7

RECEIVED
JAN 29 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES	))))	CASE NO. 2009-00549

VOLUME 5 OF 5

DIRECT TESTIMONY AND EXHIBITS

Filed: January 29, 2010

Louisville Gas and Electric Company
Case No. 2009-00549
Historical Test Period Filing Requirements
Table of Contents

Louisville Gas and Electric Company
Case No. 2009-00549
Historical Test Period Filing Requirements
Table of Contents

Table of Contents

Vol. No.	Tab No.	Filing Requirement	Description	Sponsoring Witness
1	10	807 KAR 5:001 Section 10(2)	*Notice of Intent. Utilities with gross annual revenues greater than $1,000,000 shall file with the commission a written notice of intent to file a rate application at least four (4) weeks prior to filing their application. The notice of intent shall state whether the rate application shall be supported by a historical test period or a fully forecasted test period. This notice shall be served upon the Attorney General, Utility Intervention and Rate Division.*	Mr. Bellar
1	11	807 KAR 5:001 Section 10(3)	*Form of notice to customers. Every utility filing an application pursuant to this section shall notify all affected customers in the manner prescribed herein. The notice shall include the following information: (a) The amount of the change requested in both dollar amounts and percentage change for each customer classification to which the proposed rate change will apply; (b) The present rates and the proposed rates for each customer class to which the proposed rates would apply; (c) Electric, gas, water and sewer utilities shall include the effect upon the average bill for each customer class to which the proposed rate change will apply; (d) Local exchange companies shall include the effect upon the average bill for each customer class for the proposed rate change in basic local service; (e) A statement that the rates contained in this notice are the rates proposed by (name of utility); however, the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice; (f) A statement that any corporation, association, or person with a substantial interest in the matter may, by written request, within thirty (30) days after publication or mailing of this notice of the proposed rate changes request to intervene; intervention may be granted beyond the thirty (30) day period for good cause shown; (g) A statement that any person who has been granted intervention by the commission may obtain copies of the rate application and any other filings made by the utility by contacting the utility through a name and address and phone number stated in this notice; (h) A statement that any person may examine the rate application and any other filings made by the utility at the main office of the utility or at the commission's office indicating the addresses and telephone numbers of both the utility and the commission; and (i) The commission may grant a utility with annual gross revenues greater than $1,000,000, upon written request, permission to use an abbreviated form of published notice of the proposed rates provided the notice includes a coupon which may be used to obtain all of the information required herein.*	Mr. Bellar

Louisville Gas and Electric Company
Case No. 2009-00549
Historical Test Period Filing Requirements
Table of Contents

Vol. No.	Tab No.	Filing Requirement	Description	Sponsoring Witness
1	12	807 KAR 5:001 Section 10(4)(a)	*Manner of notification. Sewer utilities shall give the required typewritten notice by mail to all of their customers pursuant to KRS 278.185.*	Mr. Bellar
1	13	807 KAR 5:001 Section 10(4)(b)	*Manner of notification. Applicants with twenty (20) or fewer customers affected by the proposed general rate adjustment shall mail the required typewritten notice to each customer no later than the date the application is filed with the commission.*	Mr. Bellar
1	14	807 KAR 5:001 Section 10(4)(c)	*Manner of notification. Except for sewer utilities, applicants with more than twenty (20) customers affected by the proposed general rate adjustment shall give the required notice by one (1) of the following methods: 1. A typewritten notice mailed to all customers no later than the date the application is filed with the commission; 2. Publishing the notice in a trade publication or newsletter which is mailed to all customers no later than the date on which the application is filed with the commission; or 3. Publishing the notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area, the first publication to be made within seven (7) days of the filing of the application with the commission.*	Mr. Bellar
1	15	807 KAR 5:001 Section 10(4)(d)	*Manner of notification. If the notice is published, an affidavit from the publisher verifying the notice was published, including the dates of the publication with an attached copy of the published notice, shall be filed with the commission no later than forty-five (45) days of the filed date of the application.*	Mr. Bellar
1	16	807 KAR 5:001 Section 10(4)(e)	*Manner of notification. If the notice is mailed, a written statement signed by the utility's chief officer in charge of Kentucky operations verifying the notice was mailed shall be filed with the commission no later than thirty (30) days of the filed date of the application.*	Mr. Bellar
1	17	807 KAR 5:001 Section 10(4)(f)	*Manner of notification. All utilities, in addition to the above notification, shall post a sample copy of the required notification at their place of business no later than the date on which the application is filed which shall remain posted until the commission has finally determined the utility's rates.*	Mr. Bellar
1	18	807 KAR 5:001 Section 10(4)(g)	*Manner of notification. Compliance with this subsection shall constitute compliance with 807 KAR 5:051, Section 2.*	Mr. Bellar
1	19	807 KAR 5:001 Section 10(5)	*Notice of hearing scheduled by the commission upon application by a utility for a general adjustment in rates shall be advertised by the utility by newspaper publication in the areas that will be affected in compliance with KRS 424.300*	Mr. Bellar

Louisville Gas and Electric Company
Case No. 2009-00549
Historical Test Period Filing Requirements
Table of Contents

Louisville Gas and Electric Company
Case No. 2009-00549
Historical Test Period Filing Requirements
Table of Contents

Vol. No.	Tab No.	Filing Requirement	Description	Sponsoring Witness
2	32	807 KAR 5:001 Section 10(6)(m)	*The most recent Federal Energy Regulatory Commission Form 1 (electric), Federal Energy Regulatory Commission Form 2 (gas), or Automated Reporting Management Information System Report (telephone) and Public Service Commission Form T (telephone);*	Ms. Scott
2	33	807 KAR 5:001 Section 10(6)(n)	*A summary of the utility's latest depreciation study with schedules by major plant accounts, except that telecommunications utilities that have adopted the commission's average depreciation rates shall provide a schedule that identifies the current and test period depreciation rates used by major plant accounts. If the required information has been filed in another commission case a reference to that case's number and style will be sufficient.*	Ms. Charnas
2	34	807 KAR 5:001 Section 10(6)(o)	*A list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and work papers associated with the filing of the utility's application. This list shall include each software, program, or model; what the software, program, or model was used for; identify the supplier of each software, program, or model; a brief description of the software, program, or model; the specifications for the computer hardware and the operating system required to run the program.*	Ms. Scott
2	35	807 KAR 5:001 Section 10(6)(p)	*Prospectuses of the most recent stock or bond offerings.*	Mr. Rives
2	36	807 KAR 5:001 Section 10(6)(q)	*Annual report to shareholders, or members, and statistical supplements covering the two (2) most recent years from the utility's application filing date.*	Mr. Rives
3	37	807 KAR 5:001 Section 10(6)(r)	*The monthly managerial reports providing financial results of operations for the twelve (12) months in the test period.*	Ms. Scott
3	38	807 KAR 5:001 Section 10(6)(s)	*Securities and Exchange Commission's annual report for the most recent two (2) years, Form 10-Ks and any Form 8-Ks issued within the past two (2) years, and Form 10-Qs issued during the past six (6) quarters updated as current information becomes available.*	Mr. Rives

Table of Contents

Louisville Gas and Electric Company
Case No. 2009-00549
Historical Test Period Filing Requirements
Table of Contents

Vol. No.	Tab No.	Filing Requirement	Description	Sponsoring Witness
3	43	807 KAR 5:001 Section 10(7)(b)	*Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application: (b) The most recent capital construction budget containing at least the period of time as proposed for any pro forma adjustment for plant additions.*	Ms. Charnas
3	44	807 KAR 5:001 Section 10(7)(c)	*Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application: (c) For each proposed pro forma adjustment reflecting plant additions provide the following information: 1. The starting date of the construction of each major component of plant; 2. The proposed in-service date; 3. The total estimated cost of construction at completion; 4. The amount contained in construction work in progress at the end of the test period; 5. A schedule containing a complete description of actual plant retirements and anticipated plant retirements related to the pro forma plant additions including the actual or anticipated date of retirement; 6. The original cost, cost of removal and salvage for each component of plant to be retired during the period of the proposed pro forma adjustment for plant additions; 7. An explanation of any differences in the amounts contained in the capital construction budget and the amounts of capital construction cost contained in the pro forma adjustment period; and 8. The impact on depreciation expense of all proposed pro forma adjustments for plant additions and retirements;*	Ms. Charnas
3	45	807 KAR 5:001 Section 10(7)(d)	*Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application: (d) The operating budget for each period encompassing the pro forma adjustments.*	Ms. Scott

Louisville Gas and Electric Company
Case No. 2009-00549
Historical Test Period Filing Requirements
Table of Contents

Vol. No.	Tab No.	Filing Requirement	Description	Sponsoring Witness
3	46	807 KAR 5:001 Section 10(7)(e)	*Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application: (e) The number of customers to be added to the test period-end level of customers and the related revenue requirements impact for all pro forma adjustments with complete details and supporting work papers.*	Mr. Seelye

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

APPLICATION OF LOUISVILLE GAS	)	
AND ELECTRIC COMPANY FOR AN	)	CASE NO. 2009-00549
ADJUSTMENT OF ITS ELECTRIC	)	
AND GAS BASE RATES	)	

TESTIMONY OF
WILLIAM STEVEN SEELYE
PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

Filed: January 29, 2010

Table of Contents

Exhibits

Seelye Exhibit 1 – Qualifications
Seelye Exhibit 2 – Residential Electric Unit Cost
Seelye Exhibit 3 – Time of Day Loads
Seelye Exhibit 4 – Cost Support for New Lighting Rates
Seelye Exhibit 5 – Reconstruction of Electric Billing Determinants
Seelye Exhibit 6 – Summary of Electric Revenue Increase
Seelye Exhibit 7 – Electric Revenue Increase by Rate Schedule
Seelye Exhibit 8 – Reconstruction of Gas Billing Determinants
Seelye Exhibit 9 – Summary of Gas Revenue Increase
Seelye Exhibit 10 – Gas Revenue Increase by Rate Schedule
Seelye Exhibit 11 – Cable TV Attachment Charges
Seelye Exhibit 12 – Excess Facilities Charge Cost Support
Seelye Exhibit 13 – Meter Relay Pulse Charge Cost Support
Seelye Exhibit 14 – Customer Deposit Requirements
Seelye Exhibit 15 – Electric Temperature Normalization Bandwidth
Seelye Exhibit 16 – Electric Temperature Normalization Coefficients
Seelye Exhibit 17 – Electric Temperature Normalization kWh Adjustments
Seelye Exhibit 18 – Electric Temperature Normalization Revenue and Expense Adjustments
Seelye Exhibit 19 – Gas Temperature Normalization Adjustment
Seelye Exhibit 20 – Electric Year-End Customer Adjustment
Seelye Exhibit 21 – Gas Year-End Customer Adjustment
Seelye Exhibit 22 – Base-Intermediate-Peak (BIP) Differentiation
Seelye Exhibit 23 – Electric Cost of Service Study – Functional Assignment
Seelye Exhibit 24 – Electric Cost of Service Study – Class Allocation
Seelye Exhibit 25 – Zero Intercept – Overhead Conductor
Seelye Exhibit 26 – Zero Intercept – Underground Conductor
Seelye Exhibit 27 – Zero Intercept – Transformers
Seelye Exhibit 28 – Gas Cost of Service Study – Functional Assignment
Seelye Exhibit 29 – Gas Cost of Service Study – Class Allocation
Seelye Exhibit 30 – Gas Demand Allocation Factors
Seelye Exhibit 31 – Gas Zero Intercept – Distribution Mains

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6001 Claymont Village Dr., Suite 8, 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 depreciation studies.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of Louisville Gas and Electric Company ("LG&E").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (i) to describe the proposed allocation of the revenue increases for LG&E's electric and natural gas operations; (ii) to support LG&E's proposed rates; (iii) to discuss the revenue impact of modifying certain miscellaneous charges and customer deposit requirements; (iv) to sponsor the temperature normalization adjustments and year-end adjustments; (v) to sponsor the fully allocated class cost of service studies based on LG&E's embedded cost of providing electric and natural gas service for the 12 months ended October 31, 2009.

Q. Please summarize your testimony.

A. In developing its proposed rates in this proceeding, LG&E relied heavily on the results of the electric and gas cost of service studies. The Company's fully allocated, embedded cost of service studies for its electric and gas operations were prepared 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 calculated for each rate class. Based on the relatively narrow range in the class rates of return from the electric cost of service study, LG&E is proposing to increase each electric rate class by the same percentage. Because of the large differences in the class rates of return from the gas cost of service study, LG&E is proposing to allocate most of the natural gas increase to the residential, commercial and industrial sales services.

The Company is proposing unit charges that are more cost based for its gas and electric rates and is a proposing a Straight Fixed Variable rate design for residential gas service. Straight Fixed Variable rates align the interests of LG&E and its customers in promoting conservation by removing all incentives for the Company to encourage customers to use more natural gas. Straight Fixed Variable rates also send the appropriate price signal to customers, remove the subsidy that low-income customers are providing to other residential customers, reduce the volatility in customers' bills, are easy for customers to understand, are more consistent with accepted ratemaking principles, and will help make LG&E's gas distribution operations a more viable business.

LG&E is proposing electric and gas temperature normalization adjustments in this proceeding to more accurately represent its revenue and expenses on a going-forward basis. The Company is also proposing a standard year-end customer adjustment.

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:

- Cost of Service Studies — 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) Introduction, (II) Qualifications, (III) Electric Rate Design and the Allocation of the Increase, (IV) Gas Rate Design and the Allocation of the Increase, (V) Increase in Miscellaneous Service Charges and Deposits, (VI) Pro-Forma Adjustments, (VII) Electric Cost of Service Study, and (VIII) Gas Cost of Service Study.

II. 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 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 another former employee of the Company. Since then, we have performed cost of service studies, developed revenue requirements and designed rates for over 150 investor-owned, cooperative and municipal utilities across North America. A more detailed description of my qualifications is included in Seelye Exhibit 1.

Q. Have you ever testified before any state or federal regulatory commissions?

A. Yes. I have testified in over 50 regulatory proceedings in 11 different jurisdictions. A listing of my testimony in other proceedings is included in Seelye Exhibit 1.

Q. Please describe your work and testimony experience as they relate to topics addressed in your testimony?

A. I have performed or supervised the development cost of service and rate studies for over 150 utilities throughout North America. I have also testified on numerous occasions regarding the rates proposed by electric, gas and water utilities, including LG&E in its last rate case. In addition, I have testified on numerous occasions regarding year-end adjustments for gas and electric utilities, including LG&E, Kentucky Utilities Company, Delta Natural Gas Company, Westar Energy, Inc., Kansas Gas and Electric Company, Mobile Gas Company, Northern Neck Electric Cooperative, and Richmond Power Company. I have also testified on numerous occasions regarding temperature normalization adjustments for gas distribution utilities, including LG&E and Delta Natural Gas Company.

I have been developing models to measure the effect of temperature on hourly, daily and monthly sales for over 30 years. Throughout my career at LG&E and afterwards at The Prime Group, I have developed statistical models to measure temperature/load relationships, to evaluate extreme temperature conditions, to analyze price variability and risk, and numerous other applications in the utility planning process. I have worked regularly in this area for the last 30 years. I have developed the electric temperature normalization models for LG&E, Cajun Electric Power Cooperative, Inc., Southern Mississippi Electric Power Association, and Lee County Electric Cooperative. I also have experience working with the electric temperature normalization adjustments used for Westar Energy, Inc. and Kansas Gas and Electric Company. I have developed sales and load forecasts for numerous electric utilities using the statistical techniques for weather normalization described in my testimony.

III. ELECTRIC RATE DESIGN AND THE ALLOCATION OF THE INCREASE

A. ALLOCATION OF THE ELECTRIC REVENUE INCREASE

Q. Please summarize how LG&E proposes to allocate the electric revenue increase to the classes of service?

A. LG&E relied on the results of the electric cost of service study to determine the methodology used to allocate the revenues to the classes of service. Ultimately, because LG&E's electric cost of service study indicated that the class rates of return are narrowly banded around the overall rate of return, the Company decided to increase all rates classes by the same percentage. It is important to point out, however, that the test-year in this rate case is somewhat unusual, and, as a result, the results of the cost of service study are also somewhat unusual. Particularly, during the test year for this rate case, based on the combined system loads for LG&E and

KU, the system peak occurred during a winter month. This is a highly unusual result based on what the Company has experienced in the past. In preparing the cost of service study, the decision was made to use *actual* hourly system loads in the cost of service study rather than engaging in the complicated process of normalizing peak demands. Although the Company is proposing to normalize kWh sales for abnormal weather during the test year, the normalization of peak demands (which would require normalization of hourly loads) is a much more difficult and controversial endeavor. For this reason, the Company decided to prepare the electric cost of service studies without normalizing hourly loads for weather or other factors. However, one of the consequences of using the actual load is that the results of the Base-Intermediate-Peak (BIP) methodology used in the electric cost of service studies are significantly altered from previous studies, shifting the largest component of production and transmission costs to a winter coincident peak allocator rather than a summer peak allocator. I am making note of this fact because allocating a larger percentage of costs has resulted in lowering the class rates of return for industrial customers below what they would have been had a normal summer peaking pattern occurred during the test year. The results of the cost of service study in this proceeding, without taking into consideration the shift in production and transmission allocation to the winter, might suggest that large industrial customers should receive a larger percentage increase than certain other customer classes. However, because the class rates of return in the cost of service study are still narrowly banded around the overall rate of return, and because of the unusual weather patterns in the cost of service study, the decision was made to apply the same percentage increase to all rate classes rather than running the risk of over-correcting for the relatively small variance in the rates of return seen in this cost of service study.

B. RESIDENTIAL ELECTRIC RATE INCREASE

Q. Is LG&E proposing to bring the rate components in residential electric rates more in line with the unit costs shown in the cost of service study?

A. Yes. LG&E is proposing to increase the monthly residential basic service charge from $5.00 to $15.00 to bring it more in line with the customer-related costs identified in the cost of service study. Even considering this increase, the basic service charge will be less than the cost of service. The cost of service study indicates that the customer-related cost for the residential class is $15.80 per customer per month, so LG&E is proposing to increase the basic service charge in a direction that will more accurately reflect the actual cost of providing service. This cost is derived in Seelye Exhibit 2.

Q. Does the current monthly basic service charge of $5.00 adequately recover customer-related costs from residential customers?

A. No. The current basic service charge of $5.00 per customer per month does not even recover all of the customer-related operating expenses, let alone any of the margins (return) that would normally be assigned as customer-related cost. Based on calculations from the cost of service study, customer-related costs are $15.80 per customer per month; therefore, there is under-recovery of $10.80 customer-related costs through the basic service charge. When this under-recovery of $10.80 per customer per month is multiplied by the 4,170,876 customer months for the residential rate class during the test year, the result is $45,045,461 in fixed operating expenses and margins that are not being recovered through the basic service charge. When this amount is recovered through the energy charge instead, the result is about 1.10 cents per kWh of fixed operating expenses and margins collected through the energy charge (calculated as $45,045,461 / 4,099,843,486 kWh = $0.0110 per kWh). Thus, the basic service charge is $10.80 per customer per month too low and the energy charge is 1.10 cents per kWh too high. This recovery of fixed operating expenses and margins through the energy charge results in intra-class subsidies and does not provide the proper environment for energy efficiency and conservation.

Q. What are intra-class subsidies and how can intra-class subsidies be avoided?

A. When one rate class subsidizes another rate class it is referred to as "inter-class subsidies", but when customers within a particular rate class subsidize other customers served under the same rate schedule it is referred to as "intra-class subsidies." The rate-making principle that should be followed to avoid intra-class subsidies is that, as much as possible, fixed costs should be recovered through fixed charges (such as the basic service charge and demand charge) and variable costs should be recovered through variable charges (such as the energy charge). If fixed costs are recovered through variable charges, each kWh contains a component of fixed costs and customers using more energy than the average customer in the class are paying more than their fair share of fixed costs and margins, while customers using less energy than the average customer in the class are paying less than their fair share of fixed costs and margins. These fixed costs and margins should be collected through the billing units associated with the appropriate cost driver, and energy usage clearly is *not* the correct cost driver for fixed costs. The collection of fixed costs through the energy charge typically results in customers with above-average usage subsidizing customers with below-average usage. The collection of variable costs through fixed charges also results in an intra-class subsidy, with customers with below-average usage subsidizing customers with above-average usage. In order to eliminate this source of intra-class subsidies, LG&E wants to pursue a rate design that moves more in the direction of recovering fixed costs through fixed charges and variable costs through variable charges.

Q. What impact would recovering the increase through the basic service charge instead of increasing both the basic service charge and the energy charge have on the average customer?

A. Given a specified increase for the class, the average residential customer would see the same increase whether all of the increase is recovered through the basic service charge or through an increase of both the basic service charge and energy charge. Ultimately, the proposed rate for any given class of customers is based on averages and any rate design that was revenue neutral (i.e., generates the same amount of revenue) would have no impact whatsoever on a customer with a usage equal to the class average. The impact on customer energy bills would be greatest at the extremes of very low energy usage and very high energy usage. The change would result in higher energy bills for low-usage customers, as the subsidy that they had been receiving was removed, and lower energy bills for high-usage customers as the subsidies that they had been paying were eliminated.

Q. Typically, who are the low-usage customers who would be paying higher energy bills once the subsidies were removed?

A. For utilities such as LG&E, operating in an urban service territory, low usage customers tend to be loads like garages, workshops, outbuildings, and unusual service connections, and for utilities such as Kentucky Utilities Company ("KU"), operating in a mixed service territory consisting of both urban and suburban customers, their low-usage customers tend to be loads like garages, workshops, outbuildings, vacation homes, hunting camps, and fishing camps. All of these loads typically consume very few kilowatt hours during the course of a year and the usage is sporadic. However, the utility still incurs fixed costs in installing the minimum system requirements necessary to serve these loads. A rate design with a low basic service charge and with a significant portion of fixed operating expenses and margins recovered through the energy charge would result in revenue that was insufficient to support the investment necessary to serve loads such as garages, workshops, and outbuildings. Such a rate design would result in these customers being subsidized by the other customers who have above-average usage. A rate design with a low basic service charge and with a significant portion of the utility's fixed operating expenses and margins recovered through the energy charge sends an improper economic signal to customers. It sends a signal that it is relatively inexpensive to provide the physical equipment necessary to provide service to customers, and this is definitely not the case.

Q. What would be the impact of a higher basic service charge and a reduced energy charge on low income customers?

A. For low income customers to benefit from a rate design with a lower basic service charge and higher energy charge than the cost of service study indicates is appropriate, these customers would need to have an energy usage that is lower than the class average. Generally, this is not the case for low income customers. In working with utilities all over North America, it has been my experience that low-income customers tend to use more electric energy than the average. The housing stock in which many low income customers are living is relatively inefficient from an energy usage standpoint, so their energy usage is frequently above the class average.

In 2008 LG&E collected sales data on customers who meet the state standards for participating in low income energy assistance programs ("LIHEAP"). The average monthly usage for LG&E's customers was 1,066 kWh per month while the average monthly usage for LG&E's low income customers was 1,084 kWh per month. Thus, the typical low income customer would actually benefit from a rate design that had a higher basic service charge and a lower energy charge, as these customers, because of their higher usage, are currently helping to subsidize low usage customers.

Q. Would recovering the increase through the basic service charge rather than through the energy charge send the wrong signals for energy conservation?

A. No. In the 1970s and early 1980s conservation advocates would often argue in favor of higher energy charges and lower service charges as a way to encourage conservation. Utilities in some of the more progressive jurisdictions, however, have moved away from that position. Many conservation advocates have realized that a more constructive approach is to try and align the interests of the customers and the utility in a way that encourages the utility to promote conservation rather than being penalized by it. In fact, LG&E and KU are currently doing more in the area of demand-side management, energy efficiency, and energy conservation than any of the other utilities in Kentucky.

The problem with recovering fixed costs through the energy charge is that whenever customers take measures to conserve energy they reduce the amount of fixed costs recovered by the utility. In this situation, even though its revenues have been reduced by efforts of its customers to conserve energy, none of the utility's fixed costs have been avoided. What happens in this situation is that the utility's earnings are reduced as a result of customers using less energy. This is exactly what has happened with natural gas distribution companies. As customers have installed more efficient furnaces, customer usage has gone down resulting in a corresponding reduction in revenues. The utility's fixed costs, however, will have remained the same or may have even gone up causing its earnings to go down. It is difficult for a utility to favor conservation when it results in earnings deterioration. To align the interests of customers and the utility, regulators in some jurisdictions have moved toward a straight fixed-variable rate design for gas distribution utilities. A Straight Fixed Variable rate design, or other forms of decoupling, helps prevent the utility from being harmed by energy efficiency and conservation, and helps to create an environment where the utility can work with customers to encourage greater energy efficiency. Even though LG&E is proposing a Straight Fixed Variable rate design for its *gas* rates but not its *electric* rates in this proceeding, it is important to point out that regulators in other jurisdictions have concluded that appropriately recovering fixed costs through the basic service charge removes disincentives for utilities to promote conservation.

Q. Would recovering the more of the cost through the basic service charge rather than through the energy charge have the effect of stabilizing customers' monthly

bills?

A. Yes. Increasing the basic service charge will reduce the spikes that customers see in their bills during high usage months and cause customer bills to be somewhat more level throughout the course of a year.

C. LARGE CUSTOMER TIME OF DAY RATES

Q. Please describe the Company's proposed changes to the large power rates.

A. LG&E is proposing to consolidate Industrial Power Service and Commercial Power Service into a single rate schedule, which will be called Power Service - PS. This service will be available to medium size industrial and commercial customers with loads not exceeding 250 kW. Combining these rate schedules will help harmonize KU's and LG&E's rates. LG&E is not proposing to combine the large commercial and industrial time-of-day (TOD) rates. The new rates will be designated Industrial Time-of-Day Secondary Service - ITODS, Commercial Time-of-Day Secondary Service - CTODS, Industrial Time-of-Day Primary Service - ITODP and Commercial Time-of-Day Primary Service - CTODP. The Company is proposing to bill primary voltage customers (CTODP and ITODP) on a kVA basis and to modify the time-of-day rate structure of ITODS, CTODS, ITODP, CTODP and Retail Transmission Service - RTS.

Q. Why is the Company proposing to bill primary voltage customers on a kVA basis rather than a kW basis?

A. This is a continuation of the transition to kVA billing for large voltage customers that was begun in the Company's last rate case. In the rates that were approved in the

Company's last rate case (Case No. 2008-00252), LG&E began billing transmission voltage customers on a kVA basis. A kVA charge does a better job of reflecting the cost of providing service to transmission customers. The power that the Company actually delivers to its customers is better represented by kVA billing than by kW billing. In terms of generalized vectors, the power $\overline{kVA}$ supplied to the customer at any given interval includes both a real component $\overline{kW}$ and a reactive component $\overline{kVar}$ as follows:

$$\overline{kVA} = \overline{kW} + \overline{kVar}$$

The Customer's kW demand therefore represents only the real component of power $\overline{kW}$ and does not capture the reactive component of the power $\overline{kVar}$ that must be supplied to the customer. The Company must provide both real and reactive power, and the generation and transmission system must be sized adequately to provide both components of power on an instantaneous basis. Billing the demand charge on a kVA basis properly charges the individual customers for the cost they impose on the system and thus sends a better price signal. Those customers that respond to the price signal by improving their power factor avoid additional charges.

Billing on a kVA basis also avoids the necessity of including a power factor adjustment charge as a component of the rate. With the high cost of installing generation and transmission capacity, utilities are attempting to avoid these costs by more efficiently utilizing existing capacity through customer power factor improvements. KVA billing and power factor adjustment charges provide an economic incentive for customers to pursue power factor improvements. The industry is becoming increasingly aware of the need to charge customers for departures from unity power factor on an instantaneous, peak-demand basis, especially customers with large motor loads.

Q. Why are time-of-day rates appropriate?

A. Using rates that send the appropriate price signals, such as time-of-day rates, is one of the best ways of encouraging customers to manage their loads more effectively. LG&E and KU have had very positive experiences with time-of-day rates for large commercial and industrial customers. Time-of-day rates more accurately reflect the actual cost of providing service to customers. Production and transmission plant costs are designed to meet the maximum load requirements placed on the systems. Because loads vary significantly throughout the course of a day, the likelihood of maximum loads occurring during certain hours greatly exceeds the likelihood of maximum system loads occurring during other hours of the day. It is therefore reasonable from a cost of service perspective to recover the majority of the Company's fixed production and transmission costs through the application of demand charges that would only be applicable during Peak or Intermediate load periods. Time-of-day rates also send a better price signal to customers encouraging them to reduce their loads during Peak or Intermediate hours of the day – periods during which the Company must install new production and transmission facilities to meet load increases on the system. Time-of-day rates represent a standard ratemaking tool to encourage the efficient utilization of resources on the part of customers. Large industrial and commercial customers in particular can modify their operations to take advantage of the price signals provided by time-of-day rates. Because the large industrial and commercial loads are substantially larger than those of residential and small commercial loads, utilities can experience significant load reductions through the implementation of time-of-day rates for large industrial and commercial customers. The changes the Company is proposing in this proceeding will significantly enhance the ability of large industrial and commercial customers to realize savings through reduction in peak demands.

Q. What changes is the Company proposing to make to the time-of-day rate structure?

A. In an effort to shorten the peak period window for large commercial and industrial customers, the Company is proposing essentially to separate a single peak period, which covers a large number of hours during the day into two separate periods – a peak period and an intermediate period. The purpose of this change is to provide customers a much shorter peak period to enable them to shift load outside of the highest cost period. This is a response to suggestions that have been made by a number of commercial and industrial customers. A common complaint that large commercial and industrial customers have made about the Company's TOD rates is that the peak period encompasses too many hours for them to shift load outside of the peak period. They have indicated that they could do more to manage their load if the Company could reduce the peak period to eight hours or less, which is the length of a single shift for their operations. LG&E has therefore restructured the rate to respond to this request but to retain some safeguards in case the Company's system peak shifts away from its current patterns.

Additionally, the Company is proposing to include May as a summer month in the TOD rates. Currently, the summer season includes the months of June through

September; however, the load patterns in May suggest that May has a summer load pattern rather than a winter load. Therefore, the Company is proposing to redefine the summer months to include May.

Q. Please describe the time-differentiated rate structure that will be used for Rate Schedule RTS and Rate Schedule TOD.

A. The time-differentiated demand charges for ITODS, CTODS, ITODP, CTODP and RTS will consist of a Base, Intermediate and Peak demand charge. The Base demand charge will be applied to the customer's maximum demand during the month, whenever it occurs. The Intermediate demand charge will be applied to the customer's maximum demand that occurs during the Intermediate period, and the Peak demand charge will be applied to the customer's maximum demand that occurs during the Peak period. These three demand charges are additive; that is, the Intermediate demand charge will be added to the amount charged as Base demand, and the Peak demand charge will be added to the amount charged as Base and Intermediate demands. During the summer months, the Intermediate period is defined as the weekday hours between 10:00 A.M. and 10:00 P.M., and during the non-summer months the Intermediate period is defined as the weekday hours between 6:00 A.M. and 10:00 P.M. During the summer months, the Peak period is defined as the weekday hours between 1:00 P.M. and 7:00 P.M., and during the non-summer months the Peak period is defined as the weekday hours between 6:00 A.M. and 12:00 Noon. It should be noted that the proposed Peak period is defined so that it will be encompassed entirely within the Intermediate period; and, likewise, the Intermediate period is defined so that it will be encompassed entirely within the Base period, which consists of all hours during the month. Thus, the

Intermediate demand charge can be viewed as being layered on top of the Base demand charge, and the Peak demand charge can be viewed as being layered on top of both the Base and Intermediate demand charges.

Q. Why is the Company proposing a "layered" time-of-day demand charge rather than time-of-day demand charges that would apply respectively to a "peak" period, a "shoulder" period and an "off-peak" period?

A. There are a number of reasons that LG&E is proposing a *layered* structure. The layered structure sends a strong price signal encouraging customers to reduce demands during the Peak and Intermediate periods. If a customer taking service under Rate Schedule RTS reduces its Peak Period demand (but does not modify the Intermediate and Base demands) then the customer will avoid $4.55 per kVA in demand charges per month. If a customer reduces *both* its Peak *and* Intermediate Period demands (but does not modify its Base demand) then the customer will avoid $7.60 per kVA in demand charges per month (i.e. $4.55/kVA for the Peak demand and $3.05/kVA for the Intermediate demand). Therefore, LG&E's proposed rate structure will send a strong signal encouraging large power customers to reduce demands during both the Peak and Intermediate periods. Furthermore, the Company's proposed rate structure will not penalize customers that have significant off-peak demands. A rate structure consisting of demand charges that apply separately to "peak", "shoulder" and "off-peak" periods penalize high load-factor customers that have significant off-peak loads. LG&E has significant experience with implementing a layered time-of-day rate structure. A layered structure was first implemented by LG&E in the early 1980s. What the Company has found from the implementation and use of this rate design for almost 30 years is that it has encouraged customers to shift demands off-peak without penalizing high load-factor customers with significant off-peak usage. Industrial and commercial customer reception of this type of design has been favorable. Additionally, a layered structure provides an almost seamless transition *from* a standard rate structure consisting of a demand charge that applies to the customer's maximum monthly 15-minute demand *to* a time-differentiated structure. A customer will be rewarded by paying lower demand charges if it shifts its maximum demand away from the peak period or has already shifted its demand away from the peak period; however, the customer will not be penalized if it already has significant off-peak demands or if it increases its demand during the off-peak period.

Q. Why is the Company proposing to implement both a Peak and Intermediate Period rather than simply a single peak period that encompasses a longer period of time during the day?

A. LG&E and KU have time-of-day rate structures for their large commercial and industrial customers that include a single peak period that encompasses a larger number of hours during the day. As mentioned earlier, a common complaint voiced by industrial and commercial customers is that the Peak Period is too long for customers to shift their loads outside of the Peak Period. The difficulty with simply shortening the peak window by a large number of hours is that any such reduction will increase the likelihood of the system peak falling outside of the designated Peak Period. By implementing both a Peak and Intermediate Period during the weekday, the Company is attempting to provide industrial and commercial customers with greater opportunity to shift their demands away from the peak but without creating a significant exposure to the Company if the system peak occurs within the Intermediate rather than the Peak Period. In other words, LG&E is trying to balance its objective of providing its large commercial and industrial customers with a significant opportunity to realize savings by shifting demands away from the Peak Period while protecting the interests of other customers if the system peak falls outside of the designated Peak Period because of unusual weather patterns or other factors.

Q. How were the Peak and Intermediate Periods determined?

A. The Peak and Intermediate Periods were determined by analyzing the combined LG&E and KU system loads during the peak day of each month of 2008. Again, the objective was to define a Peak Period that is as narrow as possible but will still likely encompass the system peak demand and to define the Intermediate Period so that it will almost certainly encompass the system peak demand during any given month. Specifically, the Companies' primary objective was to define the Peak Period so that it would include less than eight hours during the day. As mentioned earlier, certain customers, particularly manufacturing customers, have indicated a preference for having a Peak Period that could fall within an eight hour shift, so that it would be possible to arrange a two eight-hour shift operation around the designated Peak Period. The system loads used to define the Peak and Intermediate Periods are shown graphically in Seelye Exhibit 3 of my testimony.

D. LOW EMISSION VEHICLE RATE

Q. Is the Company proposing a Low Emission Vehicle LEV rate?

A. Yes. The reasons for proposing this rate are discussed in the testimony of Mr. John Wolfram.

Q. How is the rate structured?

A. The LEV rate is structured as a time-of-day rate in order to provide customers with low emission vehicles an opportunity to charge their vehicles during lower cost off-peak hours. The time periods are defined in accordance with the large power time-of-day rates. The pricing is structured to be generally consistent with the Company's current Real Time Pricing pilot program, except that the LEV rate does not include a critical peak pricing component. The LEV rate is designed to be revenue neutral with the Company's standard Residential Service Rate RS. In other words, when the time-differentiated unit charges for the proposed LEV rate are applied to estimated time-differentiated billing units for RS, the revenues are approximately equal to total RS revenues.

E. CURTAILABLE SERVICE RIDER

Q. Please summarize the proposed changes to the Company's curtailable service riders.

A. The Company currently has three curtailable service riders – CSR1, CSR2, and CSR3. CSR1 provides for up to 200 hours of curtailment, includes a buy-through provision for curtailable service, and is restricted to customers receiving curtailable service as of May 12, 2004. Two LG&E customers and one KU customer take service under CSR1. CSR2 provides for up to 425 hours of curtailment, includes a buy-through provision, and is not restricted. No customers are currently taking service under CSR2, which provides slightly higher credits than CSR1. CSR3 provides for up to 100 hours of curtailment, does not include a buy-through provision, and is restricted to customers taking service under Rate IS. The curtailable credits provided under CSR3 are significantly lower than the credits provided under CRS1 or CSR2. Only one customer on the combined system takes service under CSR3 – an arc furnace load served by KU ("Arc Furnace") that is the largest customer on the combined system. The three curtailable service riders were the result of negotiated settlements in the Companies' last two rate cases.

In this proceeding, LG&E is proposing to consolidate the three curtailable service riders into a single rider, which will be called Curtailable Service Rider CSR. The Rider will provide up to 500 hours of total curtailment and will provide credits consistent with CSR1. Under the proposed CSR, the Company will have the right to request up to 100 hours of physical curtailment without buy-through and up to 400 hours of curtailment with a buy-through option, where the customer can choose to either curtail its load or purchase buy-through power. The buy-through power will be priced at an automatic, formula-based price determined by multiplying an indexed cost of natural gas ($/MMBtu) by a specified heat rate (.01200 MMBtu/kWh) representative of the heat rate of a typical single-cycle combustion turbine. The Company will provide at least a 10 minute notice prior to curtailment.

Q. Why is the Company proposing to adopt the credits provided in CSR1 as the basis for the proposed CSR?

A. When the credits set forth in CSR1 were developed they were based on the estimated carrying costs associated with a combustion turbine. In today's economic environment, these credits significantly overstate the value of curtailable service. Currently, the Company can purchase capacity in the marketplace at a much lower cost than the value of the credits being provided to its curtailable customers. Furthermore, utilities are currently not purchasing combustion turbines. There have been reports over the past few years of independent power producers selling combustion turbines at distressed prices. In spite of the currently prevailing soft market for capacity, which may or may not be temporary, the Company concluded that it was appropriate to leave the credits for CSR at the current levels set forth in CSR1, which were determined in accordance with the avoided capacity cost of a combustion turbine. However, the Company is proposing to refine the provisions of the proposed rider so that they correspond more closely to the operational characteristics the Company would actually enjoy if it were to install combustion turbine capacity rather than providing customers with a credit for the right to curtail their load under CSR. In other words, the Company wants the provisions of CSR to mirror as much as possible the benefits that the Company would receive if it installed a combustion turbine.

Specifically, the Company is proposing to increase the hours of curtailment to 500 hours, which is more in line with the amount of hours that a new combustion turbine would be scheduled to operate. The Company is also proposing to require at least 100 hours of physical interruption without buy-through, which, again, is more consistent with the expectation that the Company would receive at least 100 hours of physical power from a combustion turbine. Buy-through power would be indexed to the cost of natural gas, which is the primary fuel used in LG&E's combustion turbine units. Additionally, the Company would be able to request CSR customers to curtail their load within 10 minutes, which is consistent with the start-up time for a quick-start combustion turbine and is consistent with the requirement for using capacity as spinning reserves.

Q. Are there any other changes being proposed to CSR?

A. Yes. The credit will only be applied during periods of the day when the Company is likely to need curtailable service. Specifically, the credit will be applied to the difference between (a) the Customer's measured maximum kilowatt demand during any 15-minute interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M, and (ii) for the months October continuously through May, from 6 A.M. to 10 P.M, and (b) the firm contract demand. The purpose of this change is to help ensure that the Company can actually curtail the load for which it is providing a credit. Specifically, curtailable service has minimal value to the Company if the curtailable load can only be called upon during the middle of the night or during weekends. It is not reasonable to provide a curtailable credit for load that is only present on the system during off-peak hours. This modification will prevent customers from receiving credits for both operating during off-peak hours under a time-of-day rate and receiving credits for strictly off-peak loads.

F. FLUCTUATING LOAD SERVICE

Q. What is Fluctuating Load Service?

A. Fluctuating Load Service FLS (currently called "Industrial Service IS") is a rate schedule that is available to large loads that fluctuate significantly within short periods of time. Specifically, this rate schedule is available to loads that either increase or decrease 20,000 kVA or more per minute or 70,000 kVA or more in ten minutes. KU only has one customer served under this rate schedule and LG&E currently does not have any customers taking service under this rate. The Arc Furnace mentioned earlier in connection with the Curtailable Service Rider is the only customer taking service under this rate schedule. The rate is currently called Industrial Service IS, but the Company is proposing to change the name of the rate schedule to "Fluctuating Load Service" (Rate FLS) so as to provide a more descriptive name for the service and to avoid both internal and external confusion about the availability and nature of the service. As is currently the case for Industrial Service IS, the Company is proposing the same charges under both LG&E and KU's Fluctuating Load Service rates.

Q. What changes is the Company proposing for the rate schedule?

A. The rate currently consists of two categories of demand charges – Standard Load Charges that are billed on the basis of 15-minute integrated demands and Fluctuating Load Charges that are billed on the basis of the maximum demands measured on a 5-minute integrated basis less the demands measured on a 15-minute integrated basis. Both components include an On-Peak and Off-Peak Charge. The original purpose of this somewhat complicated formula, which was the result of a negotiated settlement, was to provide a simple average of demand charges billed on a 15-minute basis and demand charges billed on a 5-minute basis. The Company is proposing to simplify the rate schedule by implementing the time-of-day rate structure described earlier in connection with Rate TOD, but with demands determined on the basis of 5-minute integrated demands as opposed to a complicated formula that considers both 5-minute and 15-minute demands.

Q. Does the change in the billing from a 5-minute and 15-minute average to a 5-minute demand affect the proposed revenue attributable to the Arc Furnace?

A. The Company would allocate the same amount of revenue increase to FLS irrespective of the rate structure developed for the service. In other words, rates were developed to produce a specified revenue requirement for the Fluctuating Load Service based on the underlying billing determinants associated with the rate structure. In calculating the revenue at the proposed rate, the unit charges were applied to time-differentiated 5-minute demands to produce the revenue requirement for this single-customer rate class. Therefore, had a different rate structure been adopted, the pro-forma revenue after the increase would have been the same (within rounding) as currently proposed in this proceeding, except the unit charges, of course, would have been different. Consequently, neither the use of 5-minute demands nor the implementation of the new time-of-day structure affects the proposed test-year revenue for which the Arc Furnace is responsible.

Q. Why is the Company proposing to apply the demand charges to 5-minute demands?

A. Although it does not affect the proposed test-year revenue requirement allocated to the Arc Furnace, the use of 5-minute demands is designed to provide an incentive or inducement for customers served under this rate to manage their loads in a less volatile manner. In other words, LG&E will be providing customers served under this rate, which currently only includes the Arc Furnace, with an inducement to manage spikes in their demands.

Q. Why is the Company adopting the time-of-day structure in Rate TOD for Fluctuating Load Service?

A. As mentioned earlier, LG&E and KU are adopting a uniform time-day-structure for all demand-billed rates, which separates the current peak time period into two time periods to provide customers with greater opportunity to reduce or shift their Peak and Intermediate period demands.

Q. Was the fluctuating nature of the Arc Furnace's load taken into account in the cost of service study?

A. No. All demand allocators in the cost of service study were measured on an hourly basis, and since the Arc Furnace is a KU customer, its load is not included in LG&E's electric cost of service study. Nonetheless, using hourly demands in the cost of service study likely understates KU's costs allocated to the Arc Furnace and thus overstates the rate of return for the Arc Furnace. Furthermore, the cost of service study did not identify any incremental load-following or regulation costs associated with serving the Arc Furnace. This is another area where the cost of service study likely understates KU's cost of serving the Arc Furnace.

G. CONJUNCTIVE DEMAND

Q. Was there a provision in the Settlement Agreement in LG&E and KU's last general rate cases to study Conjunctive Demand?

A. Yes. Section 3.11 of the Settlement Agreement, Stipulation, and Recommendation ("Settlement Agreement") stated that LG&E and KU "agree to work with interested parties to study the feasibility of measuring demand for generation service to multi--site customers based on conjunctive demand, where 'conjunctive demand' herein refers to the measured demand at a meter at the time that the total demand of a multi-site customer's load, measured over a coinciding time period, has reached its peak during the billing period."

Q. Please explain what this means.

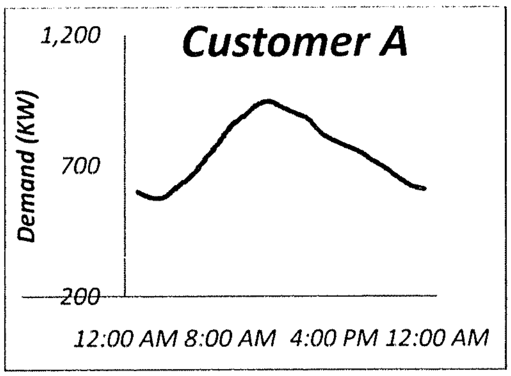
A. Conjunctive demand is a form of aggregated billing, where the loads for a customer with multi-site accounts, such as a group of grocery stores or retail stores owned by a single corporate entity, are aggregated for purposes of billing a component of the utility's demand charge.

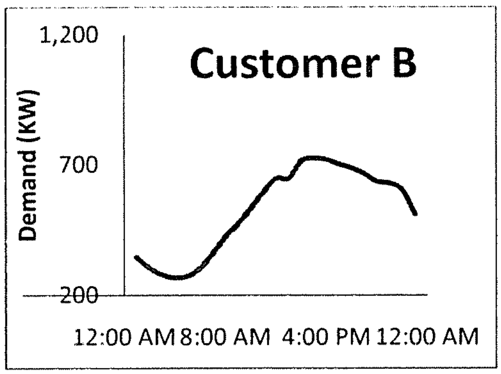
Q. Is aggregated billing allowed under the Commission's regulations?

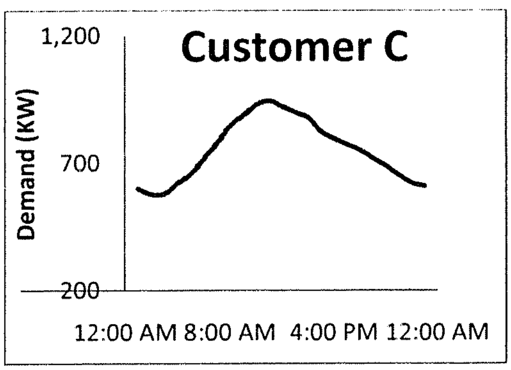
A. No. Section 9(2) of 807 KAR 5:041 states that, "The utility shall regard each point of delivery as an independent customer and meter the power delivered at each point. Combined meter readings shall not be taken at separate points, nor shall energy used by more than one (1) residence or place of business on one (1) meter be measured to obtain a lower rate." Thus any sort of aggregated billing would require a deviation that could only be authorized by a Commission Order upon a showing of good cause. Certainly, under 807 KAR 5:041, Section 22, the Companies and interested parties could request a deviation from this provision in order to allow for a form of conjunctive demand that is consistent with cost of service and ratemaking principles, provided there is good cause for such deviation.

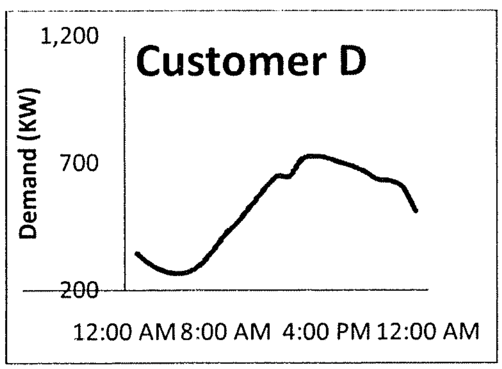
Q. Explain how Conjunctive Demand would be billed?

A. Perhaps an easy way to understand what the provision of the Settlement Agreement means is to consider four customers with two different demand profiles, referred to as Customer A, Customer B, Customer C and Customer D. In this example, Customer A and Customer C share the same load characteristics for the month (Load Profile 1). Customer B and Customer D also share the same load characteristics (Load Profile 2) which is different from Customer A and Customer C. As a further simplifying assumption, suppose that the maximum monthly demands for all four customers occur on the same day, which happens to be the same day during which the utility's monthly system peak occurs. The 15-minute peak-day loads for the four hypothetical customers are shown below:



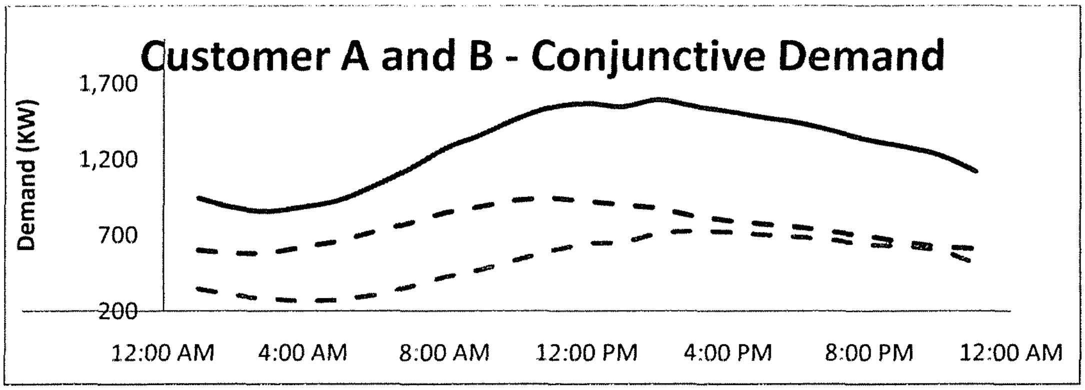


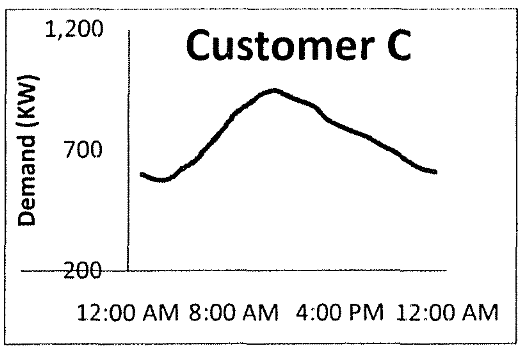


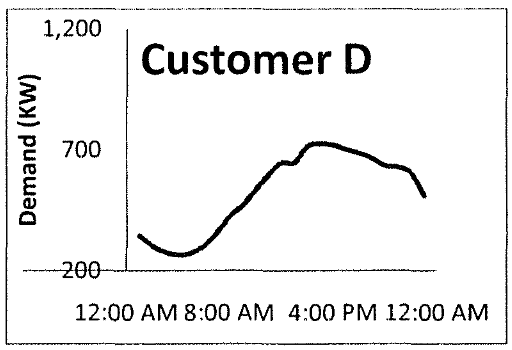


Now suppose that Customer A is a warehouse and Customer B is a retail store owned by the same corporate entity. Therefore, Customer A and Customer B represent a single "multi-site customer" according to Section 3.11 of the Settlement Agreement. Further, suppose that Customer C is also a warehouse and Customer D is a retail store, not owned by the same entity but separate individual entities.

Under Section 3.11 of the Settlement Agreement, the Conjunctive Demand for Customer A and Customer B would be determined by aggregating (or "conjoining") the 15-minute loads for the two customers and applying the generation component of the demand charge to the maximum 15-minute demand from the aggregated loads, whereas the billing demands for Customer C and Customer D would continue to be determined individually, as follows:







For the multi-site customers, in this example, the Conjunctive Demand applicable to the production demand component would be 1,593 kW, whereas the billing demand for the two non-multi-site customers would continue to be 1,750 kW, even though their loads are identical.

Q. Could you provide hypothetical demand charge calculations for these four hypothetical customers without using Conjunctive Demand.

A. Yes. Suppose that the utility's total monthly demand charge is $10 per kW as applied to each individual customer's maximum demand, which consists of a $6.50 per kW production demand component and a $3.50 per kW transmission and distribution demand component. With a standard non-coincident peak (NCP) rate applied to each individual customer's demand, the demand charge billing for Customer A would be the same as the demand charge billing for Customer C. Likewise, the demand charge billing for Customer B would be the same as the demand charge billing for Customer D, as follows:

Customer A (multi-site warehouse)

Demand Charges = 1,000 kW x $10.00/kW = $10,000

Customer C (non-multi-site warehouse)

Demand Charges = 1,000 kW x $10.00/kW = $10,000

Customer B (multi-retail retail store)

Demand Charges = 750 kW x $10.00/kW = $ 7,500

Customer D (non-multi-site retail store)

Demand Charges = 750 kW x $10.00/kW = $ 7,500

Under this example Customer A (the multi-site warehouse) and Customer B (the multi-site retail store), together, would be billed demand charges of $17,500 for the month. Customer C (the non-multi-site warehouse) and Customer D (the non-multi-site retail store owned by some other individual entity), together, would be billed $17,500, the same amount as the two-multi-site accounts.

Q. What happens with Conjunctive Demand?

A. With Conjunctive Demand, the 15-minute loads for the two multi-site customers would be aggregated and the production demand component would be applied to the maximum aggregated demand during the month, and transmission demand component would continue to be applied to the maximum demands for the individual accounts, as follows:

Customer A and Customer B (multi-site customers)

Production –	1,593 kW x $6.50/kW	= $10,354.50
Trans & Dist	1,750 kW x $3.50/kW	= $ 6,125.00
Total Customers A & B		= $16.479.50

Customer C and Customer D (non-multi-site customers)

Demand Charges =	1,000 kW x $10.00/kW	= $10,000.00
Demand Charges =	750 kW x $10.00/kW	= $ 7,500.00
Total Customers C and D		= $17,500.00

Therefore, under Conjunctive Billing, as defined in the Settlement Agreement, Customer A and Customer B, together, would pay $16,479.50 in demand charges, while Customer C and Customer D, together, with identical loads, would pay $17,500. Under the form of Conjunctive Billing as defined in the Settlement Agreement, the multi-site customers would realize a rate benefit (or rate disparity) of $1,020.50 without taking any action to modify their load patterns. In other words, the multi-site customers would receive a rate benefit through conjunctive billing of $1,020.50 compared to the two non-multi-site customers even though the cost of serving the multi-site customers is the same as the two non-multi-site customers.

Q. Do you believe that the type of Conjunctive Demand defined in the Settlement Agreement is consistent with sound cost of service and ratemaking principles?

A. No. In a regulatory context, the term "fair, just, and reasonable rates" has taken on the meaning that the rates are cost based and non-discriminatory. The cost of serving Customers A and C in the example above would be the same, and the cost of serving Customers B and D would be the same. As can be seen from the example above, there is clearly an advantage to aggregating the loads of Customers A and B before applying the rates whenever there is diversity among the load patterns. Allowing loads to be aggregated before the rates are applied results in a lower bill. Allowing such load aggregation for multi-site accounts yet denying it for non-multi-site accounts could easily be regarded as discriminatory treatment.

Q. Would a full-scale implementation of the type of Conjunctive Demand as defined in the Settlement Agreement result in even greater disparities than shown in your example?

A. Yes. As more accounts are added the total amount of the rate disparities would be larger.

Q. Are there other forms of conjunctive billing that are more consistent with cost of service and ratemaking principles?

A. Yes. Coincident peak CP demand billing can be viewed as a form of conjunctive billing, and can be applied on an aggregated basis so that it can be implemented as a full-fledged conjunctive billing approach. With CP demand rates, the production (and perhaps transmission) demand costs would be applied to the customer's demand at the time of the Company's system peak. CP demand rates are fully consistent with cost of service principles. An important consideration in the Companies' generation resource planning efforts is to plan the system so that it has adequate capacity to meet maximum system demands, which determine the time when CP demands are measured. In the Company's cost of service study, a significant portion of production and transmission demand-related costs are allocated on the basis of class contributions to CP demands. Therefore, conjunctive demands determined on the basis of multi-site customer's CP demands would be consistent with cost of service and ratemaking principles. However, because CP demands are additive (i.e., because they are determined for loads at a particular point in time) CP billing will result in the same demand charges regardless of whether they are applied conjunctively or individually.

Q. Would the Company be willing to consider conjunctive billing if it is applied on a system CP basis?

A. Yes, as long as there are some restrictions. If the parties to this proceeding are interested in conjunctive demand based on the billing of production demand-related costs on the basis of system CP demands, the Company would be willing to develop conjunctive rates along these lines for filing with the Commission as a pilot program. Any such pilot program would need to include some restrictions on the rate, such as minimum load-factor and minimum individual load thresholds, in order to limit the revenue impact on the Company. Of course, customers would be responsible for any additional metering, billing and administrative costs associated with providing this service by paying a higher basic service charge. Again, for a system CP-based conjunctive demand rate, it would not be necessary to aggregate the loads for individual accounts; therefore, it would not be necessary for the parties to request a deviation from Section 9(2) of 807 KAR 5:041.

H. OTHER RATES

Q. Is LG&E proposing any new lighting services in this proceeding?

A. Yes. The Company is proposing to offer a fixture-only option for Contemporary High Pressure Sodium installations where multiple fixtures can be installed on a single pole. The support for this new rate offering is included in Seelye Exhibit 4. In allocating the proposed revenue increase to street lights and outdoor lights the same percentage increase was applied to each light with the exception of mercury vapor and incandescent lights. Because mercury vapor and incandescent lights have been restricted for a number of years and are not being replaced, the Company is not proposing to increase the charges for these lights.

Q. Other than the changes mentioned previously, is the Company proposing any other significant structural changes to its rates?

A. No. However, in general, the Company is proposing to modify individual rate components to more accurately reflect the results of the cost of service study. For example, the Company is proposing to increase the basic service charge for General Service Rate GS, under which small commercial and industrial customers take service, from $10.00 to $20.00 per month to more accurately reflect the actual cost of providing service.

I. SUMMARY OF ELECTRIC RATE INCREASES

Q. Have you prepared exhibits reconstructing LG&E's test-year billing determinants for the electric business and showing the impact of applying the new rates to test-year billing determinants?

A. Yes. The reconstruction of LG&E's electric billing determinants is shown on Seelye Exhibit 5. The revenue increase by rate class is summarized on Seelye Exhibit 6. Seelye Exhibit 7 shows the impact of applying the current and proposed rates to test-year billing units.

Q. What revenue increase is LG&E proposing for electric operations?

A. LG&E is proposing an increase in electric test-year revenues of $94,572,202, which is calculated by applying the proposed rates to test-year billing determinants. It should be pointed out that this amount is less than the revenue requirement increase of $94,973,371 shown in Rives Exhibit 8. Subsequent to developing the proposed electric rates and immediately prior to submitting the statutory newspaper notice for publication, the Company made an upward adjustment to its revenue requirements revising an earlier calculation. Although LG&E could have supported a higher revenue increase than what is included in the application, the Company did not make an upward adjustment to its rates to produce revenues that more exactly match the revenue requirement increase shown in Rives Exhibit 8 at this time.

IV. GAS RATE DESIGN AND THE ALLOCATION OF THE INCREASE

A. ALLOCATION OF THE GAS REVENUE INCREASE

Q. Please summarize how LG&E proposes to allocate the gas revenue increase to the classes of service?

A. In developing its proposed gas rates, LG&E also relied heavily on the results of the cost of service study. LG&E is proposing to increase Residential Gas Service -- Rate RGS by 8.75 percent, Commercial Gas Service -- Rate CGS by 6.20 percent, Industrial Gas Service -- Rate IGS by 5.23 percent. The Company is not proposing to increase the other rates because of the high rates of return for these other classes.

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. The natural gas cost of service study indicated that the individual class rates of return ranged between 3.90% and 25.71% as measured against an overall adjusted actual return on rate base of 5.06%, with RGS at 3.90%. While the rate of return for

IGS is lower than both the overall rate of return and the rate of return for CGS, the Company is not proposing to increase the IGS rates above the CGS rates. Analyzing the load factors for IGS customers suggests that these industrial customers now have load characteristics that are more representative of commercial customers. The reason for this is that industrial customers appear to be using a smaller percentage of their purchased gas for manufacturing and a larger percentage for space heating. However, it is difficult to ascertain whether this is a temporary result because of the downturn in the economy or represents a more permanent pattern.

Another reason that the Company is not proposing to increase IGS above CGS is that competitive issues must be considered in designing rates, particularly in regard to industrial customers. Industrial customers generally have more options for switching to an alternative fuel or by-passing the utility's distribution system than other customers. 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. 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. Bypass can result in lost margins and can contribute to attrition in the utility's earnings.

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 customers in particular have more options than residential customers. Therefore, it is important not to charge rates to industrial customers that are uncompetitive and exceed the cost of providing service. Otherwise, industrial customers will leave the system thus forcing residential and commercial customers, who have fewer options, to pay for fixed costs that are left stranded by the departing customers.

B. RESIDENTIAL GAS SERVICE - STRAIGHT FIXED VARIABLE RATES

Q. Please describe the rate design that is being proposed for the Residential Gas Service – Rate RGS.

A. LG&E is proposing a Straight Fixed Variable rate design for Rate RGS, whereby the Company's fixed distribution delivery costs are recovered through a fixed monthly charge. Under its proposed Straight Fixed Variable rate for Rate RGS, the Company would eliminate the Distribution Cost Component of the rate, which is a volumetric charge currently equal to $ 0.21349 per 100 cubic feet or $2.1349 per Mcf , and increase the basic service charge from $9.50 per month to $26.53 per month. By recovering its fixed distribution costs through a fixed monthly charge, the Company would be severing the relationship between its natural gas delivery revenue (revenue less the cost of gas) and its sales of natural gas.

Q. What are fixed costs?

A. Fixed costs are costs that do not vary with the annual amount of gas that is sold by the utility. 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 do not disappear if it sells less gas, but instead are spread over a smaller sales volume, thus causing the utility's rates to increase. For a local gas distribution company, essentially all of its storage and distribution costs are fixed. For example, depreciation expense, interest expenses, return on equity, income taxes, property taxes, insurance expenses, and essentially all non-gas operation and maintenance expenses associated with LG&E's gas storage and distribution facilities do not vary with the amount of gas that the Company sells and are therefore fixed.

The only variable non-gas expense that the Company has been able to identify is the cost of odorant, which is the chemical that is injected into the gas to give it the unique "gas smell" that customers associate with natural gas. (Natural gas is actually odorless and some form of mercaptan is added to the natural gas to make it noticeable to customers in the event of a leak.) The unit costs included in rates for odorant are *de minimus*.[1] Not only are LG&E's distribution costs made up almost exclusively of fixed costs, they are essentially the same for all residential customers. The Company installs the same basic facilities for all residential customers on the system. Any difference between serving one residential as opposed to another has more to do with geography and the time frame when the customers' facilities were installed than any other factors.[2] Although geography and vintage considerations can have a significant impact on the

[1] The annual cost of odorant is approximately $70,000. See response to Question No. 3 or the Response to Initial Data Request of Commission Staff dated May 22, 2009, in Case No. 2009-0017 concerning the Application of Louisville Gas and Electric Company for Permanent Approval of its Gas Weather Normalization Adjustment Clause.

[2] For example, the cost of connecting a new residential customer will vary depending on whether a customer is located in the vicinity of a low-, medium, or high-pressure line. The cost of serving one customer as opposed to another customer will also vary depending on the time period when the facilities were originally installed, with the cost of serving a new home likely being higher than the cost of serving a home that was connected to the system 30 years ago. Yet, a home connected to the system 75 years ago might be more costly to serve than one connected 30 years ago because of the possibility that the gas mains serving a 75-year old home might have been recently replaced.

cost of serving residential customers, the amount of gas that a residential customer uses during a month or during the year does not have *any* measurable impact on the cost of providing service to the customer. If its residential customers were to use significantly more gas in a given period of time, then its storage and distribution costs (with the exception of the cost of odorant) would be the same as they would be if these same customers used significantly less gas. For this reason, the Company's distribution and storage costs are considered to *fixed costs*.

Q. Why is it important for LG&E to implement a Straight Fixed Variable rate design?

A. There are a number of reasons to implement a Straight Fixed Variable rate design. Listed below are some of the more important reasons to adopt Straight Fixed Variable rates:

- A Straight Fixed Variable rate design is a simple form of decoupling, which many environmental and conservation advocates consider to be a cornerstone to the implementation of comprehensive energy conservation programs.
- A Straight Fixed Variable rate design removes all incentives for the Company to encourage customers to use more natural gas.
- A Straight Fixed Variable rate design reflects the cost of providing natural gas delivery service and sends the appropriate price signal to customers.
- Because low-income customers on average use more gas than the average customer, a Straight Fixed Variable rate design will remove the subsidy that low-income customers are providing to other residential customers.

- Through the implementation of a Straight Fixed Variable rate design, the volatility of customers' bills will be reduced.
- A Straight Fixed Variable rate design is easy for customers to understand.
- Adopting a Straight Fixed Variable rate design will make LG&E's gas distribution operations a more viable business.
- Straight Fixed Variable rate designs have been implemented in a number of progressive regulatory jurisdictions and are being considered in many others.
- A Straight Fixed Variable rate design is consistent with national energy policy.

Q. How is a Straight Fixed Variable rate design a form of decoupling?

A. Currently, under tariffs like LG&E's Rate RGS, a significant portion of a local distribution company's ("LDC's") fixed costs, including a significant portion of its return or profits, is recovered through a volumetric charge (i.e., the Distribution Cost Component of the rate). Therefore, under a rate design that recovers fixed costs through a volumetric charge, the LDC is rewarded through higher returns (profits) when customers buy more gas and is penalized through lower returns (profits) when customers buy less gas. Consequently, under rate designs like LG&E's current Rate RGS, the LDC is not economically or financially motivated to encourage customers to take actions to reduce their consumption of natural gas. In fact, the opposite is the case – the LDC is financially and economically motivated to encourage customers to buy more, not less natural gas. Because with a Straight Fixed Variable rate design all of its fixed distribution costs, including the return component of costs, would be recovered through a fixed monthly charge, rather than a volumetric charge, the LDC's margins would no longer be affected by the amount of gas it sells. Therefore, with a Straight Fixed Variable rate design, the LDC's fixed cost recovery which includes return would be decoupled from its sales. While there are other, more complicated decoupling mechanisms in use, a Straight Fixed Variable rate design is the simplest form of decoupling and is thus considered by many industry leaders to be the purest form of decoupling.

Q. Under its proposed Straight Fixed Variable rate design, will all disincentives for encouraging residential customers to use less gas be removed?

A. Yes. Under its proposed Rate RGS, all distribution costs, including the return component of revenue requirements, will be recovered through the Basic Service Charge, which is a fixed monthly charge that does not vary with the volume of natural gas that the customer purchases. While LG&E has been very proactive in encouraging customers to conserve their energy use, the implementation of Straight Fixed Variable rates will remove the financial penalty that the Company realizes when customers take actions to reduce their natural gas consumption. With the adoption of a Straight Fixed Variable rate design, all financial and economic disincentives to residential natural gas conservation will be removed. With the implementation of Straight Fixed Variable rates, the Company will not only be encouraged to continue its current practices of promoting natural gas conservation but will be free to be even more proactive in this area.

From a business perspective, the prospects for even more reductions in natural gas usage by residential customers presents conflicting objectives – on one hand the Company and its management, like most citizens in the U.S., would like to see customers use less of this limited natural resource, but on the other hand, the Company doesn't want its earnings to deteriorate because of lower sales volumes. Under its current rate structure, with a significant portion of fixed costs recovered through a volumetric charge, LG&E is penalized when customers conserve natural gas. With a Straight Fixed Variable rate design, the conflicting objectives that currently exist can be alleviated by eliminating the volumetric component of delivery service and thus removing the financial and economic penalty brought upon the Company whenever customers conserve their natural gas usage. Compared to the current residential rate structure, the Straight Fixed Variable rate design will create a far superior alignment of interests between the utility and its customers in effectuating reductions in natural gas usage.

Q. Has LG&E already implemented demand-side management and energy efficiency programs that benefit natural gas customers?

A. Yes. LG&E was the first utility in Kentucky to implement a demand-side management tariff. LG&E's first demand-side management programs were implemented for both its gas and electric operations on January 1, 1994. With the largest portfolios of residential demand-side management and energy efficiency programs in the state, LG&E and KU are currently doing more in this area than any of the other utilities in Kentucky. Customer participation in these programs has been extensive and continues to grow. The Companies will continue to expand and improve upon their demand-side management programs.

Q. Why do you claim that a Straight Fixed Variable Rate design sends a better price signal than recovering gas delivery costs through a volumetric charge?

A. As indicated earlier, LG&E's storage and distribution costs do not vary with the amount of gas that a customer buys during the month. Consequently, recovering fixed costs through a volumetric charge sends an incorrect price signal to residential customers that the more gas they use the greater the cost of providing natural gas delivery service, which is contrary to the invariant nature of these costs. With a Straight Fixed Variable rate design, customers will not be misled into believing that reductions in consumption will allow them to avoid the fixed costs of the distribution system.

Q. But won't lowering the volumetric charge encourage greater natural gas consumption?

A. No, I don't believe that it will. First, customers respond more to the level of their bills than they do to the level of each component of the rate. Based on my own personal experiences responding to inquiries by all types of customers, I have found that most residential customers are generally unfamiliar with the intricacies of the rate structure under which they take service. Second, and more importantly, the cost of the commodity itself represents by far the most significant portion of the cost of serving natural gas customers. Natural gas is one of the most volatile commodities traded in the market. Depending on the prevailing price, the cost of the commodity itself will make up anywhere from 60 to 80 percent of a residential customer's total gas bill. The pricing mechanism for the remaining distribution costs will therefore have far less impact on the customer behavior than the cost of the commodity itself, since the cost of the gas itself will continue to be priced as a volumetric charge. Third, suggesting that shifting fixed cost recovery from a volumetric charge to the basic service charge will not provide the right incentive for energy efficiency and conservation ignores the tremendous stress that customer budgets are under from a host of sources, including gasoline, medical and food cost increases. Customers are trying to save money wherever they can, and aligning the interests of customers and the Company through Straight Fixed Variable rates helps create the right environment for this effort.

Q. How will a Straight Fixed Variable rate design for residential customers help alleviate the subsidies that low-income customers are providing to other residential customers?

A. Based on every empirical study that I have seen for both natural gas and electric utility customers in the region, low-income customers use more energy than the average customer. In 2008, the Company conducted a study of low-income customer usage and found that low-income customers on average use significantly more natural gas than the average customer. The reason for this is likely related to the relatively inefficient energy characteristics of low-income customer housing. Poor energy usage characteristics are often associated with a lower price for a residential dwelling, which makes the initial purchase price or rental price of an energy inefficient home or apartment more affordable for low income customers. Unfortunately, the tradeoff is a lower purchase or rental price for a home or apartment in exchange for higher monthly energy bills. Because low-income customers use more natural gas than the average customer, their gas bills will be higher with the Company's current rate structure that includes a volumetric delivery charge than a Straight Fixed Variable rate design that doesn't include a volumetric delivery charge. Consequently, when fixed costs are recovered through a volumetric component, as in LG&E's current Rate RGS, customers who use energy for reasons beyond their control, such as a large number of persons sharing a household or less energy efficient housing stock, will no longer have to pay their own fair share plus a part of someone else's share of the fixed costs of natural gas delivery service.

Q. How does a Straight Fixed Variable rate design reduce the volatility of customer bills?

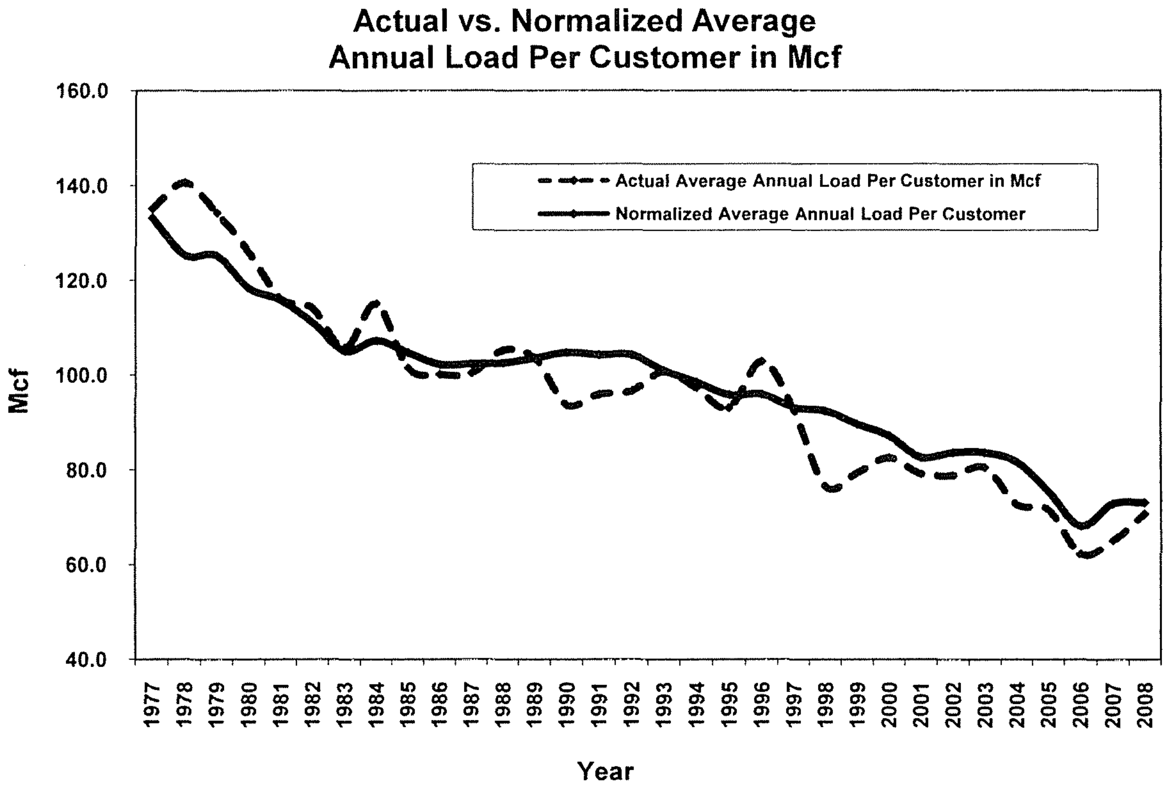
A. During the winter heating months, customers use more natural gas. With a Straight Fixed Variable rate design, the volumetric component of the bill will be reduced and as a result customer bills will be more level, thus reducing monthly volatility in customers' bills.

Q. Is a Straight Fixed Variable rate design easy for customers to understand?

A. Yes. Customers are accustomed to fixed rate delivery services. Fixed rate pricing is common for local telephone service, internet service, trash collection, cable service, certain cell phone plans, and certain overnight delivery services. Furthermore, fixed rate delivery service is far easier for customers to understand than other forms of decoupling.

Q. How will a Straight Fixed Variable rate design make LG&E's natural gas operations a more viable business?

A. With large fixed costs and steadily declining sales volumes, it is extremely difficult for gas utilities to maintain adequate rates of return on their investments. Consumers have made great strides at conserving their natural gas usage. As can be seen from Graph 1, there has been a steady decline in the normalized annual usage per residential customer on LG&E's system from 1977 to 2008.



Graph 1

During this period, there has been a 2.3 percent annual reduction in natural gas usage per customer. On the positive side, this decline represents a significant reduction in the consumption of a limited natural resource and has also resulted in economic savings to customers. But, on the negative side, this decline in usage per customer means that LG&E's fixed costs – including depreciation expense, interest expenses, return on equity, income taxes, property taxes, insurance expenses, and essentially all non-gas operation and maintenance expenses – must be spread over an ever shrinking sales volume. Stated differently, the declining usage per customer places downward pressure on the Company's earnings and upward pressure on its need to increase base rates.

Certainly, besides helping prevent the deterioration in the Company's earnings, Straight Fixed Variable rates will lessen the need for frequent rate increases to the extent those rate increases are driven by falling residential sales, which should also help reduce customer confusion and dissatisfaction resulting from hearing or reading about frequent rate case filings in the media.

Q. Will Straight Fixed Variable rates eliminate all downside margin risks that the Company faces?

A. No. While a Straight Fixed Variable rate design represents an improvement over LG&E's current residential rate structure, a Straight Fixed Variable rate design is no panacea. It is possible that some residential customers may permanently disconnect their gas service as a result of the implementation of Straight Fixed Variable rates. Although the vast majority of LG&E's gas customers use natural gas for heating, water heating, and cooking, a number of customers use natural gas solely for more limited purposes, such as for decorative fireplace logs, decorative lighting, and outdoor grills. Increasing the Basic Service Charge may result in some of these customers disconnecting their gas service. Although no one knows for sure, the Company anticipates that the loss in margins due to these customers disconnecting their gas service will be less than the likely loss in margins resulting from the continued reduction in per customer sales due to conservation.

Furthermore, there will likely always be inflationary pressures on LG&E's costs. Consequently, the Company will continue to face risks associated with higher marginal costs. For example, the incremental cost of connecting a new residential customer (marginal cost) to the system will almost certainly be higher in 2010 than the average cost upon which rates are based (embedded cost).

Q. Is a Straight Fixed Variable rate design consistent with accepted ratemaking principles?

A. Yes. Straight Fixed Variable rate design is consistent with the ratemaking principle that fixed costs should be recovered through fixed charges and variable costs should be recovered through variable charges. Adhering to this principle avoids intra-class subsidies. Additionally, under Straight Fixed Variable rates, fixed costs are recovered through the basic service charge and the company recovers no margins on the commodity itself or the amount of gas sold. Thus, with a Straight Fixed Variable rate design fixed costs are less likely to be over-recovered if customers use more gas or under-recovered if customers use less gas than with a rate design that recovers fixed costs through a volumetric charge, such as LG&E's current Rate RGS. Therefore, Straight Fixed Variable rates provide a better matching of costs and revenues.

Q. Has a Straight Fixed Variable rate design been adopted in other jurisdictions?

A. Yes. The Missouri Public Service Commission ("Missouri Commission") recently adopted a straight fixed-variable rate design for Atmos Energy Corporation (*Case No. GR-2006-0387*, Order dated February 22, 2007) and Missouri Gas Energy, a division of Southern Union Company (*Case No. GR-2006-0422*, Order dated March 22, 2007). The straight fixed-variable rate design was proposed by the Missouri Commission Staff in the Atmos proceeding. A straight fixed-variable rate design is also used by the Atlanta Gas Light Company in Georgia.

In the Atmos proceeding, the Missouri Commission accepted the Staff's recommendation to eliminate the traditional two-part rate structure and to adopt instead a straight fixed-variable design because collecting fixed costs through a volumetric charge:

- Increases volatility in customer bills by collecting too much cost in the winter months;
- Sends incorrect price signals to residential customers;
- Forces residential customers whose usage is greater than the average to pay more than the cost of service, while allowing lower usage customers to pay less than the cost of service;
- Provides no incentive for the utilities to promote conservation.

(*Atmos Energy Corporation, Case No. GR-2006-0387*, Order dated February 22, 2007, at 19-20.)

More recently, the Public Utilities Commission of Ohio ("Ohio Commission") authorized Vectren Energy Delivery of Ohio to transition to a Straight Fixed Variable rate design over a 12-month period. (*Vectren Energy Delivery of Ohio, Case No. 07-1080-GA-AIR; Case No. 07-1081-GA-ALT; Case No. 08-632-GA-AAM*, Order dated January 7, 2009.) In that proceeding the Ohio Commission Staff argued that Straight Fixed Variable rates are "reasonable, understandable, and send the proper price signals to customers." (*Id.*, at 22.) The Ohio Commission found that a Straight Fixed Variable rate design, "promotes the regulatory principles of providing a more equitable allocation among customers, regardless of usage. It fairly apportions the fixed costs of service among all customers so that everyone pays their fair share." (*Id.*, at 30.) The Ohio Commission also concluded that a Straight Fixed Variable rate design sends a better price signal, stating as follows:

> [T]he Commission believes that a levelized rate design sends better price signals to consumers. The possible response of consumers to an increase in the customer charge, i.e., dropping gas service entirely and switching to a different fuel, is much less likely to occur than consumers changing their level of gas usage in response to a change in the volumetric rates. When a utility is entitled to recover costs in excess of its costs for providing the next increment of gas service, a more economically efficient rate design is one that recovers these additional costs largely through a change that has little impact on consumer behavior.
>
> Customers will not be misled into believing that reductions in consumption will allow them to avoid the fixed costs of the distribution system, as feared by Staff. However, the commodity costs comprise 75 to 80 percent of the total bill. (TR. III at 68). Therefore, we believe that the gas usage will still have the biggest influence on the price signals received by customers when making gas consumption decisions and that customers will still receive the appropriate benefits of any conservation efforts. (*Id.*, at 25-26.)

In Kentucky, Straight Fixed Variable rates have also been proposed by Duke Energy Kentucky, Inc. (Case No. 2009-00202) and by Columbia Gas of Kentucky, Inc. (Case No. 2009-00141). While both of those proceeding settled without Straight Fixed Variable rate designs, the parties agreed to, and the Commission approved, significant increases in their residential customer charges.

Q. Are there any federal and state directives that require consideration of Straight

Fixed Variable rates or other forms of decoupling?

A. Yes. Section 532(b)(6), Rate Design Modification to Promote Energy Efficiency Investments – Gas Utilities, of the federal Energy Independence and Security Act of 2007 (EISA 2007) states that, "each State regulatory authority and each non-regulated utility shall consider separating fixed-cost revenue recovery from the volume of transportation or sales service provided to the customer ...." On November 13, 2008, the Kentucky Public Service Commission issued an Order in Case No. 2008-00408 to initiate an administrative proceeding to consider the requirements of the EISA 2007. That case is still pending. In 2005, the National Association of Regulatory Utility Commissioners ("NARUC") passed a resolution that stated that decoupling mechanisms such as Straight Fixed Variable rates, "may assist, especially in the short term, in promoting energy efficiency and energy conservation and slowing the rate of demand growth of natural gas." (*National Association of Regulatory Utility Commissioners Resolution on Energy Efficiency and Innovative Rate Design*, adopted November 16, 2005.)

C. OTHER GAS RATE CHANGES

Q. What increases are being proposed for Rate CGS and Rate IGS?

A. Yes. For Rate CGS, LG&E is proposing to increase the on-peak Distribution Cost Component from $1.70520 per Mcf to $1.9795 per Mcf and the off-peak Distribution Cost Component from $1.20520 per Mcf to $1.4795 per Mcf. For Rate IGS, LG&E is proposing to increase the on-peak Distribution Cost Component from $1.6524 per Mcf to $1.9795 per Mcf and the off-peak Distribution Cost Component from $1.1524 per

Mcf to $1.4795 per Mcf. For Rate CGS and Rate IGS, we are proposing to increase the monthly basic service charge for meters less than 5,000 cubic feet per hour from $23.00 to $30.00 and to increase the monthly basic service charge for meters of 5,000 cubic feet per hour or higher from $160.00 to $170.00.

Q. Have you prepared exhibits reconstructing LG&E's test-year billing determinants for the gas business and showing the impact of applying the new rates to test-year billing determinants?

A. Yes. The reconstruction of LG&E's gas billing determinants is shown on Seelye Exhibit 8. The revenue increase by rate class is summarized on Seelye Exhibit 9. Seelye Exhibit 10 shows the impact of applying the current and proposed rates to test-year billing units.

Q. What revenue increase is LG&E proposing for gas operations?

A. LG&E is proposing an increase in gas test-year revenues of $22,588,249, which is calculated by applying the proposed rates to test-year billing determinants. This increase is slightly different from the revenue requirement increase of $22,598,160 shown in Rives Exhibit 8 because the number of decimal places in the proposed charges cannot be carried out far enough to yield the exact amount shown in Mr. Rives' exhibit.

V. MISCELLANEOUS SERVICE CHARGES AND CUSTOMER DEPOSITS

A. CABLE TV ATTACHMENT CHARGES

Q. Is the Company proposing to adjust the Cable TV Attachment charges?

A. Yes.

Q. When were the charges last updated?

A. The charges were last updated pursuant to a general rate application filed on July 13, 1990, in Case No. 90-158. Therefore, these charges have not been adjusted for nearly 20 years.

Q. How were the proposed charges for Cable Television Attachment Charges developed?

A. In its Order in Administrative Case No. 251, the Commission prescribed a methodology for determining the attachment charges. The calculations proposed in this filing, as set forth in Seelye Exhibit 11, follow the guidelines established in Administrative Case No. 251 and also follow the methodology that was approved by the Commission in Case No. 90-158. Although the methodology is the same as filed in Case No. 90-158, in order to harmonize methodologies used by LG&E and KU to *bill* the attachment charges, the Company is proposing to apply a single charge for attachments rather than to apply two separate charges based on pole size. However, in determining the charge the Company weighted the carrying costs between the two categories of poles by the number of poles in each category. LG&E is proposing to use the same billing methodology as used by KU, specifically, to calculate the rate as an annual charge, as opposed to a monthly charge, and to bill the cable companies once every six months, as KU currently does, rather than monthly, as LG&E currently does. The Company has determined that billing these charges biennially is administratively more efficient than billing them monthly.

B. EXCESS FACILITIES RIDER

Q. Please describe the proposed changes to the Excess Facilities Rider.

A. The Excess Facilities Rider applies to customer requests for service arrangements requiring equipment and facilities in excess of those the Company would normally install. Examples of excess facilities would include requests for non-standard facilities such as emergency backup feeds, automatic transfer switches, redundant transformer capacity, and duplicate or check meters. The Company is proposing to modify the tariff so that the customer would have the option of either (i) requesting that LG&E incur the full cost of the equipment (including up-front equipment cost), in which event the monthly excess facilities charge would cover the expected carrying charges on the equipment, the estimated maintenance cost on the equipment, and the estimated cost of replacing the equipment if it fails prior to the service life of the facilities, or (ii) making an up-front payment to cover the cost of the facilities, in which event the monthly excess facilities charge would only cover the Company's estimated maintenance cost on the equipment and the estimated cost of replacing the facilities if they fail prior to the expected service life of the equipment. Because estimated failure costs would be included in the charge for either scenario, LG&E would replace the equipment if it fails prior to the end of the specified service life under either option. The primary change that the Company is proposing in this filing is to replace the equipment if it fails rather than require the customer to replace the equipment. The Company has determined that agreeing to replace the facilities in the event of failure will reduce potential questions and possible litigation necessary to determine whether the Company or the customer is responsible for the equipment failure. Under the current proposal, the charge will include the cost of replacing the facilities. The Company will simply replace the facilities in the event of equipment failure and the monthly carrying charges paid by the customer will be updated to reflect the replacement cost.

Q. What are the proposed excess facilities charges?

A. Under the first option, in which the Company makes the up-front investment, the monthly charge would be 1.73 percent of the original cost of the facilities. Under the second option, in which the customer makes the initial up-front investment, the monthly charge would be 0.87 percent of the original cost of the facilities.

Q. How are the excess facilities charges calculated?

A. For the first option, in which LG&E makes the up-front investment, the charge includes (i) the levelized carrying charges associated with both the original cost of the facilities and the present value of the expected replacement cost of the facilities, plus (ii) operation and maintenance expenses as a percentage of the original cost of the plant. The levelized carrying charge rate is calculated using an 8.32 percent cost of capital for the estimated 30-year recovery period for long-lived distribution property. The present value of the expected replacement costs is determined using an actuarial approach based on Iowa-type survivor curves, which are the survival frequency distributions developed by Iowa State University that are used in depreciation studies for electric and gas utilities throughout the U.S. Specifically, the present value replacement cost is determined by calculating the replacement cost for each year based on the failure percentage given by a specified survivor curve, adjusted to reflect a three percent inflation factor and present valued using an 8.32 percent discount rate. A 30-year R-2 Iowa curve is used to determine the annual replacement percentages. This curve is typical of an Iowa curve that might be used for transformers and other distribution facilities.

For the second option, in which the customer makes the initial up-front investment, the charge includes (i) the levelized carrying charges associated with the present value of the expected replacement cost of the facilities, plus (ii) operation and maintenance expenses as a percentage of the original cost of plant. Therefore, under this option, the charge would not include the carrying charges associated with the initial cost of the facilities, but would include carrying charges on the present value of the replacement cost.

For both options, the operation and maintenance component is determined by dividing (i) actual operation and maintenance expenses less purchased power expenses during the test year by (ii) electric plant in service as of the end of the test year. Cost support for the proposed excess facilities charges is included in Seelye Exhibit 12.

C. METER PULSE CHARGE

Q. Is the Company proposing a meter relay pulse charge for gas meters?

A. Yes. The Company is also proposing to offer a Gas Meter Pulse Service for gas installations. The proposed charge for this service is $8.20 for customers served under Rate FT and $21.30 for customers taking service under some other rate schedule. The reason that the charge is lower for Rate FT customers is that some of the metering facilities will already be in place to provide this service to FT customers. These charges are calculated using the same methodology used to determine the electric charge. The cost support for these charges is included in Seelye Exhibit 13.

Q. Is the Company proposing any changes to the meter relay pulse charge set forth in the electric tariff?

A. No. Even though the Company could support increasing the meter pulse charge based on the cost of providing the service, the Company is not proposing to increase the charge at this time. The meter pulse relay service is a special service provided strictly at the option of the customer whereby the Company installs special equipment on industrial and commercial demand meters to provide customers a demand pulse so that they can better manage their demands. The charge was filed for the first time in the Company's recent general rate case. The charge is somewhat understated because the costs were simply amortized over 5 years without any consideration for carrying costs and replacement. The proper calculation of a charge that includes carrying costs is included in Seelye Exhibit 13. The carrying charge methodology is consistent with the methodology shown in the Excess Facilities Rider, except the life of electronic metering equipment is much shorter than the type of long-lived utility property contemplated under the Excess Facilities Rider. However, due to the magnitude of the increase required to provide full recovery and because the charge was introduced only recently, the Company decided not to adjust the charge at this time.

D. CUSTOMER DEPOSITS

Q. Is LG&E proposing any changes to its residential customer deposit requirements?

A. Yes. The current residential deposit requirements are \$135 for electric customers, \$160 for gas customers, and \$295 for combination electric and gas customers. The

Commission's regulations 807 KAR 5:005, Section 7(b) state that, "The utility may establish an equal amount for each class based on the average bill of customers in that class. Deposit amounts shall not exceed two-twelfths (2/12) of the average bill of customers in the class where bills are rendered monthly...." Consistent with these regulations, the Company is proposing deposit requirements of $160 for electric customers, $115 for gas customers, and $275 for combination customers. See Seelye Exhibit 14.

VI. PRO-FORMA REVENUE ADJUSTMENTS

A. ELECTRIC TEMPERATURE NORMALIZATION ADJUSTMENT

Q. Is LG&E proposing a temperature normalization adjustment for electric operations in this proceeding?

A. Yes.

Q. What is the purpose of making such an adjustment in a rate case?

A. In a general rate case, service rates are set at a level that will provide the utility a reasonable opportunity to recover its costs on a going-forward basis, including a fair, just and reasonable return on investment. The underlying principle is that when rates go into effect as a result of a general rate case, those rates will represent a level of revenue that will allow the utility to recover its reasonably incurred costs on a going-forward basis. This principle holds regardless of whether a projected test year or a historical test year is used to set rates. When rates are based on a historical test year, pro-forma adjustments are made to test-year operating results so that revenues and expenses will be representative on a going-forward basis. This is the principle behind adjusting certain test-year operating results to reflect a going-forward level of expenses and revenues for things such as storm damage expenses, injuries and damages, and year-end levels of customers. (See Reference Schedules 1.21, 1.22, and 1.12 to Rives Exhibit 1) or annualizing other revenues and expenses (e.g., depreciation expenses and wages and benefits expense) to reflect the full amount on a going forward basis. In this proceeding, the Company has made a number of other normalization adjustments to help ensure that the historical test year will be representative of costs and revenues on a going-forward basis. Normalization adjustments that are not supported by a *sound statistical methodology* and do not apply *clear and objective measures*, but are ad hoc and results-oriented, are *not* used to adjust test year results.

Q. Why is it appropriate to make a temperature normalization adjustment in this proceeding?

A. Electric utility sales vary with temperature. As temperatures rise during the summer, more electric energy is used by customers to operate the compressors on their air-conditioners. Likewise, as temperatures go down in the winter, more electric energy is used by customers to operate electric furnaces and other space-heating appliances. Consequently, for any day during the summer or winter, LG&E's electric sales will increase and decrease as a result of changes in temperature.

Q. For electric operations, should revenues and expenses reflect a *range* of cooling and heating degree days representative of normal conditions?

A. Yes. What is considered normal can be represented in a number of statistically valid ways. One methodology – the mean-value approach – is to represent normal degree days by calculating a 30-year average. Another methodology would be to establish a statistically determined range centered on the mean-value degree days.

From a statistical perspective, a 30-year mean, or average, would represent a measure of the *expected value* for heating degree days. For a normally-distributed probability density function, the expected value of a random variable is equal to the mean value. Or stated more rigorously, the maximum likelihood estimator for a normally distributed random variable is equal to the sample mean value. (For example, see Robert V. Hogg and Allen T. Craig, *Introduction to Mathematical Statistics*, Third Edition, 1975, at 257.) Therefore, for LG&E's natural gas operations, the 30-year average heating degree days are considered to be representative of a going-forward level of heating degree days for purposes of determining test-year levels of revenues and sales.

This is a standard approach for normalizing natural gas revenues and expenses, and is also used in other jurisdictions to normalize electric revenues and expenses. Although it has accepted the mean-value methodology for calculating gas temperature normalization adjustments for many years, the Commission has expressed concerns about using the mean-value approach for electric temperature normalization. In its Order in Case No. 10064, the Commission stated as follows:

> The Commission is of the opinion that there is adequate evidence to suggest that a range of temperatures and not a specific mean temperature is a more appropriate measure of normal temperatures. As long as the temperature falls within these bounds then it is inappropriate to adjust sales for temperature. However, if the

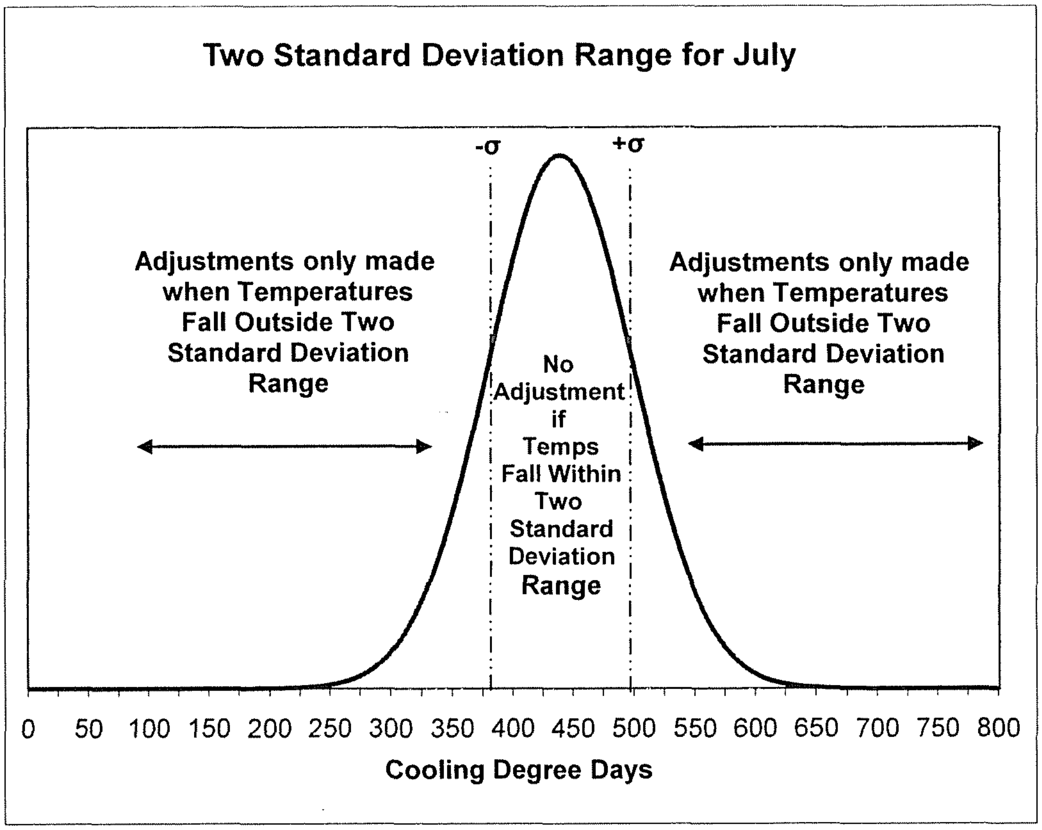
> temperature falls outside those bounds then it is appropriate to adjust sales to the nearest bound. (Order in Case No. 10064, dated July 1, 1988, at 39.)

Therefore, an alternative to the mean-value approach, one which was suggested by the Commission's Order in Case No. 10064 and is well-grounded by statistical theory, would be to determine a *range* of cooling and heating degrees days that would be considered normal. Instead of normal degree days being represented by a mean value, as is done in the gas temperature normalization adjustment, a bandwidth around the mean value could be established. Cooling degree days inside the bandwidth would then be considered normal, and cooling degree days outside the bandwidth – either high or low – would be considered abnormal or extraordinary, requiring a normalization adjustment to bring revenues and sales to within a normal range. A standard approach for establishing a *normal range* of a random variable is to determine a bandwidth of two standard deviations centered on the mean. The rationale for this approach is that for a normally-distributed (Gaussian) probability density function, the random variable will fall within a range between one standard deviation above and one standard deviation below the mean value 68 percent of the time. More important for our purposes is the fact that a random variable will only exceed the two standard deviation bandwidth 16 percent of the time. Assuming that cooling and heating degree days are normally distributed, which is a standard supposition well-grounded in empirical research, only 16 percent of the time would temperatures be expected to exceed one standard deviation above or below the mean.

Q. Using cooling degree days in July as an example, how would the range for the

temperature adjustment be determined?

A. The following graph shows a normally-distributed probability density function for July based on a mean level of cooling degree days of 439 and a standard deviation of 60. In this example, no temperature normalization adjustment would be made if the cooling degree days fall between 379 and 499 during July. If cooling degrees fall above 499 during a particular July then a temperature normalization adjustment would be made to reduce sales to what they would have been if there actually had been 499 cooling degree days for the month. If cooling degree days fall below 379, then sales would be adjusted upward to what they would have been if there actually had been 379 cooling degree days for the month.



Q. Is the Company proposing to adjust revenues and sales to reflect the 30-year average level of cooling and heating degree days?

A. No. Unlike the temperature normalization adjustment for natural gas sales, which adjusts base rate revenues to reflect the 30-year average, for electric operations, the Company is proposing a more conservative approach. Specifically, if heating and cooling degree days during a month are *within* plus or minus one standard deviation of the mean degree days for the month, then no adjustment would be made during that month. If heating or cooling degree days for a month are more than one standard deviation above the average for that month, then sales would be adjusted either upward or downward to reflect the heating or cooling degree days at the top end of the range. In other words if the degree days are above the top end of the range, they are not adjusted to the *average* but only to *one standard deviation above* the average. Likewise if heating or cooling degree days for a month are more than one standard deviation below the average for that month, then sales would be adjusted downward or upward to reflect the heating or cooling degree days at the bottom end of the range.

This approach places constraints on the magnitude of the temperature normalization adjustment. First, a constraint is placed on the magnitude of the total revenue and expense adjustment because monthly normalization adjustments would only be made during months when cooling or heating degree days fall outside a particularly wide range of degree days. Second, the methodology would only adjust sales to one of the two end points of the degree day range. Thus, this approach would certainly result in lower revenue and expense adjustments than adjusting to the midpoint of the degree-day range (the mean value), as is done with the gas temperature normalization adjustment.

Q. Are there months during the year that would not be adjusted under this methodology?

A. Yes, for most months no adjustments are required and there are many others when somewhat small adjustments are required. Seelye Exhibit 15 shows the following information for each month during the test year: (1) the 30-year average monthly HDD and CDD for the month, (2) the standard deviation for the monthly HDD and CDD for the 30-year period, (3) the upper and lower end of the HDD or CDD range, determined by subtracting or adding one standard deviation to the average HDD or CDD for the month, (4) the actual HDD or CDD for the month, (5) an indication of whether the HDD or CDD is outside the bandwidth for the month, and (6) the amount by which the HDD or CDD is outside of the bandwidth. As can be seen from this exhibit, the only adjustments that would be required are for the months of March, July and October. March is 8 HDD warmer than the bottom end of the range; July is 111 CDD cooler than the bottom end of the range; and October being 6 HDD cooler than the top end of the range.

Q. Why is the Company proposing a different temperature normalization methodology for its electric operations than for its natural gas operations?

A. Natural gas is primarily used by residential customers for space heating. Other residential uses of natural gas, such as for water heating, cooking, and lighting, make up a relatively small percentage of total residential gas usage. Therefore, the temperature dependence of natural gas sales is easier to determine from a mathematical or statistical perspective. Electric energy on the other hand is used by residential customers for a myriad of purposes, including summer air-conditioning, space heating, water heating, cooking, refrigeration, lighting, home audio-video systems, personal computers, operating small appliances, etc. Consequently, determining the temperature dependence of electric sales requires more sophisticated mathematical modeling than for determining the temperature dependence of gas sales.

Although the temperature dependence of electric sales can be determined with great accuracy, it is reasonable to use a bandwidth approach for making the electric temperature normalization adjustment. As mentioned earlier, the Commission commented on the appropriateness of a bandwidth approach in its Order in Case No. 10064.

Q. How was the temperature relationship for electric sales determined during the test year?

A. The Companies' goal was to develop a well-formed linear regression model to measure the statistically significant temperature dependence on the kWh sales for the class of service being analyzed and to use that model to measure the temperature-sales relationship. In a linear regression model, the expected value of the response variable (dependent variable) y would be related to a regressor (independent variables) x_1, in the following manner:

$$E(y|x) = \beta_0 + \beta_1 x_1$$

The parameter β_0 is called the intercept of the model and the parameter β provides the linear relationship between the response variable and the regressor identified in the model. For each month where CDDs or HDDs fell outside of the two standard deviation bandwidth, a rigorous parameter estimation process was followed for each class of service to develop a regression model to measure the impact of temperature on daily kWh sales.

Q. Is this the same model that was proposed in the Company's last rate case?

A. It is essentially the same, except that the model that the Company is proposing in this proceeding is a simpler approach. In the last proceeding, primarily to address concerns raised by the Commission regarding prior temperature normalizations adjustments, the Company proposed a more complicated methodology consisting of multiple regression models evaluated using step-wise regression. The witness for the Attorney General, Glenn Watkins, criticized the Company's proposed methodology for being too complicated. While Mr. Watkins opposed making a temperature adjustment as a matter of principle, he suggested that a single-variable model would be more appropriate if the Commission authorized a temperature normalization adjustment for electric operations. In data requests, the Staff also requested that the Company calculate the electric temperature adjustment using a simpler, single variable approach. For these reasons, the Company is proposing a simpler model in this proceeding.

Q. Is regression analysis a widely used statistical methodology?

A. Yes. As explained in Douglas C. Montgomery, Elizabeth A. Peck, and G. Geoffrey Vinning, *Introduction to Linear Regression Analysis*, Fourth Edition, Wiley Series in Probability and Statistics, 2006:

> Regression analysis is one of the most widely used techniques for analyzing multifactor data. Its broad appeal and usefulness result from the conceptually logical process of using an equation to express the relationship between a variable of interest (the response) and a set of related predictor variables. Regression analysis is also interesting theoretically because of elegant underlying mathematics and a well-developed statistical theory. Successful use of regression requires an appreciation of both the theory and the practical problems that typically arise when the technique is employed with real-world data. ... [a]pplications of regression analysis are numerous and occur in almost every field, including engineering, the physical and chemical sciences, economics, management, life and biological sciences, and social sciences. In fact, regression analysis may be the most widely used statistical technique. (Ibid., at xiii and 1.)

Although regression is a widely-used statistical technique, it is important that well-formed models be developed for purposes of performing an electric temperature normalization adjustment. The multiple regression models must be constructed in accordance with sound mathematical and statistical practices.

Q. Where were the daily kWh sales for each rate class obtained?

A. The daily kWh sales for each rate class were obtained from census or sampled load research data. LG&E has census data (daily kWh readings for each customer) for Rate CTOD, Rate ITOD, Rate RTS and the special contract customers. Except for the lighting classes, which are not temperature sensitive, the Company has accurate load research data for all of the rate classes. The load research data is designed to meet the accuracy requirements that were set forth in Section 133 of the Public Utilities Regulatory Policy Act (PURPA).

Q. What statistical software package was used to develop the multiple regression models?

A. SAS, which is a leading statistical software package, was used to perform statistical modeling. SAS incorporates a wide range of statistical and data analysis tools, including regression modeling (linear, generalized linear, and non-linear), nonparametric analysis, operations research, and multivariate analysis. According to its 2007 annual report, there are over 43,000 university, business and government SAS installations.

Q. What is an R-Square and why is it used in the parameter estimation process?

A. The term "R-Square" refers to the multiple coefficient of determination and is a measure of the proportion of the variation of the predictor variable (y) explained by the regressors (x_1, x_2, ..., $x_{i,}$) in a model. R-Square is the square value of the multiple correlation coefficient (R). Values of R-Square that are close to 1.00 imply that most of the variation in the response variable is explained by the regression model. Generally, I would consider an R-Square above 0.60 as being adequate.

Q. What rate classes were *not* normalized because of the absence of statistically significant temperature sensitive sales?

A. Obviously, the residential and commercial rate classes are the most temperature sensitive, and the large industrial and large industrial time-of-day classes less so. The rates classes (using the current rate designations) that were normalized include: (a)

Rate RS, (b) Rate GS, (c) Rate CPS, (d) Rate CTOD, and (f) the commercial special contract customers.

Q. **Once the parameter estimates were determined how were they used to determine the normalization adjustment?**

A. In calculating the kWh sales for the normalization adjustment by class and by month, the parameter estimate for each applicable temperature variable (CDD65 and HDD65) from Seelye Exhibit 16 was applied to the difference between the actual value for the temperature variable during the month and the end-point of the two standard deviation range centered on the 30-year average value for the temperature variable to the extent the actual was not within the bandwidth, in which case no adjustment was made. These adjustments are shown on Seelye Exhibit 17.

Q. **After the kWh sales adjustments were determined for each class, how was the revenue component of the adjustment calculated?**

A. The revenue adjustment was calculated by applying the kWh adjustment for each rate class to the energy charge applicable to the rate schedule. No attempt was made to normalize the demand charges of three-part rate schedules consisting of a basic service charge, energy charge and demand charge. The proposed temperature normalization procedure normalized kWh sales and not maximum individual demands. Had demands been normalized, the revenue adjustment would have been larger without materially changing the expense adjustment. The revenue component of the temperature normalization adjustment is calculated in Seelye Exhibit 18.

Q. **How was the expense component of the adjustment determined?**

A. The expense component of the temperature normalization adjustment was calculated by applying the kWh sales adjustment to the variable expenses per kWh during the test year. Variable expenses were determined using the FERC predominance methodology that was used in the Company's embedded cost of service study, which will be discussed later in my testimony. The expense component of the temperature normalization adjustment is also calculated in Seelye Exhibit 18.

Q. Has the Commission ever considered an electric temperature normalization adjustment in an LG&E rate proceeding?

A. Yes. Electric temperature normalization adjustments were considered in Case No. 8284, Case No. 8616, Case No. 8924, Case No. 10064, and Case No. 98-426 all of which were LG&E rate proceedings. In each of these proceedings, the Commission denied the adjustment, noting that the Company had failed to adequately support the adjustment. The Commission however continued to endorse the concept of normalization and expressed a willingness to consider temperature adjustments in future rate proceedings. (See Commission's Order in Case No. 98-426, dated January 7, 2000, at 73.)

In Case No. 98-426, the Commission expressed concern that the Company had failed to file the supporting regression analyses, modeling and forecasting assumptions, and calculation details. The Commission also expressed concern about the use of 20-year average degree days rather than a 30-year average, noting that "previous electric weather normalization adjustments proposed in the LG&E rate cases were based on a 30-year average. The 30-year average is typically used in gas weather normalization adjustments." (Ibid., at 74.)

In Case No. 10064, the Commission expressed concern that the Company did not construct a "confidence interval" for temperature adjustment purposes. On page 38 of the Order, the Commission observed that LG&E "adjusted each month's actual billing-cycle temperature-sensitive load to a mean determined temperature-sensitive load instead of to a temperature-sensitive load determined by the boundaries of a range of acceptable values constructed around the mean." (Order in Case No. 10064, dated July 1, 1998, at 38-39.) The Commission also expressed concern about the accuracy of the billing-cycle degree days used in the temperature normalization adjustment. Additionally, the Commission criticized the Company's adjustment because it did not rely on a regression model to adjust test-year sales and only analyzed one variable. (Ibid., at 42-43.) Finally, the Commission stated:

> [I]f LG&E desires to propose an electric temperature adjustment in future rate applications, it should develop a methodology that will accurately and appropriately match random effects of weather to electric consumption. Further, LG&E should provide adequate support to verify the accuracy and appropriateness of any model presented. The Commission will require that LG&E provide documentation, including adequate statistical analysis, sufficient to support the accuracy of the relationships in the methodology developed and submitted in subsequent rate cases. (Ibid., at 43.)

The adjustments proposed by the Company in Case Nos. 8284 and 8616 were developed without relying on any sort of statistical analysis. Temperature-sensitive load was estimated by first selecting a single month to calculate a base load level and then all sales during the summer months above that base load level were considered to be the temperature-sensitive load. The

Commission rejected the methodologies proposed in those proceedings for obvious reasons.

Q. Do you believe that the Commission's concerns expressed in the previous rate cases have been adequately addressed in the Company's filing in Case No. 2008-00252 and in this filing?

A. Yes. All previous concerns expressed by the Commission have been thoroughly and comprehensively addressed.

Q. Does the temperature normalization have the effect of increasing test-year operating income and thus lower the Company's proposed revenue increase?

A. Yes, the temperature normalization adjustment increases operating income and lowers the Company's proposed rate increase in this filing.

Q. Do you recommend that this adjustment be made?

A. Yes. I believe that it is appropriate to make an electric temperature normalization adjustment.

B. GAS TEMPERATURE ADJUSTMENT

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 November through April. Because the WNA automatically normalizes customer billings for Rates RGS and CGS during the months of November through April it is not necessary to perform a temperature normalization adjustment for these two classes during the months of November 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, AAGS, 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, AAGS, FT, and the special contracts. Heating degree days related to cycle billed customer deliveries were 89 above the 30-year average NOAA heating-degree days of 4,163. The 30-year average was determined using the most recent 30-year period (i.e., the 30-year period ended October 2009). Thus, LG&E's actual revenues were overstated due to colder-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 (4,252 for billing cycle customers and 4,279 for classes billed on calendar month) in the test period. The resulting Mcf per degree day was then multiplied by the degree-day departure from normal (89 and 111, 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 $42,618 for rate classes not billed under the WNA. The details of these calculations are shown on page 2 of Seelye Exhibit 19.

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 November 2008, through April 2009. As mentioned earlier, there were 89 more billing-cycle degree days than normal during the twelve months ended October, 2009. However, there were 85 more billing-cycle degree days from normal during the WNA months of November, 2008, through April,

2009. In other words, the non-WNA months were 4 degree days greater 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 4 degree days colder 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 a downward adjustment to gas operating revenue of $206,330 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 19.

Q. Please summarize the total impact of the gas temperature normalization adjustment.

A. The gas temperature normalization adjustment results in a net reduction of $248,948 to LG&E's gas operating revenue. The calculation of this amount is summarized on page 1 of Seelye Exhibit 19. This adjustment is included in Reference Schedule 1.40 of Rives Exhibit 1.

C. YEAR-END CUSTOMER ADJUSTMENTS

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 number of customers for the 13-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 basic service charges, energy charges, demand charges and minimum bills), resulting in an upward adjustment to electric operating revenue of $11,451,462.

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 69.48 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 $7,956,625.

The detailed calculations of the electric year-end customer adjustment to revenues and expenses are contained in Seelye Exhibit 20. This adjustment is included in Reference Schedule 1.12 of Rives Exhibit 1.

Q. Please explain the adjustment to annualize for year-end customers for the natural gas business.

A. The numbers of customers served at the end of the test period for the rate classes were different from the average number of customers for the 13-month test period. The purpose of this adjustment is to reflect the deliveries and revenue assuming that the year-end number 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 basic service charges, distribution charges and minimum bills), resulting in an upward adjustment to gas operating revenue of $1,760,940.

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 Case No. 2000-080, the operating ratio of 30.76 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 an upward adjustment to expenses of $541,722.

The detailed calculations of the year-end adjustment to revenues and expenses are contained in Seelye Exhibit 21. This adjustment is included in Reference Schedule 1.12 of Rives Exhibit 1.

VII. ELECTRIC COST OF SERVICE STUDY

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 October 31, 2009?

A. Yes. I supervised the preparation of a fully allocated, time-differentiated, embedded cost of service study for electric operations. The cost of service study corresponds to the pro-forma financial exhibits included in the testimony of Mr. Rives. 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. Did you develop the model used to perform the cost of service study?

A. Yes. I developed the spreadsheet model used to perform the cost of service study submitted in this proceeding.

Q. What procedure was used in performing the cost of service study?

A. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – 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 the rate classes. These steps are depicted in the following diagram (Figure 1).

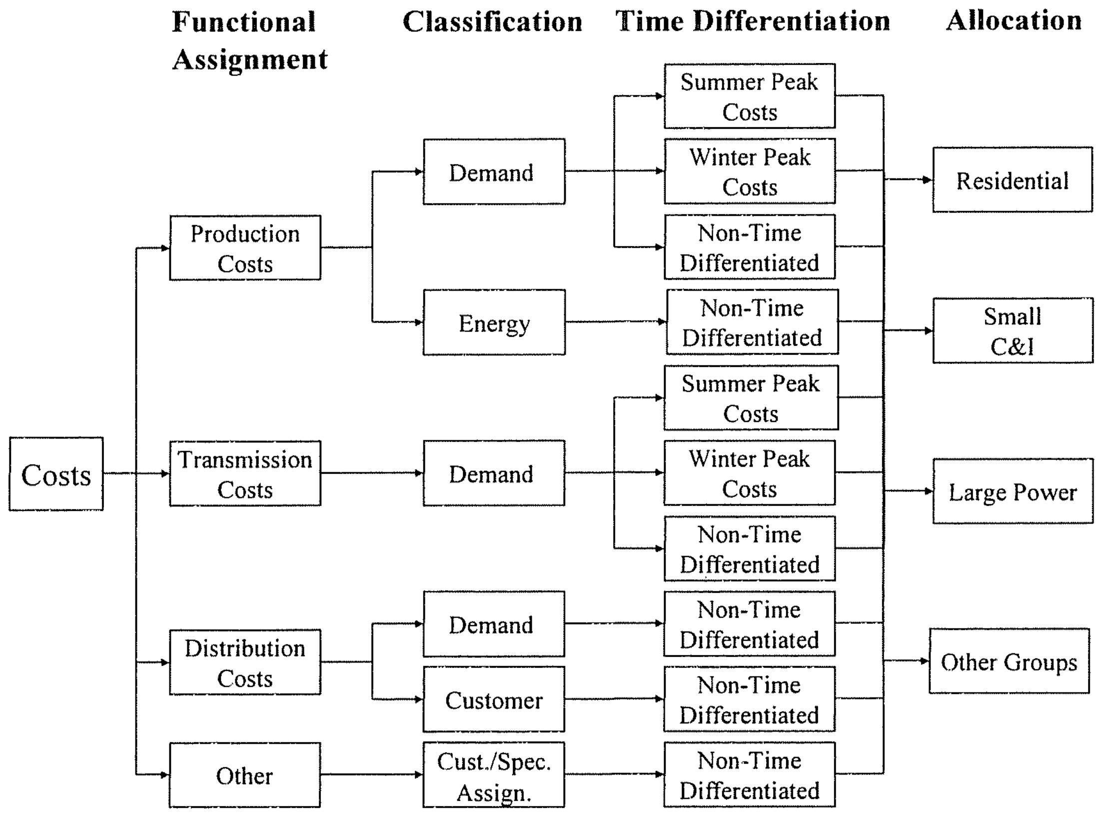


Figure 1

The following 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. 2009-00548?

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.[3] 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 demand. Intermediate costs were calculated by dividing the summer peak demand by the winter 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 or winter peak periods or assigned as non-time-differentiated. Base costs were 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 winter peak period.

Q. In applying the modified BIP methodology, what demands were used?

A Demands for the combined LG&E and KU systems are used to determine the costing periods and in determining the percentages of production and transmission fixed cost assigned to the costing periods. Since the two systems are planned and operated jointly it is important to develop costing periods and assign costs to the costing

[3] In Case No. 90-158, 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, at 58.)

periods based on the combined loads for LG&E and KU. 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 KU cost of service studies.

Q. What percentages were assigned to the costing periods?

A Seelye Exhibit 22 shows the application of the modified BIP methodology. Using this methodology 43.25% of LG&E's production and transmission fixed costs were assigned to the winter peak period, 21.86% to the summer peak period, and 34.89% as non-time-differentiated. While the Company used the BIP methodology as was used in the last several rate cases, the results are significantly different in this study. Because the test year exhibited an unusual weather pattern, the maximum system demand occurred during a winter month rather than during a summer month as in previous studies. As mentioned earlier, in preparing the cost of service study, the decision was made to use *actual* hourly system loads in the cost of service study rather than engaging is the complicated process of normalizing peak demands. This is consistent with the Company's historical practice of using actual demands to determine allocation factors in the cost of service study. The normalization of peak demands, which would require normalization of hourly loads, would be an extremely difficult task. For this reason, the Company decided to prepare the electric cost of service studies without normalizing hourly loads for weather or other factors. However, one of the consequences of using the actual load is that the results of the

Base-Intermediate-Peak (BIP) methodology used in the electric cost of service studies are significantly altered, increasing the percentage of production and transmission costs allocated on the basis of the winter CP. Ultimately, the unusual demand patterns that occurred during the test year resulted in shifting the class rates of return in this cost of service study as compared to previous studies.

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. Fuel and purchased power expenses are examples of costs typically classified as energy costs. 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 transmission lines are examples of costs typically classified as demand 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 23 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 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 customers.
- **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 a customer weighting factor based on discussions with LG&E's meter reading, billing and customer service departments.
- **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 year-end number of customers using

line transformers and secondary voltage conductor.

- **YECust08** – The customer cost component is allocated on the basis of the year-end number of customers using primary voltage conductor.

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 23, 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 43 through 45. 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 also shown on pages 43 through 45 of Seelye Exhibit 23. An example of this process is the use of total operation and maintenance expenses less purchased power ("OMLPP") 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 purchased power expenses, it is appropriate to functionally assign and classify