far enough above investments of lesser risk in order to be able to attract capital. Thus, if we apply the risk premium approach correctly, we will ensure that the subject company is allowed a high enough return on its common equity, compared with investments of lesser risk, so as to be able to attract capital and to meet the standards laid down by the *Hope* decision.

In general, the equity risk premium can be expressed in the following manner:

$$RP = K_e - K_d$$

The above equation implies that the equity risk premium is equal to the required return on equity (K_e) minus the required return on debt (K_d).

Q. Would you please describe your first risk premium analysis?

A. To measure the expected risk premium between utility common stock and utility bonds, I use the average return spread actually achieved by investors in these instruments in the past. Between 1932 and 2001, Moody's electric utility common stock index achieved a market return of 10.93 percent, on average. (The market return in any given year was calculated by summing the dividend paid during that year and the year-end market price and dividing that sum by the beginning-of-year market price.) Over that same period, the average of Moody's composite bond yields for utilities was 6.64 percent. Thus, the historically achieved spread between electric utility stock returns and utility bond yields was 4.29 percent (10.93 - 6.64 = 4.29). If we add this average spread to the recent level of bond yields, we can obtain an estimate of the return on utility common stocks that investors are currently expecting/requiring.

Over the six-month period ending September 2003, the average bond yield for Moody's A rated utility bonds was 6.52 percent. Adding this recent average bond yield to the historic average spread between electric utility common stock returns and utility bond yields of 4.29 percent, we obtain a cost of equity estimate for the proxy group of 10.81 percent.

Q. In your second risk premium analysis, is there a proxy for required returns on equity that you use?

A. Yes, there is—returns on common equity allowed to electric utilities by regulation.[9] Most regulatory commissions frequently refer to movements in, or the level of, interest rates in their decisions establishing an allowed return on equity. Since authorized returns appear to be interest-rate sensitive, employing allowed returns from across the United States in calculating the risk premium serves to use outside,

[9] Regulators sometimes allow companies to keep earnings above the nominally allowed return on equity. Thus, the use of allowed returns in this analysis may well understate the returns investors actually expect a company to earn.

objective evidence as to what the consensus of regulation believes is the spread between the cost of equity and bond yields.

Q. How specifically did you perform your second risk premium analysis?

A. I first conducted an analysis of risk premiums implied by allowed returns on equity since 1980. Specifically, quarterly average allowed returns for the first quarter 1980 through the third quarter 2003 were obtained from data in Regulatory Research Associates *Regulatory Focus*. These data reflect the average of allowed returns for all electric utility cases decided in the quarter specified. An implied risk premium (which can also be thought of as an allowed return spread) was derived by comparing the average allowed return in a given quarter with the average yield for Moody's Utility Composite Bond Index in the two quarters prior to the average allowed return.

In deriving the implied risk premium, the utility bond yields were lagged behind the allowed returns on equity because of the likelihood that changes in allowed returns on equity often lag somewhat behind changes in bond yields. This could be so for two reasons—one economic and one practical. The economic reason is that commissions might want to be convinced that a change in interest rates actually represented a trend that might persist before reflecting such change in the allowed return on equity. The practical reason simply deals with the logistics of a rate case—the record that a commission examines may be several months old by the time it renders a decision. (While certain commissions update record data in their decisions, many commissions do not do so.) Furthermore, the simple logistics of writing a decision may cause a delay between the period upon which the allowed return was based and the date on which the decision was released to the public.

To determine the sensitivity of the implied risk premiums described above to the level of interest rates, a regression analysis was conducted. In this regression, the implied risk premium described above was the dependent variable and the level of interest rates, as proxied by the yield on long-term Treasury bonds lagged two quarters behind the allowed return on equity, was the independent variable. This model attempts to capture the statistical relationship between implied risk premiums (*i.e.*, allowed returns minus utility bond yields) and the level of interest rates (as indicated by the yields on long-term Treasury bonds), with the interest rates being lagged two quarters behind the allowed return on equity. The regression equation is reported below:

$$\text{Risk Premium} = 6.477 - 0.432 \left\{ \begin{matrix} \textit{Yield on Long-Term} \\ \textit{Treasury} \\ \textit{Bonds} \end{matrix} \right\}$$

The adjusted R^2 of the regression (which measures the proportion of variation in the dependent variable explained by variation in the independent variable) is 0.78. Thus, this regression relationship demonstrates that changes in the level of interest rates explain a substantial proportion of the changes in implied risk premiums.

One might well ask why one should go through the process of creating the model described above when one could merely just examine recent levels of allowed returns. There are justifications for the model in this context. First, it is possible that in certain quarters there are an insufficient number of allowed returns to use as a guide by themselves. Second, allowed returns are not a perfect proxy for required returns and the use of the long-term relationship between allowed returns and bond yields allows us to overcome any unusual allowed return results in a particular period.

The average yield on long-term Treasury bonds for the six months ending September 2003 is 4.95 percent. Inserting this into the model shown above, I obtain a calculated risk premium of 4.36 percent as follows:

Risk Premium = 6.477 - 0.432(4.95)

Risk Premium = 4.34%

The average yield on Moody's A rated bonds in the six months ending September 2003 was 6.52 percent. Adding the yield of 6.52 percent to the risk premium derived above of 4.34 percent produces an implied cost of equity of 10.86 percent. Thus, my second risk premium cost of equity estimate for the proxy group of utilities is 10.86 percent according to the above-described analysis.

Q. Would you summarize the results of your risk premium analyses?

A. The first risk premium approach that employs the historic average spread between utility common stock returns and utility bond yields produced a cost of equity estimate for the proxy group of 10.81 percent. The second risk premium approach which is based on a regression analysis measuring how utility risk premiums change as the level of interest rates change produced a cost of equity estimate of 10.86 percent for the proxy group. Based on these results, I will use a range of 10.8-10.9 percent as the risk premium cost of equity estimate in my further discussion.

E. Comparable Earnings Analysis

Q. Can you explain why the comparable earnings approach is helpful in assessing what return should be allowed in this proceeding?

A. The basic criteria for determining what constitutes a fair rate of return for a regulated enterprise were set forth by the U.S. Supreme Court in the *Bluefield* and *Hope Natural Gas* cases. In the *Bluefield* case the Court said:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. [Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 692-693 (1923).]

In *Hope*, the Court said:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).]

In those decisions, the Court enumerated a two-part standard for a fair rate of return: (1) a fair rate of return to a regulated company is one that is equal to that earned in other enterprises of similar risk and (2) the fair rate of return must also provide enough earnings to enable the company to maintain its credit standing[10] and to attract capital. The first part has come to be known as the "comparable earnings standard" while the second part is referred to as "the capital attraction standard."

The comparable earnings approach (*i.e.*, determining the return earned by companies of similar risk) directly meets one of the basic criteria set forth by the Supreme Court in the *Bluefield* and *Hope* decisions. But, in addition, the Court set forth the criterion that the rate of return on equity should also be sufficient for the company to attract capital. It must be acknowledged that a firm whose return is the same as that of "other enterprises having corresponding risks" is not necessarily earning enough to attract capital; but in reasonably prosperous periods, one can expect that the great majority of companies are earning enough to attract capital, and that one can also identify those that are not. Thus, if comparisons are made with a reasonably broad range of companies over a reasonably representative time period, one can be confident that a return high enough to match that of other enterprises with corresponding risks will probably also be high enough to attract capital and maintain financial integrity.

In addition to being prescribed as a standard by the *Bluefield* and *Hope* decisions, there are other reasons why a comparable earnings analysis may be helpful in determining the return to be allowed a regulated company. The comparable earnings method analyzes the question of what return should be

[10] Bond rating agencies have subjected the financial ratios of utilities to more rigorous scrutiny of late. Since the rating agencies emphasize **cash flow** measures, adequate cash flow is crucial to a company's credit standing.

allowed a regulated company from a different perspective than an approach such as the DCF method. It can be argued that the price that investors pay in the stock market for a utility depends, at least in part, on the return that investors expect a commission will allow that company. In turn, however, the return that a commission will allow a company depends, at least in part, on the price of that company in the stock market. As one commentator has stated:

> Moreover, since the most important risk to the investor is the risk as to the attitude of the regulatory commission, current security prices inevitably reflect projections not only of future physical and general economic developments of the utility and its area, but also of the anticipated rulings of the commission. For the commission to "rely" on such anticipations is palpably circular reasoning.... Commissions and investors cannot sensibly continue to look behind one another like endless images in multiple mirror.[11]

Thus there is an element of circularity in using an approach such as the DCF method to estimate the cost of equity of a utility. The comparable earnings method, which derives its results from a conceptually different approach, can shed additional light on the question of the appropriate allowed return for a utility.

Another advantage of a comparable earnings analysis is that it provides a perspective different from that implicitly employed using an approach that satisfies the capital attraction standard. If the capital attraction standard is strictly and rigidly applied, it would keep a company on the knife-edge of financial health—any shortfall in return might make it difficult for a company to attract capital. As another commentator has stated:

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[11] Harold Leventhal, "Vitality of the Comparable Earnings Standard for Regulation of Utilities in a Growth Economy," *The Yale Law Journal*, May 1965, page 1007.

> It should be evident that a rate of return which is barely adequate to allow for the raising of new capital is not necessarily a fair rate of return.[12]

The comparable earnings approach is not a market-based methodology. However, the examination of returns earned, or expected to be earned, by a large group of companies with risks similar to electric utilities, in combination with the results of various other methodologies, will produce a reasonable estimate of the return to be allowed for electric utilities.

Q. Would you now describe the comparable earnings analysis you conducted?

A. Under the comparable earnings approach, I first evaluate the risk of the comparison companies versus that of companies in the U.S. economy in general and based on this analysis determine what return on equity is appropriate.

Q. How do you evaluate the relative risk of the comparison companies versus companies in general?

A. I use the Value Line Safety Rank. *The Value Line Investment Survey* provides a safety rank for the 1700 or so companies that it follows. For the determination of Safety Rank, stocks are ranked from 1 to 5, with 1 being the safest and 5 being the most risky. Value Line defines the Safety Rank as a measure of the total risk of a stock and describes the Safety Rank as one of the main criteria investors should consider in selecting stocks. Value Line derives the Safety Rank by averaging two variables: (1) the volatility of the stock as measured by its Index of Price Stability and (2) the Financial Strength Rating as determined by Value Line analysts. Value Line defines the price stability index as being based upon a ranking of the standard

[12] Herman Roseman, "Comparable Earnings and the Fair Rate of Return," 1970 *Annual Report*, Section of Public Utility Law of the American Bar Association, page 26.

deviation of weekly percent changes in price of a stock over the last five years. Value Line evaluates the Financial Strength of a company on a scale of A++ down to C. This is a relative ranking comparing the subject company's financial strength to all other companies. The rating is based upon financial leverage, business risk, company size and the judgment of Value Line analysts. The analysts examine various ratios such as coverage, return variability, accounting methods and size.

To implement the comparable earnings analysis, I examined recent earned and projected returns on shareholders' equity earned by companies with a safety factor of 2 as reported in *The Value Line Investment Survey*.[13]

Q. Does this group of companies with the Safety Rank of 2 include unregulated companies?

A. Yes, it does. It is a financial fact of life for a utility company that it competes in the marketplace to obtain capital not only with other utilities, but with all economic enterprises. Furthermore, the *Hope* decision, which is a touchstone in the area of rate of return regulation, indicates that a company should be compared to other firms of comparable risk and did not limit this comparison only to other regulated firms. Value Line measures the risk embodied in the safety rank it assigns consistently across the 1700 or so companies that it follows to derive its safety rank and thus it measures risk in a uniform manner for both regulated and unregulated firms.

Q. What returns are companies with a Safety Rank of 2 earning?

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[13] The safety rank of the proxy group I employ is 2.

A. The earned return on shareholders' equity in any one given year is not necessarily the return that investors expect a firm to earn in the future. A company could have runs of good luck or bad luck or particular accounting adjustments so that the return earned in any one year is not necessarily a meaningful indicator of what it ought to be earning in light of the risks being borne. In order to temper the earned return data, I examined earned returns on shareholders' equity over two recent historic years. In addition, Value Line projected earned returns for 2003 (the current year), 2004 and for a period 3-5 years into the future were also employed. Thus, by looking at both the earnings experience of the recent past as well as projections for the future, unusual figures are smoothed and the end result is appropriate to employ as the comparable earnings result. To further temper the data, median results, rather than average figures, were used in any year.

The median returns on shareholders' equity in 2001 and 2002 for companies accorded by Value Line a safety factor of 2 are 14.2 and 13.7 percent, respectively. The median projected returns on shareholders' equity for these companies in 2003 and 2004 were 14.0 percent in both years. The median return for these companies projected by Value Line for the near-term future (2006-2008) is 14.5 percent.

In summary, a conservative estimate[14] of the return to be allowed on common equity using the comparable earnings approach is in the range of 14.0-14.5 percent.

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[14] The data that I examined reflect the return earned on shareholders' equity, rather than the return on common equity. Since the companies examined are financed in part by some preferred equity in addition to common equity, the returns on common equity would be higher than those reported. In addition, Value Line reports return on year-end shareholders' equity, whereas it is appropriate to use return on average equity for the

F. <u>Determination of the Cost of Equity of LG&E's Electric Operations</u>

Q. Would you describe the results of each of the four methods?

A. The DCF method produced a cost of equity range of 10.00-10.75 percent. As I indicated earlier in my testimony, I believe that a utility DCF estimate will have the potential for more measurement error than during periods in which a company's more-readily-determined future earnings and dividends prospects were the main consideration. Therefore, I believe that it is important to also consider the results of the other methods that I presented, which approach the determination of the return on equity to be allowed in this proceeding from different perspectives.

The CAPM approach can be thought of as calculating a risk premium for the market as a whole and then adjusting it for the risk of the particular utility in question. Under the CAPM approach, risk is measured by a company's beta. My CAPM analysis produced a cost of equity range of 10.75-11.50 percent.

While the CAPM approach calculates a market-wide risk premium that is then adjusted for company-specific risk, the two risk premium analyses that I performed directly estimate the risk premium for a utility. The results of these risk premium analyses produced a cost of equity estimate in the range of 10.8-10.9 percent.

The comparable earnings approach (*i.e.*, determining the return earned by companies of similar risk) directly meets one of the basic criteria set forth by the Supreme Court in the *Bluefield* and *Hope* decisions. As utilities face a more competitive environment, investors will carefully evaluate how utility returns

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comparable earnings analysis.

compare with those of unregulated enterprises. The comparable earnings analysis produced a return on equity[15] range of 14.0-14.5 percent. These expected returns on equity of comparable-risk investment alternatives would certainly be taken into account by investors in forming their return requirements for a utility. As discussed above, it is difficult to ascertain with clarity at the current time what the prospects of the utility industry will be in the future. However, the use of rates of return of companies of comparable risk across a diversity of industries provides an important benchmark as to the return to be allowed in this proceeding.

Below, I present a summary of the results I discussed above:

Cost of Equity Method	Range
1. DCF	10.00 - 10.75%
2. CAPM	10.75 - 11.50
3. Risk Premium	10.8 - 10.9
4. Comparable Earnings	14.0 - 14.5

Determination of the cost of equity requires inferences regarding investor expectations and requirements, which are not directly observable. Each of the above methods approaches the estimation of the cost of equity from a different perspective—which I believe to be a strength of this four-method approach. In my opinion, the cost of equity for the proxy group of companies used in my analysis is in the range of 10.75-11.25 percent.

[15] As indicated above, the reported range reflects returns on year-end shareholders equity (including preferred equity); returns on average common equity would be somewhat higher.

Q. Are there any other factors to consider in reaching a recommendation about the return on equity to be allowed to LG&E's electric operations in this proceeding?

A. Yes. Given the difficulty of determining the cost of equity capital with exact precision, analysts and regulatory commissions often estimate a "range of reasonableness" for the return on equity and then use qualitative factors and judgment to determine where within this range a particular allowed return should be set. I recommend that the electric operations of LG&E be allowed a return at the upper end of the 10.75-11.25 percent cost of equity range I have determined.

Q. Can you indicate the basis for this recommendation?

A. LG&E has been recognized as having very efficient operations. The Commission, at page 34 of the LG&E and KU merger proceeding, Case No. 97-300, noted that:

> LG&E and KU are recognized as efficient and high quality providers of electric service at rates that are among the lowest in the nation. Both companies also are well positioned financially and enjoy high debt ratings due to numerous factors including their low cost generation, desirable service territories and efficient management structures.

Since that time, LG&E's continued high level of efficiency has been recognized by several J.D. Powers awards. In addition, on page I-2 of its August 31, 2003 Final Report concerning the focused management audit of LG&E's and Kentucky Utilities' Earnings Sharing Mechanism, the Barrington-Wellesley Group stated:

> BWG found LG&E and KU to be well-managed utilities with a strong management team in place. The Companies have sound planning, budgeting and accounting processes and good expenditure control.

In the past there may have been somewhat of a perverse relationship between efficiency and returns allowed by regulation, in general. Less efficient companies may have been perceived as having higher risk and, other things being equal, may have been granted higher returns on equity because of that perception. Conversely, more efficient companies may have been considered less risky and, other things being equal, these companies may have been granted lower returns on equity. In my opinion, regulators should recognize efficient operations, to the extent it is within their discretion. A method of doing this would be to allow LG&E to earn a return on equity toward the upper end of the range of reasonableness that I derived above.

In addition, the unsettled nature of the industry discussed earlier in my testimony (e.g., the bond rating agencies are much quicker to downgrade now than in the past), indicates a need for a solid company financial condition at the current time. Furthermore, interest rates presently are lower than they have been in many years. It seems likely that upward changes in interest rates may be more likely than downward changes,[16] especially in light of very large projected Federal budget deficits over the next several years.

Q. Based on consideration of your discussion and analyses, what return do you recommend for LG&E's electric operations?

A. I recommend that the electric operations of LG&E be allowed a return of 11.25 percent.

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[16] For example, there is not much downside room to the Federal Funds rate—currently about at the 1 percent level—that the Federal Reserve uses to implement its monetary policy.

VI. ESTIMATION OF THE COST OF EQUITY OF LG&E'S GAS OPERATIONS

A. Use of Comparison Companies to Determine the Cost of Equity of LG&E's Gas Operations

Q. Would you indicate how you selected the group of proxy companies upon which you conducted your cost of equity analysis?

A. I started by considering companies that were listed in *The Value Line Investment Survey*'s Gas Distribution category and applied several further selection criteria to these companies. The comparison company utility subsidiaries had to have an overall senior bond rating of Aa/A from Moody's and AA/A from Standard & Poor's. The median senior bond rating of the group that I have selected is A2/A. Currently, LG&E has a senior debt bond rating of A1/A-. Thus, the risk of the comparison companies, as indicated by bond rating, is comparable to LG&E.

Companies were excluded from the proxy group if they are currently involved in any major merger activity. Companies were also excluded from the proxy group if they had significant unregulated operations. I also excluded companies not paying a dividend or for whom a dividend cut was forecast by Value Line.

Finally, I deleted Nicor, Inc. from the group due to extremely atypical events and investor reactions concerning that company. In July 2002, Nicor indicated that it was experiencing both potential accounting problems and potential regulatory program problems, the magnitude of which it was not able to estimate at the time. Nicor executives were not able to certify quarterly financial reports in 2002 due to this uncertainty. These events caused investors to drop the Nicor price by more than 50 percent in July 2002. Nicor's problems continued on into 2003, with the company being subject to several investigations (by the Illinois Commerce Commission, the SEC and the U.S. Attorney). Nicor cautioned in its June 30, 2003 Form 10-Q report that it could not predict the outcome of the various reviews and that the end result might be financial statements that are materially different from those being currently reported. Due to this turmoil and uncertainty relating to Nicor, I have excluded it from my proxy group.

The list of companies in the proxy group is shown on Schedule 4.

B. DCF Analysis

Q. Will you be providing a detailed exposition of DCF method at this point in your testimony?

A. No, in my determination of the cost of equity of LG&E's electric operations earlier in this testimony, I provided a detailed explanation of DCF theory and the specifics of my DCF methodology. I will not repeat that exposition here, but will merely present the results of my analysis for the gas proxy group, since the approach is the same.[17]

Q. What price did you use for your DCF analysis?

A. I employed a pricing period encompassing the six months ended September 2003. Schedule 5 shows the average prices for the gas comparison companies over the six

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[17] I also use the same approaches for my CAPM, risk premium and comparable earnings analyses for the determination of the cost of equity of LG&E's gas operations as was used in the determination of the cost of equity for the electric operations. Thus, for those approaches too, I will only present the results of my analysis, rather than repeating the entire theoretical exposition behind those analyses.

month period ended September 2003. The six-month average price is also shown in Column (1) of pages 1-3 of Schedule 6, which provides inputs to the DCF calculation. The dividend level (i.e., the dividends paid during my pricing period, annualized) for each of the comparison companies is shown in Column (2) of pages 1-3 of Schedule 6.

Q. How do you determine the expected growth component of the DCF model for the comparison companies?

A. I employ a two-stage growth formulation of the DCF method to estimate investors' future growth expectations. For the determination of near-term (i.e., first-stage) growth, I rely on an average of earnings projections made by Value Line and First Call. These projections for the gas comparison companies and the average of the two are shown in Columns (3)-(5) of pages 1-3 of Schedule 6.

I employ three proxies for investors' expected long-term growth. First, I employ the long-term projected nominal GDP (Gross Domestic Product) growth of 5.91 percent as a proxy for expected long-term second-stage growth. For the second proxy for investors' expected long-term growth, I employ projected sustainable growth, using Value Line projections. The projected sustainable growth rates are shown in Column (6) on page 2 of Schedule 6. For the third estimate of investors' expected long-term growth, I employ a projections of expected industry growth. Zachs, Value Line, S&P and First Call project growth for the industry to be 5.5, 6.0, 6.3 and 5.0 percent, respectively. As a proxy for projected industry growth, I will use a figure of 5.7 percent.

Q. Would you review the components of the two-stage DCF analyses for the comparison companies?

A. The DCF analyses using GDP growth, sustainable growth and industry growth are shown on Schedule 6, pages 1, 2 and 3, respectively. Columns (1) and (2) of pages 1-3 of Schedule 6 show the 6-month average price and the dividend for the comparison companies. Columns (3)-(5) show the Value Line, First Call and average projected earnings growth rates. Column (6) of page 1 of Schedule 6 shows the long-term projected growth in GDP, which is assumed to occur after the first-stage growth period. Column (7) of page 1 of Schedule 6 shows the DCF cost of equity estimate for each company calculated by an iterative process employing the internal rate of return.

Page 2 of Schedule 6 shows the two-stage DCF analysis employing projected sustainable growth for the long-term expected growth rate. Columns (1)-(5) show the same inputs as on page 1 of Schedule 6. Column (6) of page 2 of Schedule 6 shows the projected sustainable growth, which I employ as the long-term projected growth assumed to occur after the first-stage growth period. Column (7) of page 2 Schedule 6 shows the DCF cost of equity estimate for each company. Page 3 of Schedule 6 shows the two-stage DCF analysis employing projected industry growth for the long-term expected growth rate. Columns (1)-(5) show the same inputs as on pages 1 and 2 of Schedule 6. Column (6) of page 3 of Schedule 6 shows the projected industry growth, which I employ as the long-term projected growth assumed to occur after the first-stage growth period. Column (7) of page 3 of Schedule 6 shows the DCF cost of equity estimate for each company.

Q. What are the results of your DCF calculations?

A. Below, I show a table summarizing the results of the DCF calculations described above:

Long-Term Growth Rate	Schedule Page	Range	Midpoint of Range	Median	Average
GDP	Sch. 6, p.1	10.6 - 11.6	11.1	11.1	11.1
Sustainable	Sch. 6, p.2	8.7 - 16.0	12.4	11.1	11.4
Industry Avg.	Sch. 6, p.3	10.4 - 11.4	10.9	10.9	10.9

Based on the results and analysis presented above, I will use a DCF range of 10.90-11.25 percent in my further discussion of the determination of the cost of equity.

C. <u>CAPM Analysis</u>

Q. Would you briefly review the CAPM approach you are employing?

A. I will use both the "traditional" and "empirical" formulations of the CAPM approach. In order to use the CAPM approach for the comparison companies, three parameters must be estimated—beta, the current risk-free rate and the expected market risk premium. The average beta of the comparison companies is 0.68, per *The Value Line Investment Survey*. In the CAPM calculation, I use a risk-free rate of 5.0 percent, derived earlier in this testimony. For the expected market risk premium I use two approaches. The first approach relies on data from Ibbotson Associates and produces an expected market risk premium of 7.0 percent. Using these inputs, the average required return for the comparison companies is calculated below:

Traditional CAPM

$$R_i = 5.0 + 0.68(7.0) = 9.8\%$$

Empirical CAPM

$$R_i = 5.0 + 0.75(.68)(7.0) + .25(7.0) = 10.3\%$$

The second estimate of the expected market risk premium I employ is based on S&P 500 data. As explained earlier in this testimony, the S&P 500-based expected market risk premium is 9.75 percent. Using this expected market risk premium, the average required return for the gas comparison companies is calculated below:

Traditional CAPM

$$R_i = 5.0 + 0.68(9.75) = 11.6\%$$

Empirical CAPM

$$R_i = 5.0 + 0.75(.68)(9.75) + .25(9.75) = 12.4\%$$

Q. Are there any other factors to consider that may not be captured by the CAPM calculations described above?

A. Yes, there are. Ibbotson Associates indicates that companies with market capitalization in the mid- or low-capitalization range (including many utilities) require higher returns than indicated by the CAPM formulation I have employed above. As a way to account for this phenomenon, a size premium can be added to the CAPM results.

According to the Ibbotson Associates *Risk Premium Over Time Report: 2003*, size premiums of 82 and 152 basis points are appropriate for mid- or low-capitalization companies, respectively. I will use a 90 basis point size premium for the comparison group to recognize that three of the companies (AGL Resources, Atmos Energy and Peoples Energy) are in the mid-capitalization range, two of the companies (Laclede Group and Northwest Natural Gas) are in the low-capitalization range and one company (KeySpan) required no adjustment.

Q. Would you summarize the results of your CAPM analyses?

A. The CAPM results are summarized in the table below:

CAPM Formulation	Market Risk Premium Based on:	CAPM Result	CAPM Result + Size Premium
Traditional	Ibbotson	9.8 %	10.7 %
	S&P 500	11.6	12.5
Empirical	Ibbotson	10.3	11.2
	S&P 500	12.4	13.3

Based on the above analyses and results, I conclude that the CAPM estimate of the cost of equity is in the 11.00-11.75 percent range.

D. Risk Premium Analysis

Q. Would you provide an overview of your risk premium calculations?

A. I employ two risk premium approaches. The first analysis is based on the historic average spread between utility stocks and bonds. The second relies on a regression analysis to measure how utility risk premiums vary with the level of interest rates.

Q. Would you please describe your first risk premium analysis?

A. To measure the expected risk premium between utility common stock and utility bonds, I use the average return spread actually achieved by investors in these instruments in the past. Between 1954 and 2001, Moody's gas distribution common stock index achieved a market return of 12.09 percent, on average. (The market return in any given year was calculated by summing the dividend paid during that year and the year-end market price and dividing that sum by the beginning-of-year market price.) Over that same period, the average of Moody's composite bond yields for utilities was 8.12 percent. Thus, the historically achieved spread between utility stock returns and utility bond yields was 3.98 percent (12.09 - 8.12 = 3.98).[18] If we add this average spread to the recent level of bond yields, we can obtain an estimate of the return on utility common stocks that investors are currently expecting/requiring.

Over the six-month period ending September 2003, the average bond yield for Moody's A rated utility bonds was 6.52 percent. Adding this recent average bond yield to the historic average spread between gas utility common stock returns and utility bond yields of 3.98 percent, we obtain a cost of equity estimate for the proxy group of 10.50 percent.

Q. How did you perform your second risk premium analysis?

A. Similar to the approach described earlier in my testimony in the section determining the cost of equity of LG&E's electric operations, I perform a regression analysis using risk premiums implied by allowed returns on equity between the first quarter of 1980 and the third quarter of 2003. However, in this

[18] Figures do not add exactly due to rounding.

regression analysis, I employ risk premiums implied by allowed returns for gas distribution utilities. The resulting regression equation is reported below:

$$\text{Risk Premium} = 6.406 - 0.439 \left\{ \begin{matrix} \textit{Yield on Long-Term} \\ \textit{Treasury} \\ \textit{Bonds} \end{matrix} \right\}$$

The adjusted R^2 of the regression (which measures the proportion of variation in the dependent variable explained by variation in the independent variable) is 0.80.

The average yield on long-term Treasury bonds for the six months ending September 2003 is 4.95 percent. Inserting this into the model shown above, I obtain a calculated risk premium of 4.23 percent as follows:

$$\text{Risk Premium} = 6.406 - 0.439(4.95)$$

$$\text{Risk Premium} = 4.23\%$$

The average yield on Moody's A rated bonds in the six months ending September 2003 was 6.52 percent. Adding the yield of 6.52 percent to the risk premium derived above of 4.23 percent produces an implied cost of equity of 10.75 percent. Thus, my second risk premium cost of equity estimate for the proxy group of utilities is 10.75 percent according to the above-described analysis.

Q. Would you summarize the results of your risk premium analyses?

A. The first risk premium approach that employs the historic average spread between utility common stock returns and utility bond yields produced a cost of equity estimate for the proxy group of 10.50 percent. The second risk premium approach which is based on a regression analysis measuring how utility risk premiums change as the level of interest rates change produced a cost of equity estimate of

10.75 percent for the proxy group. Based on these results, I will use a range of 10.50-10.75 percent as the risk premium cost of equity estimate in my further discussion.

E. Comparable Earnings Analysis

Q. Would you report the results of your comparable earnings analysis?

A. To implement the comparable earnings analysis, I examined recent earned and projected returns on shareholders' equity earned by companies with a safety factor of 2 as reported in *The Value Line Investment Survey*.[19] Since that was also the safety factor of the electric proxy group I employed earlier in my testimony, the results are the same—a conservative estimate of the return to be allowed on common equity using the comparable earnings approach is in the range of 14.0-14.5 percent.

F. Determination of the Cost of Equity of LG&E's Gas Operations

Q. Would you summarize the results of each of the four methods?

A. Below, I present a summary of the results I discussed above for the gas distribution proxy group:

[19] The safety rank of the gas proxy group I employ is 2.

Cost of Equity Method	Range
1. DCF	10.90 - 11.25%
2. CAPM	11.00 - 11.75
3. Risk Premium	10.50 - 10.75
4. Comparable Earnings	14.0 - 14.5

In my opinion, the cost of equity for the gas distribution proxy group of companies used in my analysis is in the range of 11.0-11.5 percent.

Q. What return on equity do you recommend for LG&E's gas operations?

A. As indicated above, I found the cost of equity for the gas proxy group to be in the 11.0-11.5 percent range. For the reasons described earlier in my testimony (i.e., the efficiency of LG&E and the current business and economic climate), a return at the upper end of the range of reasonableness is appropriate. Therefore, I recommend that the gas operations of LG&E be allowed a return of 11.5 percent.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

STATE OF NEW YORK)
) **SS:**
COUNTY OF SCHOHARIE)

The undersigned, **Robert G. Rosenberg,** being duly sworn, deposes and says he is an Economist and Principal of Edgewood Consulting, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert G. Rosenberg

ROBERT G. ROSENBERG

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9 day of December 2003.

Wanda J King (SEAL)

Notary Public

My Commission Expires:

WANDA J. KING
Notary Public, State of New York #01KI4683925
Residing in Schoharie County
My Commission Expires Jan. 31, 20 07

EDUCATION AND EMPLOYMENT BACKGROUND OF ROBERT G. ROSENBERG

Education

I have a Bachelor of Arts degree in Political Science, with a minor in Economics, from Hunter College. I received a Master of Business Administration degree with a major in Finance at the New York University Graduate School of Business Administration.

Employment

From 1969 through mid-March 1983, I was employed by the firm of National Economic Research Associates (NERA), reaching the position of Senior Economic Analyst. In March of 1983, I became a principal of Benrose Economic Consultants, Inc., a consulting firm in New York City. In April 2000, I became a principal of Edgewood Consulting, Inc., a firm located in the Capital District area of New York. Edgewood Consulting performs economic research and consulting services for companies, law firms, government agencies and trade associations. Throughout this period, I have concentrated on the analysis of regulated industries, including electric and gas utilities, insurance and steamship companies. I have prepared direct and rebuttal testimony related to financial aspects of utility rate proceedings--e.g., cost of common equity, capital structure, etc. Along with these "typical" rate case issues, I have also testified regarding more unusual matters: intra-company royalty payments; the correct procedure to use in calculating the cost of debt; whether a cogeneration project met Qualifying Facility ownership standards; and responsibility for stranded costs.

I have had numerous assignments involving evaluation, consultation and/or internal reports to clients. Examples of this include: (1) analyzing issues relating to industry restructuring (e.g., implications of Commission-ordered divestiture, the risks associated with the institution of incentive plans, unbundling electric rates, etc.); (2) consulting with a utility company concerning the financial and regulatory aspects of a potential merger and the possible regulatory treatment of an acquisition premium; (3) evaluating the feasibility of instituting an administrative securitization proposal; (4) determining incremental risks flowing from purchased power contracts; and (5) analyzing studies regarding property values near transmission lines.

Outside the regulatory arena, I have estimated financial damages related to (1) breach of contract and (2) earnings losses as a result of injuries. I have also examined stock prices to see if alleged manipulation was likely and have performed economic valuation for employee stock option plan purposes.

I have presented lectures at the Pace University Center for International Business Studies regarding the regulatory process. A number of articles that I authored have been published in *Public Utilities Fortnightly* (PUF).

Appearances Before Regulatory Agencies

I have presented testimony before the Federal Energy Regulatory Commission and the regulatory agencies in the following states: Arizona, Kentucky, Massachusetts, Minnesota, Mississippi, New Hampshire, New Jersey, New York, Pennsylvania, Rhode

Island, South Dakota and Vermont. These testimonies were presented on behalf of: Blackstone Valley Electric Company, Boston Edison Company, Central Hudson Gas & Electric Corporation, Citizens Communications Company, Consolidated Edison Company, Kentucky Utilities Company, Long Island Lighting Company, Louisville Gas and Electric Company, Minnesota Power & Light Company, Mississippi Power Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Northern States Power, Orange & Rockland Utilities, Pacific Gas & Electric Company, Pike County Light & Power Company, Public Service Company of New Hampshire, Public Service Company of New Mexico, Rochester Gas & Electric Corporation and Rockland Electric Company. In addition, I have testified before: the Society of Maritime Arbitrators concerning the estimation of damages in the matter of Empresa Publica de Abastecimento de Cereais (an agency of the Government of Portugal) vs. Point Endeavor Corporation and Tradigrain, Inc.; U.S. Bankruptcy Court regarding financing for an office building in Chapter 11; and the Federal Maritime Commission regarding the fair return for Matson Navigation Company.

WHY THE ARITHMETIC, RATHER THAN THE GEOMETRIC, MEAN SHOULD BE USED IN ESTIMATING EXPECTED FUTURE RETURNS

It has been suggested that in using the Ibbotson historic rate of return data as a proxy for the expected future return, one should employ the geometric mean of the data, rather than the arithmetic mean. I will demonstrate why that contention is incorrect. The only appropriate historic average to use in forecasting expected returns for the future is the arithmetic mean. It is incorrect to use the geometric mean and the use of the geometric mean results in an understated expected future return, as will be demonstrated below.

Before beginning the discussion on this issue, it is perhaps helpful to review the basic definition of the return on an investment that an investor expects (requires). The expected (required) rate of return is the discount rate that equates the future cash flows that an investor expects to receive from an investment with the initial value (i.e., the present value) of that investment. Keeping that basic definition in mind, I will now explain why the arithmetic mean of historic return data is appropriate to use in trying to forecast the expected return in the future.

In examining complicated issues, economists often simplify the actual very complex data or situation of the real world so that the issue in question is more easily examined in the simplified context. I will do so in my discussion below, but note that the principles hold even in the more complex situation of the real world. Let us assume that over a past period, an investment earned a rate of return of either 15 percent or 5 percent, with equal probability. Thus, if we examined an historic period of, say, 100 years, we would expect to find that 50 of those years experienced a 15 percent return, while the remaining 50 years experienced a 5 percent return. Since the two possible returns in this simplified hypothetical example have the same probability, the arithmetic average of these two possible returns would be 10 percent. Having established that the arithmetic average of past returns for the series described is 10 percent, we will now examine whether it is appropriate to use that return as a proxy for expected future returns.

On Attachment 1, I show a hypothetical example of future possible investment outcomes if we assume that the distribution of possible returns from the past continues on into the future--i.e., that the only two possible returns are 15 percent or 5 percent, each with a 50 percent probability. In Column (1) of Attachment 1, I show the two possible returns that can be expected to occur in the future, given that these were the only two returns that occurred in the past in our hypothetical example. In Column (2) of Attachment 1, I show that the initial amount invested is assumed to be \$1.00. In Column (3) I show that at the end of Year 1 an investor could either end up with \$1.15 if the 15 percent return outcome happens or \$1.05 if the 5 percent return possibility happens. Since the \$1.15 outcome and the \$1.05 outcome are equally likely to happen under the hypothesized circumstances, the average possible result (known in financial parlance as the expected value) of this investment at the end of Year 1 is \$1.10--the average of the two possible outcomes that have equal probability. This expected value of the investment of \$1.10 is shown near the bottom of Column (3) of Attachment 1. If the expected value of this investment at the end of Year 1 is \$1.10 and \$1.00 had been invested in Year 0, then clearly the discount factor that equates the expected cash flow at the end of Year 1, should the security be sold, to the value of the initial investment is 1.10 or 10 percent.

Now let us see what are the possible investment outcomes for Year 2 under the hypothesized circumstances. The possible outcomes are shown in Column (4) of Attachment 1 and are explained below. If the investment earns \$1.15 in Year 1 and again, fortunately, earns a 15 percent return in Year 2, then the value of the investment would be \$1.3225 at the end of Year 2 (\$1.15 x 1.15 = \$1.3225). Another possible outcome would be if the investment earns \$1.15 in Year 1 but only earns a 5 percent return in Year 2. This would produce a value at the end of Year 2 of \$1.2075 (\$1.15 x 1.05 = \$1.2075). I will now explain how the third number in Column (4) is derived. If the investment in question earns a 5 percent return in Year 1, but then earns a 15 percent return in Year 2, then the expected value of the investment at the end of Year 2 would be \$1.2075 (\$1.05 x 1.15 = \$1.2075). The fourth possibility in Year 2 is if the investment, unfortunately, only reaches the \$1.05 level at the end of Year 1 and in Year 2 again only experiences a 5 percent return. This would produce the fourth outcome in Column (4), namely \$1.1025 (\$1.05 x 1.05 = \$1.1025).

I have thus explained how one obtains the four possible outcomes at the end of Year 2, as shown in Column (4) of Attachment 1. Given that each of these outcomes has the same probability (because in any given year there is an equal probability of experiencing either a 15 percent return, or a 5 percent return), if we add up the four possible returns and divide by 4, we obtain the expected value of the investment of \$1.21. Thus, even though there are several possible outcomes in Year 2, the expected value of this investment at the end of Year 2 is \$1.21 under the circumstances hypothesized. If the investor <u>expects</u> to be able to sell the investment at the end of Year 2 with a value of \$1.21, then the discount rate that equates the expected receipt of \$1.21 at the end of Year 2 with the initial investment of \$1.00 in Year 0 is 10 percent (\$1.21/[$(1.10)^2$]=\$1.00). Thus, again, as in Year 1, in Year 2 we find that the discount rate, or expected return, on this investment is 10 percent. This means that if an investor invested \$1.00 in Year 0 and expected the return possibilities shown on Attachment 1, that the investor would expect to earn a 10 percent return on his or her investment in either Year 1 or in Year 2.

The data shown for Years 3 and 4, in Columns (5) and (6) on Attachment 1, are derived in a similar manner. I will briefly discuss the data for Year 3 to provide continuity for this explanation. There are eight possible outcomes in Year 3, each with the same probability. Thus, if we sum up the eight possible investment outcomes for Year 3 and divide by 8, we have the average possible outcome or the expected value of the investment at the end of Year 3. As shown in Column (5) on Attachment 1, the expected value of the investment at the end of Year 3 is \$1.331. Thus, if an investor invested \$1.00 in Year 0 and could expect to sell his investment at the end of Year 3 for \$1.331, the expected return on that investment would be 10 percent. The data shown for Year 4, in Column (6) of Attachment 1, are derived in a similar manner and again it is indicated that were the investor to sell his investment at the end of Year 4, he would expect to earn a 10 percent return on the investment. This hypothetical example could be extended out further in time, but the calculations would obviously become very cumbersome. The point holds for future years, but the data for Years 1 through 4 will be used for illustrative purposes in the remainder of this discussion.

The hypothetical example shown on Attachment 1 has demonstrated that under the hypothesized circumstances, in each and every year in the future, investors will expect to earn a return of 10 percent. It is important to note that this 10 percent return that we have calculated that investors could expect in each of the years examined is the same return as the arithmetic average of the two possible return outcomes specified in the hypothetical example, namely 15 percent and 5 percent. Thus, if investors noted that historic return experience was either 5 or 15 percent, with an arithmetic average of 10 percent, and they used this arithmetic average of past returns as a projected return for the future, their projections would exactly match the expected return (or discount rate), derived in the hypothetical example on Attachment 1. Put simply, this demonstrates that the arithmetic average of past rates of return is the appropriate average to use in forecasting expected future returns, assuming that past conditions will continue on into the future.

Now let us leave the discussion of the arithmetic mean briefly in order to discuss the geometric mean. The geometric mean of two returns is calculated as follows:

$$\sqrt{(1 + r_1) \times (1 + r_2)} - 1$$

where r_1 and r_2 are the two returns in question and are expressed in decimal form.

Given that in the prior hypothetical example the only two possible returns were 15 percent or 5 percent, the geometric average of those returns would be calculated as follows:

$$\sqrt{(1 + .15)\ \text{x}\ (1 + .05)} - 1 = .0989 \text{ or } 9.89\%$$

As can be noted above, the geometric mean rate of return for the hypothetical investment we have been discussing is 9.89 percent--less than the 10.00 percent arithmetic mean. From the calculations on Attachment 1, we have shown that if an investor invested \$1.00 at Year 0 in our hypothetical investment, they could expect to have the following values of their investment for each of the years specified:

Initial Investment in Year 0	Expected Value of Investment Year 1	Year 2	Year 3	Year 4
\$1.00	\$1.10	\$1.21	\$1.331	\$1.4641

As noted previously, these expected values of the investment in each year could also be obtained by taking the arithmetic average of historic results (10 percent) and assuming that the investor expects to earn the arithmetic return in each year in the future.

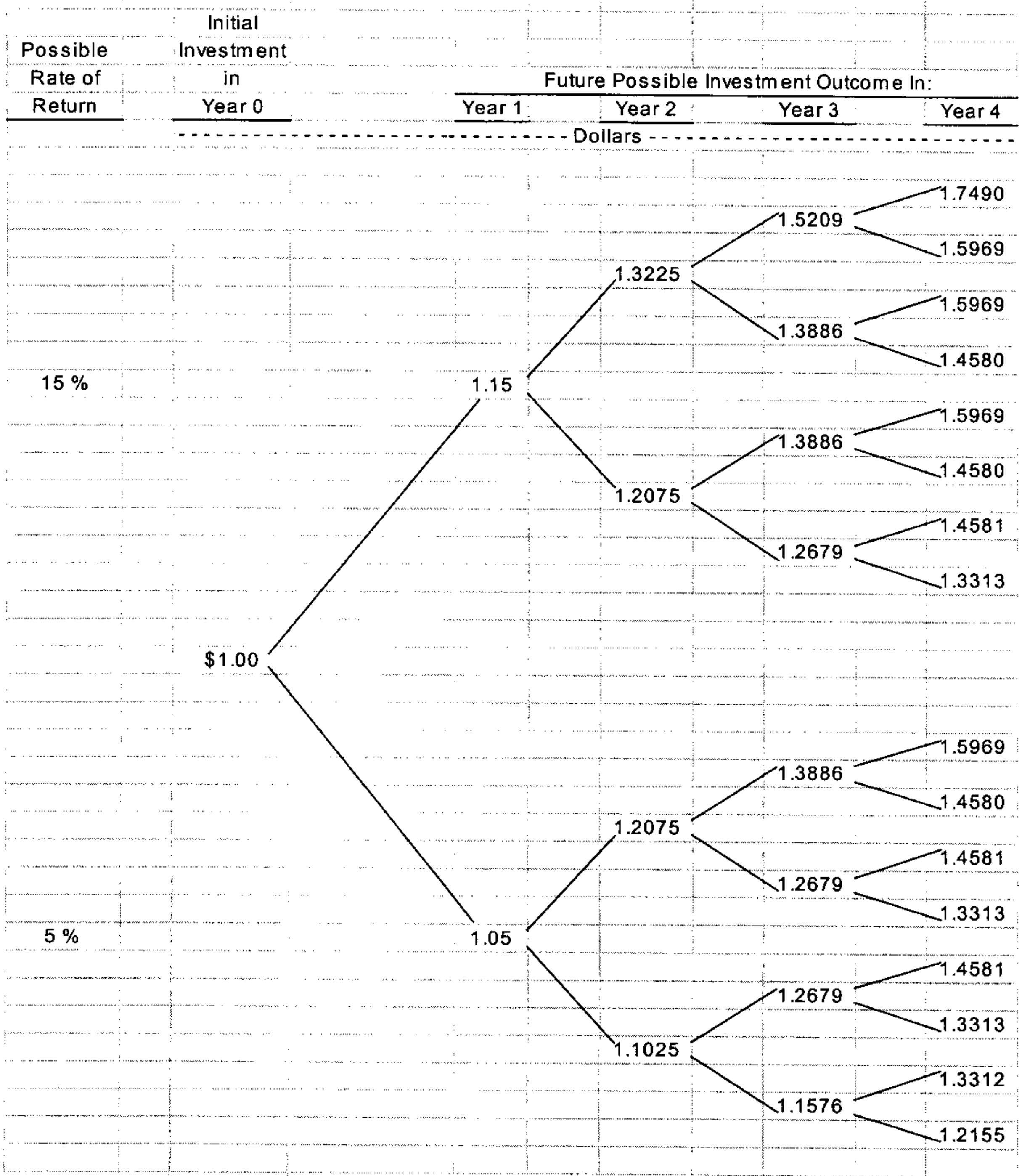
Now let us assume that an investor mistakenly took the 9.89 percent geometric mean from the historic return series and used that to project the returns earned in the future. If an investor invested \$1.00 in Year 0 and expected that he or she would only earn the 9.89 percent geometric mean, then using the geometric mean as a predictor would produce the following data:

Initial Investment in Year 0	Value Produced by Forecasting with Geometric Mean			
	Year 1	Year 2	Year 3	Year 4
$1.00	$1.0989	$1.2076	$1.3270	$1.4582

Note that the values produced above when one uses the geometric mean to forecast future investment outcomes are lower in each and every year than the actual expected value of the investment that was derived on Attachment 1. This means that the geometric mean will produce an understated prediction of the returns that investors expect in the future. As has been demonstrated throughout this discussion, the arithmetic mean of historic rate of return data produces the rate of return that investors expect in the future, assuming that future conditions parallel that of the past. In contrast, use of the geometric mean to forecast future rates of return based on past results will result in an understatement of the forecasted rate of return for the future.

Appendix B
Attachment 1

HYPOTHETICAL EXAMPLE OF FUTURE POSSIBLE INVESTMENT OUTCOMES



	Year 1	Year 2	Year 3	Year 4
Expected Value of Investment	$1.10	$1.2100	$1.3310	$1.4641
Discount Factor	1.10	$(1.10)^2$	$(1.10)^3$	$(1.10)^4$

ELECTRIC COMPARISON GROUP

Alliant Energy Corporation

Ameren Corporation

CH Energy Group

Consolidated Edison

DTE Energy Company

Exelon Corporation

MGE Energy

NSTAR

Pinnacle West Capital Corporation

SCANA Corporation

Southern Company

Vectren Corporation

Wisconsin Energy Corporation

CALCULATION OF SIX-MONTH AVERAGE PRICE
April - September 2003

	Average of Monthly High and Low Price						6-Month Average Price
	April	May	June	July	August	September	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Alliant Energy	$16.96	$18.86	$19.78	$19.56	$20.62	$21.77	$19.59
Ameren	40.12	43.45	45.01	43.18	41.90	42.70	42.73
CH Energy Group	41.88	43.74	44.85	44.25	43.61	44.79	43.85
Consolidated Edison	39.08	41.34	43.09	41.65	39.62	40.15	40.82
DTE Energy	39.74	41.74	41.48	37.35	34.79	36.21	38.55
Exelon	51.55	56.13	59.17	57.30	58.42	61.43	57.33
MGE Energy	27.65	30.01	31.83	32.98	31.00	31.41	30.81
NStar	41.52	45.25	45.95	44.97	44.74	46.46	44.82
Pinnacle West Capital	33.10	35.20	38.50	36.17	33.66	35.46	35.35
SCANA	30.80	32.68	34.54	33.30	33.39	34.51	33.20
Southern Company	28.58	30.07	31.10	29.24	28.15	28.94	29.35
Vectren	22.35	23.98	25.27	23.77	22.87	23.38	23.60
Wisconsin Energy	25.72	26.94	28.67	28.58	27.85	29.94	27.95

Source: MSN Money Central website.

DCF COST OF EQUITY CALCULATION FOR THE COMPARISON GROUP

			Near-Term Projected EPS Growth			Long-Term	
Company	6-Month Average Price	Indicated Dividend	Value Line Projected 5-Year Growth	First Call Projected 5-Year Growth	Average: Value Line and First Call [(3)+(4)]/2	Projected Growth in GDP	DCF Cost of Equity Estimate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Alliant Energy	$19.59	$1.00	5.0 %	4.8 %	4.9 %	5.91 %	11.1 %
Ameren	42.73	2.54	1.0	3.0	2.0	5.91	11.2
CH Energy Group	43.85	2.16	1.5	na	1.5	5.91	10.2
Consolidated Edison	40.82	2.24	1.0	3.0	2.0	5.91	10.8
DTE Energy	38.55	2.06	5.5	5.5	5.5	5.91	11.5
Exelon	57.33	1.92	7.0	5.0	6.0	5.91	9.5
MGE Energy	30.81	1.35	6.0	na	6.0	5.91	10.6
NSTAR	44.82	2.16	3.5	6.0	4.8	5.91	10.8
Pinnacle West	35.35	1.70	0.5	5.0	2.8	5.91	10.4
SCANA	33.20	1.38	5.0	5.0	5.0	5.91	10.1
Southern Company	29.35	1.38	6.5	5.0	5.8	5.91	10.9
Vectren	23.60	1.10	9.0	7.0	8.0	5.91	11.3
Wisconsin Energy	27.95	0.80	8.0	6.5	7.3	5.91	9.1
Median							10.8 %

NA --Not available.

Source:
Col. (1) - Schedule 2.
Col. (2) - Derived from data on the MSN Money Central website.
Col. (3) - Derived from data in *The Value Line Investment Survey*.
Col. (4) - First Call website.
Col. (6) - Derived from data in Energy Information Administration Annual Energy Outlook, 2003.
Col. (7) - Derived iteration using an internal rate of return calculation.

DCF COST OF EQUITY CALCULATION FOR THE COMPARISON GROUP

Company	6-Month Average Price	Indicated Dividend	Near-Term Projected EPS Growth: Value Line Projected 5-Year Growth	Near-Term Projected EPS Growth: First Call Projected 5-Year Growth	Near-Term Projected EPS Growth: Average: Value Line and First Call [(3)+(4)]/2	Long-Term Projected Sustainable Growth	DCF Cost of Equity Estimate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Alliant Energy	$19.59	$1.00	5.0 %	4.8 %	4.9 %	3.0 %	8.7 %
Ameren	42.73	2.54	1.0	3.0	2.0	3.7	9.4
CH Energy Group	43.85	2.16	1.5	na	1.5	1.9	6.8
Consolidated Edison	40.82	2.24	1.0	3.0	2.0	3.4	8.7
DTE Energy	38.55	2.06	5.5	5.5	5.5	6.3	11.8
Exelon	57.33	1.92	7.0	5.0	6.0	13.0	15.8
MGE Energy	30.81	1.35	6.0	na	6.0	8.6	12.9
NSTAR	44.82	2.16	3.5	6.0	4.8	4.4	9.5
Pinnacle West	35.35	1.70	0.5	5.0	2.8	3.4	8.2
SCANA	33.20	1.38	5.0	5.0	5.0	5.2	9.5
Southern Company	29.35	1.38	6.5	5.0	5.8	7.1	11.9
Vectren	23.60	1.10	9.0	7.0	8.0	6.8	12.0
Wisconsin Energy	27.95	0.80	8.0	6.5	7.3	7.0	10.1
Median							9.5 %
Median excluding CH Energy							9.8 %

NA --Not available.

Source:
- Col. (1) - Schedule 2.
- Col. (2) - Derived from data on the MSN Money Central website.
- Col. (3)&(6) - Derived from data in *The Value Line Investment Survey*.
- Col. (4) - First Call website.
- Col. (7) - Derived iteration using an internal rate of return calculation.

DCF COST OF EQUITY CALCULATION FOR THE COMPARISON GROUP

Company	6-Month Average Price	Indicated Dividend	Near-Term Projected EPS Growth: Value Line Projected 5-Year Growth	First Call Projected 5-Year Growth	Average: Value Line and First Call	Long-Term Projected Industry Growth	DCF Cost of Equity Estimate
					[(3)+(4)]/2		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Alliant Energy	$19.59	$1.00	5.0 %	4.8 %	4.9 %	5.3 %	10.6 %
Ameren	42.73	2.54	1.0	3.0	2.0	5.3	10.7
CH Energy Group	43.85	2.16	1.5	na	1.5	5.3	9.7
Consolidated Edison	40.82	2.24	1.0	3.0	2.0	5.3	10.3
DTE Energy	38.55	2.06	5.5	5.5	5.5	5.3	11.0
Exelon	57.33	1.92	7.0	5.0	6.0	5.3	8.9
MGE Energy	30.81	1.35	6.0	na	6.0	5.3	10.1
NSTAR	44.82	2.16	3.5	6.0	4.8	5.3	10.3
Pinnacle West	35.35	1.70	0.5	5.0	2.8	5.3	9.8
SCANA	33.20	1.38	5.0	5.0	5.0	5.3	9.6
Southern Company	29.35	1.38	6.5	5.0	5.8	5.3	10.4
Vectren	23.60	1.10	9.0	7.0	8.0	5.3	10.8
Wisconsin Energy	27.95	0.80	8.0	6.5	7.3	5.3	8.6
Median							10.3 %

NA --Not available.

Source: Col. (1) - Schedule 2.
Col. (2) - Derived from data on the MSN Money Central website.
Col. (3) - Derived from data in *The Value Line Investment Survey*.
Col. (4) - First Call website.
Col. (6) - See text.
Col. (7) - Derived iteration using an internal rate of return calculation.

GAS COMPARISON GROUP

AGL Resources

Atmos Energy

KeySpan

Laclede Group

Northwest Natural Gas

Peoples Energy

CALCULATION OF SIX-MONTH AVERAGE PRICE
April - September 2003

	Average of Monthly High and Low Price						6-Month Average Price
	April	May	June	July	August	September	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
AGL Resources	$24.59	$25.74	$26.13	$26.51	$27.37	$28.13	$26.41
Atmos Energy	22.00	23.68	24.55	24.78	23.95	24.40	23.89
KeySpan	33.06	35.40	35.91	34.66	33.39	34.83	34.54
Laclede Group	23.70	25.36	26.85	27.55	26.48	27.40	26.22
Northwest Natural Gas	25.39	27.02	28.04	27.84	28.02	29.26	27.60
Peoples Energy	37.25	41.53	43.85	42.60	40.45	41.31	41.17

Source: MSN Money Central website.

DCF COST OF EQUITY CALCULATION FOR THE COMPARISON GROUP

Company	6-Month Average Price	Indicated Dividend	Near-Term Projected EPS Growth: Value Line Projected 5-Year Growth	Near-Term Projected EPS Growth: First Call Projected 5-Year Growth	Near-Term Projected EPS Growth: Average: Value Line and First Call [(3)+(4)]/2	Long-Term Projected Growth in GDP	DCF Cost of Equity Estimate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
AGL Resources	$26.41	$1.12	8.0 %	5.5 %	6.8 %	5.91 %	10.6 %
Atmos Energy	23.89	1.20	9.0	6.0	7.5	5.91	11.6
KeySpan	34.54	1.78	7.5	6.0	6.8	5.91	11.6
Laclede Group	26.22	1.34	5.5	4.0	4.8	5.91	11.1
Northwest Natural Gas	27.60	1.26	5.0	5.0	5.0	5.91	10.6
Peoples Energy	41.17	2.12	4.0	5.0	4.5	5.91	11.0
Median							11.1 %

NA --Not available.

Source:
Col. (1) - Schedule 5.
Col. (2) - Derived from data on the MSN Money Central website.
Col. (3) - Derived from data in *The Value Line Investment Survey*.
Col. (4) - First Call website.
Col. (6) - Derived from data in Energy Information Administration Annual Energy Outlook, 2003.
Col. (7) - Derived iteration using an internal rate of return calculation.

DCF COST OF EQUITY CALCULATION FOR THE COMPARISON GROUP

Company	6-Month Average Price	Indicated Dividend	Near-Term Projected EPS Growth: Value Line Projected 5-Year Growth	Near-Term Projected EPS Growth: First Call Projected 5-Year Growth	Near-Term Projected EPS Growth: Average: Value Line and First Call [(3)+(4)]/2	Long-Term Projected Sustainable Growth	DCF Cost of Equity Estimate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
AGL Resources	$26.41	$1.12	8.0 %	5.5 %	6.8 %	8.6 %	12.9 %
Atmos Energy	23.89	1.20	9.0	6.0	7.5	11.2	16.0
KeySpan	34.54	1.78	7.5	6.0	6.8	6.7	12.2
Laclede Group	26.22	1.34	5.5	4.0	4.8	3.0	8.7
Northwest Natural Gas	27.60	1.26	5.0	5.0	5.0	5.3	10.0
Peoples Energy	41.17	2.12	4.0	5.0	4.5	3.1	8.7
Median							11.1 %

NA --Not available.

Source: Col. (1) - Schedule 5.
Col. (2) - Derived from data on the MSN Money Central website.
Col. (3)&(6) - Derived from data in *The Value Line Investment Survey*.
Col. (4) - First Call website.
Col. (7) - Derived iteration using an internal rate of return calculation.

DCF COST OF EQUITY CALCULATION FOR THE COMPARISON GROUP

Company	6-Month Average Price	Indicated Dividend	Near-Term Projected EPS Growth: Value Line Projected 5-Year Growth	Near-Term Projected EPS Growth: First Call Projected 5-Year Growth	Near-Term Projected EPS Growth: Average: Value Line and First Call [(3)+(4)]/2	Long-Term Projected Industry Growth	DCF Cost of Equity Estimate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
AGL Resources	$26.41	$1.12	8.0 %	5.5 %	6.8 %	5.7 %	10.4 %
Atmos Energy	23.89	1.20	9.0	6.0	7.5	5.7	11.4
KeySpan	34.54	1.78	7.5	6.0	6.8	5.7	11.4
Laclede Group	26.22	1.34	5.5	4.0	4.8	5.7	10.9
Northwest Natural Gas	27.60	1.26	5.0	5.0	5.0	5.7	10.4
Peoples Energy	41.17	2.12	4.0	5.0	4.5	5.7	10.9
Median							10.9 %

NA --Not available.

Source: Col. (1) - Schedule 5.
Col. (2) - Derived from data on the MSN Money Central website.
Col. (3) - Derived from data in *The Value Line Investment Survey*.
Col. (4) - First Call website.
Col. (6) - See text.
Col. (7) - Derived iteration using an internal rate of return calculation.

Mr. Beer

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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

TESTIMONY OF
MICHAEL S. BEER
VICE PRESIDENT – RATES AND REGULATORY
LG&E ENERGY CORP.
LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

December 29, 2003

Filed: December 29, 2003

Q. Please state your name, employer, position and business address.

A. My name is Michael S. Beer. I am employed by LG&E Energy Services, Inc. ("LG&E Energy Services"). I am the Vice President of Rates and Regulatory for LG&E Energy Corp. ("LG&E Energy"), Louisville Gas and Electric Company ("LG&E" or "the Company"), and Kentucky Utilities Company ("KU"). My business address is 220 West Main Street, Louisville, Kentucky. A statement of my qualification is attached as Appendix A.

Q. What is the relationship between LG&E Energy Services and LG&E?

A. LG&E and LG&E Energy Services are both subsidiaries of LG&E Energy. LG&E Energy Services was formed and became operational in January 2001, following completion of the Powergen merger. The Public Utility Holding Company Act of 1935 ("PUHCA") requires that registered holding company systems form a service company to perform work, services or construction for, or provide goods to, affiliate companies. Employees, including officers, who regularly provide work or services for more than one affiliate, such as LG&E or KU, are employees of LG&E Energy Services in compliance with PUHCA. This type of arrangement is common in holding company structures throughout the utility industry.

Q. Have you previously testified before this Commission?

A. Yes. I testified on regulatory policies in Case No. 2001-104, *In the Matter of: Joint Application for Transfer of Louisville Gas and Electric Company and Kentucky Utilities Company in Accordance With E.ON AG's Planned Acquisition of Powergen plc*, and have testified in environmental surcharge proceedings and cases involving requests by LG&E and KU for Certificates of Convenience and Necessity.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support certain exhibits identified below which are required by the Commission's regulations; to describe the revenue effect of the proposed rates; to present the Company's recommendation for the allocation of the proposed increase in revenues among the customer classes based on the results of the Company's cost-of-service study prepared by The Prime Group and sponsored by W. Steven Seelye in this case; to discuss the effect of the various billing mechanisms on the requested rate increase; and to present the Company's position on the expenses it has incurred for its membership in the Midwest Independent Transmission System Operator, Inc.

Q. Are you supporting the schedules that are required by Commission regulations 807 KAR 5:001, Section 10(1)(a)1-9 and 807 KAR 5:001, Sections 10(2) through Section 10(5)?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

• Reason for Rate Adjustment	Section 10(1)(a)1	Tab 1
• Most Recent Annual Reports	Section 10(1)(a)2	Tab 2
• Articles of Incorporation	Section 10(1)(a)3	Tab 3
• Limited Partnership Agreement	Section 10(1)(a)4	Tab 4
• Certificate of Good Standing	Section 10(1)(a)5	Tab 5
• Certificate of Assumed Name	Section 10(1)(a)6	Tab 6
• Proposed Tariff	Section 10(1)(a)7	Tab 7
• Proposed Tariff Changes	Section 10(1)(a)8	Tab 8
• Statement of Customer Notice	Section 10(1)(a)9	Tab 9

I am also sponsoring the schedules filed in connection with Commission regulation 807 KAR 5:001, Section 10(2) – (5):

• Notice of Intent	Section 10(2)	Tab 10
• Customer Notice Information	Section 10(3)	Tab 11
• Sewer Utility Notices	Section 10(4)(a)	Tab 12
• Typewritten Notices by Mail	Section 10(4)(b)	Tab 13
• Other Customer Notices	Section 10(4)(c)	Tab 14
• Publisher's Affidavit	Section 10(4)(d)	Tab 15
• Verification – Mailed Notices	Section 10(4)(e)	Tab 16
• Sample Notices Posted	Section 10(4)(f)	Tab 17
• Compliance with 807 KAR 5:051, Section 2	Section 10(4)(g)	Tab 18
• Hearing Notice Published	Section 10(5)	Tab 19

Q. Who is supporting certain information required by Commission regulation 807 KAR 5:001, Section 10(6)(a)-(v) and Section 10(7)(e)?

A. I am sponsoring the following schedules for the corresponding Filing Requirements:

• Local Telephone Exchange Companies	Section 10(6)(f)	Tab 25
• Local Telephone Exchange Companies	Section 10(6)(v)	Tab 41

The following required schedules will by sponsored by Mr. Seelye:

• New Rates Effect – Overall Revenues	Section 10(6)(d)	Tab 23
• Average Customer Class Bill Impact	Section 10(6)(e)	Tab 24
• Analysis of Customer Bills	Section 10(6)(g)	Tab 26
• Cost-of-Service Study	Section 10(6)(u)	Tab 40
• Period-End Customer Additions	Section 10(7)(e)	Tab 46

Q. Why is LG&E filing for a general adjustment of its rates?

A. LG&E has not sought an increase in its base electric rates in 13 years, or in its base gas rates for nearly 4 years. Several factors have affected LG&E's cost of doing business in recent years.

On the electric side of LG&E's business, for example, since December 31, 1998, the end of the test year used in Case No. 98-426, LG&E has increased its net investment in plant for electric operations by over $400 million. And, comparing the twelve months ended September 30, 2003 with the test year used in Case No. 98-426, the Company has incurred approximately $24 million in additional depreciation expense, on a pro forma basis, associated with those net investments in plant. During that same time period, on the electric side of the business, LG&E's employee pension and post-retirement expenses have increased about $10 million, on a pro forma basis, as a result of the decline in financial market performance, and the Company has seen an approximately $4 million rise in property insurance costs. LG&E has also incurred approximately $3 million in MISO Schedule 10 administrative costs, which are not currently being recovered, and has experienced significant increases in its operating expenses for electric operations, such as higher wage rates, due in part to inflation.

With regard to gas operations, since December 31, 1999, the end of the test year used in Case No. 2000-080, LG&E has increased its net investment in plant for gas operations by over $47 million. And, comparing the twelve months ended September 30, 2003 with the test year used in Case No. 2000-080, the Company has incurred approximately $5 million in additional depreciation expense, on a pro forma basis, associated with those net investments in plant. During that same time period, on the gas side of the business, LG&E's employee pension and post-retirement expenses have increased approximately $4 million, on a pro forma basis, as a result of the decline in financial market performance. LG&E has also experienced significant increases in its operating expenses for gas operations, such as higher wage rates, due in part to inflation.

Since our last base rate increases, LG&E has made extraordinary efforts to control the rising cost of doing business. However, our ability to continue to provide safe and reliable energy service to our customers is predicated on our ability to earn sufficient revenues to operate in such a manner, as well as to attract capital at competitive costs. LG&E now seeks an increase in both gas and electric rates in order to provide it an opportunity to recover sufficient revenues to operate in a safe and reliable manner, maintain its financial integrity, and properly compensate its shareholders for the risks assumed with respect to jurisdictional operations. The proposed rates are reasonable and will permit recovery of the increased costs of doing business.

Revenue Effect

Q. What is the revenue effect of the proposed rates?

A. As shown in Tab 23 of the Company's Filing Requirements, attached to the Application in this case, the total increase in revenues to LG&E that would result from the proposed rate adjustments is $63.8 million for electric operations and $19.1 million for gas operations.

Q. If the Commission approves the proposed rates, what will be the percentage increase in monthly residential gas and electric bills?

A. The monthly residential electric bill will increase by 10.70%, or approximately $6.00, for a customer using 1000 Kwh of electricity. The monthly residential gas bill will increase by 6.50%, or approximately $5.50, for a customer using 90 Ccf of gas.

Revenue Allocation

Q. Has LG&E analyzed how the proposed increase in revenue should be allocated among its customers?

A. Yes. LG&E engaged The Prime Group to analyze the existing class rates of return to determine whether any significant cross-subsidization existed between customer classes. The Prime Group conducted a fully-allocated, embedded cost-of-service study. For electric operations, that study was also time-differentiated. The details of that study are presented in the direct testimony of Mr. Seelye. However, a summary of the results of that study, reflecting the pro forma rate of return for the principal rate schedules, is set forth below:

Beer Table I – Pro Forma Electric Rates of Return

Customer Class	LG&E Electric
Residential Rate R	1.51%
General Service Rate GS	8.55%
Large Commercial – Rate LC - Primary - Secondary	 1.00% 6.66%
Industrial Power – Rate LP - Primary - Secondary	 5.48% 8.26%
Large Commercial Time of Day – Rate LC-TOD - Primary - Secondary	 5.92% 5.95%
Industrial Power Time of Day – Rate LP-TOD - Transmission - Primary - Secondary	 5.38% 3.79% 6.58%
Special Contracts	5.33%
Total System	4.06%

Beer Table II – Pro Forma Gas Rates of Return

Customer Class	LG&E Gas
Residential - Rate RGS	1.75%
Commercial – Rate CGS	6.85%
Industrial – Rate IGS	6.42%
As Available Service – Rate AAGS	10.54%
Firm Transportation Service – Rate FT	30.53%
Special Contracts	21.27%
Total System	3.56%

These returns show that there are significant disparities among the class rates of return in both LG&E's gas and electric operations.

Q. How will LG&E's recommendation for the allocation of the rate increases among its customer classes affect the rates of return for those classes?

A. The rates of return for the principal customer classes, which result from LG&E's proposed allocation of the rate increases, are summarized in the following tables:

Beer Table III –

Pro Forma Electric Rates of Return as Adjusted for Proposed Increase

Customer Class	**LG&E Electric**
Residential Rate R	3.57%
General Service Rate GS	11.33%
Large Commercial – Rate LC	
- Primary	9.75%
- Secondary	9.22%
Industrial Power – Rate LP	
- Primary	9.39%
- Secondary	11.3%
Large Commercial Time of Day – Rate LC-TOD	
- Primary	8.14%
- Secondary	7.72%
Industrial Power Time of Day – Rate LP-TOD	
- Transmission	7.18%
- Primary	5.75%
- Secondary	9.22%
Special Contracts	7.87%
Total System	6.31%

Beer Table IV –

Pro Forma Gas Rates of Return as Adjusted for Proposed Increase

Customer Class	**LG&E Gas**
Residential - Rate RGS	6.15%
Commercial – Rate CGS	8.23%
Industrial – Rate IGS	8.38%
As Available Service – Rate AAGS	10.69%
Firm Transportation Service – Rate FT	30.55%
Special Contracts	21.29%
Total System	7.14%

Again, this is a summary only. The Prime Group's study discusses this issue in more detail.

Q. Please explain LG&E's rationale for the proposed allocation of its electric revenue deficiency among rate classes.

A. The proposed allocation is designed to transition towards a better balance between class rates of return, while at the same time recognizing other ratemaking objectives such as customer acceptance, gradualism and the need to maintain price stability by avoiding overly disruptive changes. To this end, although the proposal is based on, and uses as a starting point, the cost-of-service study summarized in Mr. Seelye's testimony, it does not give full effect to that cost-of-service study.

Q. Did LG&E provide any guidance to The Prime Group in developing the electric rates for this proceeding?

A. Yes. First, consistent with the ratemaking objectives noted above, the Company advised The Prime Group that, notwithstanding its cost-of-service study results, the total residential revenue increase should be no more than one percentage point above the overall percentage increase to ultimate consumers. LG&E advised that the cost-of-service study should otherwise guide the revenue increase to the other customer classes. Second, we advised The Prime Group, with regard to the rate design, that unit charges should reflect the cost-of-service study as nearly as practicable so that customer charges were more reflective of customer-related costs, demand charges were more reflective of demand-related costs, and energy/commodities charges were more reflective of energy/commodity-related costs. Finally, we advised The Prime Group to simplify rate design whenever feasible.

Q. You suggested that the ratemaking objectives of gradualism, rate stability and customer acceptance justified a departure from the cost-of-service study for purposes of cost allocation among electric rate classes. Please elaborate on why you limited the increase for the electric residential class in the manner proposed.

A. As discussed in the testimony of Mr. Seelye, the cost-of-service study demonstrates that the rates for the electric residential class would have to be increased by approximately 29% to recover all of its costs. This compares to an overall increase of 11.34% requested by LG&E for electric operations. We were concerned that proposing an increase in rates fully consistent with the cost-of-service study would simply have too significant an impact on our residential customers. As a result, and again in recognition of the ratemaking principles of gradualism, rate continuity and customer acceptance, we limited the increase of total revenue from the residential class to 1% above the overall increase to all other customers. As noted, however, we did use the cost-of-service study as a guide in allocating increases to all other classes of electric customers.

Q. Did the Company place any limits on the increase for residential gas customers?

A. No. The Company chose to follow more closely the cost-of-service study for its gas customers, including those customers in the residential class. The magnitude of the increase on the electric side of the business, on a percentage basis, is much greater than gas. The proposed increase of LG&E's electric residential rate class is 12.32%, even applying principles of gradualism. On the gas side, however, the increase, even more closely following the cost-of-service, is only 7.60% for the gas residential class. In addition, as can be seen from Beer Table II, the rates of return among gas service customer classes were so widely disparate that it did not make sense to place a limit on the amount of only the increase to the residential class. Further, most of the capital expenditures on gas infrastructure were related to main replacement, which benefits primarily residential and commercial customers, and most of the customer additions were to the residential class. Finally, on the gas side, there is a very real threat that industrial customers may attempt to bypass the Company altogether and connect to interstate transmission pipelines directly.

Relationship of Other Ratemaking Mechanisms to Base Rates

Q. Please give an overview of the composition of LG&E's current retail rates.

A. In addition to the base rates, certain cost items, such as fuel costs, demand-side management plan costs, and environmental compliance costs are included in our retail rates but are tracked separately from base rates.

Q. Do ratemaking mechanisms such as the fuel adjustment clause, gas supply clause, environmental cost recovery/environmental surcharge, earnings-sharing mechanism

("ESM") or demand-side management cost recovery have any effect on the base rate increase which LG&E is requesting?

A. No. As discussed in detail in the testimony of Bradford Rives, the impact of those billing mechanisms has been removed from LG&E's operating revenues and expenses for the test year ended September 30, 2003, and have no effect on the base rate increase which LG&E is requesting in this case. In addition, by allowing these costs to be handled separately, there is no double recovery of these costs.

<u>**MISO**</u>

Q. Has LG&E incurred new costs since its last electric rate case in 1990 because of the changes in regulation by the Federal Energy Regulatory Commission ("FERC")?

A. Yes. Since then, there have been significant changes in the methods of regulation used by the FERC to regulate the use and operation of the transmission systems of utilities, including the use of regional transmission organizations to facilitate transmission services and power sales in the wholesale power market. In 2001, MISO became the nation's first FERC approved Regional Transmission Organization ("RTO"). As an RTO, MISO's mission is to provide non-discriminatory, open access transmission service across its multi-state geographic footprint. LG&E and KU are members of MISO which, as of December 31, 2002, had 72 members.

For the 12 months ended September 30, 2003, LG&E incurred $2.6 million in MISO Schedule 10 administrative costs. Those FERC-approved charges are now part of LG&E's cost-of-service and represent costs that are not currently reflected in LG&E's base rates. LG&E has included $3.3 million in its revenue requirement in this case to account for the ongoing costs of MISO membership. That number is higher than the costs noted above for the test year ended September 20, 2003, because, as discussed in the testimony of Valerie Scott, there were credits received during the test year which will not be received by the Company going forward.

Q. **The Commission is currently investigating the membership of LG&E and KU in MISO, in Case No. 2003-00266. If LG&E is ordered to withdraw from MISO, would such a withdrawal require LG&E to incur any costs under the terms of the MISO Agreement?**

A Yes, withdrawal would trigger the imposition of an exit fee under the MISO Agreement. Pursuant to the Transmission Owners Agreement, "[a]ll financial obligations and payments applicable to time periods prior to the effective date of [the withdrawing member's] withdrawal shall be honored by" MISO and the withdrawing member. MISO Agreement, Article Five, Section II(B). The amount of the exit fee payable by LG&E has been raised before the Commission in Case No. 2003-00266.

Q. **If the Commission ultimately issues a decision in Case No. 2003-00266 authorizing or requiring LG&E to remain in MISO, would such an order alter LG&E's base rate recovery of the ongoing MISO costs we have proposed in this rate filing?**

A. Provided the Commission allows the recovery of associated costs, it would not. If the Commission ultimately determines in Case No. 2003-00266 that LG&E's membership in MISO is in the public interest, LG&E will continue its membership in MISO and will continue to recover its ongoing MISO membership costs through the new base rates established in this proceeding.

Q. Alternatively, if the Commission ultimately issues a decision in Case No. 2003-00266 requiring LG&E to exit MISO, would such an order alter LG&E's base rate recovery of the ongoing MISO costs we have proposed in this rate filing?

A. Yes, but only after LG&E has received all necessary approvals to exit. Specifically, if the Commission issues an order in Case No. 2003-00266 that LG&E's membership in MISO is not in the public interest, and LG&E is ordered to seek withdrawal from MISO, LG&E would propose to continue to recover, through base rates as described above, all costs incurred in connection with its ongoing MISO membership obligations pending receipt of a FERC order authorizing such withdrawal. Upon receipt of such FERC authorization, the Company would take the requisite ratemaking steps (through a filing with the Commission) to remove the ongoing MISO-related expenses from base rates, and begin amortization and base rate recovery of the fixed exit fee described above over a specific term. Such a two-pronged recovery approach ensures that LG&E will not recover concurrently both ongoing MISO membership costs and exit fee costs.

Q. Does this conclude your testimony?

A. Yes.

278704.15

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Michael S. Beer**, being duly sworn, deposes and says he is the Vice President of Rates and Regulatory for Louisville Gas and Electric Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

MICHAEL S. BEER

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Melody L. Hulse (SEAL)
Notary Public

My Commission Expires:

November 26, 2007

APPENDIX A

Michael S. Beer

Vice President – Rates and Regulatory
LG&E Energy Corp.
220 West Main Street
Louisville, Kentucky 40202
(502) 627-3547

Education

Illinois Wesleyan University, B.A. in Business Administration – 1980
The John Marshall Law School, Juris Doctor (with Distinction) -- 1987

Previous Positions

Louisville Gas and Electric Company, Louisville, KY.:
- 2000-2001 – Senior Counsel Specialist-Regulatory
- 1998 – 2000 – Senior Corporate Attorney

Illinois Power Company, Decatur, Illinois
- 1997 – 1998 – Director of Federal Regulatory Affairs
- 1995 – 1997 – Senior Attorney
- 1992 – 1995 – Attorney

Soyland Power Cooperative Inc., Decatur, Illinois
- 1998 – 1991 – Attorney
- 1982 – 1984 – Contract Buyer

Millikin University, Decatur, Illinois
- January 1996 – December 1998 – Adjunct Associate Professor of Business Law
- August 1988 – December 1995 – Adjunct Assistant Professor of Business Law

Samuels, Miller, Schroeder, Jackson & Sly, Decatur, Illinois
- 1987 – 1988 – Associate

Beerman, Swerdlove, Woloshin, Barezky & Berkson, Chicago, Illinois
- 1985 – 1987 – Law Clerk

Professional/Trade Memberships

American Bar Association
Energy Bar Association
Illinois State Bar Association

Civic Activities

Volunteers of America (Kentucky & Tennessee Chapter), Director
The Louisville Orchestra, Director

Mr. Seelye

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY OF
WILLIAM STEVEN SEELYE

PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

December 29, 2003

Filed: December 29, 2003

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6435 West Highway 146, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility marketing, regulatory analysis, cost of service, rate design and fuel and power procurement.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to sponsor the fully allocated class cost of service studies based on Louisville Gas and Electric Company's ("LG&E's") embedded cost of providing both electric and natural gas service for the 12 months ended September 30, 2003; to sponsor certain pro-forma revenue and expense adjustments; to describe the proposed allocation of the revenue increase; to sponsor LG&E's proposed rates for electric and natural gas service; and to discuss the revenue impact of modifying certain miscellaneous charges.

Q. Please summarize your testimony.

A. We prepared fully allocated, embedded cost of service studies for LG&E's gas and electric operations using cost of service methodologies that have been accepted by the Commission in previous rate cases. The purpose of these studies is to determine the contribution that each customer class is making towards LG&E's overall rate of return. Rates of return are computed for each rate class. Both studies show a significant variation in the class rates of return. However, the class rates of return for LG&E's gas business vary more significantly than for the electric business.

LG&E was guided by the embedded cost of service studies in allocating the proposed revenue increase to the classes of service for both gas and electric operations. However, we followed the cost of service study more closely in allocating the gas increase to the customer classes. LG&E adhered more closely to the gas cost of service study primarily for the following reasons: First, the class rates of return for the gas business were much more out of line than they were for the electric business. Second, the overall percentage increase for the gas business was lower than for the electric business. LG&E is requesting an overall increase of 11.34% to electric ultimate consumers and 5.42% to gas ultimate consumers. Third, there are competitive issues that cannot be ignored in developing rates for the gas business. A major interstate pipeline runs directly through LG&E's service territory. As a result, there is a serious threat of by-pass on LG&E's gas system. Allocating a portion of the proposed increase to transportation rates, which already indicate high rates of return, would provide an even greater impetus for customers to physically bypass LG&E's distribution system and connect directly to the interstate pipeline.

As already mentioned, in allocating the proposed gas revenue increase, we closely followed the cost of service study. In allocating the proposed electric increase LG&E moderated the increase allocated to residential and lighting customers. Developing a cost-based residential rate for electric customers would have required an increase in residential rates of 28.91%. As discussed in the testimony of Michael S. Beer, LG&E felt that this would have been too large an increase to residential customers. Therefore, the residential rate increase was limited to approximately 1 percentage point above the overall percentage increase. Accordingly, LG&E is proposing a rate increase of 12.32% for the residential class as compared to an overall 11.34% increase for ultimate consumers. The residential increase is thus slightly less than 1 percentage point above the overall increase. For other classes, we allocated the increase to facilitate the transition to cost of service as much as practicable.

In designing rates, we developed unit charges that more closely correspond to the unit costs indicated by the cost of service study. For residential electric rates, LG&E is proposing an increase in the customer charge that will reflect 66.7% of the customer-related costs shown in the cost of service study. Although we are not proposing to recover all of the customer-related costs through the customer charge, LG&E's proposed residential customer charge will represent a significant movement in the direction of reflecting cost of service.

LG&E is also proposing to eliminate the summer inverted-block and winter declining-block rate for residential electric customers. These rate structures, especially the summer inverted-block rate, cannot be supported by the cost of service study. In examining this issue we analyzed the relationship between customer load factor and customer usage and found that the relationship does not support a blocked rate structure. Specifically, three statistical analyses were performed: (i) a statistical analysis of the relationship between monthly non-coincident peak load factor and monthly kWh energy usage; (ii) a statistical analysis of the relationship between monthly coincident peak load factor and customer usage during the summer months; (iii) a statistical analysis of the relationship between coincident peak load factor and monthly kWh energy usage during the winter months. The purpose of these statistical analyses was to correlate energy usage to key drivers in the cost of service study, namely summer coincident demand, winter coincident demand, and maximum customer demands. Neither of the two analyses examining coincident peak load factors provided any support for LG&E's current block structure. The only support indicated by any of these analyses is for a year-round declining-block rate; however, the statistics supporting this conclusion were not strong. Furthermore, the pricing decrements in the declining-block rate supported by the analysis would have been small. For these reasons, LG&E is proposing a flat energy charge, which is more reflective of the cost of providing service, is easier for customers to understand, and will decrease the volatility in customer bills during the summer months when customer usage is higher because of air-conditioning requirements.

LG&E is also proposing to transition the customer charge for commercial and industrial customers toward the customer-related costs indicated in the cost of service study. Additionally, we are proposing to move the demand and energy charges toward cost of service. This generally translates into decreasing the energy charge and increasing the demand charge for demand/energy rates. LG&E is also proposing to increase the per kW credit provided to curtailable/interruptible customers based on the results of an analysis of current avoided capacity costs of a combustion turbine.

We are implementing a redundant capacity charge for customers with backup distribution feeds. As they rely more heavily on technology, commercial and industrial customers are installing backup distribution feeds with automatic switchgear to guard against electric service interruptions. LG&E's proposed redundant capacity rate will allow the utility to provide this service without adversely impacting other customers that do not require the same level of reliability.

As much as possible, we are also trying to simplify LG&E's rate schedules and tariff language. Furthermore, LG&E is making changes to harmonize the service schedules offered by LG&E and Kentucky Utilities Company so that operating practices and policies are more consistent between the two companies. KU and LG&E have consolidated many of the operating departments that use the tariffs and must explain rate schedules to customers. Harmonizing tariffs between the companies is important if the utilities are to achieve the cost savings contemplated by their merger.

Q. Are you supporting certain information required by Commission Regulations 807 KAR 5:001, Section 10(6)(a)-(v)?

A. Yes. I am sponsoring the following schedules for the corresponding Filing Requirements:

• New Rates Effect – Overall Revenues	Section 10(6)(d)	Tab 23
• Average Customer Class Bill Impact	Section 10(6)(e)	Tab 24
• Analysis of Customer Bills	Section 10(6)(g)	Tab 26
• Cost of Service Study	Section 10(6)(u)	Tab 40
• Period-End Customer Additions	Section 10(7)(e)	Tab 46

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Qualifications, (II) Gas Cost of Service, (III) Gas Pro-forma Adjustments, (IV) Gas Revenue Allocation and Rates, (V) Electric Cost of Service (VI) Electric Pro-Forma Adjustments, (VII) Electric Revenue Allocation and Rates, and (VIII) Miscellaneous Service Charges.

I. QUALIFICATIONS

Q. Please describe your educational background and prior work experience.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). From May 1979 until December, 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E.

Since leaving LG&E, I have provided consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs. Specifically, I have prepared and filed Order No. 888 and Order No. 889 compliance filings at the Federal Energy Regulatory Commission ("FERC") for a number of electric utilities as well as Order No. 888 and Order No. 889 waiver requests for other utilities. I have prepared market power analyses in support of market-based rate filings at FERC for utilities and their marketing affiliates, as well as assisting other utilities with their market-based rate filings. I have assisted utilities with developing strategic marketing plans and implementing these plans. I have provided utility clients with assistance regarding regulatory policy and strategy; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; the unbundling of rates and the development of menus of rate alternatives for use with customers; and performance-based rate development. I have provided training to account executives in sales and customer negotiation, as well as providing training in ratemaking and utility finance regarding basic utility marketing. I have provided marketing, market research and marketing support services for utility clients and have assisted them in assessing their marketing capabilities and processes.

Q. Have you ever testified before any state or federal regulatory commissions?

A. Yes, on a number of occasions. In Kentucky, I testified in Administrative Case No. 244 regarding rates for co-generators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings. I testified in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg City's Utilities Commission ("Prestonsburg") rates. I testified in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. ("Delta") concerning its rate stabilization plan and in Case No. 99-176 concerning cost of service, rate design and expense adjustments in connection with Delta's rate case. In Case No. 2000-080, I testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses. In Florida, I testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service. I also testified in Alabama in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments. In Illinois, I testified in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service. In Colorado, I testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case. I submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program. I submitted testimony on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings. I testified before the FERC in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment. I testified before the Public Utilities Commission of Nevada on behalf of Nevada Power Company in Case No. 03-10001 regarding cash working capital. Most recently, I testified before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company in Case No. 03-12002 regarding cash working capital.

II. GAS COST OF SERVICE

Q. Did you prepare a cost of service study for LG&E's natural gas operations based on financial and operating results for the 12 months ended September 30, 2003?

A. Yes. I supervised the preparation of a fully allocated, embedded cost of service study for natural gas service based on LG&E's accounting costs per books, adjusted for known and measurable changes to test year operating results, for the 12 months ended September 30, 2003. The Commission in other rate case proceedings has accepted the methodologies used in LG&E's gas cost of service study. The cost of service study corresponds to the pro-forma financial exhibits included in the testimony of S. Bradford Rives. The objective in performing the natural gas cost of service study is to determine the rate of return on rate base that LG&E is earning from each customer class, which provides an indication as to whether LG&E's gas service rates reflect the cost of providing service to each customer class.

Q. Have you ever prepared an embedded gas cost of service study?

A. Yes, on many occasions. While employed at LG&E, I prepared numerous gas and electric cost of service studies, many of which were filed in rate cases before the Commission. Since leaving LG&E, I have prepared or supervised the preparation of well over 100 embedded cost of service studies for electric, gas and water utilities. Although I have prepared many cost of service studies for gas utilities, the majority of the studies have been for electric utilities. I supervised and participated in the preparation of the embedded gas cost of service study submitted in LG&E's last gas rate case, Case No.

2000-080, and the embedded cost of service study submitted in Delta Natural Gas Company, Inc.'s last rate case, Case No. 99-176.

Q. Did you develop the model used to perform LG&E's cost of service studies?

A. Yes. I developed the spreadsheet model used to perform the gas and electric cost of service studies being submitted in this proceeding.

Q. What procedure was used in performing the cost of service study?

A. The cost of service study was prepared using the following basic procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups, (2) costs were then *classified* as commodity-related, demand-related, or customer-related; and then (3) costs were allocated to LG&E's rate classes. These steps are depicted in the following diagram (Figure 1). This is a standard approach utilized in the preparation of embedded cost of service studies for gas utilities.

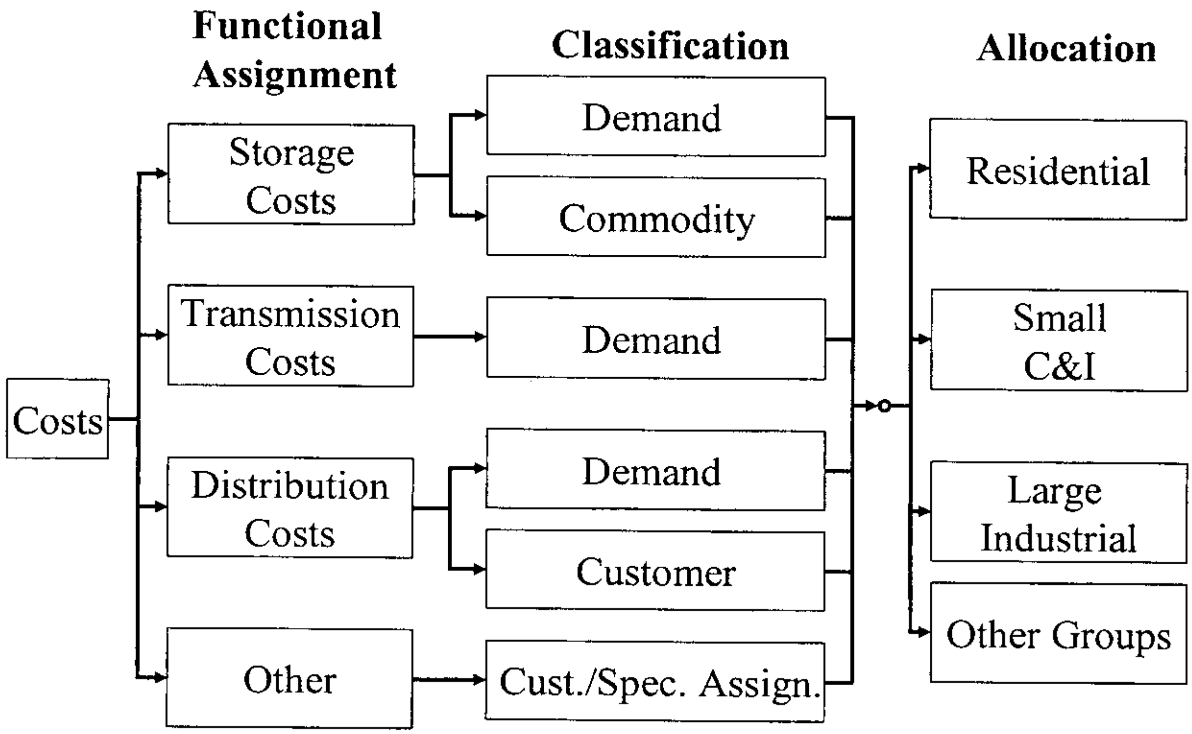


Figure 1

Q. What is the purpose of functionally assigning costs?

A. Functional assignment serves the following purposes: (1) it groups associated costs together to facilitate allocation on the basis of cost responsibility; (2) it provides a rational mechanism for grouping costs that do not appear to be related to major service functions; and (3) it provides a mechanism for separating assignable costs from joint costs, which must be allocated. The process of rate unbundling begins with functionally assigning the costs. Later, in developing rates, it is possible to unbundle rates to a level corresponding to the original functional assignment in the cost of service study.

Q. What functional groups were used in the natural gas cost of service study?

A. The following standard functional groups were identified in the cost of service study: (1) Procurement, (2) Storage, (3) Transmission, (4) Distribution Commodity, (5) Distribution Structures and Equipment, (6) Distribution Mains - Low and Medium Pressure, (7) Distribution Mains - High Pressure, (8) Services, (9) Meters, (10) Customer Accounts, and (11) Customer Service Expense.

Q. How were costs classified as commodity related, demand related or customer related?

A. Classification provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. Costs classified as *commodity related* tend to vary with the quantity of gas delivered, such as gas supply and the operation of compressors. Since gas supply costs were removed from the cost of service study, it was not necessary to classify gas supply costs. Costs classified as *demand related* are costs related to facilities installed to meet design-day usage requirements. Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of gas purchased or the peak requirements of the customers. All transmission plant costs were classified as demand related and are allocated on the same basis as storage. Unlike other local gas distribution companies ("LDCs"), LG&E's transmission system is used primarily to get gas in and out of its gas storage fields. Distribution Structures and Equipment costs were classified as demand-related. As will be discussed later in my testimony, costs related to Distribution Mains were functionally assigned as either low and medium pressure mains or high-pressure mains and then classified as demand-related and customer-related using the zero intercept methodology. Services, Meters, Customer Accounts, and Customer Service Expenses were classified as customer-related.

Q. Have you prepared an exhibit showing the results of the functional assignment and classification steps of the cost of service study?

A. Yes. Seelye Exhibit 1 shows the results of the first two steps of the natural gas cost of service study, functional assignment and classification.

Q. In your cost of service model, once costs are functionally assigned and classified, how are these costs allocated to the customer classes?

A. In the cost of service model used in this study, LG&E's accounting costs are functionally assigned and classified using what are referred to in the model as "functional vectors". These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Seelye Exhibit 1, LG&E's accounting costs are functionally assigned and classified using the explicitly determined functional vectors of the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 27 and 28 of Seelye Exhibit 1. Internally generated functional vectors are utilized throughout the study to functionally assign costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are shown on pages 29 and 30 of Seelye Exhibit 1. An example of this process is the use of total operation and maintenance expenses excluding gas supply expenses ("OMT") to allocate cash working capital included in rate base. Because cash working capital is determined on the basis of 12.5% of operation and maintenance expenses, exclusive of gas supply expenses, it is appropriate to functionally assign and classify these costs on the same basis. (See Seelye Exhibit 1, pages 5 and 6 for the functional assignment of cash working capital on the basis of OMT shown on pages 21 and 22.) The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name".

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors". This process is illustrated in Figure 2 below.

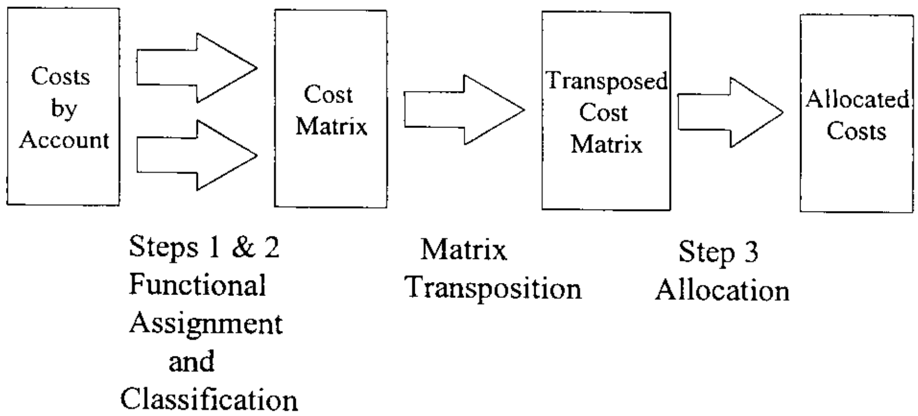


Figure 2

The results of the class allocation step of the cost of service study are included in Seelye Exhibit 2. The costs shown in the column labeled "Total System" in Seelye Exhibit 2 were carried forward *from* the functionally assigned and classified costs shown in Seelye Exhibit 1. The column labeled "Ref" in Seelye Exhibit 2 provides a reference to the results included in Seelye Exhibit 1.

Q. Please describe the allocation factors used in the gas cost of service study.

A. The following allocation factors were used in the gas cost of service study:

- **DEM01** is used to allocate procurement demand-related costs; these costs are the procurement-related expenses that are not recovered through LG&E's Gas Supply Clause.

- **DEM02** is used to allocate Storage demand-related costs and represents a composite allocation based on extreme winter season requirements and design day demands. The class allocation factor is the sum of (a) the volumes (commodity) withdrawn from storage during the design winter season, and (b) the volumes needed in storage to meet the design-day demands. The calculation of this allocation factor is shown on Seelye Exhibit 3.

- **DEM03** is used to allocate Transmission demand-related costs and is allocated on the same basis as storage demand. Because LG&E's transmission lines are used to either fill the storage fields or remove gas from storage, transmission demand-related costs are allocated on the same basis as storage demand-related costs.

- **DEM04** is used to allocate Distribution Structures and Equipment demand-related costs and represents maximum class demands determined at LG&E's -12 degree F design day mean temperature. These demands, which are shown in Seelye Exhibit 4, were calculated using base loads and temperature sensitive loads developed for the temperature normalization adjustment. The temperature normalization adjustment will be discussed later in my testimony.

- **DEM05** is used to allocate the demand-related portion of the cost of high-pressure distribution mains and represents maximum class demands determined at the design day mean temperature of customers served at high-pressure or below. The high-pressure system consists of pipe pressured above 50 psi. All of the gas delivered into the low- and medium-pressure system must first pass through the high-pressure system. Consequently, all customers utilize the high-pressure system.

- **DEM05a** is used to allocate the demand-related portion of the cost of low and medium-pressure distribution mains and represents maximum class demands determined at the design day mean temperature of customers served at medium pressure or low-pressure. The low- and medium-pressure system consists of pipe pressured at 50 psi and below. The demands of customers served at high pressure are not included in the determination of this allocation factor. The low- and medium-pressure system is not used to provide distribution delivery service to customers served at high pressure.

- **COM01** is used to allocate commodity-related procurement expenses and represents annual throughput volumes (including both sales and transportation). Procurement expenses correspond to expenses incurred by LG&E's gas supply department (including labor), which are not recovered through the Gas Supply Clause. This department not only purchases gas for sales customers but also administers LG&E's transportation service schedules.

- **COM02** is used to allocate Storage commodity-related costs and represents actual customer class deliveries during the winter withdrawal season (defined as the months of November through March.)

- **COM03** is used to allocate Transmission commodity-related costs and represents actual customer class deliveries during the winter withdrawal season (defined as the months of November through March).

- **COM04** is used to allocate Distribution commodity-related costs and represents annual throughput volumes (including both sales and transportation).

- **CUST01** is used to allocate the customer-related portion of LG&E's high-pressure distribution mains and represents the year-end number of customers served at high pressure and below.

- **CUST01a** is used to allocate the customer-related portion of LG&E's low and medium pressure distribution mains and represents the year-end number of customers at low and medium pressure. The customers served at high pressure are not included in the determination of this allocation factor. The low- and medium-pressure system is not used to provide distribution delivery service to customers served at high pressure.

- **CUST02** is used to allocate Services and is based on the total estimated cost of installing a service line per customer in each customer class weighted by the year-end number of customers in each class.

- **CUST03** is used to allocate Meters and is based on the total cost of meters and meter installation costs per customer in each customer class weighted by the year-end number of customers in each class.

- **CUST04** is used to allocate customer accounts expenses (Accounts 901 through 905) and represents a composite allocation factor.[1]

- **CUST05** is used to allocate customer service expenses using the same customer-weighting factor used to allocate Accounts 901, 902, 903, and 905 as in the calculation of CUST04.

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[1] This allocation factor is determined as follows: First, customer accounts supervision (Account 901), meter reading (Account 902), customer records and collections (Account 903), and miscellaneous customer account expenses (Account 905) were allocated to each customer class using a customer weighting factor based on discussions with LG&E's meter reading, billing and customer service departments. A cost weighting factor of 1.0 was utilized for Residential Gas Service, a cost weighting factor of 1.1 was utilized for Commercial Gas Service, a cost weighting factor of 10 was utilized for Industrial Gas Service, Rate G-6 and Rate G-7 (to be combined under Rate AAGS as discussed in Clay Murphy's testimony), and a customer weighting factor of 20 was utilized for Firm Transportation Service Rate FT and special contracts. Using a cost weighting factor of 20 for Rate FT and special contracts, for example, means that the cost of performing the meter reading, billing and customer service functions for customers served under Rate FT is 20 times more than the cost of performing these same services for customers served under Rate RGS. Second, uncollectible accounts (Account 904) were allocated on the basis of bad-debt write-offs for each customer class. The development of the composite allocation factor for customer accounts expenses is shown in Seelye Exhibit 5.

Q. How are mains typically classified between demand and customer costs?

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero-intercept" methodology. In the minimum system approach, a "minimum" standard pipe size is selected and the minimum system is obtained by pricing all of the distribution mains at the unit cost of this minimum size pipe. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system.

In preparing this study, the "zero-intercept" methodology, rather than the minimum system methodology, was used to determine the customer component of mains. Because the zero-intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is strongly preferred over the minimum system methodology when the necessary data is available. With the zero intercept methodology, we are not forced to choose a minimum size main to determine the customer component. In the zero intercept methodology, a zero-diameter pipe is the absolute minimum system.

Q. What is the theory behind the zero intercept methodology?

A. The theory behind the zero intercept methodology is that there is a linear relationship between the unit cost ($/ft) of mains and the gas flow capability of the pipe, which is proportionate to its diameter. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the pipe,

x is the size of the pipe, and

a, **b** are the coefficients representing the intercept and slope, respectively

it can be determined that, theoretically, the unit cost of a pipe with zero diameter (or pipe with zero load carrying capability) is **a**, the zero intercept. The zero intercept is essentially the cost component of mains that is invariant to the size (and load carrying capability) of the pipe.

Like most gas distribution systems, the number of feet of mains on LG&E's system is not uniformly distributed over all sizes of pipe. For example, LG&E has over 9.8 million feet of 2-inch mains, but only 438 feet of 2.5-inch mains. 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. Using a weighted regression analysis, the cost and diameter of each size pipe is, in effect, weighted by the number of feet of installed pipe. In a weighted regression analysis, the following weighted sum of squared differences

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

is minimized, where **w** is the weighting factor (in this case the feet of pipe) for each size of pipe, and **y** is the observed value and **ŷ** is the predicted value of the dependent variable (in this case the unit cost of the pipe).

Attached as Seelye Exhibit 6 is the zero-intercept analysis used in this study. The zero-intercept unit cost of $2.79 per foot pipe is applied to the total feet of mains in the analysis to determine the customer cost component. The listing on page 1 of the analysis indicates that the coefficient of determination R-squared for mains is 0.97718. The coefficient of determination is a relative measure of the goodness of fit, where a coefficient of 0.0 indicates no linear correlation between the independent variable and dependent variable and a coefficient of 1.0 indicates perfect linear correlation.

Q. **Has the Commission accepted the use of the zero-intercept methodology in previous cases?**

A. Yes, on many occasions. LG&E utilized the zero-intercept methodology in the cost of service studies (both electric and gas) submitted by the company in its last two base rate cases (Case No. 2000-080 and Case No. 90-158) and the Commission found them to be reasonable, thus providing a means of measuring class rates of return and suitable for use as a guide in developing appropriate revenue allocations and rate design. The Commission also found the embedded cost of service study submitted by Union Light Heat and Power in its recent rate case (Case No. 2001-00092), which utilized a zero-intercept methodology, to be reasonable. In my experience, the zero-intercept methodology is the predominant method used in Kentucky and is used widely in other jurisdictions.

Q. How were distribution mains functionally separated between high pressure and low and medium pressure?

A. The feet of high-pressure mains by size of pipe were identified from LG&E's maps and records. The feet of low- and medium-pressure pipe were determined residually by subtracting the specifically identified high-pressure mains from the total feet for each pipe size. The zero-intercept unit cost of $2.79 was then applied to the high-pressure mains and to the low and medium pressure mains to determine the customer-related portion of the mains. By identifying high-pressure mains from LG&E's maps and records, it was determined that LG&E's high-pressure distribution mains represent 12.98% of the total installed cost, with 0.95% corresponding to customer related costs and 12.03% corresponding to demand related costs. The low- and medium-pressure pipe comprises the remaining 87.02% of installed cost, with 12.66% classified as customer related and 74.36% classified as demand related. The breakdown is shown on page 6 of Exhibit 6.

Q: Was a similar separation made in the electric cost of service study?

A. Yes. The electric cost of service study separates distribution conductor between primary voltage conductor and secondary voltage conductor. The functional separation in the gas cost of service study between high-pressure and low- and medium-pressure pipe is analogous to the primary and secondary splits determined in the electric cost of service study. Differences in pressure in a pipe are often used as an analogy to differences in voltages.

Q. Please summarize the results of the gas cost of service study.

A. The following table (Table 1) summarizes the rates of return on net cost rate base for natural gas service for each customer class before and after reflecting the rate adjustments proposed by LG&E. The rates of return shown in Table 1 can be found on pages 16-17 of Seelye Exhibit 2. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the pro-forma adjustments discussed in Mr. Rives' testimony. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 1 Gas Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return**
Residential - Rate RGS	1.75%	6.15%
Commercial – Rate CGS	6.85%	8.23%
Industrial – Rate IGS	6.42%	8.38%
As Available Service – Rate AAGS (Combining Rates G-6 and G-7)	10.54%	10.69%
Firm Transportation Service – Rate FT	30.53%	30.55%
Special Contracts	21.27%	21.29%
Total System	3.56%	7.14%

Q. Is the current rate of return for natural gas service for the residential class adequate?

A. No. As shown in Table 1, the rate of return for the residential class is below the rates of return for the other customer classes. LG&E's overall adjusted rate of return is 3.56%, while the rate of return for the residential class is only 1.75%. In my opinion, LG&E should be allowed to charge rates that bring the rate of return more in line with the overall rate of return.

Q. Would LG&E's proposed rates move the company toward bringing the class rates of return closer together?

A. Yes. As can be seen in Table 1, the residential rates proposed by LG&E result in a pro-forma rate of return of 6.15%, which brings the residential class within approximately one percentage point of the proposed overall rate of return of 7.14%.

III. GAS PRO-FORMA ADJUSTMENTS

Q. Please explain the purpose of the gas pro-forma revenue adjustments that you are sponsoring in this proceeding.

A. The Commission has established certain standards or guidelines for determining test year revenues and expenses for purposes of establishing rates. For gas distribution companies, revenues are generally (1) adjusted to reflect normal temperatures, (2) annualized to reflect the numbers of customers served at year-end, (3) adjusted to reflect the currently effective rates for the entire test-period, (4) adjusted to reflect the revenue impact of customers switching from sales to transportation service or to special contracts, and (5) adjusted to exclude gas supply cost recovery and other ratemaking mechanisms that operate independently of base rates.

Q. Was an adjustment made to eliminate unbilled revenues for gas operations?

A. Yes. Consistent with prior rate cases, unbilled revenues were removed from test-year operating revenues. For LG&E's gas operations, $2,780,000 of unbilled revenues were removed from test-year operating results. An adjustment to remove unbilled revenues was accepted by the Commission in LG&E's last two base rate cases, Case No. 2000-080 and Case No. 90-158. LG&E had not recorded unbilled revenues prior to Case No. 90-158. This adjustment is included in Schedule 1.00 of Rives Exhibit 1.

Q. Has an adjustment been made to eliminate gas supply revenue and expenses?

A. Yes. Consistent with past Commission practice, Gas Supply Clause ("GSC") revenues and corresponding gas supply expenses have been removed from test year operating results.

This Adjustment is shown on Seelye Exhibit 7. This exhibit shows the GSC revenue collected for each rate class and the monthly gas supply costs recovered through LG&E's GSC. Because gas supply costs are recovered through a stand-alone cost-recovery mechanism, the Commission requires that the distributor remove these costs from revenues in order to establish the base revenues that relate to the delivery of gas. This adjustment eliminates the possibility of over- or under-recoveries resulting from timing differences from the collection of revenues under the GSC and the actual incurrence of the cost and thus ensures that base rates recover only the utility's distribution-related costs. This adjustment is included in Schedule 1.33 of Rives Exhibit 1.

Q. Was this adjustment made in LG&E last base rate case?

A. Yes. This adjustment was made in LG&E's last gas base rate case (Case No. 2000-080) and was accepted by the Commission.

Q. Was an adjustment made to eliminate demand-side management revenues and expenses from test-year operating results?

A. Yes. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment was made to eliminate $1,526,197 of revenue recovered through the Demand-Side Management Cost Recovery Mechanism ("DSMRM") and the corresponding $1,527,223 of demand-side management expenses recorded during the test year. As with LG&E's Gas Supply Clause, the DSMRM includes a balance adjustment that automatically adjusts unit charges under the mechanism to account for differences between revenues collected and demand-side management program costs incurred during the applicable period. This adjustment is included in Schedule 1.09 of Rives Exhibit 1.

Q. Please explain the calculations and methodology used to determine the temperature normalization adjustment to test period revenue.

A. LG&E has a Weather Normalization Adjustment ("WNA") clause that automatically adjusts the distribution cost component of customer bills to reflect normal temperatures. The WNA clause is applicable to Rates RGS and CGS and is currently applied during the months of December through April. Because the WNA automatically normalizes customer billings for Rates RGS and CGS during the months of December through April it is not necessary to perform a temperature normalization adjustment for these two classes during the months of December through April of the test year. However, it is necessary to perform a temperature normalization adjustment for Rates RGS and CGS to reflect the heating months not covered by the WNA. Additionally, it is necessary to perform a temperature normalization adjustment for rate classes not billed under the WNA, namely, Rates IGS, G-6, G-7, FT, and the special contracts.

Q. How was the gas temperature normalization adjustment performed for the rate classes not billed under the WNA?

A. A standard temperature normalization adjustment covering the entire heating season was performed for Rates IGS, G-6, G-7, FT, and the special contracts. Heating degree days related to cycle billed customer deliveries were 145 above the 30-year average Weather Bureau heating-degree days of 4,271, where the 30-year average was determined using the most recent 30-year period (i.e., the 30-year period ended June 2003). Thus, LG&E's

actual revenues were overstated due to cooler than normal temperatures experienced during the test period. The degree-day data used for purposes of calculating the temperature normalization adjustment were obtained from the Louisville, Kentucky weather station.

The first step in computing the temperature-related variance in deliveries was to determine the annual non-temperature sensitive and temperature sensitive volumes for each rate class. The determination of the non-temperature sensitive volumes was based on the gas deliveries that occurred in July and August since those months had the lowest volumes and also had no heating degree days. The volumes in those two months were then multiplied by six to calculate an annual non-temperature sensitive load that was deducted from total deliveries to arrive at the annual temperature sensitive volumes. The next step was to determine the volumetric adjustment required to normalize deliveries to reflect normal temperatures. The annual temperature sensitive volumes were divided by the actual heating degree days (4,416 for billing cycle customers and 4,448 classes billed on calendar month) in the test period and the resulting Mcf per degree day was then multiplied by the degree-day departure from normal (145 and 177, respectively) to arrive at the volumetric adjustment for each rate class.

In the final step, the volumetric adjustment for each rate class was applied to the applicable distribution component (rate per Mcf) for each rate schedule, resulting in a downward adjustment to gas operating revenue of $98,528 for rate classes not billed under the WNA. The details of these calculations are shown on page 2 of Seelye Exhibit 8.

Q. How was the gas temperature normalization adjustment performed for Rates RGS and CGS, which are billed under the WNA?

A. For Rates RGS and CGS the difference in degree days from normal for the entire test year (as a practical matter, for the heating season) was compared to the difference in degree days from normal for the WNA months of December, 2002, through April, 2003. As mentioned earlier, there were 145 more billing-cycle degree days than normal during the twelve months ended September 30, 2003. However, there were 148 more billing-cycle degree days from normal during the WNA months of December, 2003, through April, 2003. In other words, the non-WNA months were 3 degree days warmer than normal. Therefore, it was necessary to adjust the actual billing adjustments (in Mcf) determined under the WNA to reflect the fact that the heating months not covered by the WNA were 3 degree days warmer than normal. This was done by pro-rating the actual billing adjustments (in Mcf) determined under the WNA down by the ratio of the degree days over normal for the 12 months compared to the WNA period. This resulted in an upward adjustment to gas operating revenue of $85,506 for rate classes billed under the WNA, namely Rates RGS and CGS. The details of these calculations are shown on pages 3 and 4 of Seelye Exhibit 8.

Q. Please summarize the total impact of the gas temperature normalization adjustment.

A. The temperature normalization adjustment results in a net reduction of $13,022 to LG&E's gas operating revenue. The calculation of this amount is summarized on page 1 of Seelye Exhibit 8. This adjustment is included in Schedule 1.35 of Rives Exhibit 1.

Q. Please explain the adjustment to annualize for year-end customers.

A. The numbers of customers served at the end of the test period for the rate classes were different from the average numbers of customers for the 12-month test period. The purpose of this adjustment is to reflect the deliveries and revenue assuming that the year-end numbers of customers had been served for the entire test period. The differences between the number of customers served at year-end and the average number for each rate class during the test period was multiplied by the average annual consumption per customer in order to determine the deliveries expected. The average annual consumption per customer from the temperature normalization adjustment was utilized. The volumetric adjustment for each rate class was then multiplied by the average rate per Mcf (including customer charges, distribution charges and minimum bills), resulting in a downward adjustment to gas operating revenue of $56,581.

The additional operating expenses associated with serving the higher number of customers and volumes were calculated by applying an operating ratio to the revenue adjustment. Consistent with the Commission's Order in LG&E last gas base rate proceeding, Case No. 2000-080, the operating ratio of 29.87 percent was determined by dividing operation and maintenance expenses, exclusive of gas supply costs, wages and salaries, pensions and benefits, and regulatory commission expenses, by base rate revenues calculated at the currently effective rates. When applied to the year-end revenue adjustment, the application of the operating ratio resulted in a downward adjustment to expenses of $16,901.

The detailed calculations of the year-end adjustment to revenues and expenses are contained in Seelye Exhibit 9. This adjustment is included in Schedule 1.10 of Rives Exhibit 1.

Q. Please explain the adjustment to reflect customers switching to other rates during the test year.

A. Seelye Exhibit 10 includes three adjustments for known and measurable changes that occurred after the end of the test year but prior to filing the application: (1) an adjustment to reflect the change in revenue due to a customer switching from Rate G-6 to Rate CGS after the end of the test year resulting in an increase in net revenue of $2,769, (2) an adjustment to reflect the change in revenue due to a customer switching from sales service under Rate G-6 to transportation service under Rate FT after the end of the test year resulting in a decrease in net revenue of $9,381, and (3) an adjustment to reflect a customer plant closing effective after the end of the test year resulting in a decrease in net revenue of $34,719. The exhibit shows the detailed calculations restating the revenues for these customers. The total impact on net revenue is a reduction of $41,331. This adjustment is included in Schedule 1.28 of Rives Exhibit 1.

Q. Please explain the adjustment to reflect the current costs for storage field losses and purification expense.

A. Storage field losses and purification expenses are determined by applying the withdraw cost of underground storage each month to the storage field loss and purification gas volumes measured in Mcf. To determine the expense appropriate on a going-forward basis, an adjustment was made to reflect the inventory cost of natural gas stored underground at the end of the test year. Since the summer injection period is basically over, the average inventory cost at the end of the test year will be used to determine storage field loss and purification expenses for the next several months. The volume of gas used for gas purification was 103,103 Mcf during the test year, recorded at an average unit cost of \$3.80/Mcf. There were 260,502 Mcf of storage losses, recorded at an average unit cost of \$4.36/Mcf. The average cost of gas stored underground as of September 30, 2003, was \$5.3753/Mcf. Restated at the average cost of gas stored underground at the end of the test year, the pro-forma purification expenses are \$162,791 higher than the test-year actual expenses, and the pro-forma storage field loss expenses are \$263,963 higher than test-year actual expenses, resulting in a total adjustment of \$426,754. These expenses are not recovered through the GSC. The calculation of this adjustment is shown in Seelye Exhibit 11. The adjustment is included in Schedule 1.34 of Rives Exhibit 1.

IV. ALLOCATION OF THE GAS REVENUE INCREASE AND RATE DESIGN

Q. Have you prepared an exhibit reconstructing LG&E's test-year billing units for the gas business?

A. Yes. In order to develop LG&E's proposed rates it was necessary to reconstruct test-year billing units. The reconstruction of LG&E's billing determinants is shown on Exhibit 12. As shown on column 3 of page 2 of Seelye Exhibit 12, the base rate revenues calculated on pages 3 through 8 of that exhibit were within a factor of 0.996782 of LG&E's actual net revenues shown on column 1 of page 2 of the same exhibit, thus, confirming the accuracy of the test period billing determinants.

Q. After considering all of the required adjustments, what is the proposed increase in revenues and how is the increase apportioned to the individual customer classes?

A. In this filing, LG&E is proposing to increase its annual gas revenues by $19,104,714 (reflecting a revenue deficiency of $19,106,269 shown on Exhibit 7 of Mr. Rives' testimony). Seelye Exhibit 13, page 2 of 4, shows that the proposed increase would result in an increase of 5.42% in revenues from total sales and transportation and in total revenues. In addition to requesting an increase in gas service rates, LG&E is also proposing to increase certain miscellaneous charges thus resulting in an increase in miscellaneous revenues. The revenue impact of changes to miscellaneous charges is discussed later in my testimony.

The proposed rates apportion the revenue increase among the customer classes as follows:

TABLE 2
Proposed Gas Increase

Customer Class	Proposed Increase	Percentage
Residential Gas Service (Rate RGS)	$17,187,887	7.60%
Commercial Gas Service (Rate CGS)	$ 1,593,870	1.54%
Industrial Gas Service (Rate IGS)	$ 198,751	1.66%
Total Sales and Transportation	$18,980,514	5.42%

As shown on Seelye Exhibit 14, pages 1-4, the effects on individual class revenues were determined by applying both the current and proposed prices to the adjusted billing determinants for each customer class.

Q. What was the basic underlying information that supported the proposed allocation between classes?

A. The cost of service study provided information measuring the extent to which the revenues generated by each customer class contribute to the overall return earned by the Company. As shown on Table 1, the cost of service study indicated that the individual class rates of return ranged between 1.75% and 30.53% as measured against an overall adjusted actual return on rate base of 3.56%, with Rate RGS at 1.75%. This indicates a need to increase the revenues produced by sales to Rate RGS more than the other classes. The rates of return for Rate CGS, IGS, and G-6 were considerably higher than Rate RGS. The cost of service study also showed that the earned return for Rate FT was extremely high when compared to the other classes of service. Because the rate of return for Rate RGS is significantly below LG&E's proposed overall rate of return of 7.14%, we are proposing to increase Rate RGS by a larger percentage than the other classes in order to bring the rate of return for Rate RGS more in line with the overall rate of return. We are not proposing to increase Rate FT, Rate AAGS (consolidating Rates G-6 and G-7) or the Special Contracts.

Q. Is it important to consider competitive issues when designing rates?

A. Yes. It is extremely important to take into consideration the competitive pressures facing the utility when designing rates. Utility customers have many more options than they did in the past, and they are also becoming more sophisticated in how to utilize the various competitive products that are now available to them. However, the natural gas industry has always experienced keen competition from alternative fuels. When customers have alternatives (and the ability to substitute fuel oil for natural gas is only one example), gas distribution companies must be able to ensure that the revenues contributed by these customers are retained as long as they make some contribution to the utility's fixed costs. Industrial and commercial customers generally have more options than residential customers. Therefore, it is important not to charge rates to commercial and industrial customers that are uncompetitive and exceed the cost of providing service. Otherwise, large commercial and industrial customers will leave the system thus forcing residential and small commercial customers, who have fewer options, to pay for fixed costs that are left stranded by the departing customers. The impact of competition on LG&E's gas business is discussed more fully in Mr. Murphy's testimony.

Q. Does LG&E compete with other utilities for new natural gas loads?

A. Yes. Not only does LG&E need to retain existing customers by providing attractive service offerings and low prices, it needs to be able to attract new natural gas loads in its service territory which can contribute towards recovery of fixed costs.

Q. What are fixed costs?

A. Fixed costs are the demand-related and customer-related costs that I discussed in the portion of my testimony dealing with the cost of service study. These costs do not vary with the annual amount of gas that is sold by the utility. Therefore, fixed costs do not go away if the amount of gas the utility sells decreases. Unlike commodity-related costs, such as the cost of the gas commodity that a distribution company buys for its customers, a utility's fixed costs generally do not disappear if it sells less gas, but instead are spread over a lower volume of gas, thus causing the utility's rates to increase. Therefore, if a utility loses several large high-load factor industrial customers, then the utility's fixed costs do not suddenly disappear but are shifted to the remaining customers in future rate proceedings. On the flipside, if the utility can attract high-load factor customers or, even better, customers with off-peak usage, then the utility's fixed costs can be spread over a larger volume of gas thus causing gas rates to go down, benefiting all customers. Again, that is why it is important for LG&E to keep the rates applicable to price sensitive customers as low as practicable.

Q. Besides alternative fuel and economic development efforts, how else is the natural gas industry becoming more competitive?

A. It is much easier today for industrial and commercial customers to bypass the utility as either a gas supply provider (i.e., as a commodity supplier) or even as a provider of distribution services. In the first form of bypass, the customer purchases gas from a supplier and transports the gas across the distribution utility's system. When a customer purchases gas supply from an alternative supplier and transports the gas across the utility's transmission and distribution system, the utility will continue to collect distribution revenues. However, when customers switch from sales service to firm transportation service the utility still has some earnings exposure. Customers switching from sales service to transportation service can create temporarily stranded costs. For example, when a customer switches from Rate IGS to Rate FT on LG&E's system, the storage costs utilized to serve the customer can be temporarily stranded until these resources can be redeployed to serve the remaining customers.

In the second form of bypass, the customer physically bypasses the utility and connects directly to an interstate pipeline. When a customer physically bypasses a distribution utility, the utility loses *any* contribution that the customer makes toward fixed costs. Physical bypass represents a particularly serious threat to LG&E because a major interstate pipeline runs through LG&E's gas service territory.

Although physical bypass represents the more serious threat, both forms of bypass can result in lost margins and can contribute to attrition in the utility's earnings.

Q. What were the ratemaking objectives in developing the proposed gas rates?

A. In general, we tried to develop rates that more closely reflect the cost of providing service. Therefore, one of our key objectives was to bring the unit charges more in line with the unit costs derived from the cost of service study. LG&E's sales rates consist of a Customer Charge and a Distribution Cost Component. Currently the Distribution Cost Component is the same for all three of LG&E's standard sales rates – Rates RGS, CGS, and IGS. We are proposing slightly lower distribution cost component charges for Rates CGS and IGS.

Q. Have you analyzed the customer-related costs for Rate RGS?

A. Yes. Seelye Exhibit 15 shows the unit customer-related costs for Rate RGS based on the results of the cost of service study. The customer-related cost was derived by calculating the customer-related cost of service, or "revenue requirement" and dividing this amount by the number of customers. LG&E's cost of service includes (1) return on investment, (2) income taxes, (3) operation and maintenance expenses, (4) depreciation expenses, and (5) other taxes. The proposed rate of return for Rate RGS of 6.15% was utilized to calculate the unit cost.

Q. What does this analysis show?

A. Seelye Exhibit 15 shows that the customer-related cost for Rate RGS is $10.85.

Q. What customer charge is LG&E proposing for Rate RGS?

A. We are proposing to increase the customer charge to $10.80 per customer per month, and we are proposing a distribution cost component of $1.5352 per Mcf.

Q. What is the proposed rate of return for Rate RGS?

A. The proposed rate of return for Rate RGS is 6.15%, which is slightly more than one percentage point below the overall rate of return of 7.14%.

Q. Is LG&E proposing to change the Volunteer Fire Department Rate ("VFD")?

A. Yes. Rate VFD contains the same charges as Rate RGS. LG&E is proposing changes to VFD to match those requested for Rate RGS. Consequently, we are proposing to increase the customer charge to $10.80 per customer per month, and we are proposing a distribution cost component of $1.5352 per Mcf.

Q. What are the proposed unit charges for Rate CGS and Rate IGS?

A. Rate CGS is the standard sales service for commercial customers and Rate IGS is the standard sales service for industrial customers. We are proposing to increase the Distribution Cost Component from $1.3457 to $1.4830. We are not proposing an increase in the monthly customer charge for Rate CGS and IGS, nor are we proposing to modify the off-peak pricing provision. The proposed rates will result in a rate of return of 8.23% for Rate CGS and 8.38% for Rate IGS, as compared to an overall rate of return of 7.14%.

Q. What are the proposed unit charges for Rate AAGS?

A. LG&E is proposing to consolidate Rates G-6 and G-7 into a new As Available Gas Service Rate AAGS. Mr. Murphy discusses the terms and conditions of this rate schedule in his testimony. LG&E's proposed unit charges for Rate AAGS were designed to be revenue neutral with respect to Rates G-6 and G-7 considered as a group. We are proposing a monthly customer charge of $150.00 and a Distribution Cost Component of $0.5053.

Q. Why are you not proposing to increase Rate FT and the special contracts?

A. An increase to Rate FT cannot be justified. The rate of return for this class of customers is 30.53%, which is significantly higher than any other rate class.

Q. Is LG&E proposing any other rate changes?

A. Yes. We are proposing an increase in the Summer Air Conditioning Rider for Rate RGS, CGS and IGS. The Distribution Cost Component of the rate is currently $0.50 lower than Rate RGS, CGS and IGS. We are proposing to maintain this $0.50 rate differential. Therefore, in calculating the Distribution Cost Component for the Summer Air Conditioning Rider we have reduced the Distribution Cost Component set forth in the otherwise applicable rate by $0.50.

Q. Is LG&E proposing any changes to the Weather Normalization Adjustment ("WNA") clause?

A. Yes. LG&E is proposing to increase the period of time covered by the WNA to include November. The WNA, which was recently until April 30, 2006, by the Commission in its Order in Case No. 2003-00357, dated October 30, 2003, is currently applied during the period from December through April. Instead, the WNA would be applied during the period November through April. There are often significant heating degree days during November.

Q. Is LG&E proposing other general changes to the gas tariffs or other changes not specifically discussed in your testimony?

A. Yes. LG&E's gas rate schedules have been updated to include a listing of all applicable adjustment clauses. There are a number of changes that have been proposed to simplify or clarify the language in the gas tariff or to re-organize the structure of the tariff which are not detailed in my testimony. Other changes are discussed in the testimonies of Mr. Murphy and Sidney "Butch" Cockerill.

V. ELECTRIC COST OF SERVICE

Q. Did you prepare a cost of service study for LG&E's electric operations based on financial and operating results for the 12 months ended September 30, 2003?

A. Yes. I supervised and participated in the preparation of a fully allocated, time-differentiated, embedded cost of service study for electric operations based on LG&E's accounting costs per books, adjusted for known and measurable changes to test year operating results, for the 12 months ended September 30, 2003. The cost of service study corresponds to the pro-forma financial exhibits included in the testimony of Mr. Rives. As with the gas cost of service study, the objective in performing the electric cost of service study is to determine the rate of return on rate base that LG&E is earning from each customer class, which provides an indication as to whether LG&E's electric service rates reflect the cost of providing service to each customer class.

Q. Were the procedures used in performing the electric cost of service study the same as those that you described above for the natural gas cost of service study?

A. Yes, with the exception that the study was time differentiated. The three traditional steps of an embedded cost of service study were augmented to include a fourth step, assigning costs to costing periods. The cost of service study was therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; (3) costs were assigned to the costing periods; and then (4) costs were allocated to LG&E's rate classes. These steps are depicted in the diagram (Figure 3) shown on the following page.

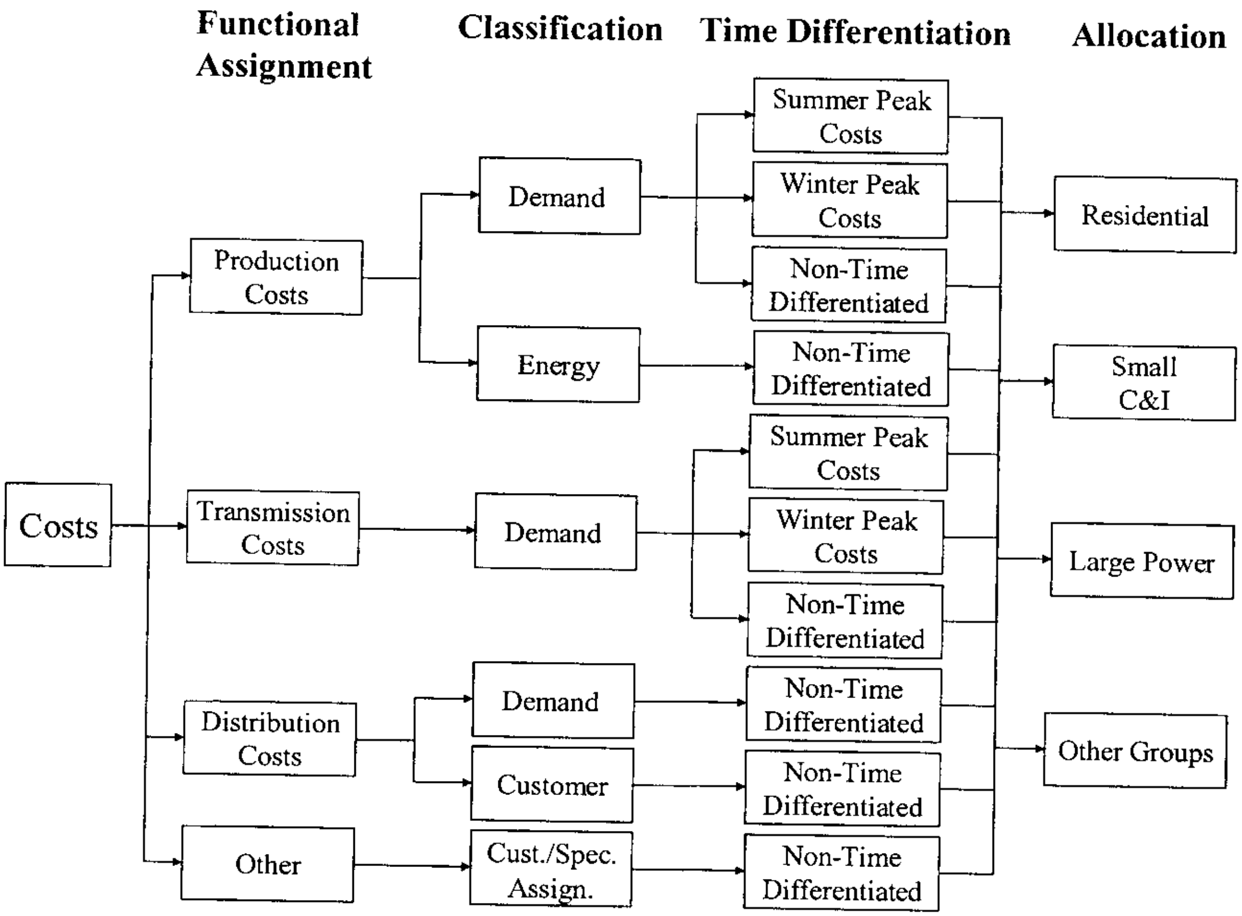


Figure 3

Q. What functional groups were used in the electric cost of service study?

A. The following standard functional groups were identified in the cost of service study: (1) Production, (2) Transmission, (3) Distribution Substation, (4) Distribution Primary Lines, (5) Distribution Secondary Lines, (6) Distribution Line Transformers, (7) Distribution Services, (8) Distribution Meters, (9) Distribution Street and Customer Lighting, (10) Customer Accounts Expense, (11) Customer Service and Information, and (12) Sales Expense.

Q. Did you use the same methodology in LG&E's cost of service study as was used in KU's cost of service study filed concurrently in Case No. 2003-00434?

A. Yes.

Q. How were costs time differentiated in the study?

A. A modified Base-Intermediate-Peak ("BIP") methodology was used to assign production and transmission costs to the costing period. In Case No. 90-158, which was LG&E's last electric base rate case, the Commission found LG&E's cost of service study, which utilized the modified BIP methodology, to be "acceptable and suitable for use as a starting point for electric rate design." (Order in Case No. 90-158, dated December 21, 1990, page 58.) Using this methodology, production and transmission demand-related costs were assigned to three categories of capacity – base, intermediate, and peak. Base costs were determined by dividing the minimum system demand by the maximum (summer) demand. Intermediate costs were calculated by dividing the winter peak demand by the summer peak demand and subtracting the base component. Peak costs included all costs not assigned to base and intermediate components.

Costs that were assigned as base, intermediate, and peak were then either assigned to the summer and winter peak periods or assigned as non-time-differentiated. Intermediate costs were pro-rated to the winter and summer peak periods in the same ratio as the number of hours contained in each costing period to the total. Peak costs are assigned to the summer peak period.

Q. How were the summer and winter peak periods determined?

A. The summer peak period corresponds to the four-month period from June through September. The winter peak period corresponds to the eight non-summer months of October through May. The load curves included in Seelye Exhibit 16 showing the monthly peak days in the summer and winter months supports the selection of the hours in the summer and winter peak periods. The hours between the hour ending 11 and the hour ending 21 of June through September were selected as the summer peak period. The hours between the hour ending 9 and the hour ending 22 of October through May were selected as the winter peak period. The load curve is flatter during the winter months, thus necessitating a larger number of hours to be included in the peak period during the winter period.

We have shortened the peak periods from earlier cost of service studies, for a number of reasons. First, we believe that the costing periods are more reflective of the hours during which the company could realize a peak. Second, shortening the time periods in the company's time-of-day rates may provide customers with a greater opportunity to shift load to the off-peak period.

Q. In determining the costing periods and applying the modified BIP methodology, what demands were used?

A Demands for the combined LG&E and Kentucky Utilities systems were used to determine the costing periods and in determining the percentages of production and transmission fixed costs assigned to the costing periods. Since the two systems are planned jointly, it was important to develop costing periods and assign costs to the costing periods based on the combined loads for LG&E and Kentucky Utilities. Developing the costing periods and allocation factors in the cost of service study do not result in any shifting in booked expenses of one utility to the other. LG&E's cost of service study relied on LG&E's accounting costs, and KU's cost of service study relied on KU's accounting costs. The modified BIP methodology simply affects how costs are assigned to the costing periods within the LG&E and Kentucky Utilities cost of service studies.

Q. What percentages were assigned to the costing periods?

A Seelye Exhibit 17 shows the application of the modified BIP methodology. Using this methodology 26.45% of LG&E's production and transmission fixed costs were assigned to the summer peak period, 39.97% to the winter peak period, and 33.58% as non-time-differentiated.

Q. How were costs classified as energy related, demand related or customer related?

A. Classification provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. Costs classified as *energy related* tend to vary with the amount of kilowatt-hours consumed. Typical examples of energy related costs are fuel and purchased power expenses. Costs classified as *demand related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet a customer's needs. Production plant and the cost of transmissions lines are examples of typical demand-related costs. Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of electric energy purchased or the peak requirements of the customers and include the cost of the minimum system necessary to provide a customer with access to the electric grid. As will be discussed later in my testimony, costs related to Distribution Primary Lines, Distribution Secondary Lines and Distribution Line Transformers were classified as demand-related and customer-related using the zero intercept methodology. Distribution Services, Distribution Meters, Distribution Street and Customer Lighting, Customer Accounts Expense, Customer Service and Information and Sales Expense were classified as customer-related.

Q. Have you prepared an exhibit showing the results of the functional assignment, time-differentiation and classification steps of the electric cost of service study?

A. Yes. Seelye Exhibit 18 shows the results of the first three steps of the electric cost of service study, functional assignment, time differentiation and classification.

Q. Please describe the allocation factors used in the electric cost of service study.

A. The following allocation factors were used in the LG&E electric cost of service study:

- **E01** – The energy cost component of purchased power costs was allocated on the basis of the kWh sales to each class of customers during the test year.

- **PPWDA and PPSDA** – The winter demand and summer demand cost components of production and transmission fixed costs were allocated on the basis of each class's contribution to the coincident peak demand during the winter and summer peak hour of the test year.
- **NCPP** – The demand cost component is allocated on the basis of the maximum class demands for primary and secondary voltage customer.
- **SICD** – The demand cost component is allocated on the basis of the sum of individual customer demands for secondary voltage customers.
- **C02** – The customer cost component of customer services is allocated on the basis of the average number of customers for the test year.
- **C03** – Meter costs were specifically assigned by relating the costs associated with various types of meters to the class of customers for whom these meters were installed.
- **YECust04** – Costs associated with lighting systems were specifically assigned to the lighting class of customers.
- **YECust05 and YECust06** – Meter reading, billing costs and customer service expenses were allocated on the basis of the estimated cost of reading the meter, rendering a bill

and providing customer service for each class of customers.

- **Cust05** – The customer cost component is allocated on the basis of the average number of customers for the test year.
- **YECust07** – The customer cost component is allocated on the basis of the number of year-end customers using line transformers and secondary voltage conductor.
- **YECust08** – The customer cost component is allocated on the basis of the number of year-end customers using primary voltage conductor.

Q. Have you prepared an exhibit showing the results of allocating costs to the customer classes?

A. Yes. Seelye Exhibit 19 shows the results of allocating costs to the customer classes.

Q. Was the zero intercept methodology used to classify distribution costs as customer- and demand-related?

A. Yes. The zero-intercept methodology was used to classify overhead conductor, underground conductor, and line transformers. The zero-intercept analyses for overhead conductor, underground conductor, and line transformers are included in Seelye Exhibits 20, 21, and 22.

Q. Please summarize the results of the electric cost of service study.

A. The following table (Table 3) summarizes the rates of return for each customer class before and after reflecting the rate adjustments proposed by LG&E. The Actual Adjusted

Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the pro-forma adjustments discussed in Mr. Rives' testimony. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 3
Electric Class Rates of Return

Customer Class	Actual Adjusted Rate of Return	Proposed Rate of Return
Residential Rate R	1.51%	3.57%
General Service Rate GS	8.55%	11.33%
Large Commercial – Rate LC		
- Primary	1.00%	9.75%
- Secondary	6.66%	9.22%
Industrial Power – Rate LP		
- Primary	5.48%	9.39%
- Secondary	8.26%	11.30%
Large Commercial Time of Day – Rate LC-TOD		
- Primary	5.92%	8.14%
- Secondary	5.95%	7.72%
Industrial Power Time of Day – Rate LP-TOD		
- Transmission	5.38%	7.18%
- Primary	3.79%	5.75%
- Secondary	6.58%	9.22%
Special Contracts	5.33%	7.87%
Total System	4.06%	6.32%

Determination of the actual adjusted and proposed rates of return are detailed in Seelye Exhibit 19, pages 43-45 and pages 49-51.

VI. ELECTRIC PRO-FORMA ADJUSTMENTS

Q. Was an adjustment made to eliminate unbilled revenues for electric operations?

A. Yes. Consistent with prior rate cases, unbilled revenues were removed from test-year operating revenues. For LG&E's electric operations, $1,867,000 of unbilled revenues were removed from test-year operating results. This adjustment is consistent with the adjustment to eliminate unbilled revenues for the gas business. An adjustment to remove unbilled revenues was accepted by the Commission in LG&E's last two base rate cases, Case No. 2000-080 and Case No. 90-158. This adjustment is included in Schedule 1.00 of Rives Exhibit 1.

Q. Has an adjustment been made to eliminate the mismatch in fuel cost recovery?

A. Yes. Consistent with past Commission practice, the mismatch between fuel costs and fuel cost recovery through LG&E's fuel adjustment clause ("FAC") has been eliminated. These over- or under-recoveries were taken directly from LG&E's monthly FAC filings. This adjustment is included in Schedule 1.01 of Rives Exhibit 1.

Q. Has an adjustment been made to reflect the roll-in of the FAC and Environmental Cost Recovery ("ECR") for a full year?

A. Yes. Test-year revenues have been adjusted to reflect the rolled-in level of base rates and FAC and ECR billings for a full year. Seelye Exhibit 23 shows the impact on base rate revenues of the FAC and ECR roll-ins for a full year. Seelye Exhibit 24 shows the impact on FAC billings of reflecting the new base fuel cost (Fb/Sb) for a full year. The adjustment to reflect the FAC roll-in is included in Schedule 1.02 and the adjustment to reflect the ECR roll-in is included in Schedule 1.04 of Rives Exhibit 1.

Q. Was an adjustment made to eliminate environmental cost recovery ("ECR") revenues and expenses?

A. Yes. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment was made to eliminate $11,228,429 of ECR revenues and $1,766,344 in ECR costs. The ECR surcharge provides for full recovery of environmental costs that qualify for the surcharge and contains a mechanism to true up actual ECR revenues to allowed ECR revenues under the surcharge. The adjustment to revenues of $11,228,429 includes <u>all</u> ECR billings during the test year (including ECR recoveries for the 1995 Plan and for the post-1995 Plan). The adjustment to expenses of $1,766,344 includes operating expenses recovered under the ECR during the test year for compliance costs that will continue to be recovered through the surcharge (i.e., operating expenses relating to the post-1995 Plan). Because LG&E is proposing to eliminate the 1995 Plan from its monthly Environmental Surcharge filings on a going-forward basis, only the operating expenses associated with the post-1995 Plan are eliminated in this adjustment. However, all ECR revenues collected in the test year are eliminated because failure to do so would overstate LG&E's adjusted operating revenues by that portion of ECR revenues not eliminated. LG&E proposes to recover the revenue requirements on any remaining rate base in the 1995 Plan through base rates, and proposes to recover revenue requirements of remaining rate base in the post-1995 Plan through the monthly Environmental Surcharge filings. LG&E's capitalization includes an adjustment to eliminate the ECR rate base for the post 1995 Plan and does not include an adjustment for the ECR rate base for the 1995 Plan (see Rives Exhibit 2).

Q. Please explain the off-system sales revenue adjustment for the ECR calculation shown in Schedule 1.05 of Rives Exhibit 1.

A. In the determination of the ECR surcharge, a portion of LG&E's environmental compliance costs recovered through the surcharge are allocated to off-system sales. However, by including off-system revenues in test-year operating results, off-system revenues are credited to jurisdictional customers. This results in an overstatement of margins from off-system sales and a mismatch of the revenues and expenses relating to the off-system sales portion of the allocated environmental surcharge monthly revenue requirement. Therefore, consistent with the methodology prescribed in the Commission's Order on rehearing in Case No. 98-426 dated June 1, 2000, an adjustment of $1,929,923 was made to reduce revenues to reflect the environmental surcharge calculations recognized in the determination of off-system sales.

Q. Was an adjustment made to eliminate demand-side management revenues and expenses from test-year operating results?

A. Yes. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment was made to eliminate $3,277,501 of revenue recovered through the Demand-Side Management Cost Recovery Mechanism ("DSMRM") and the corresponding $3,280,013 of demand-side management expenses recorded during the test year. The DSMRM includes a balance adjustment that automatically adjusts unit charges under the mechanism to account for differences between revenues collected and demand-side management program costs incurred during the applicable period. This adjustment is included in Schedule 1.09 of Rives Exhibit 1.

Q. Was an adjustment made to annualize for year-end customers for the electric business?

A. Yes. The numbers of customers served at the end of the test period for the rate classes were higher than the average numbers of customers for the 12-month test period. The differences between the number of customers served at year-end and the average number for each rate class during the test period was multiplied by the average annual kWh usage per customer. The average usage for each rate class was then multiplied by the average revenue per kWh (including customer charges, energy charges, demand charges and minimum bills), resulting in an upward adjustment to electric operating revenue of $2,614,347.

The additional operating expenses associated with serving the higher number of customers and volumes were calculated by applying an operating ratio to the revenue adjustment. Consistent with the Commission's practice, the operating ratio of 55.79 percent was determined by dividing operation and maintenance expenses, exclusive of wages and salaries, pensions and benefits, and regulatory commission expenses, by base rate revenues calculated at the currently effective rates. When applied to the year-end revenue adjustment, the application of the operating ratio resulted in an upward adjustment to expenses of $1,458,544.

The detailed calculations of the electric year-end adjustment to revenues and expenses are contained in Seelye Exhibit 25. This adjustment is included in Schedule 1.10 of Rives Exhibit 1.

Q. Please explain the adjustment to reflect customers switching to other rates during the test year.

A. Seelye Exhibit 26 includes an adjustment to reflect the change in revenue due to a customer switching from a special contract rate to Rate LP-TOD (with interruptible service) resulting in an increase in revenue of $6,445. This adjustment is included in Schedule 1.28 of Rives Exhibit 1.

VII. ALLOCATION OF ELECTRIC REVENUE INCREASE AND RATE DESIGN

Q. Have you prepared an exhibit reconstructing LG&E's test-year billing determinants for the electric business?

A. Yes. The reconstruction of LG&E's electric billing determinants is shown on Exhibit 27. As shown in the column labeled "Calculated Divided by Actual" of Seelye Exhibit 27, page 1, the net base rate revenues calculated on pages 2 through 30 of that exhibit were within a factor of 1.000795 of LG&E's actual net revenues, thus confirming the accuracy of the test period billing determinants.

Q. After considering all of the required adjustments, what is the proposed increase in revenues and how is the increase allocated among the individual customer classes?

A. In this filing, LG&E is proposing to increase its annual electric revenues by $63,765,324 (reflecting a revenue deficiency of $63,764,203 shown on Exhibit 7 of Mr. Rives' testimony). Seelye Exhibit 28 shows that the proposed increase would result in an increase of 11.34% percent in revenues to total sales to ultimate consumers. In addition to requesting an increase in electric service rates, LG&E is also proposing to increase certain miscellaneous charges, resulting in an increase in miscellaneous revenues. The revenue impact of changes to miscellaneous charges is discussed later in my testimony.

The proposed rates apportion the revenue increase among the customer classes as follows:

Table 4
Proposed Electric Increase

Customer Class	Proposed Increase	Percentage
Residential	$26,430,885	12.32%
General Service	$ 8,978,115	11.04%
Large Commercial	$11,596,050	11.14%
Large Commercial Time of Day – Rate LC-TOD	$ 2,112,587	8.57%
Industrial Power – Rate LP	$ 3,714,694	12.51%
Industrial Power Time of Day – Rate LP-TOD	$ 6,385,440	9.33%
Special Contracts	$ 3,028,038	11.08%
Lighting	$ 1,386,184	12.19%
Total Ultimate Consumers	$63,631,993	11.34%

As shown on Seelye Exhibit 29, the effects on individual class revenues were determined by applying both the current and proposed prices to the adjusted billing determinants for each customer class.

Q. **How was the proposed allocation among the rate classes determined?**

A. We were guided by the cost of service study in allocating the proposed increase among the rate classes, but did not follow the cost of service study as closely as we did for the proposed gas increase. The increase for the electric business is larger and the class rates of return for the electric business were not as far out of line. If LG&E had tried to equalize the rates of return by rate classes, the residential rate would have received an increase of 28.91%, as shown in Seelye Exhibit 30. LG&E thus limited the increase that Rate R could receive to approximately one percentage point above the overall percentage increase to ultimate consumers, as further discussed in Mr. Beer's testimony. Consequently, LG&E is proposing an increase of 12.32% to the residential class and 11.34% to total ultimate consumers. The Company provided me with strong guidance that the residential increase should be no more than approximately 12.4%. LG&E wants to transition towards a better balance between class rates of return, while at the same time recognizing other ratemaking objectives such as customer acceptance, gradualism and the need to maintain price stability by avoiding overly disruptive changes.

Q. How were the increases allocated to the other rate classes?

A. The class rates of return fell within a pattern. Some were above the overall rate of return, but none were too far above the overall rate of return (when compared to the results of the gas cost of service study and other cost of service studies with which I am familiar). Other classes were below the overall rate of return, but none, except Water Heating, were too far below the overall rate of return. Therefore, we developed two increase tiers for allocating the LG&E electric increase. One tier, applicable to customer classes with rates of return below the overall rate of return, such as the residential class, was set at *approximately* 12.3%. This approximate increase was applied to the residential class, lighting and certain special contract customers. The other tier was determined by the percentage increase required to produce the required increase requested by LG&E. This increase tier was approximately 10.6%.

Q. If you used only two tiers, why do some of the increases to the rate classes appear to vary from these percentages?

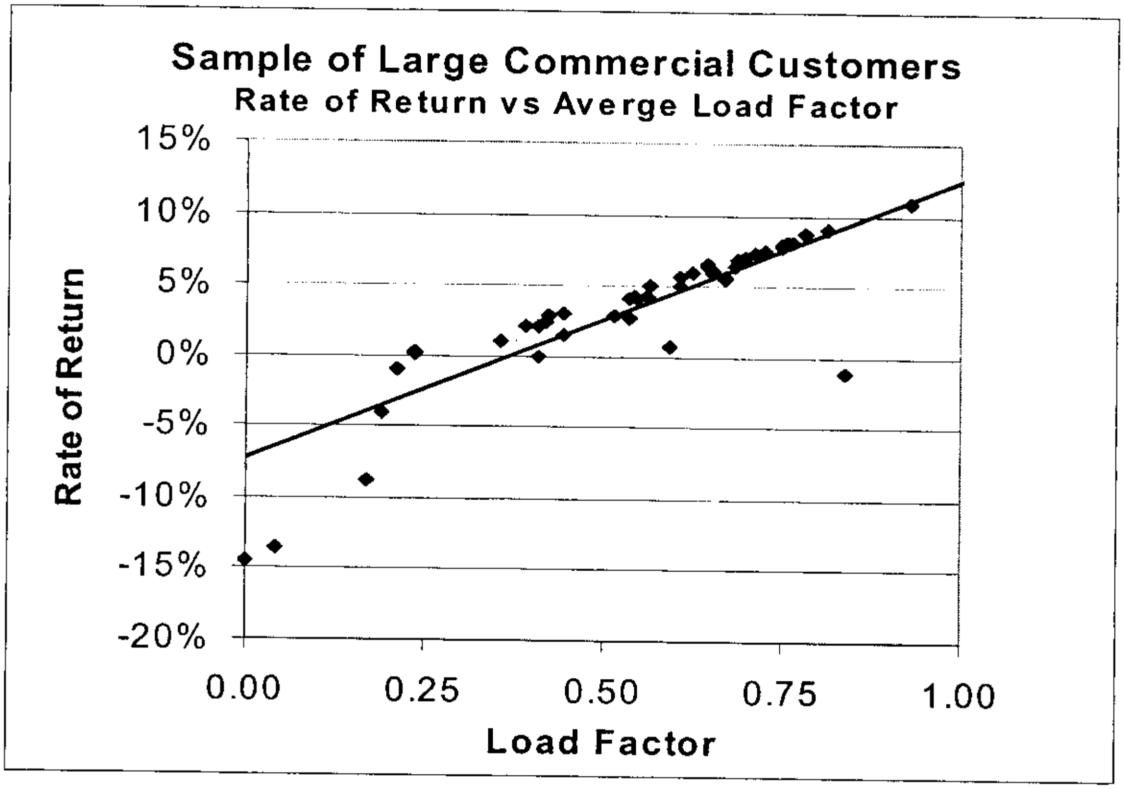
A. There are several reasons. First, the two-tier approach that I described was a general rule that was not strictly followed in all cases. Rate design for this number of rate schedules is too complex to use a simple "one size fits all" rule of thumb. Second, and more significantly, there were other rate design objectives that we followed. For example, Rates LC and Rate LC-TOD are essentially the same rate, except Rate LC-TOD has a time-of-day structure. (Likewise, Rate LP and Rate LP-TOD are essentially the same rate.) We have long tried to maintain parity between these two rate schedules in order to discourage the creation of automatic savings by customers moving from one rate schedule to the other. Although the rate is essentially the same, customers on one rate schedule may have higher load factors than customers on the other. Since we also tried to more accurately reflect the demand/energy cost relationship in the company's demand/energy rates, some customers will be impacted more than others. It is virtually impossible to transition toward cost of service rates without producing these sorts of effects. Third, some of the apparent increases are due to the fact that LG&E is proposing a significant increase in the Interruptible Credit (to be renamed the "Curtailable Service Rider" or "CSR" credit). Customers taking interruptible service will see a lower overall increase. Changes to Interruptible Service will be discussed later in my testimony.

Q. What guidelines were followed in designing the electric rates?

A. As with the gas rates, unit charges were developed that would transition toward the unit costs indicated in the electric cost of service study. For LG&E's two-part rates consisting of a customer charge and energy charge, such as Residential Rate R and General Service Rate GS, the customer charges were increased to cover more of the customer-related costs identified in the cost of service study, and energy charges were set at a level that more properly reflected energy- and demand-related costs. Similarly, for LG&E's three-part rates consisting of a customer charge, demand charge and energy charge, such as the Large Commercial and Industrial Power rates, unit charges were selected that more closely followed the unit costs determined in the cost of service study. In most cases this translated into increasing the customer and demand charges but lowering the energy charge.

Q. Why is it important to develop unit energy and demand charges for commercial and industrial rates that reflect unit costs identified in the cost of service study?

A. Just as there are different rates of return from one class of service to another, there are different rates for return from one customer to another within any given customer class. If the unit charges in a utility's rate schedule do not reflect cost of service, then the differences in intra-class rates of return (as opposed to inter-class rates of return) can be significant. The following graph of a typical group of large commercial customers illustrates this point.



In this graph, individual rates of return (or "individual customer profitability") are graphed against load factor. The upward slope in the graph illustrates that with a demand-energy rate that does not properly reflect the cost of providing service, the individual rates of return for customers with high load factors are significantly greater than for customers with low load factors, within the same class. High load-factor customers are thus being penalized instead of rewarded for having a more constant usage pattern. This situation can be alleviated, or at least mitigated, by designing rates that do not recover too much of a utility's fixed costs through the energy charge. A properly designed rate will flatten the linear trend line shown in the graph, thus eliminating intra-class subsidies. Ignoring the results of a cost of service study can cause individual rates of return within a class to get further and further out of line, creating even greater intra-class subsidies.

Q. Has LG&E made any general changes to the electric tariffs or other changes not specifically discussed in your testimony?

A. Yes. LG&E's electric rate schedules have been updated to include a listing of all applicable adjustment clauses. There are a number of changes that have been proposed to simplify or clarify the language in the electric tariff or to re-organize the structure of the tariff which are not detailed in my testimony. Other changes are discussed in Mr. Cockerill's testimony.

Q. Please describe the current rate structure for Rate R.

A. Rate R is a two-part rate consisting of a customer charge and a seasonally differentiated energy charge. The energy charge is higher in the summer months than during the winter months. The energy charge also consists of a declining-block rate structure during the winter months and an inverted-block rate structure during the summer months. LG&E is proposing to eliminate the blocked rate structure contained in the winter and summer energy charge.

Q. Is there any basis for the seasonal rate structure?

A. Yes. A seasonal rate structure is consistent with the seasonal nature of LG&E's costs and can be supported by LG&E's cost of service study.

Q. What is a declining-block rate structure?

A. A declining-block rate, or "declining step" rate as it is sometimes called, is a rate where the charges *decrease* at specified increments of usage. For example, in the case of the winter season energy charge set forth in LG&E's current Residential Rate R the price for the first

600 kWh of customer usage is currently $0.05526 per kWh, and for all usage over 600 kWh the energy charge is $0.04261 per kWh. With a declining-block rate structure, a customer using a large amount of electric energy would receive a lower average price than a customer using a small amount of electric energy. In other words the rate goes down with increased usage. A declining-block rate is still a pricing structure that is commonly used within the industry.

Q. What is an inverted-block rate structure?

A. A inverted-block rate, or "increasing step" rate as it is sometimes called, is a rate where the charges *increase* at specified increments of usage. For example, in the case of the summer season energy charge set forth in LG&E's current Residential Rate R the price for the first 600 kWh of customer usage is currently $0.05993 per kWh, and all usage over 600 kWh the energy charge is $0.06159 per kWh of customer usage. Ignoring the effect of the customer charge, with an inverted-block rate structure a customer using a small amount of electric energy would receive a lower average price than a customer using a large amount of electric energy. In other words the rate goes up with increased usage.

Q. How can either a declining-block rate structure or inverted-block rate structure be supported based on the cost of providing service?

A. Within a rate class, if the non-customer-related cost per kilowatt-hour of serving a smaller customer is higher than the cost per kilowatt-hour of serving a larger customer, then a declining-block rate can be supported. Conversely, if the cost per kilowatt-hour for serving a smaller customer is lower than the cost per kilowatt-hour of serving a larger customer, then an inverted block rate can be supported.

Q. Based on the cost drivers identified in the cost of service study, is there any basis for a declining block rate structure?

A. A standard justification for a declining-block rate structure is to provide for recovery of customer-related costs through the initial block of the rate. If customer-related costs were recovered through the energy charge rather than through a customer-charge, then the cost per kilowatt-hour would certainly decrease in proportion with customer usage. However, if all customer-related costs are recovered through the customer charge, then there is less of a justification for a declining-block structure. However, a declining block rate structure could be justified if it can be shown that demand-related costs, which would still be recovered through the energy charge in a two-part rate, go down as customer usage levels go up. Likewise, an inverted block rate structure could be justified if it can be shown that demand-related costs go up as customer usage levels go up. This would be equivalent to showing that customer load factor is either positively or negatively correlated with customer usage.

Q. What do you mean by customer load factor?

A. Customer load factor is the relationship between a customer's kWh usage and maximum demand, and can be calculated by dividing a customer's kWh usage by the customer's maximum demand multiplied by the number of hours over which the kWh usage was measured. Load factor can be determined by measuring the customer's maximum monthly demand or by measuring the customer's kW demand at the time of the utility system peak. A blocked rate structure can be supported if there is a positive or negative correlation between a customer's load factor and kWh usage. If load factors within a customer class increase with greater usage, then a declining-block rate structure can be supported.

However if load factors within a customer class decrease in relation to greater usage, then an inverted block rate structure can be supported.

Q. Have you performed an analysis of this relationship?

A. Yes. A statistical analysis was performed on LG&E load research data to determine whether there is a relationship between load factor and kWh energy for residential customers. The data that was used was monthly load research data that contained observations for individual customer energy usage, non-coincident peak demand and coincident peak demand. Coincident peak demands and non-coincident peak demands are key drivers in the electric cost of service study. Specifically, three statistical analyses were performed. First, the monthly non-coincident peak load factor for all customers in the sample for all months of the year was regressed on customers' monthly kWh energy usage. Second, the coincident peak load factor for all customers in the sample for the summer months of June, July, August, and September was regressed on customers' monthly kWh energy usage for those same months. Third, the coincident peak load factor for all customers in the sample for the non-summer months of January through May and October through December was regressed on customers' monthly kWh energy usage for those same months. The purpose of these regression analyses was to correlate energy usage to key drivers in the cost of service study, namely summer coincident demand, winter coincident demand, and maximum customer demands.

Q. What did these analyses indicate?

A. The linear regression analysis indicated a statistically significant relationship between monthly *non-coincident peak load factor* and monthly *energy usage* for LG&E residential customers based on observations for all months during the year. The regression coefficient for kWh energy usage is positive which indicates that kWh energy usage has a relationship with non-coincident peak load factor, with a t-value of 26.438, which indicates statistical significance at the 99% confidence level. In other words, the analysis indicated that non-coincident peak load factor increases with customer usage. However, the R-square is only 0.31, which indicates that only 31% of the variation in the non-coincident peak load can be explained by kWh usage. The results of this statistical analysis are contained in Seelye Exhibit 31. These results suggest that *there is a moderate basis for a declining-block rate structure* year around based on non-coincident peak load factors.

The linear regression analysis did not indicate a statistically significant relationship between monthly *coincident peak load factor* and monthly *energy usage* for LG&E residential customers based on observations for the *summer months*. The t-value for kWh energy usage is -1.16, which is not statistically significant at the 95% level. This lack of relationship can be visually verified in the graph contained in Seelye Exhibit 32. The R-Square statistic of 0.003 shows that summer kWh energy usage for LG&E residential customers explains only about 0.3% of the variation in summer coincident peak load factor. Stated differently, about 99.7% of the variation in summer coincident peak load factor for LG&E residential customer is unexplained by this model. The results of this statistical analysis are also contained in Seelye Exhibit 32. These results suggest that *there is no basis for LG&E's current inverted-block rate structure during the summer months* based on coincident peak load factors. This is extremely important given that summer peak period costs are allocated on the basis of coincident peaks during the summer months.

The linear regression analysis indicated a statistically significant relationship between monthly *coincident peak load factor* and monthly *energy usage* for the LG&E residential customers based on observations for the *winter months*. The regression coefficient for kWh energy usage is negative which indicates that kWh usage has an inverse relationship with winter coincident peak load factor, with a t-value of -5.214, which indicates statistical significance at the 99% confidence level. However, the R-Square statistic of 0.026 shows that only about 2.6% of the variation in winter coincident peak load factor can be explained by kWh usage. The results of this statistical analysis are contained in Seelye Exhibit 33. These results suggest that *there is no basis for a declining-block rate structure during the winter months* based on coincident peak load factors.

Q. Do you believe that a declining-block rate or inverted-block rate can be strongly supported based on these analyses?

A. No. Importantly, neither of the analyses examining coincident peak load factors provides any support for LG&E's current block structure. The only support indicated by any of these analyses is for a year around declining-block rate as shown in the analysis of the non-coincident peak load factor. However, the R-Square supporting this conclusion is not strong. Furthermore, this analysis only relates to distribution demand-related costs. Even if, in spite of the relatively poor R-Square, a year around declining-block rate were developed based on distribution costs, the pricing decrement or "step" in the rate would be very small because distribution demand-related costs are a relatively small portion of LG&E's total demand-related costs.

Q. But doesn't the fact that production and transmission demand-related costs are higher in the summer than in the winter support an inverted block rate in the summer months and a declining-block rate in the winter months?

A. No. It is important not to confuse seasonal differences in costs with differences that would translate into an inverted- or declining-block structure. The higher costs in the summer months only support a seasonally differentiated rate, not an inverted block rate. A seasonally differentiated rate fully addresses the seasonal nature of the costs, while blocked rates should address any cost changes resulting from load factor differences across usage levels within each costing period. As indicated by the load factor analyses described above, there are no material load-factor differences across usage levels within each costing period that would justify a blocked rate structure.

Q. Are you proposing to eliminate the block rate structure for residential service?

A. Yes. A flat energy charge is more reflective of the cost of providing service, is easier for customers to understand, and will decrease the volatility in customer bills during the summer months. Furthermore, with a higher customer charge there is less need to retain the declining-block rate structure.

Q. What rate design is being proposed for residential service?

A. We are proposing a two-part rate consisting of a customer charge and a flat, seasonally differentiated energy charge. We are proposing to eliminate the blocked rate structure in both the winter and summer months. We are proposing a customer charge of $9.00 per month and an energy charge of $0.04953/kWh during the winter months and $0.06327/kWh during the summer months.

Q. What is the relationship between the proposed customer charge and the customer-related costs identified in the cost of service study?

A. As shown in Seelye Exhibit 34, the cost of service study indicates that customer-related costs for Rate R are $13.49 per month. A $9.00 per month customer charge would represent a significant movement in the direction of reflecting LG&E's customer-related costs in rates. Even so, a $9.00 customer charge represents only 66.8% of total customer-related costs ($9.00 ÷ $13.49 = 66.7 %). The increase in the customer charge would be similar to the increase toward cost of service with respect to the residential gas customer charge in LG&E's last gas base rate case, Case No. 2000-080. In that proceeding, the customer charge was increased to $7.00, with the cost of service study then indicating that customer-related costs were $11.48. Thus, in the last gas rate case the Commission approved a customer charge that reflected 61.0% of total customer-related costs ($7.00 ÷ $11.48 = 61.0%).

Q. Are any other changes being proposed to the residential rate schedule?

A. Yes. The name of the rate schedule is being changed to Residential Service Rate RS to conform to Kentucky Utilities' standard residential service rate. In addition, the availability of service description has been simplified and a reference to the terms and conditions for service has been added.

Q. Is LG&E proposing to change the level of base rates for residential Prepaid Metering Pilot Program Rate RPP?

A. Yes. LG&E is proposing to modify the base rates set forth in the Rate RPP. We are not proposing to change the facilities charge included in the rate, which was approved by the

Commission in Case No. 2000-548 earlier this year. The basic customer charge and kilowatt-charge were simply modified to correspond to the average rate for service under Rate RS. The Basic Customer Charge set forth in the rate will be increased from $3.31 to $9.00 per meter per month (from $39.72 to $108.00 per meter per year) and the kilowatt-hour charge will be decreased from $0.05537/kWh to $0.05518/kWh.

Q. Is LG&E proposing to change the Volunteer Fire Department Rate ("VFD") for electric service?

A. Yes. Rate VFD currently contains the same charges as Rate R and LG&E is proposing changes to VFD to match the increase requested for Rate RS. Consequently, we are proposing a customer charge of $9.00 per month and an energy charge of $0.04953/kWh during the winter months and $0.06327/kWh during the summer months.

Q. Is LG&E proposing to eliminate the Water Heating rider?

A. Yes. The rate has been frozen since August 20, 1974. We are proposing to consolidate the Water Heating rider with Rates RS and GS, as applicable. Customers currently served under this rate schedule would take service under either Rate RS or Rate GS. The electric cost of service study indicates an extremely low rate of return for this customer class.

Q. Is LG&E proposing any changes to the rate structure of Rate GS?

A. No.

Q. Besides the rate structure, are any other changes being proposed to the Rate GS service schedule?

A. Yes. The availability of future service under this rate schedule has been limited to secondary service at maximum loads no greater than 200 kW per month. Customers already receiving primary service under this rate schedule as of its effective date will continue to be served under this schedule. Additionally, we are eliminating the exception to the minimum bill provision for three phase service.

Q. Why has LG&E proposed that future service under Rate GS be limited to secondary service at loads no greater than 200 kW?

A. LG&E proposes to limit service under this schedule to secondary service because customers should be served on a rate schedule that provides the appropriate price signals through demand and energy charges. Ideally, all customers should be served under a three-part rate consisting of a customer charge, demand charge and energy charge. A three-part rate more properly reflects the principal cost drivers of utilities – namely number of customers served, maximum demand, and the amount of energy used. However, the higher cost of installing metering equipment to measure demands has been a prohibiting factor to implementing three-part rates on a wider scale.

Q. Is LG&E proposing to eliminate the General Service Space Heating rider?

A. Yes. This is an old promotional rate that is no longer justified. The seasonal rate structure for General Service, which includes a lower energy charge during the winter months, obviates the need for this rider. It is not identified separately in the electric cost of service study due to the small number of customers served under this rider.

Q. Is LG&E proposing any rate design changes to Large Commercial Rate LC and Large Commercial Time-of-Day Rate LC-TOD?

A. Although we are not proposing to change the basic structure of these rate schedules, the proposed rate would lower the energy charge in Rate LC from $0.02886 to $0.02400/kWh and in LC-TOD from $0.02890 to $0.02400/kWh and would increase the customer and demand charges. As mentioned earlier, Rates LC and LC-TOD are designed to have the same underlying charges, except LC-TOD is time differentiated. For customers whose maximum demand occurs during the peak period, the rates are identical. The way that a customer can receive a lower average price under Rate LC-TOD is to shift its maximum demand to the off-peak period. Under the proposed rates, the peak and basic demand charges when added together under Rate LC-TOD will equal the demand charge under Rate LC.

Q. Are any other changes being proposed to the Rate LC service schedule?

A. Yes. We have eliminated redundant or unnecessary language and have clarified that where regulations require a separate circuit for exit or emergency lighting, the demand and energy usage of the separate circuit may be combined for billing purposes with those of the principal power circuit. All alternating current service under this schedule remains limited to those customers whose monthly demand is less than 2000 kW and whose entire lighting and power requirements are purchased under this schedule at a single service location.

Q. Are any other changes being proposed to the Rate LC-TOD service schedule?

A. Yes. The availability of future alternating current service under this rate schedule has been limited to customers whose monthly demand is 2000 kW or greater and whose entire lighting and power requirements are purchased under this schedule at a single service location. However, such customers already receiving service under this rate schedule as of its effective date will continue to be served under this schedule. As will be described below, LG&E has also modified the time periods applicable to this schedule and eliminated redundant or unnecessary language.

Q. Is LG&E proposing any rate design changes to Industrial Power Rate LP and Industrial Power Time-of-Day Rate LP-TOD?

A. Again, we are not proposing to change the basic structure of Rate LP and LP-TOD. However, the proposed rate would lower the energy charge from \$0.02480 to \$0.0200/kWh and increase the customer and demand charges. As with LC and LC-TOD, Rates LP and LP-TOD are designed to have the same underlying charges, except LP-TOD is time differentiated. For customers whose maximum demand occurs during the peak period, the rates are identical. Under the proposed rates, the peak and basic demand charges when added together under Rate LP-TOD will equal the demand charge under Rate LP.

Q. Are any other changes being proposed to the Rate LP service schedule?

A. We have eliminated redundant or unnecessary language and added language regarding a customer's ability to opt out of the DSM Cost Recovery Mechanism. All service under this schedule for three-phase power and lighting service remains limited to those industrial customers whose monthly demand is less than 2000 kW.

Q. Are any other changes being proposed to the Rate LP-TOD service schedule?

A. Yes. The availability of future three-phase power and lighting service under this rate schedule has been limited to customers whose monthly demand is 2000 kW or greater. However, such customers already receiving service under this rate schedule as of its effective date will continue to be served under this schedule. As will be described below, LG&E has also modified the time periods applicable to this schedule and eliminated redundant or unnecessary language.

Q. Is LG&E proposing to change the peak periods set forth in Rates LC-TOD and LP-TOD?

A. Yes. We are proposing to reduce the number of hours in both the winter and summer peak period, and to eliminate holidays as off-peak periods. During the summer billing months the peak period will be reduced by 3 hours, and during the winter billing months the peak period will be reduced by 2 hours. Additionally, the peak periods will always be determined on the basis of Eastern Standard Time (EST) instead of local time. The shorter peak periods should provide large commercial and industrial customers with slightly greater opportunity to shift load to off-peak periods. The following table summarizes the changes to the peak periods:

Table 5 Changes to Peak Periods Rates LC-TOD and LP-TOD	
Current Peak Periods	**Proposed Peak Period**
Summer Peak Period Weekdays, except holidays as recognized by Company, from 9 A.M. to 11 P.M. local time, during the 4 monthly billing periods of June through September.	**Summer Peak Period** Weekdays, from 10 A.M. to 9 P.M. Eastern Standard Time (EST) during the 4 monthly billing periods of June through September.

Table 5
Changes to Peak Periods
Rates LC-TOD and LP-TOD

Current Peak Periods	**Proposed Peak Period**
Winter Peak Period Weekdays, except holidays as recognized by Company, from 6 A.M. to 10 P.M. local time, during the 8 monthly billing periods of October through May.	**Winter Peak Period** Weekdays, from 8 A.M. to 10 P.M Eastern Standard Time (EST) during the 8 monthly billing periods of October through May.

Q. What changes are being proposed to the Interruptible Service Rider?

A. LG&E is proposing several major changes to this rider. First, the company is changing the name of the rider to Curtailable Service Rider ("CSR") in order to harmonize the tariffs with Kentucky Utilities' tariffs. Second, the credit available under Rate CSR would vary with voltage levels, with primary customers receiving a slightly higher credit than transmission customers. Third, the credit would be increased from $3.30 to $4.05 for customers served at primary voltages and from $3.30 to $3.98 for customers served at transmission voltages. Fourth, the hours of interruption would be increased to 500 hours of interruption per year. Because the credit will be determined on the basis of the full capacity cost of a combustion turbine generating unit, it is important that customers receiving the credit be subject to interruption for a number of hours representative of the amount of time that combustion turbines could be expected to operate according to the company's resource planning models. Fifth, LG&E is proposing to increase the charge for non-compliance during a requested interruption from $15/kW to $16/kW. LG&E also intends to make it clear that this charge will apply to *each* failure to interrupt. There has been some confusion on this issue, and we want to make it as clear as we can how the non-compliance charge will be applied. For example, if the customer fails to interrupt twice during a single billing period, we want to make it clear that two separate non-compliance charges will be assessed during the billing period. Furthermore, we want to clarify how the demand amount will be determined to which the non-compliance charge will apply.

Q. What is the basis of the proposed CSR credit?

A. The credit will be based on the avoided capacity cost of a combustion turbine generator. The avoided cost was determined by applying a levelized annual carrying charge to the installed cost per kW of a combustion turbine. Levelized fixed operation and maintenance expenses were also included in the avoided cost calculation. Additionally, the avoided cost was increased to reflect LG&E's planning reserve margin. The credits were loss adjusted to calculate a credit for transmission and primary voltage customers. The avoided cost calculation is included in Seelye Exhibit 35. The utility depends on being able to call upon the interruptible load during periods of capacity constraint. If the load is not interrupted, then there can be serious consequences. Furthermore, if the customer does not interrupt, no avoided costs are realized for LG&E and its customers.

Q. What is the basis of the proposed charge for failure to interrupt?

A. The $16/kW non-compliance charge was based on approximately 4 months of the credit. The foundation for the charge is that each failure to comply with a request to curtail the customer's load should result in the customer paying back 4 months of the credit, which is not an unreasonable charge given that in its resource planning scenarios the company does not plan to serve load that can be curtailed.

Q. Is LG&E proposing to increase the Supplemental or Standby Service?

A. Yes. This rate is available for customers with their own generation who want to purchase back-up generation, transmission and distribution capacity from the company. Although LG&E had no billings under this rate during the test year, we are proposing to increase the demand charge by the overall percentage to electric ultimate consumers being proposed in this proceeding. Therefore, LG&E is proposing to increase the demand charge by 11.34%, or from $5.61/kW to $6.25/kW. LG&E is not proposing any other changes to the rate schedule.

Q. What changes are being proposed to LG&E lighting rates?

A. The lighting rates are being increased by approximately 12.2%. In addition, LG&E is proposing to freeze Rates OL and PSL and offer prospective lighting customers a new lighting service, Lighting Service Rate LS, which will list a wider array of lighting options. Rates OL and PSL are outdated and do not accurately reflect the variety or the current cost of lights being offered by the utility. The company wants to provide a detailed pricing structure that more accurately reflects the types of lights actually being offered. LG&E also wants to increase the rates charged for new lighting service to reflect current marginal costs without significantly impacting current lighting customers, including municipal governments, who may have been using the same light or group of lights for a number of years. The company is also making changes to harmonize the lighting rate schedules for both LG&E and Kentucky Utilities.

Q. Have you prepared an exhibit showing the cost support for Lighting Service Rate LS?

A. Yes. Seelye Exhibit 36 shows the cost support for the new rates. For each light the monthly unit cost includes three cost components: (i) the carrying costs plus operation and maintenance expenses applied to the total installed cost of the lighting equipment, (ii) the demand- and energy-related cost of serving the light (including production, transmission, and distribution costs), and (iii) the customer-related cost of serving the light.

Q. Is LG&E proposing to add a Rider for Intermittent and Fluctuating Loads ("IFL")?

A. Yes. We are proposing that the IFL rider be added to address concerns about loads having a detrimental effect on the system, thus potentially adversely affecting other LG&E customers or LG&E's facilities.

Q. Are changes being proposed to LG&E's Excess Facilities rider?

A. Yes. LG&E is making changes to the Excess Facilities rider to standardize its practices and offerings across LG&E and Kentucky Utilities. Kentucky Utilities has a widely used facilities lease arrangement that is similar in purpose to LG&E's Excess Facilities rider. If a customer on Kentucky Utilities' system requires non-standard facilities (such as a second back-up feed or automatic switchgear) or wants to lease transformers from the utility to take service at a lower voltage, Kentucky Utilities' longstanding practice was to lease the facilities to the customer at an annual lease rate of 28% of the cost of the facilities. The lease payment was intended to cover the carrying costs on the investment, depreciation, and operation and maintenance expenses. The payment would continue for as long as the customer required the facilities. The way that the 28% was determined, the lease payment in effect provided for the eventual replacement of the facilities through the application of a straight carrying charge methodology (as opposed to a levelized carrying charge methodology). Kentucky Utilities has been offering lease arrangements since at least the early 1980s and has numerous such arrangements with customers.

LG&E has an Excess Facilities rider designed to accomplish some of the same objectives. However, LG&E's Excess Facilities rider operates differently in some key respects. First, the monthly charge set forth in LG&E's Excess Facilities rider is separated into two components: (i) a capital recovery charge and (ii) an operating expenses charge. The capital recovery charge provides for recovery of the cost of the facilities over a 5-, 8-, 10-, 12- or 15-year contract term selected by the customer. The monthly capital recovery charge rates are currently as follows:

5-Year	2.65%
8-Year	1.87%
10-Year	1.63%
12-Year	1.47%
15-Year	1.32%

The operating expense charge is 0.14%, regardless of the term of the contract. This charge would also apply if the customer makes a contribution in aid of construction in the form of an upfront payment to cover the cost of the excess facilities instead of paying the monthly capital recovery charge.

These charges are applied as follows: if a customer wants the company to install a piece of non-standard equipment, such as a second feed, then the customer would pay

LG&E 1.63% of the cost of the equipment for 10 years if the customer agrees to enter into a contract with a 10-year term. The customer would also pay 0.14% of the cost of the equipment for the term of the contract or until the facilities fail, at which time the customer would be responsible for replacing the facilities or terminating service under the rider.

Q. Has LG&E's Excess Facilities Charge been widely used?

A. No. Only four LG&E electric customers have taken service under the rider. No gas customers are served under the Excess Facilities rider.

Q. Are there any problems with the Excess Facilities rider?

A. Yes. Although the current level of the charge cannot be supported, Kentucky Utilities' approach is more flexible and is more suitable for meeting the needs of customers. The problem that customers have with LG&E's Excess Facilities rider is the prospect of replacing the equipment if it fails. Under Kentucky Utilities' approach, the company is responsible for the equipment even if it fails. Although the monthly lease charge is relatively high at Kentucky Utilities, not having to be concerned about the replacement of the facilities is an attractive feature to customers. I believe that this in large part explains the popularity of the special lease arrangements at Kentucky Utilities.

Q. How is LG&E proposing to structure the Excess Facilities rider?

A. We are proposing to separate the rate into two components: (i) a carrying charge component and (ii) an operating expenses component. For LG&E the carrying charge component for distribution facilities would be 0.93% per month as applied to the original cost of the facilities, and the operating expenses component would be 0.68%. The carrying charge component would cover the utility's cost of capital, grossed up for income taxes related to the investment. The operating expenses component would cover the operation and maintenance expenses, property taxes, *and* the cost of replacing the facilities. A customer can choose either to pay for the facilities up front through a contribution in aid of construction or pay the carrying charge set forth in the rate. If a customer chooses to make a contribution in aid of construction for the facilities then only the operating expenses component of the rate (0.68%) would apply. If a customer does not want to pay for the facilities up front, then both the carrying charge component and the operating expenses component would apply. In either case, the utility will be responsible for replacing the facilities should the facilities fail. This is a much more straightforward approach than currently followed in LG&E's Excess Facilities rider and is better suited to meet the needs of customers.

Q. Have you prepared an exhibit showing the calculation of the charges set forth in the proposed Excess Facilities rider?

A. Yes. The cost support for the charges is included in Seelye Exhibit 37. As can be seen from this exhibit, the carrying charge component of the rate corresponds to the weighted cost of capital proposed by LG&E in this proceeding, grossed up for income taxes. The operating expenses component includes operating expenses, maintenance expenses, insurance, taxes other than income taxes, and depreciation expenses. The depreciation expenses are intended to cover the replacement over time of the facilities.

Q. How will the four customers currently taking service under the Excess Facilities rider be handled?

A. LG&E intends to grandfather these contracts under the current rate schedule.

Q. Are you also making these same changes to the Excess Facilities rider included in LG&E's gas tariff?

A. Yes. However, there appears to be very little interest on the part of gas customers in non-standard service configurations of the type that would be covered by the Excess Facilities rider.

Q. Please describe the Redundant Capacity rider proposed by LG&E.

A. The purpose of the Redundant Capacity rider is to allow customers that have one or more redundant feeds to reserve back-up capacity on the distribution system. As customers come to rely on greater use of electric technology, there is more and more customer interest in having a redundant feed along with automatic relay equipment capable of switching from a principal circuit to a backup circuit in the event that electric service from the primary feed is lost. With the greater use of technology, some customers are finding it increasingly difficult to tolerate electrical outages for even short periods of time. A customer who wants a second feed must pay the cost of the customer-specific facilities required to provide the feed, including the second distribution line, automatic relay equipment, or other customer-specific facilities that may be required. Customers can pay for the customer-specific facilities by either making a contribution in aid of construction or by taking service under the Excess Facilities rider. If the customer wants to have full backup capacity on the second feed, there are additional costs incurred by LG&E of ensuring that there is sufficient network distribution capacity to provide full backup in the event that a relay occurs on the automatic switchgear. In order to ensure that there is sufficient backup capacity for the redundant feed the utility must plan the distribution facility as if there were two customers placing demands on the system. For this reason, LG&E is proposing to implement a demand charge to cover the distribution demand-related cost of providing backup service for new customers with redundant feeds. The demand charge would be applied to the customer's monthly billing demand determined under the standard rate schedule under which the customer receives electric service.

Q. What are the proposed Redundant Capacity charges?

A. The proposed demand charge for primary voltage customers is $1.06 per kW per month of billing demand and the proposed demand charge for secondary voltage customers is $1.43 per kW per month of billing demand.

Q. How was the demand charge for the proposed Redundant Capacity rider determined?

A. The demand charge was determined by computing the distribution demand-related revenue requirements from the electric cost of service study for primary and secondary voltage service under LG&E standard demand/energy rates (Rates LC, LC-TOD, LP, and LP-TOD) and dividing this amount by the billing demands for this class of customers. LG&E is proposing different demand charges for customers served at primary and secondary voltages. The cost support for the proposed demand charges is included in Seelye Exhibit 38.

VII. MISCELLANEOUS SERVICE CHARGES

Q. Is LG&E proposing to change any of its miscellaneous non-recurring charges?

A. Yes. LG&E is proposing to change or add a number of miscellaneous non-recurring charges. First, LG&E is proposing to increase the disconnect/reconnect charge from $18.50 to $23.00. This modification is discussed in Mr. Cockerill's testimony. Second, LG&E is proposing to add a meter-test charge. The charge will be $31.40 for electric meters and $69.00 for gas meters. Again, these charges are discussed in Mr. Cockerill's testimony. Third, LG&E is proposing to increase the third-trip gas inspection charge from $5.00 to $135.00. I will address the change in the third-trip inspection charge.

Q. Please describe the third-trip gas inspection charge?

A. The general rules of LG&E's gas tariff provides as follows:

> With respect to customer's service line and house line inspections prior to initiation or resumption of gas service, the Company will make two such inspections without charge. When more than two trips are necessary to complete the inspection at any one location, a charge of $5.00 will be made for each additional trip.

The recipient of this charge is generally a home construction contractor or plumber for whom LG&E must make multiple trips to inspect work that was not done in accordance with requirements set forth in regulations. The existing $5.00 charge has not been modified since it was first implemented on May 15, 1977. The purpose of the increase is simply to provide recovery of the cost of inspecting customer service and house lines. LG&E does not believe that contractors and plumbers should be subsidized by LG&E's other customers for the cost of the third inspection. The costs were not adjusted ("burdened") to include the company's overheads. The estimated unburdened cost provided to me by LG&E was $137.49. In order to moderate the impact of the increase, LG&E is proposing to use the unburdened cost to determine the charge. The cost support for the proposed charge is included in Seelye Exhibit 39.

Q. Have you prepared an exhibit showing the revenue impact of the proposed changes to the miscellaneous charges?

A. Yes. Seelye Exhibit 40 shows the impact on miscellaneous revenue of the proposed changes. Page 1 shows the revenue impact of modifying the disconnect/reconnect charge. This change results in an increase of $12,006 in annual gas revenue and $132,044 in annual electric revenue. Page 2 shows the revenue impact of implementing a meter-test charge for the gas and electric businesses. The implementation of a meter-test charge results in an increase of $31,464 in annual gas revenue and $1,287 in annual electric revenue. Page 3 shows the revenue impact of modifying the third-trip inspection charge. This change results in an increase of $80,730 in annual gas revenue. However, it should be pointed out that increasing these charges could result in a reduction in the utilization of these charges, thus producing slightly lower revenue than the proposed pro-forma amount requested in this proceeding. Nevertheless, economic efficiencies can be achieved by sending the correct price signal through the implementation of charges that properly reflect the cost of providing the service. This is what we have tried to do with all of the rate modifications discussed in my testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, William Steven Seelye, being duly sworn, deposes and states that he is a Principle with The Prime Group, that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

WILLIAM STEVEN SEELYE

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24 th day of December, 2003.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

TAMMY J. ELZY
~~NOTARY PUBLIC~~
STATE AT LARGE
KENTUCKY
My Commission Expires Nov. 9, 2006

Mr. Murphy

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:	)	
	)	
AN ADJUSTMENT OF THE GAS	)	CASE NO: 2003-00433
AND ELECTRIC RATES, TERMS	)	
AND CONDITIONS OF LOUISVILLE	)	
GAS AND ELECTRIC COMPANY	)	

TESTIMONY OF
CLAY MURPHY
DIRECTOR – GAS MANAGEMENT, PLANNING, AND SUPPLY
LOUISVILLE GAS AND ELECTRIC COMPANY

December 29, 2003

Filed: December 29, 2003

Q. Please state your name and business address.

A. My name is Clay Murphy and my business address is 820 West Broadway, Louisville, Kentucky.

Q. What position do you currently hold at Louisville Gas and Electric Company ("LG&E")?

A. I am currently the Director – Gas Management, Planning, and Supply.

Q. What is your role as Director - Gas Management, Planning and Supply?

A. I am responsible for overseeing the procurement of natural gas supplies and pipeline transportation services for LG&E, end-use natural gas transportation services, and regulatory issues related to LG&E's pipeline transportation service providers. I am also involved in a number of other regulatory and planning activities and initiatives related to LG&E's natural gas business.

Q. What is your educational background and experience?

A. I graduated from Bellarmine College in Louisville, Kentucky, with a B. A. degree in Accounting in 1979. I graduated from Indiana University in Bloomington, Indiana, with an M.B.A. in 1981. I was employed by LG&E in the same year in the Rate Department, where I remained until 1986 when I transferred to the newly created Gas Supply Department. I became manager of that department in 1989 and director in 2001. A statement of my education, work experience and professional activities is contained in Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I submitted written testimony in the Commission's Administrative Case No. 346, "An Investigation of the Impact of the Federal Energy Regulatory Commission's Order

636 on Kentucky Consumers and Suppliers of Natural Gas." I also submitted testimony on LG&E's gas supply cost Performance-Based Ratemaking ("PBR") mechanism in Case No. 97-171 and Case No. 2001-017. I also testified in Case No. 2000-080, LG&E's last gas rate case.

Q. What is the purpose of your testimony in this case?

A. I would like to outline the increasingly competitive nature of the natural gas industry and some of the challenges for the future. In addition, my testimony also addresses certain specific changes that LG&E is proposing to its natural gas transportation services as well as certain sales services. As a part of that discussion, I will describe the services LG&E proposes to modify and discuss the proposed modifications to those services.

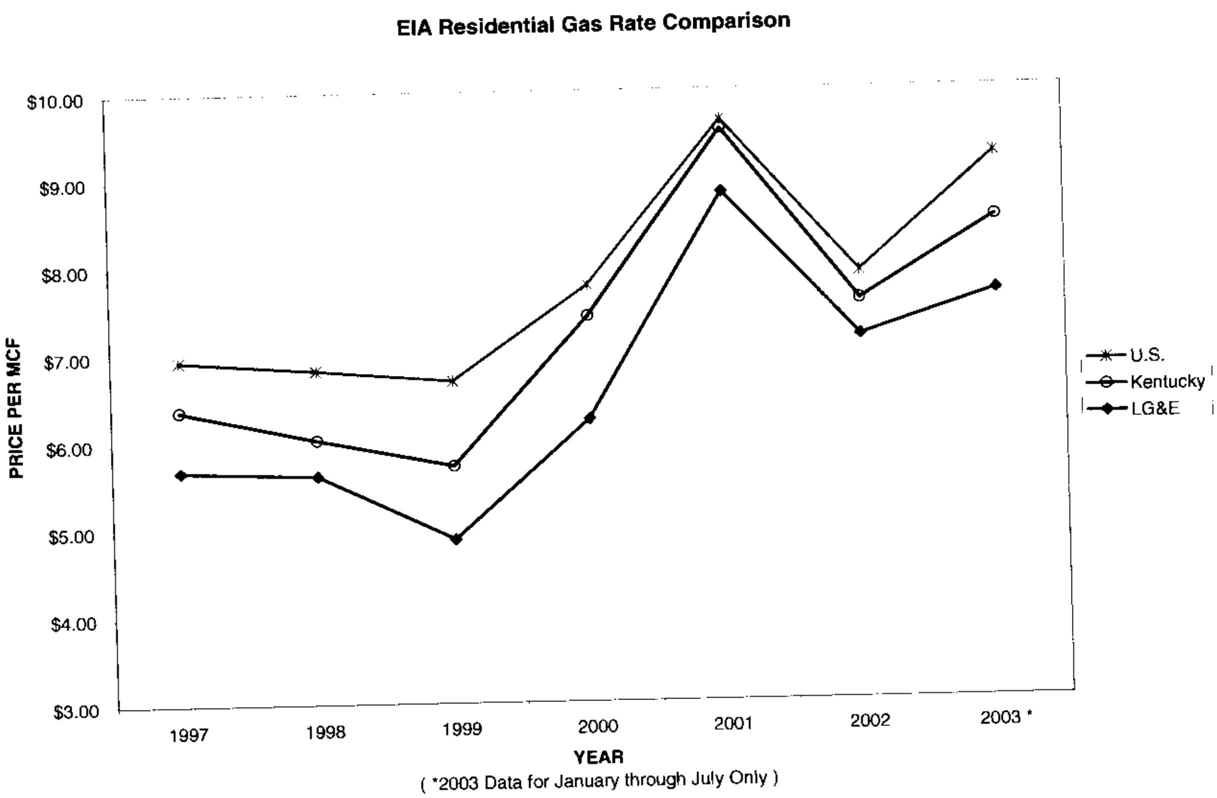
I. INDUSTRY COMPETITIVENESS AND OTHER CHALLENGES

Q. What are some of the issues you plan to discuss in this section of your testimony?

A. In his testimony Chris Hermann discusses some of the operating challenges associated with LG&E's gas business, including the replacement of gas mains in various portions of LG&E's system, the installation of facilities to serve new customers as well as some of the requirements that may be imposed upon LG&E by the Pipeline Safety Improvement Act of 2002. I would like to discuss non-operating challenges which affect the competitive nature of LG&E's gas business.

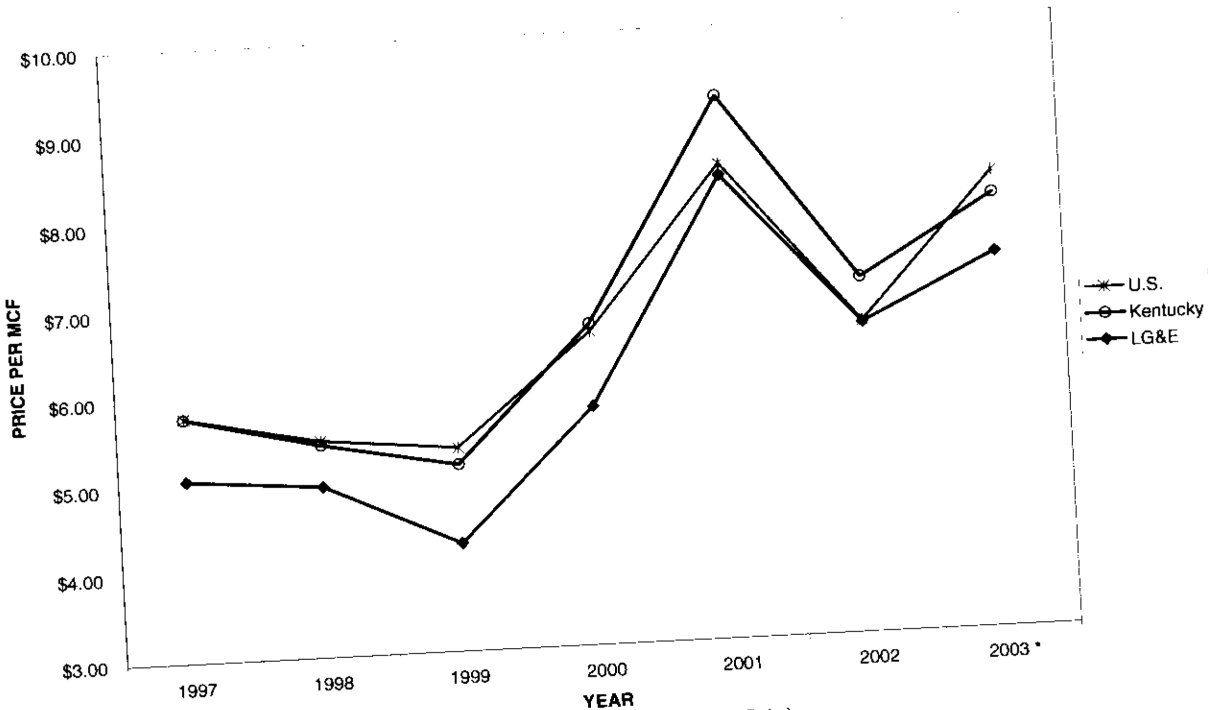
Q. How competitive are LG&E's gas rates compared to the rates charged by other gas utilities?

A. In terms of its residential gas rates, LG&E's rates have been below the national average for some time, as illustrated by the graph showing data published by the Energy Information Administration ("EIA") for Kentucky and the nation compared with that of LG&E. LG&E is very pleased that its residential rates have been low relative to others, but it is also important to consider other consequences of the disparity between LG&E's residential rates and the rates for gas services to its other gas customers.



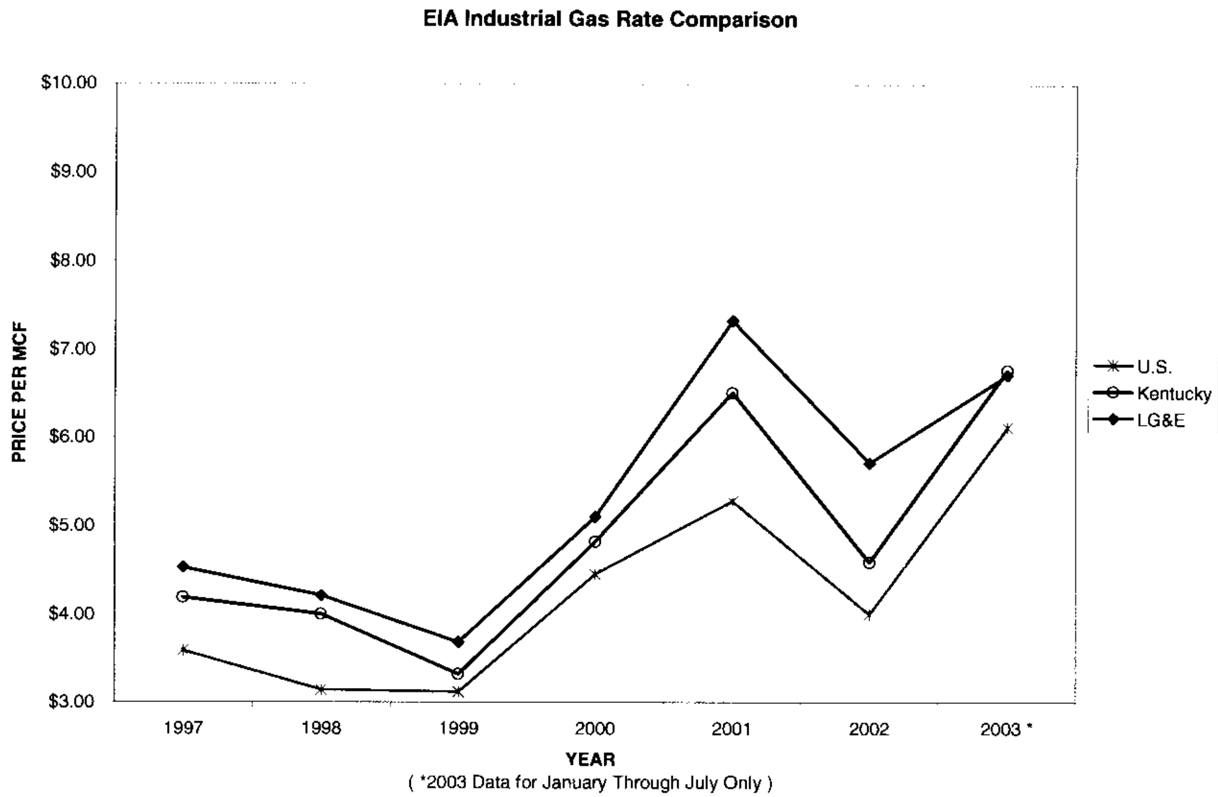
LG&E's commercial rates are generally comparable with or lower than the national average, as illustrated by the graph showing EIA data for Kentucky and the nation compared with that of LG&E.

EIA Commercial Gas Rate Comparison



(*2003 Data for January Through July Only)

On the other hand, LG&E's industrial rates are higher than the national average, as illustrated by the graph showing EIA data for Kentucky and the nation compared with that of LG&E.



In combination with the cost of service data analyzed by W. Steven Seelye in his testimony, LG&E has also considered its relative price standing to other gas utilities in recommending changes to its natural gas rates.

Q. How is LG&E responding to the increasingly competitive nature of the natural gas industry?

A. The natural gas business has always been competitive, and it continues to become increasingly a more competitive and complex environment in which to do business. Certain forms of competition (such as alternate fuel use and competition for load growth through economic development) have been around for some time. Others, such as bypass, are more recent.

Q. **Please explain LG&E's concerns about physical bypass.**

An important competitive factor that affects LG&E's gas business is the ability of gas customers to physically bypass the LG&E gas distribution system and receive gas service directly from an interstate pipeline without making use of LG&E's facilities. LG&E's efforts to prevent bypass and ensure that these customers continue to make some contribution to fixed costs have been successful to date. However, those pressures remain considerable, and they offer one explanation as to why LG&E has proposed no rate increase to customers who may potentially bypass or who have other alternatives. LG&E has also considered bypass among other factors in verifying the validity of its cost of service study. Increasing the rates of large volume industrial customers increases the feasibility of bypass. LG&E's cost of service study has shown that customers served under Rate FT generally have higher rates of return than other classes, and has therefore not allocated a portion of the proposed rate increase to these customers. As LG&E's distribution charges increase, and along with it the feasibility of bypass, customers that may not have previously considered physical bypass an option may do so. Therefore, competitive pressures support LG&E's revenue allocation derived from its cost of service studies.

Q. Is physical bypass the only competitive pressure to which LG&E is subject?

A. No. In addition to physical bypass, economic development efforts and activities have not resulted in the addition of new large natural gas customers in the last several years. While natural gas costs are not the only factor considered in locating new industrial loads, it is an important one. Maintaining competitively priced industrial natural gas service is one important aspect in maintaining a healthy environment for economic development.

This provides another reason why LG&E has proposed no increase in the charges for natural gas service to large customers served under Rate FT or related special contracts.

Q. What about competitive pressures resulting from large customers leaving the LG&E gas service areas?

A. It has been difficult to prevent large customers from leaving LG&E's service territory or closing altogether. In addition to closings by such customers as Philip Morris, Fischer Packing, Earthgrains, Pasta Group, and others, there is considerable uncertainty about the future of other large natural gas consumers served by LG&E.

Q. Are there competitive pressures associated with residential customers?

A. Yes. The two most important competitive pressures associated with LG&E's residential customers has been a decline in natural gas consumption by existing customers and the cost to add new residential gas customers.

Q. Please explain some of the problems associated with declining residential gas consumption.

There has been a consistent decline in the average annual consumption of natural gas by LG&E's residential customers that contributes to the need for rate relief. In LG&E's last gas rate case, its rates were calculated on the basis that the temperature normalized average annual consumption of LG&E's residential gas customers was 91.3 Mcf. The temperature normalized consumption of LG&E's residential gas customers during the test year in this case was 82.5 Mcf. So there has been a reduction of 8.8 Mcf per customer per year, or a 9.6% reduction in average consumption per residential customer. This reduction is temperature normalized and is not the result of comparing a warmer period to a colder one.

Q. **Why does this situation contribute to the need for rate relief?**

A. Even though LG&E's Weather Normalization Adjustment tariff ("WNA") helps to provide earnings stability by removing weather variability, it does not maintain normalized customer consumption at the same levels at which rates were set. Because such a significant amount of LG&E's costs are fixed and are not covered through the customer charge, LG&E is at risk for revenue decreases that result from load loss, such as that demonstrated here. Other factors aside, lower consumption results in lower revenues to cover the same costs.

Q. **Can you further illustrate your point about rate relief and reduced consumption?**

The distribution charge and the customer charge are designed to recover the non-gas costs of providing natural gas service, including a reasonable return. The distribution charge is applied on a volumetric basis and, if the volume of gas per customer declines, then LG&E is not recovering all of these costs. The arithmetic is simple. Each residential gas customer consumed 8.8 Mcf less gas during the current test year than during the test year of LG&E's last rate case. The Distribution Cost Component approved in that case was $1.3457 per Mcf. Thus, the revenue shortfall for each residential customer was $11.84 during the test year. The average number of residential gas customers during the test year in this case was 286,590. Thus, the total residential revenue shortfall attributable to reduced consumption was about $3,393,000.

Q. **Is LG&E's experience regarding residential gas consumption consistent with the experience of other local distribution companies?**

A. Yes. The Energy Information Administration has found that there has been a general decline in average normalized natural gas consumption per residential customer, both nationally and regionally, including Kentucky.

Q. Are there other competitive pressures associated with residential customers?

A. Yes, it is difficult to economically add small residential customers given the inadequate return to cover the costs of adding those customers. So, even adding more residential customers doesn't help improve LG&E's earnings. Since LG&E's last gas rate case, facilities for more than 16,000 net customers (the overwhelming majority of which have been residential) have been placed in service. LG&E has an obligation to serve new residential customers by providing each new customer with 100-foot free main extension. LG&E's rates, which are based on embedded costs, are lower than the incremental cost to add new customers. Therefore, one of the causes of the erosion of LG&E's rate of return is the fact that the revenue produced by the new residential customers does not offset the incremental cost of adding new residential customers. Thus, rate relief is necessary to enable us to earn a return on the facilities installed to serve these new customers.

Q. How would LG&E summarize the challenges and risks of the gas business that you have outlined in your testimony?

In addition to the operating challenges outlined in Chris Hermann's testimony, LG&E is also confronted with a growing number of residential customers whose rates do not cover the incremental cost of adding the customer. Yet again, the average gas consumption of these residential customers is declining, further hampering LG&E's ability to recover its costs. Larger customers impose another set of challenges and risks including bypass, economic development, and load retention.

Q. Does this conclude this portion of your testimony at this time?

A. Yes.

II. RATE CHANGES AND TARIFF MODIFICATIONS

Q. What matters do you propose to discuss in this section of your testimony?

A. In this section I will discuss certain proposed modifications related specifically to LG&E's gas sales and transportation services and rate schedules.

Q. Generally describe the nature of the changes LG&E is proposing to its natural gas transportation and sales services.

A. LG&E is not proposing drastic changes to the provisions of either its firm sales or its natural gas transportation services. Instead, LG&E is proposing to modify the cash-out mechanism and certain notice periods under its transportation services. It is also proposing to improve and simplify the structure of its interruptible sales services. The primary purpose of these modifications is to enhance the reliability of LG&E's system operations.

Types of Transportation Services Offered by LG&E

Q. Generally, what kinds of transportation services are offered by LG&E?

A. LG&E currently provides two types of natural gas transportation services. The first type includes a standby sales service. The second type is a transportation-only service.

Q. Please describe LG&E's standby transportation service offered under Rate TS.

A. Standby transportation service has been offered by LG&E since 1984 and was LG&E's first transportation service offering. This service provides customers with a level of service and reliability equivalent to the underlying sales service. It allows a customer the option of purchasing its natural gas supply from a third-party instead of from LG&E. Over the years, Rate TS has undergone several modifications. These modifications have been in response to changes in the industry as well as LG&E's growing experience with transportation service and some of the issues that can arise. For example, in order to reflect the additional administrative costs of providing transportation service, an Administrative Charge was added. In conformity with the Commission Order in Administrative Case No. 297, a daily minimum threshold was incorporated. In LG&E's last gas rate case, Case No. 2000-080, the availability of service under Rate TS was expanded, and a cash-out mechanism applicable to over-deliveries was added.

Q. What are the resources which LG&E uses to provide standby sales service to transportation customers?

A. LG&E provides standby sales service to transportation customers through its on-system storage and pipeline transportation capacity. The standby transportation customer is allocated its share of these two costs.

Q. How does LG&E's standby sales transportation service rate reflect the costs of these resources?

A. The standby transportation rate includes two components. The first component is the Distribution Charge applicable to the sales rate under which the customer is served. The second component is the Pipeline Supplier's Demand Component ("PSDC"). The PSDC chiefly includes pipeline capacity demand costs associated with holding firm pipeline transportation capacity required to serve sales and standby sales customers. If the customer chooses not to purchase its own gas supply, or the customer fails to deliver any part or all of its requirements, LG&E is required to provide the customer with gas supply under the terms of the otherwise applicable sales rate schedule. To the extent that the customer purchases gas from LG&E, those charges are the same as those incorporated in the Gas Supply Cost Component ("GSCC") of the Gas Supply Clause. The standby sales transportation service rate is designed to be revenue neutral and thus prevents cost shifts to other customers as a result of providing this type of transportation service.

Q. Please describe LG&E's non-standby transportation services.

A. Non-standby transportation service has been offered by LG&E since 1988. It was originally offered under Rate T. Non-standby service differs from standby service in that LG&E provides no standby sales service to customers. If the customer chooses not to purchase its own gas supply, or if the customer fails to deliver all or any part of its requirements, LG&E has no obligation to provide natural gas or balancing services to the customer. Since no standby sales service is provided, LG&E does not charge the customer for pipeline capacity costs (which are collected from standby transportation customers through the PSDC) or for storage costs (which are collected from standby transportation customers through the Distribution Charge).

Q. Has LG&E's non-standby transportation service undergone any changes since its inception?

A. Like Rate TS, Rate T has been modified over the years by adding an Administrative Charge, a daily minimum threshold, and minimum receipt and delivery tolerance levels.

In 1995, Rate T was significantly modified, particularly with respect to balancing requirements and re-named the transportation service Rate FT. In LG&E's last gas rate case, Case No. 2000-080, the cash-out mechanism incorporated in Rate FT was modified. Rate FT includes provisions designed to protect and enhance system reliability and prevent cost shifting to sales customers. Telemetry equipment must be in place for all customers served under Rate FT in order to allow for determination of imbalances between the volume of gas the customer delivers to LG&E and the volume of gas the customer uses. Rate FT customers are encouraged not to take actions that would jeopardize service to LG&E's sales customers through the use of Operational Flow Order ("OFO") provisions and penalties, daily utilization charges outside an "as available" 10% tolerance, and monthly cash-out charges. Cost-shifting to sales customers is prevented by these mechanisms as well as by requiring that customers requesting service under Rate FT provide six (6) months prior notice. This prior notice permits LG&E to adjust its supply and transportation portfolio.

Overview of Proposed Changes to Transportation Services

Q. Please describe the changes LG&E proposes to its transportation services in this proceeding?

A. The changes proposed are a general updating of LG&E's tariffs to reflect new market conditions and regulatory changes in the natural gas industry. The changes proposed by LG&E are necessary to ensure that LG&E can properly manage its system operations and supply requirements, maintain system reliability and integrity, and operate its storage facilities without compromising service to LG&E's other customers. With these changes, LG&E believes that it can continue to provide reliable service to both transportation and sales customers and prevent sales customers from bearing costs more properly associated with the activities of transportation customers.

Q. Briefly, what are the changes that LG&E is proposing to its transportation rate schedules?

A. While LG&E has proposed no increase in the rates for transportation service under Rate FT, LG&E has proposed to modify the balancing charges for transportation services to prevent subsidies by residential sales customers to industrial transportation customers. Specifically, LG&E proposes to modify Rate FT by:

- decreasing the notice period for issuing an OFO from 24 hours to 18 hours; and
- changing the cash-out reference price for over- or under-deliveries while otherwise retaining the application of sliding scale cash-out percentages.

LG&E proposes to modify Rate TS by:

- changing the cash-out reference price for over-deliveries while otherwise retaining the application of sliding scale cash-out percentages as it pertains to over-deliveries.

Therefore, although LG&E is proposing no change to the base rates of these customers, LG&E is proposing changes to further ensure that residential customers do not subsidize transportation customers through the provision of balancing services.

Q. Has LG&E considered proposing any other changes to its transportation services?

A. Yes. LG&E has considered including a "Loss and Use Factor" in both Rate FT (and the three special contracts that operate under conditions nearly the same as Rate FT) and Rate TS.

Q. What prompted LG&E to consider such a "Loss and Use Factor"?

A. LG&E has recently been the subject of a focused gas procurement audit. The audit afforded LG&E the opportunity to demonstrate LG&E's effectiveness and efficiency in dealing with gas supply, planning, and procurement matters. The final report was issued in November 2002. LG&E is pleased that it is recognized as a low-cost provider of natural gas. The auditor recognized LG&E's gas supply activities as innovative in the quest for lower commodity prices, attentive to market developments, and sophisticated in advancing the interests of its customers. In fact, the audit report states that LG&E's "very impressive record in keeping its rates down provides sound evidence on the excellent job done in the area of gas supply procurement and management." The audit also provided LG&E with some recommendations to consider.

Q. How many recommendations must LG&E address as a part of the focused gas procurement audit?

A. There are only four recommendations to which LG&E must respond. Those recommendations relate to (i) the reporting of potential natural gas storage development projects; (ii) improving the formatting of reports sent to senior management by the Gas Supply Department; (iii) reviewing whether a provision that transportation customers share in Lost and Unaccounted for Gas ("LAUFG"); and (iv) providing findings and proposed actions on its recent study of LAUFG. LG&E made its initial report to the Commission on September 30, 2003, and requested that the second and fourth of the four recommendations be closed. LG&E is addressing the third recommendation here.

Q. What would be the purpose of a "Loss and Use Factor" as applied to natural gas transportation customers?

A. In general, a loss and use factor would provide that transportation customers contribute to volumes of LAUFG used in the operation of a distribution system. Typically, two of the more significant causes of LAUFG are measurement differences and losses. A certain amount of gas that a gas distribution company sends out into its system is measured in such a way that the volumes delivered into the system do not match the volumes of gas metered and billed to customers. A certain amount is also lost through leaks. All distribution systems experience LAUFG in varying degrees depending upon the particular system operations and configuration of the gas distribution company.

Q. Why has LG&E not proposed to include such a factor in its transportation tariffs?

A. Generally, there are three reasons that a "Loss and Use Factor" may be inappropriate if applied to LG&E's transportation customers. The first reason is that a portion of the loss is the result of metering losses arising from pressure and temperature variation. As the result of the installation of telemetry required for service under Rate FT (and the three special contracts that operate under conditions nearly the same as Rate FT), the volumes delivered to LG&E's transportation customers served under Rate FT are already corrected for pressure and temperature variation. Therefore, Rate FT customers and special contract customers should not be responsible for losses caused by pressure and temperature variation. The second reason that it may not be appropriate to include this factor in transportation tariffs is that a portion of LAUFG is the result of gas leaks that are generally unrelated to the service being provided to these customers. Most leaks occur in the lower-pressure and medium-pressure systems. LG&E's transport customers are typically served directly from LG&E's higher-pressure systems since the delivery of the larger volumes consumed by these customers cannot generally be served at lower pressures. Therefore, Rate FT customers and special contract customers are generally not responsible for losses due to leaks.

Q. What is the third reason?

A. Subjecting these customers to a "Loss and Use Factor" raises the customer's cost of having LG&E as their natural gas distributor, thus increasing the risk of bypass or load loss. As stated above, these transportation customers are more likely to bypass LG&E's facilities or to utilize an alternative energy source. A "Loss and Use Factor" will decrease LG&E's competitiveness as a provider of natural gas services. It is in the best interests of LG&E and all of its customers to continue to provide service to these transportation customers to the extent that they contribute to fixed costs.

Changes to Rate FT

Q. Please describe Rate FT.

A. Rate FT is a natural gas transportation-only service available to customers who use more than 50 Mcf per day. Under Rate FT, LG&E provides firm transportation service from the point where the customer effectuates the delivery of gas to LG&E (the city-gate) to the customer's facility. If the customer electing service under Rate FT chooses not to purchase its own gas supply, or if the customer fails to deliver all or any part of its requirements, LG&E has no obligation to provide natural gas, storage, pipeline transportation services (or any associated balancing services) to the customer. Customers served under Rate FT are at risk for their own supply and are required to manage and acquire their own supplies within the confines of LG&E's Rate FT.

The level of the rates is addressed in the testimony of William Steven Seelye.

Q. Why is eligibility for service under Rate FT limited to customers consuming in excess of 50 Mcf per day?

A. The current 50 Mcf/day threshold incorporated in Rate FT is intended to ensure that customers served under that rate schedule are not primarily space-heating customers. Allowing space-heating customers to transport under Rate FT poses risks with respect to LG&E's system reliability and integrity. Extending Rate FT transportation service to predominantly temperature sensitive space-heating customers, whose hourly and daily usage fluctuates greatly during peak periods, is likely to jeopardize LG&E's ability to meet sales requirements, especially when customers served under Rate FT provide LG&E with inadequate or no resources to manage the hourly and daily load variations. Under certain operating conditions, hourly balancing in particular is critical to the operational integrity and reliability of LG&E's system.

Q. What resources are in place to manage the loads of customers served under Rate FT?

A. LG&E does not procure resources such as natural gas supplies, storage, or pipeline transportation capacity to serve Rate FT customers because LG&E has no obligation to serve these customers. Customers under Rate FT do have telemetry that allows each customer to manage its purchases by determining how much gas is being consumed. LG&E also has access to telemetry data to assist it in managing system loads, but LG&E does not have the ability to remotely interrupt or control the flow of gas to the customer's facility. However, LG&E has included certain features in Rate FT that are designed to maintain and enhance system reliability.

Q. Please describe some of the features included in Rate FT that are designed to maintain and enhance system reliability.

A. Rate FT incorporates various mechanisms so that customers served under Rate FT are encouraged to take actions that are appropriate to preserving system reliability and are discouraged from taking any action that might jeopardize service to LG&E's sales customers. One of the mechanisms incorporated in Rate FT is the application of daily utilization charges outside an "as-available" 10% daily balancing tolerance, an OFO provision and penalty, and monthly cash-out charges.

On a daily basis, a customer served under Rate FT is allowed to vary its usage within +/- 10% (ten percent) from the quantity nominated by the customer's supplier and delivered by the interstate pipeline. For example, if the customer has 100 Mcf/day delivered to LG&E, the customer can use from 90 to 110 Mcf /day without incurring a discrete balancing charge. Outside of this 10% (ten percent) tolerance band, the customer is charged a Utilization Charge for Daily Imbalances. That charge is $0.3807/Mcf for daily balancing (based on rates effective November 1, 2003, which rates change quarterly).

In certain circumstances, the mismatch (or imbalance) between the deliveries and usage by a Rate FT customer can jeopardize LG&E's system reliability. When necessary, the customer's +/- 10% (ten percent) daily balancing tolerance can be fully suspended through the issuance of an OFO. During the period for which an OFO is issued, customers must match their transportation gas deliveries to their usage. If a customer fails to comply with the OFO directive, it is financially penalized, in addition to any other action which LG&E may be required to take such as physically isolating and curtailing the customer to preserve system integrity.

Under Rate FT monthly over- and under-deliveries are discouraged through the application of a cash-out mechanism. At the end of the month, all daily over- and under-deliveries are summed, and the net over- or under-deliveries are eliminated through the cash-out mechanism. Eliminating over- or under-deliveries through a cash-out mechanism allows LG&E to avoid carrying imbalances from one month to the next.

Under the cash-out mechanism, over-deliveries are purchased at a price based on the monthly average of the *Gas Daily* "Dominion--South Point" price. As the level of the over-delivery increases, the price paid to the customer for over-deliveries decreases based on a sliding scale. Conversely, under-deliveries are sold to customers at a price based on the monthly average of the *Gas Daily* "Dominion—South Point" price. As the level of the under-deliveries increases, the price paid by the customer for under-deliveries increases based on a sliding scale.

Q. With regard to Rate FT, please discuss the specific changes which LG&E is proposing?

A. LG&E is proposing two modifications to Rate FT. LG&E is proposing to modify the method for calculating the cash-out price under the cash-out mechanism. It is also proposing to shorten the OFO notice period.

Q. Didn't LG&E receive Commission approval to modify the cash-out mechanism under Rate FT in its last gas rate case?

A. Yes. In LG&E's last gas rate case, LG&E proposed and the Commission approved a modification to change how the cash-out price is determined under the cash-out mechanism. LG&E currently calculates the cash-out price based on "*the monthly average of the daily mid-point prices posted in "Gas Daily" for Dominion--South Point for the month during which the imbalance occurred.*" A sliding scale step percentage is applied to the cash-out price so that customers receive less for their over-delivered gas as their percentage of over-deliveries increases above certain levels and pay more for their under-delivered gas as their percentage of under-deliveries increases above certain levels.

Q. Why is LG&E proposing to change its methodology for determining the cash-out price?

A. LG&E is proposing to change the methodology for determining its cash-out price in order to further encourage Rate FT customers to minimize imbalances. LG&E's proposed methodology for determining the cash-out price is constructed to further deter potential gaming and encourage transportation customers to balance their loads more closely, thus not adversely impacting residential and commercial firm sales customers.

Under LG&E's proposal, the cash-out purchase price for over-deliveries will be the lowest daily mid-point price posted in *Gas Daily* for Dominion-South Point during the month. The cash-out sales price for under-deliveries will be the highest daily mid-point price posted in *Gas Daily* for Dominion-South Point during the month. This method will penalize customers that deliver quantities of gas in excess of their requirements, for example when prices are low in order to hedge against higher prices that may occur later in the month. Conversely, this method will penalize customers that deliver quantities of gas that are less than their requirements, for example in order to avoid current high prices. This modification will deter customers from over-delivering or under-delivering quantities of gas in an effort to "game" LG&E's cash-out mechanism as described above.

Gaming increases daily and monthly imbalances that can jeopardize LG&E's system reliability and increases the costs paid by firm residential and commercial sales customers that purchase their gas supplies from LG&E.

Q. Has LG&E been able to detect that any "gaming" has occurred?

A. Gaming is often difficult to detect and nearly impossible to prove conclusively. LG&E is concerned that the potential may exist and proposes this modification to further neutralize the possibility. The current cash-out reference price is an average of the daily price postings during the month for both over- and under-deliveries. LG&E is proposing to use a cash-out mechanism that will use the highest daily price during the month as a reference price for the cash-out of under-deliveries and the lowest daily price for the cash-out of over-deliveries. This more stringent mechanism will make the cash-out mechanism more difficult to game.

Q. Who will benefit from the more stringent cash-out reference price proposed by LG&E?

A. Sales customers will benefit. The modified cash-out mechanism is designed to purchase over-deliveries from transporting customers at the lowest daily market price during the month. Conversely, the mechanism as modified is designed to sell over-deliveries to transporting customers at the highest daily market price during the month. Since these purchases and sales and the associated costs and revenues are reflected in the Gas Supply Clause, and because sales customers are paying for the costs associated with contracting for firm gas supplies and transportation capacity, the sales customers will benefit from purchases at the lowest market price during the month and likewise benefit from sales at the highest market price during the month.

Q. What is an OFO?

A. An OFO is an Operational Flow Order. In certain circumstances, the mismatch (or imbalance) between the deliveries and usage by a Rate FT customer can jeopardize LG&E's system reliability. Through an OFO, LG&E can direct a Rate FT customer to either (1) deliver to LG&E at least as much gas as it is using (typically in a potential under-supply situation), or (2) use at least as much gas as it is delivering to LG&E (typically in a potential over-supply situation). If a customer fails to comply with the OFO directive, it is financially penalized in addition to any other action which LG&E may be required to take (e.g., physically isolating and curtailing the customer if necessary to preserve system integrity). The OFO charge is equal to $15.00 per Mcf plus the mid-point price posted in *Gas Daily* for "Dominion--South Point" on the day for which the OFO was violated. All penalties collected through the OFO provision are returned to sales customers through the Gas Supply Clause.

Q. What is the current notice required to implement an OFO?

A. The current OFO notice period is twenty-four (24) hours. This same notice period has been in effect since the rate was first approved in 1995.

Q. Why is LG&E now proposing a shorter OFO notice period?

A. LG&E is proposing to shorten the OFO notice period from 24 to 18 hours in order to reflect regulatory changes in the gas industry, and to increase its flexibility in issuing such OFOs when conditions exist that may cause supply disruptions. When the 24-hour notice period was first introduced in 1995, the nomination requirements of interstate pipelines were not as flexible as they are now. At that time, it was necessary to provide customers with 24-hour notice so that they could modify the volume they were delivering to LG&E

on the interstate pipeline within the interstate pipeline's notice periods. With the implementation of certain changes by the Federal Energy Regulatory Commission ("FERC"), shorter and more frequent "intra-day" nomination notice periods are now available to transporters, such as LG&E's transportation customers, to modify the volumes to be transported. Hence, the original *rationale* for the 24-hour notice is no longer present. As such, LG&E proposes to reduce the OFO notice period to 18-hours in order to allow it more flexibility to respond to conditions that may threaten system reliability.

Q. Will reducing the OFO notice period impose an undue burden on FT customers?

A. LG&E does not believe that it will. Some customers served under Rate FT (either by themselves or through their Pool Manager) currently make nomination changes with less than 24 hours notice, which LG&E accepts when feasible.

Q. Are there benefits to a shorter OFO notice period?

A. Yes, there are benefits to both transport and sales customers. Having a shorter notice period will allow LG&E more time to evaluate the situation which is causing it to consider issuing an OFO and collect more facts prior to issuing the OFO. This shorter notice period may allow LG&E to avoid issuing some OFOs because it will have more time to determine if the condition prompting the OFO will be delayed or not materialize. For example, an extra six hours may be critical in determining whether the path of a hurricane in the Gulf of Mexico is likely to cause supply disruptions. Likewise, in the event of an unexpected supply disruption, LG&E will have the ability to issue an OFO more quickly in an effort to balance its system and maintain system reliability.

Q. Is LG&E proposing any other changes to Rate FT?

A. Yes, LG&E is proposing two minor clarifications to the section of Rate FT called "Remote Metering." LG&E is proposing to clarify two minor issues: (1) that the customer is responsible for paying for any modifications to its own facilities (such as piping) which might be required in order to effectuate the installation of remote metering equipment, and (2) that the customer's electric and phone services, which it is required to install at its cost in order to operate the remote metering equipment, must meet the requirements of LG&E. These changes will conform to current practice.

Changes to Rate TS

Q. Please describe Rate TS.

A. Standby sales service has been offered by LG&E to transportation customers since 1984. Standby sales service provides customers with a level of service and reliability equivalent to the associated underlying sales service. LG&E provides this standby sales service to transportation customers through its on-system storage and pipeline transportation capacity. The standby transportation customer is allocated its share of these two costs. Rate TS customers (unlike customers served under Rate FT) are not subject to either daily balancing requirements or OFO provisions because these customers pay the costs associated with daily balancing and standby supply through their total sales rate.

If the customer chooses not to purchase its own gas supply, or the customer fails to deliver any part or all of its requirements, LG&E is required to provide the Rate TS customer with gas supply under the terms of the otherwise applicable sales rate schedule.

To the extent that the customer purchases gas from LG&E, those charges are the same as those incorporated in the Gas Supply Cost Component ("GSCC") of the Gas Supply Clause. Over-deliveries by Rate TS customers are eliminated using the same cash-out mechanism that applies to Rate FT over-deliveries as discussed previously.

Q. What change is LG&E proposing to Rate TS in this proceeding?

A. LG&E is proposing to modify the cash-out mechanism applicable to over-deliveries by customers served under Rate TS.

Q. How is LG&E proposing to change the cash-out mechanism applicable to customers served under Rate TS?

A. LG&E is proposing to modify the cash-out mechanism applicable to over-deliveries by customers served under Rate TS to mirror that proposed for over-deliveries by Rate FT customers. Because customers served under Rate TS pay for and are entitled to standby sales service, under-deliveries by sales customers will continue to be cashed-out through the application of the otherwise applicable sales rate.

Q. Didn't LG&E receive Commission approval to modify the cash-out mechanism under Rate TS in its last gas rate case?

A. Yes. In LG&E's last gas rate case, LG&E proposed and the Commission approved a modification to change how the cash-out price for over-deliveries is determined under the cash-out mechanism. LG&E now determines the cash-out price based on "*the monthly average of the daily mid-point prices posted in "Gas Daily" for Dominion--South Point for the month during which the imbalance occurred.*" A sliding scale step percentage is applied to the cash-out price so customers receive less for their over-delivered gas as their percentage of over-deliveries increases above certain levels.

Q. Why is LG&E proposing this change to Rate TS?

A. LG&E is proposing to change the methodology for determining its cash-out price in order to further encourage Rate TS customers to minimize imbalances. LG&E is proposing the revised cash-out mechanism to deter any potential gaming and encourage transportation customers to balance their loads more closely by not delivering excess natural gas to LG&E.

Under LG&E's proposal, the cash-out price for over-deliveries will be the lowest daily mid-point price posted in *Gas Daily* during the month. This method will penalize customers that deliver quantities of gas in excess of their requirements when prices are low in order to hedge against higher prices that may occur later in the month.

This modification will deter customers from over-delivering quantities of gas in an effort to "game" LG&E's cash-out mechanism. Gaming increases daily and monthly imbalances that can jeopardize LG&E's system reliability and increases the costs paid by firm residential and commercial sales customers.

Q. Has LG&E been able to detect that any "gaming" has occurred?

A. As indicated above with regard to Rate FT, gaming is often difficult to detect and impossible to prove conclusively. LG&E is concerned that the potential may exist and proposes this modification to further neutralize the possibility. The current cash-out mechanism applicable to Rate TS is an average of the daily price postings during the month for over-deliveries. LG&E is proposing to use a cash-out mechanism that will use the lowest daily price during the month as a reference price for the cash-out of over-deliveries. This more stringent mechanism will make cash-out more difficult to game.

Q. Who will benefit from the more stringent cash-out reference price proposed by LG&E?

A. Sales customers will benefit. Like the cash-out mechanism proposed for Rate FT, the modified cash-out mechanism under Rate TS is designed to purchase over-deliveries from transporting customers at the lowest daily market price during the month. Since these purchases and the associated revenues are reflected in the Gas Supply Clause, and because sales customers are paying for the costs associated with contracting for firm gas supplies and transportation capacity, sales customers will benefit from purchases at the lowest market price during the month.

Q. Is LG&E proposing any other changes to Rate TS?

A. No.

Types of Sales Services Offered by LG&E

Q. Generally, what kinds of sales services are currently offered by LG&E?

A. LG&E currently provides two basic types of natural gas sales services. The first type includes LG&E's firm sales services under Rates RGS, CGS, and IGS. The second type includes LG&E's interruptible sales services under Rates G-6 and G-7.

Q. Are you sponsoring any changes to LG&E's firm sales services through your testimony?

A. No, I am not.

Q. Are you sponsoring any changes to LG&E's interruptible sales services through your testimony?

A. Yes, I am.

Q. Please describe LG&E's interruptible sales services.

A. As I mentioned, LG&E offers two kinds of interruptible sales service, one under Rate G-6 and another under Rate G-7. Both provide that the sales service provided to the customer can be suspended by LG&E as described in the respective rate schedule.

Q. If Rate G-6 and Rate G-7 are both interruptible, what are the differences between the services?

A. The primary difference in these services relates to the duration of the interruption period. Rate G-6 is interruptible only for the 90 days from December 15 through March 15, which is the core of the winter heating season. Rate G-7 is interruptible all year round.

Q. Are there other differences between Rate G-6 and Rate G-7?

A. Yes, there are several other differences. In addition to differences in the distribution and customer charges applicable to each rate schedule, there are differences in the access to transportation service. Customers served under Rate G-6 who meet certain size qualifications have access to standby transportation service. Customers served under Rate G-7 are not eligible for standby transportation irrespective of size or any other factor.

Q. Is LG&E proposing modifications to either Rate G-6 or Rate G-7?

A. Yes. LG&E is proposing to withdraw both Rate G-6 and Rate G-7. LG&E proposes to create a new updated interruptible sales service by combining certain features formerly found in Rate G-6 and Rate G-7. The new interruptible rate schedule will be called Rate AAGS for As-Available Gas Service.

Q. Why is LG&E proposing the addition of this new rate schedule and the deletion of the other schedules?

A. Although the construction of these rate schedules was appropriate at one time, LG&E believes that both Rate G-6 and Rate G-7 require updating. Interruptible loads are an important system management tool. Although these customers are responsible for a relatively small portion of LG&E's total throughput, LG&E needs to be sure that these customers are indeed fully interruptible. However, neither Rate G-6 nor Rate G-7 includes a penalty provision to encourage customers to discontinue using gas during the interruption period. Similarly, the interruption period for service under Rate G-6 should be broadened to include the whole year, not just the 90 days from December 15 through March 15, in order to maximize system operating flexibilities.

Combining these customers into one interruptible rate schedule will also provide benefits to customers that transfer to this service from Rate G-6 and Rate G-7. For example, Rate G-6 customers will experience an otherwise lower distribution charge to reflect year-round interruptibility, and Rate G-7 customers will have the opportunity to transport if they meet the availability requirements of Rate TS.

Modifications to Interruptible Sales Services

Q. Please describe the main features of LG&E's proposed Rate AAGS for As-Available Gas Service.

A. The sales service offered by LG&E under Rate AAGS will be interruptible on a year-round basis. As reflected in the revised tariff, the

> *Company shall have the right to discontinue the supply of natural gas wholly or in part for such period or periods as, in the sole judgment of Company, may be necessary or advisable to enable it to supply the full gas requirements of its customers served under higher priority rate schedules.*

The level of the rates is addressed in the testimony of Mr. Seelye.

Q. Will the customers currently served under Rate G-6 and Rate G-7 be automatically transferred to Rate AAGS?

A. There are fewer than thirty customers served under both Rate G-6 and Rate G-7. The customers served under existing rate schedules Rate G-6 and Rate G-7 as of the effective date of Rate AAGS will have the option of being served under the new rate schedule or being served under one of the already existing firm rate schedules (either Rate CGS or Rate IGS). Since all of these customers currently are taking interruptible sales service under similar though not identical rate schedules, LG&E currently anticipates that all of these customers will take interruptible sales service under this new rate schedule.

Q. Is there a minimum size provision?

A. Yes. Any new customers must use at least 50 Mcf per day when gas is available and the customer cannot use gas primarily for space-heating purposes. Customers transferring to Rate AAGS from discontinued Rate G-6 and Rate G-7 will not be required to meet the minimum size provision. The minimum size provision is designed to ensure that this rate schedule is not available to customers with loads which are predominantly space-heating in character.

Q. Will customers served under Rate AAGS be allowed to transport?

A. Yes, to the extent that customers served under Rate AAGS can meet the eligibility requirements applicable under Rate TS, they will be able to transport their own gas under

Rate TS. Previously, only customers served under Rate G-6 were allowed to transport, while customers served under Rate G-7 could not. This modification will provide an added option for customers previously served under Rate G-7 in the event that sales service is suspended under Rate AAGS.

Q. What are some of the other features LG&E proposes to include in Rate AAGS?

A. LG&E is proposing that customers served under Rate AAGS comply with a minimum one-year contract term and be assessed penalties for failure to interrupt.

Q. Please describe each of these beginning with contract term.

A. LG&E is proposing that an eligible customer sign a contract with a term of at least one year commencing on or before November 1 and continuing through October 31 of the following year. For example, if a customer begins taking service under Rate AAGS on May 1, 2003, then that customer's contract will extend through October 31, 2005. In addition, customers served under either Rate CGS or IGS will need to provide notice on or before April 30 of a request for service to be effective commencing no later than the following November 1. This provision is similar to the provision in Rate FT for election of transportation-only service. Both the required contract term and notice provision will enable LG&E to plan its gas purchase and transportation requirements with greater certainty by conforming the interruptible service contract to the generally accepted planning and contracting horizon of the natural gas industry.

Q. What is the proposed notice period for interruption and the penalty for failure to interrupt?

A. LG&E proposes to provide 18 hours notice prior to the commencement of interruption. This is the same as the notice period proposed for the issuance of an OFO under Rate FT.

Previously, neither Rate G-6 nor Rate G-7 had a defined interruption notice period. Customers were expected to comply as soon as practicable.

If the Customer fails to discontinue the consumption of natural gas at its facility at the conclusion of the 18-hour notice period, the Company may charge the Customer a penalty for failing to interrupt. LG&E proposes that the penalty shall be equal to $15.00 per Mcf plus the mid-point price posted in *Gas Daily* for "Dominion--South Point" on the day to which such interruption of service is applicable. This penalty is the same as that currently incorporated in Rate FT.

The proposed rate schedule also allows LG&E to take other actions if the customer fails to interrupt. Those actions may involve physically isolating the customer and terminating service under Rate AAGS and transferring the customer to a firm rate schedule.

Q. Who will benefit from the application of the penalty if customers served under Rate AAGS fail to interrupt as directed?

A. Sales customers will benefit. Customers who fail to interrupt will be charged the regular gas commodity charges applicable under the Gas Supply Clause. In addition, the customer which fails to interrupt will be assessed the interruption penalty of $15.00 per Mcf plus the referenced price posting from *Gas Daily*. Like the OFO charge applicable to customers served under Rate FT, any revenue resulting from the application of the interruption penalty applied to customers served under Rate AAGS will be used to reduce the costs that sales customers pay through the Gas Supply Clause. Therefore, this revenue is not retained by LG&E, but rather is credited to sales customers.

Q. What if the Rate AAGS customer is transporting under transportation rider Rate TS when the interruption notice is issued?

A. If the customer is delivering natural gas to LG&E for redelivery to the customer's facility during the interruption period, the penalty for failure to interrupt will only be applicable to those quantities used by the customer in excess of those quantities being delivered by Customer to Company.

Q. What other special terms and conditions will be associated with Rate AAGS?

A. LG&E is proposing several special terms and conditions for service under Rate AAGS as set forth in the pro-forma tariff sheet.

Q. Will the adoption of Rate AAGS require other changes in LG&E's tariff?

A. Yes, LG&E also proposed to make other conforming changes to Rate TS, Rate PS-TS, Curtailment Rules, General Rules, and elsewhere in the proposed tariffs to conform with the above changes to its interruptible sales rate schedules.

Q. Is LG&E also proposing other changes to LG&E's natural gas tariffs?

A. Yes, LG&E is proposing certain other modifications to LG&E's gas tariffs. Changes to the terms and conditions are discussed in the testimony of Sydney L. "Butch" Cockerill, and changes to the rates and charges are discussed in the testimony of Mr. Seelye.

Q. Would you please summarize your testimony regarding the proposed changes to LG&E's natural gas transportation and sales services?

A. Yes. LG&E is not proposing significant changes to either of its transportation services. It does, however, propose to change the cash-out mechanism for both Rate TS and Rate FT and certain notice periods under its transportation service under Rate FT. These changes are designed to improve the operation of the services and to eliminate potential cross-subsidies. LG&E is also proposing to modify is interruptible sales services by eliminating Rates G-6 and G-7 and implementing a new Rate AAGS. LG&E believes that these modifications will enhance the reliability of its gas system operations and simplify its service offerings.

Q. Does this conclude your testimony?

A. Yes, it does.

292243.06

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, Clay Murphy, being duly sworn, deposes and says he is the Director – Gas Management, Planning, and Supply for Louisville Gas and Electric Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Clay Murphy
CLAY MURPHY

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

[illegible] (SEAL)
Notary Public

My Commission Expires:
Oct. 31, 2004

APPENDIX A

J. Clay Murphy

Director -- Gas Management, Planning, and Supply
Louisville Gas and Electric Company
820 West Broadway
Louisville, Kentucky 40202

Education

Indiana University
Bloomington, Indiana (8/79 – 5/81)
    Master of Business Administration with emphasis in Finance
    Graduate Assistant in the School of Business
Bellarmine College
Louisville, Kentucky (8/75 - 5/79)
    Bachelor of Arts with Major in Accounting
    Graduated Magna Cum Laude

Previous Positions

Louisville Gas and Electric Company
    Manager -- Gas Supply (12/89 – 7/00)
    Gas Supply Coordinator (10/86 – 12/89)
    Rate Analyst (10/81 – 10/86)

Professional/Trade Memberships

American Gas Association
    FERC Regulatory Committee
Southern Gas Association
    Liaison Representative for Committees
        on Rates, Gas Transportation, and
        Gas Supply Marketing

Mr. Cockerill

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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

TESTIMONY OF
SIDNEY L. "BUTCH" COCKERILL
DIRECTOR – REVENUE COLLECTIONS
LOUISVILLE GAS AND ELECTRIC COMPANY

December 29, 2003

Filed: December 29, 2003

Q. Please state your name, position and business address.

A. My name is Sidney L. "Butch" Cockerill. I am employed by LG&E Energy Services, Inc. as Director of Revenue Collections for Louisville Gas and Electric Company ("LG&E" or the "Company") and Kentucky Utilities Company ("KU"). My business address is 220 West Main Street, Louisville, Kentucky 40202. A statement of my qualifications is included in the Appendix attached hereto.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe and support the proposed revisions to the Company's terms and conditions for furnishing electric and gas service. In addition, I will discuss proposed changes to some of LG&E's non-recurring charges. Finally, I will review the Company's efforts to assist its low income customers.

Q. What is the primary purpose for the proposed revisions to LG&E's tariff?

A. In addition to reflecting the proposed rates, which are discussed in detail in the testimony of W. Steven Seelye, the proposed revisions also attempt to harmonize the tariffs of LG&E and KU, to simplify the language in LG&E's existing tariff, to eliminate redundancy, thus allowing some business processes to run more efficiently.

Q. Have you made any changes to the Company's tariffs that are not expressly discussed in your testimony?

A. Yes. There are a number of minor changes that have been proposed to simplify or clarify the language in the tariff or to re-organize the structure of the tariff which are not detailed in my testimony. For example, non-recurring charges have been moved from the general terms and conditions to Section I of the tariff under the subsection "Special Charges." Additionally, the sections in the current gas and electric tariffs titled "Rules and

Regulations Governing the Supply of Gas Service" and "Rules and Regulations Governing the Supply of Electric Service" has been renamed to "Terms and Conditions" with the provisions being reorganized into appropriate subsections for ease of reference. These changes are, however, clearly identified in the proposed tariffs located at Tab 7 of the Filing Requirements and in the side-by-side comparison of current versus proposed tariffs located at Tab 8 of the Filing Requirements attached to the Application .

<u>Changes in LG&E's Electric Tariff</u>

Q. Will you address all of the proposed revisions to LG&E's electric tariff in your testimony?

A. No. The revised rates will be addressed in the testimony of Mr. Seelye. My testimony will address the terms and conditions changes and special charges in the electric tariff.

Q. What changes were made to the Company's non-recurring charges?

A. We have raised the Disconnect/Reconnect charges from $18.50 to $23.00. We have also added a meter test charge of $31.40.

Q. Please explain the proposed revision to LG&E's tariff to increase its Disconnect/Reconnect charge following disconnection for nonpayment of bills or for violation of the company's Rules and Regulations.

A. LG&E currently under-recovers its costs for disconnecting and reconnecting service associated with nonpayment of bills or for violation of the Company's Rules and Regulations. As a result, the Company proposes to increase its charge in order to collect the cost of this service from any reconnecting customer. Pursuant to 807 KAR 5:006, Section 8(3)(b), customers qualifying for service reconnection under 807 KAR 5:006, Section 15, will continue to be exempt from this charge.

The Company proposes to increase its Charge for Disconnecting and Reconnecting Service to $23.00 per transaction. The schedule attached hereto as SLC Exhibit 1 provides the cost support for the proposed change.

Q. The Company is proposing to implement a charge to recover the cost of a meter test when permitted by regulation. Please explain.

A. LG&E's existing tariff has no provision for the recovery of a reasonable charge for a customer-requested meter test and associated transportation cost when the results show that the meter was not more than two percent fast. On the other hand, KU's tariff does provide for a meter test charge when the meter is shown to be functioning within tolerance. That cost is currently being borne by LG&E's other customers who are receiving no direct benefit from the service provided. In order to better harmonize the tariffs of the two utilities and to recover its reasonable costs from those customers who are initiating the extra costs, LG&E is proposing to add this customer-specific charge in the amount of $31.40 to its tariff. The schedule attached hereto as SLC Exhibit 2 provides the cost support for the new charge.

Q. Please describe LG&E's proposed revisions to its deposit policy for electric customers.

A. We are proposing revisions to simplify our deposit policy whereby a single deposit amount will apply to every residential electric customer, and to clarify the conditions under which LG&E will refund the deposit. The calculation of this deposit has been made pursuant to 807 KAR 5:006, Section 7(1)(b). The revisions will also allow LG&E

to retain the deposits of its non-residential customers as long as the customers remain on service, thus harmonizing these provisions with KU's tariff. In addition, the proposed revisions provide for the subsequent collection of a service deposit or alternate security from non-residential customers, even if initially waived, should their credit history decline.

Q. Please describe the proposed changes to LG&E's budget payment plan for electric customers.

A. We are harmonizing LG&E's electric budget payment plan with KU's revised plan. The most significant change to LG&E's plan is to require each budget billing customer to become current at least once every twelve months as permitted by the Commission's regulations. The method by which customer accounts are reviewed for budget payment adjustments is also being modified to synchronize the methodology with the KU plan.

Q. Please describe the other changes which the Company is proposing to the Terms and Conditions of its tariff.

A. We have made a number of changes to better harmonize the language contained in LG&E's tariff with that contained in KU's tariff.

We have added new language relating to Company liability to the tariff.

We have proposed language to clarify that, in accordance with the Commission's regulations, customer-read information must be verified by the Company at least once per calendar year and that the remaining meters must be read at least quarterly, except if prevented from doing so by reasons beyond its control.

The Company is also proposing new language to protect against theft of service in the absence of an active account at a given location.

Finally, the Company's motor start requirements have been reworked to increase understanding and application without diminishing the enforcement provisions. The language proposed for both LG&E's and KU's tariffs again seeks to harmonize the two tariffs for purposes of operational simplification and to eliminate out-dated standards.

Changes in LG&E's Gas Tariff

Q. Will you address all of the proposed revisions to LG&E's gas tariff in your testimony?

A. No. The revised rates and other changes to the gas rate schedules will be addressed in the testimonies of Mr. Seelye and Mr. Clay Murphy. My testimony will address the terms and conditions changes and special charges in the gas tariff.

Q. What changes were made to the Company's non-recurring charges for gas service?

A. We have raised the Disconnect/Reconnect charges from $18.50 to $23.00. We have also added a meter test charge of $69.00.

Q. Please explain the proposed revision to LG&E's gas tariff to increase its Disconnect/Reconnect charge following disconnection for nonpayment of bills or for violation of the company's Rules and Regulations.

A. LG&E currently under-recovers its costs for disconnecting and reconnecting service associated with nonpayment of bills or for violation of the Company's Rules and Regulations. As a result, the Company proposes to increase its charge in order to collect the cost of this service from any reconnecting customer. Pursuant to 807 KAR 5:006, Section 8(3)(b), customers qualifying for service reconnection under 807 KAR 5:006, Section 15, will continue to be exempt from this charge.

The Company proposes to increase its Charge for Disconnecting and Reconnecting Service to $23.00 per transaction. The schedule attached hereto as SLC Exhibit 1 also provides the cost support for the proposed change.

Q. The Company is proposing to implement a charge to recover the cost of a meter test when permitted by regulation. Please explain.

A. LG&E's existing tariff has no provision for the recovery of a reasonable charge for a customer-requested meter test and associated transportation cost when the results show that the meter was not more than two percent fast. On the other hand, KU's tariff does provide for a meter test charge when the meter is shown to be functioning within tolerance. That cost is currently being borne by LG&E's other customers who are receiving no direct benefit from the service provided. In order to better harmonize the tariffs of the two utilities and to recover its reasonable costs from those customers who are initiating the extra costs, LG&E is proposing to add this customer-specific charge in the amount of $69.00 to its tariff. The schedule attached hereto as SLC Exhibit 3 provides the cost support for the new charge.

Q. Please describe LG&E's proposed revision to its deposit policy for gas customers.

A. We are proposing revisions to simplify our deposit policy whereby a single deposit amount will apply to every residential gas customer, and to clarify the conditions under which LG&E will refund the deposit. The calculation of this deposit has been made pursuant to 807 KAR 5:006, Section 7(1)(b). The revisions will also allow LG&E to retain the deposits of its non-residential customers as long as the customers remain on service, thus harmonizing these provisions with KU's tariff. In addition, the proposed revisions provide for the subsequent collection of a service deposit or alternate security from non-residential customers, even if initially waived, should their credit history decline.

Q. Please describe the proposed changes to LG&E's budget payment plan for gas customers.

A. We are harmonizing LG&E's gas budget payment plan with KU's revised plan. The most significant change to LG&E's plan is to require each budget billing customer to become current at least once every twelve months as permitted by the Commission's regulations. The method by which customer accounts are reviewed for budget payment adjustments is also being modified to synchronize the methodology with the KU plan.

Q. Please describe the changes which the Company is proposing to the Terms and Conditions of its gas tariff.

A. We have made a number of changes to better harmonize the language contained in LG&E's gas tariff with that contained in KU's and LG&E's electric tariffs.

We have added new language relating to Company liability to the tariff.

We have proposed language to clarify that, in accordance with the Commission's regulations, customer-read information must be verified by the Company at least once per calendar year and that the remaining meters must be read at least quarterly, except if prevented from doing so by reasons beyond its control.

The Company is also proposing new language to protect against theft of service in the absence of an active account at a given location.

Finally, we have modified a provision in our tariff to clarify that temporary or short-term service will be provided at the Company's actual cost.

Low-Income Assistance

Q. Describe LG&E's efforts to assist its low-income customers.

A. LG&E recognizes that winter can be a particularly difficult time for those in need. As a result, we have several means of providing assistance. For example, we match a portion of the contributions received from customers to Community Winterhelp ("Winterhelp"), which is designed to assist low-income customers with their winter heating bills. The funds are administered by third parties with distribution based upon need and income level of the customer. In addition to encouraging customers to contribute, LG&E also advises customers how to apply for assistance.

LG&E is also a primary sponsor of Project WARM, an agency that aims to educate low-income customers about conservation and offers free weatherization services to low-income elderly or disabled customers in LG&E's service territory. These services include sealing air leaks, adding loft insulation and offering basic energy education. Each year, Project WARM also sponsors the Project WARM Blitz, an event where volunteers, including a large number of LG&E employees, work to insulate the homes of eligible individuals and families.

In addition to Winterhelp and Project WARM, LG&E offers services and options to assist all customers in better managing their energy bills. One such program is LG&E's WeCare program. The WeCare program offers energy education and weatherization to low-income families. WeCare helps to make low-income customers' homes healthier, safer, more comfortable and links them to other low-income services. Weatherization usually includes air sealing, duct sealing, and adding insulation among other things. WeCare has weatherized over 600 low-income homes served by LG&E in

2003. Other services and options include credit counseling, payment arrangements, and the budget payment plan.

Q. Does this conclude your testimony?

A. Yes, it does.

292499.08

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, Sidney L. "Butch" Cockerill, being duly sworn, deposes and says he is Director of Revenue Collections for LG&E Energy Services, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Sidney L Butch Cockerill
SIDNEY L. "BUTCH" COCKERILL

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of December 2003.

Melody K. Hulle (SEAL)
Notary Public

My Commission Expires:

November 26, 2007

Appendix A

S. L. "Butch" Cockerill

Director – Revenue Collection
LG&E Energy Services, Inc.
220 West Main Street
Louisville, KY 40202
(502) 627-4772

Education

Spaulding University, B.A. in Business Administration – 1998

Previous Positions

Louisville Gas and Electric Company
- 2002-2003 – Director of Distribution Operations
- 2000-2002 – Director of Gas Control and Storage
- 1997-2000 – Manager of Gas Storage Operations
- 1995-1997 – Manager of Gas Distribution
- 1990-1995 – Manager of Transportation Department

Professional/Trade Memberships

American Gas Association
Kentucky Gas Association
Electric Utilities Fleet Management

Civic Activities

Kentucky Derby Festival, Director

LG&E Disconnect/Reconnect Cost Justification

* Labor – 45 Minutes at 25.50/hr.	$19.13
** Vehicle – 45 Minutes at $5.40/hr	4.05
Total Cost	**$23.18**

*This is the average hourly rate for all employees who perform this work, including our contract partners. It also includes all time (travel, set-up, testing, etc.) associated with performing this work.

**This is the hourly rate for the class of vehicle used to perform this work.

LG&E
Meter Test
Cost Justification

* Labor – One Hour at	$26.00
** Vehicle	5.40
Total Cost	**$3l.40**

*This is the average hourly rate for all employees who perform this work. It also includes all time (travel, set-up, testing, etc.) associated with performing this work.

**This is the average hourly rate for the class of vehicle used to perform this work.

LG&E
Gas Meter Test
Cost Justification

* Labor	$55.83
** Meter Test	13.44
Total Cost	**$69.27**

*This is all of our contract partner's cost to perform this work. It includes travel, set-up, turning off and on gas service, turning off and relighting customer's gas appliances, removing existing gas meter and installing new gas meter.

**This is all of our contract partner's cost to perform the in-shop meter test.