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
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PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

Filed: January 29, 2010

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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.

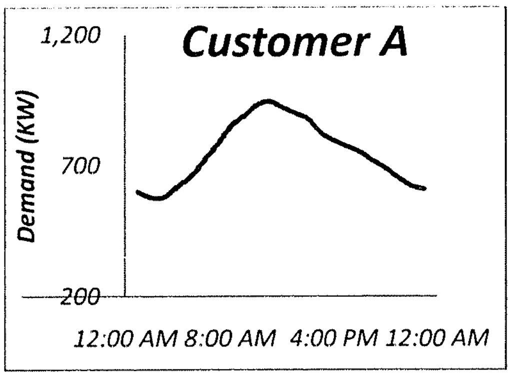
A. Conjunctive demand is a form of aggregated billing, where the loads for a customer with multi-site accounts, such as a group of grocery stores or retail stores owned by a single corporate entity, are aggregated for purposes of billing a component of the utility's demand charge.

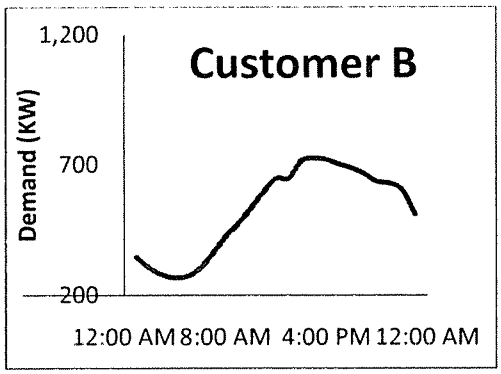
Q. Is aggregated billing allowed under the Commission's regulations?

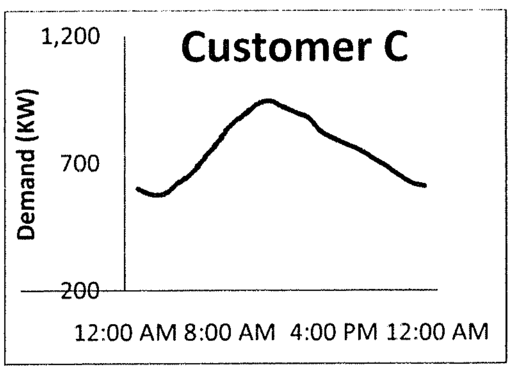
A. No. Section 9(2) of 807 KAR 5:041 states that, "The utility shall regard each point of delivery as an independent customer and meter the power delivered at each point. Combined meter readings shall not be taken at separate points, nor shall energy used by more than one (1) residence or place of business 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.

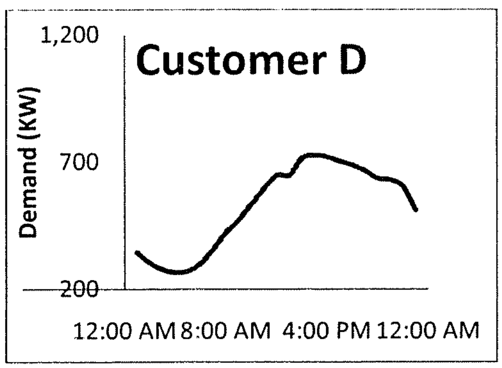
Q. Explain how Conjunctive Demand would be billed?

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:



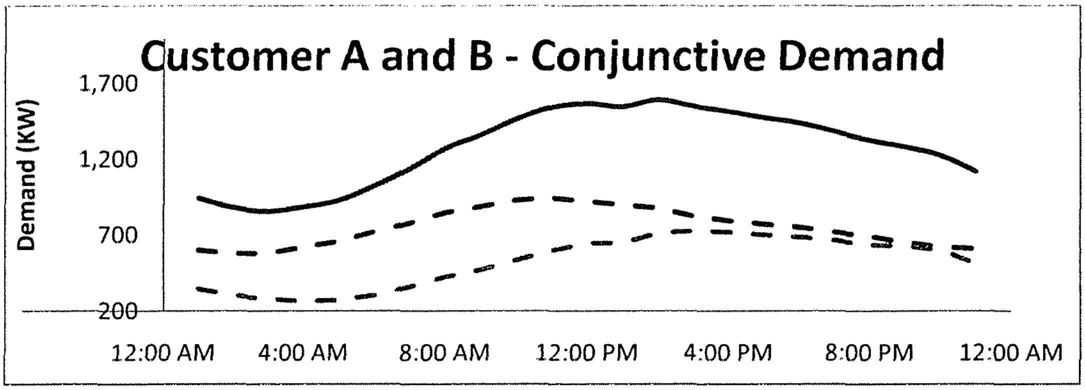


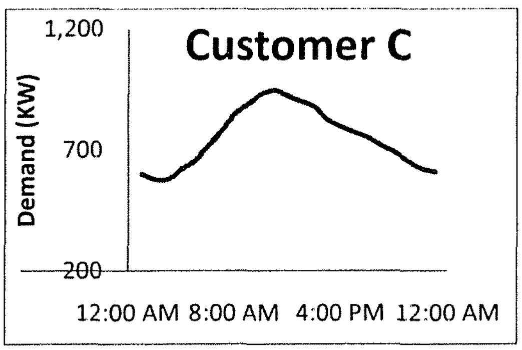


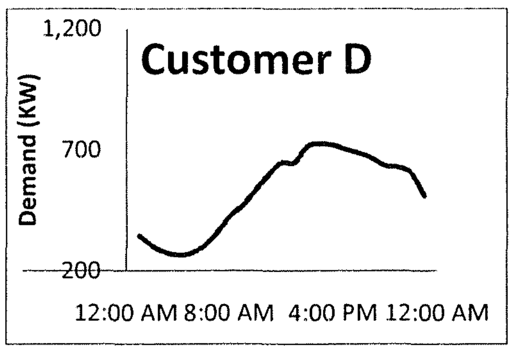


Now suppose that Customer A is a warehouse and Customer B is a retail store owned by the same corporate entity. Therefore, Customer A and Customer B represent a single "multi-site customer" according to Section 3.11 of the Settlement Agreement. Further, suppose that Customer C is also a warehouse and 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?

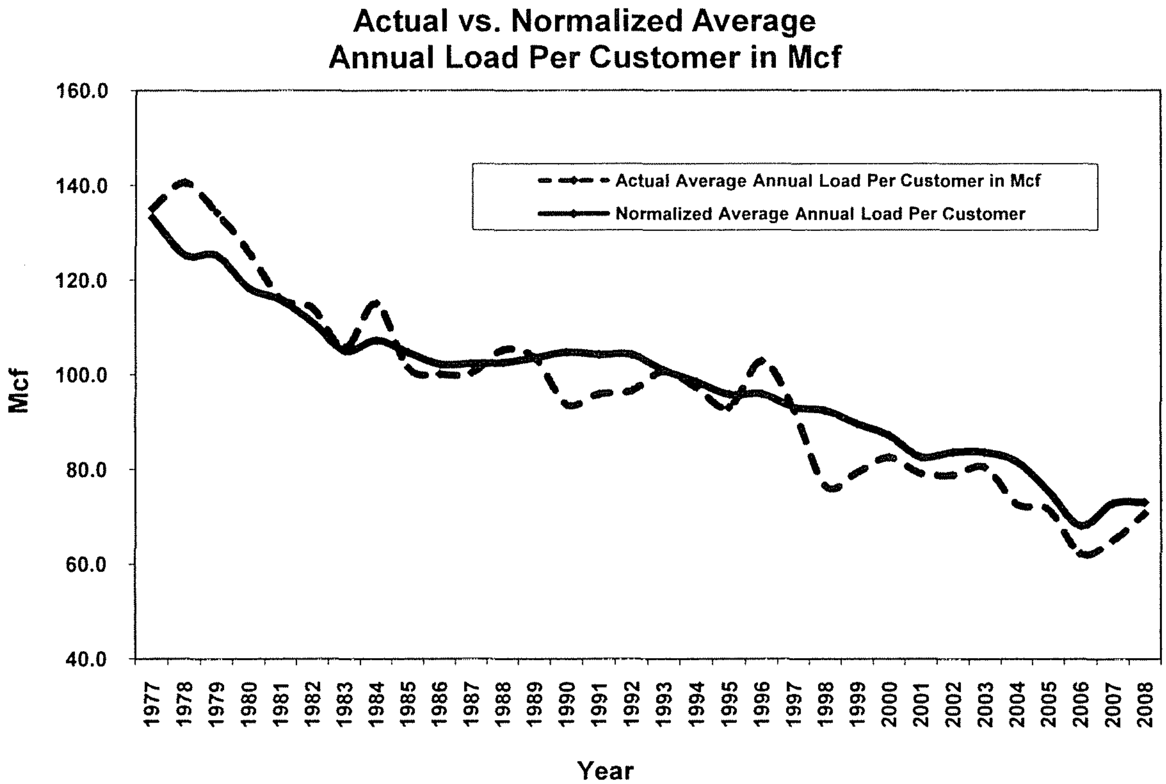
A. During the winter heating months, customers use more natural gas. With a Straight Fixed Variable rate design, the volumetric component of the bill will be reduced and as a result customer bills will be more level, thus reducing monthly volatility in customers' bills.

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

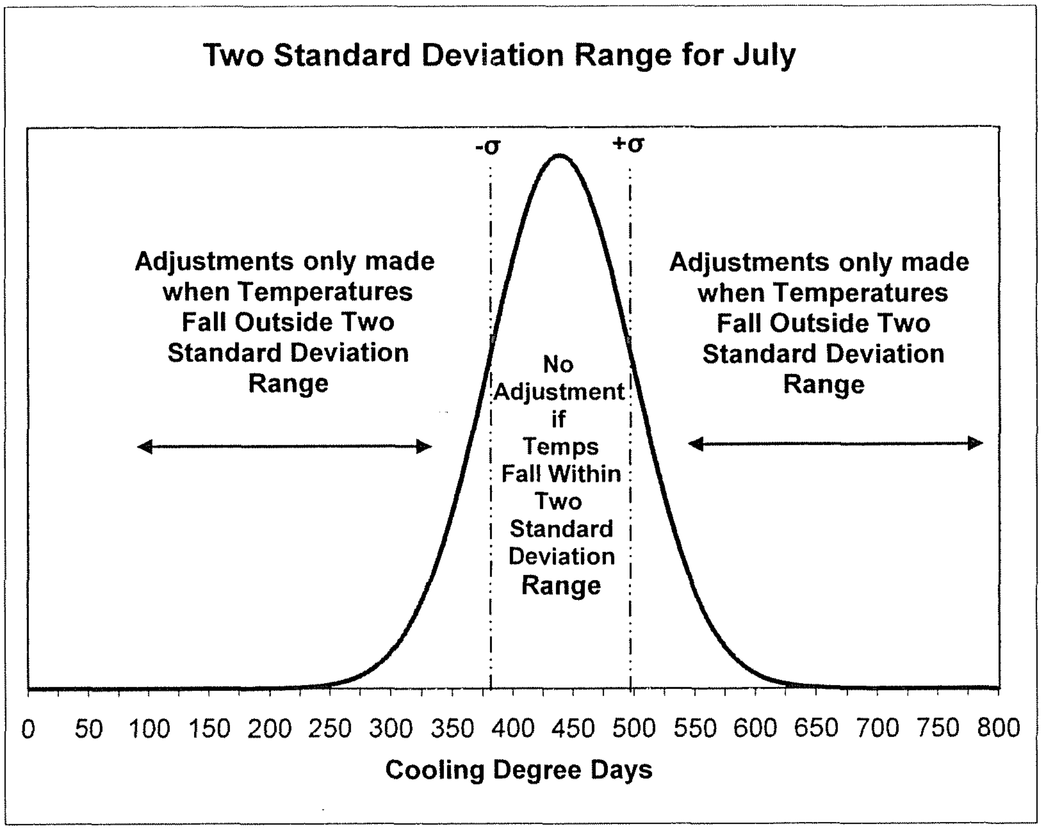
> temperature falls outside those bounds then it is appropriate to adjust sales to the nearest bound. (Order in Case No. 10064, dated July 1, 1988, at 39.)

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).

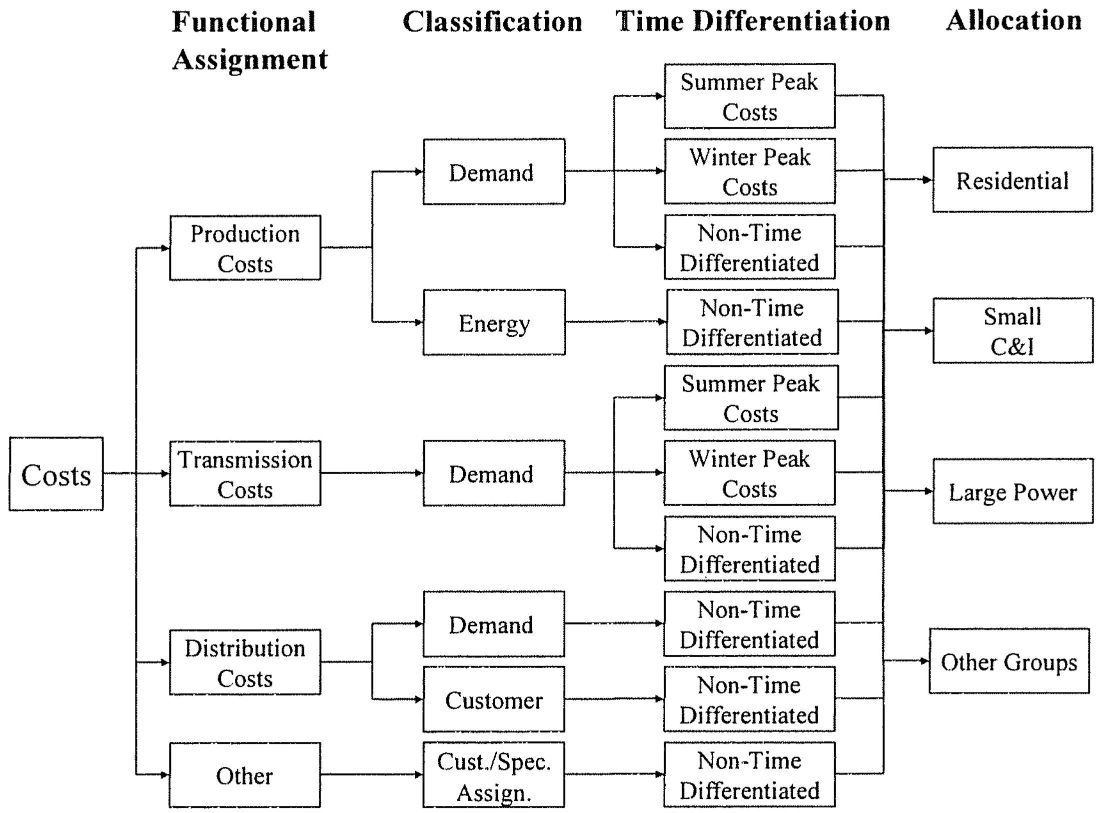


Figure 1

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 these costs on the same basis. (See Seelye Exhibit 23, pages 7 through 9 for the functional assignment of cash working capital on the basis of OMLPP shown on pages 43 through 45.) The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name".

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors". This process is illustrated in Figure 2 below.

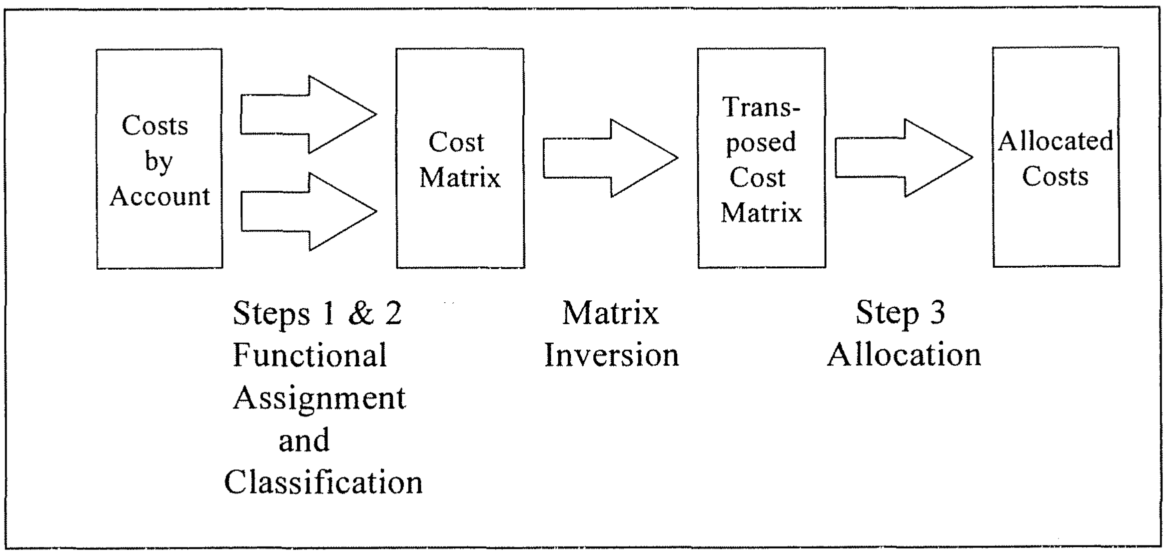


Figure 2

The results of the class allocation step of the cost of service study are included in Seelye Exhibit 24. The costs shown in the column labeled "Total System" in Seelye Exhibit 24 were carried forward *from* the functionally assigned and classified costs shown in Seelye Exhibit 23. The column labeled "Ref" in Seelye Exhibit 24 provides a reference to the results included in Seelye Exhibit 23.

Q. What methodologies are commonly used to classify distribution plant?

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero-intercept" methodology. In the minimum system approach, "minimum" standard poles, conductor, and line transformers are selected and the minimum system is obtained by pricing all of the applicable distribution facilities at the unit cost of the minimum size plant. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system.

In preparing this study, the "zero-intercept" methodology was used to determine the customer components of overhead conductor, underground conductor, and line transformers. Because the zero-intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is strongly preferred over the minimum system methodology when the necessary data is available. With the zero-intercept methodology, we are not forced to choose a minimum size conductor or line transformer to determine the customer component. In the zero-intercept methodology, a zero-size conductor or line transformer is the absolute minimum system.

Q. What is the theory behind the zero-intercept methodology?

A. The theory behind the zero-intercept methodology is that there is a linear relationship between the unit cost ($/ft or $/transformer) of conductor or line transformers and the load flow capability of the plant, which is proportionate to the cross-sectional area of the conductor or the kVA rating of the transformer. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the conductor or transformer,

x is the size of the conductor (MCM) or transformer (kVA), and

a, **b** are the coefficients representing the intercept and slope, respectively

it can be determined that, theoretically, the unit cost of a foot of conductor or transformer with zero size (or conductor or transformer with zero load carrying capability) is **a**, the zero-intercept. The zero-intercept is essentially the cost component of conductor or transformers that is invariant to the size (and load carrying capability) of the plant.

Like most electric utilities, the feet of conductor and number of transformers on LG&E's system is not uniformly distributed over all sizes of wire and transformer. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Without performing a weighted regression analysis all types of conductor and transformers would have the same impact on the analyses, even though the quantity of conductor and transformers are not the same for each size and type.

Using a weighted regression analysis, the cost and size of each type of conductor or transformer is, in effect, weighted by the number of feet of installed conductor or the number of transformers. In a weighted regression analysis, the following weighted sum of squared differences

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

is minimized, where **w** is the weighting factor for each size of conductor or transformer, and **y** is the observed value and $\hat{\mathbf{y}}$ is the predicted value of the dependent variable.

Q. Has the Commission accepted the use of the zero-intercept methodology?

A. Yes. The Commission found LG&E's cost of service studies (both electric and gas) submitted in Case No. 2000-080 and Case No. 90-158 to be reasonable, thus providing a means of measuring class rates of return and suitable for use as a guide in developing appropriate revenue allocations and rate design. The Commission also found the embedded cost of service study submitted by The Union Light Heat and Power in Case No. 2001-00092, which utilized a zero-intercept methodology, to be reasonable.

Q. Have you prepared exhibits showing the results of the zero-intercept analysis?

A. Yes. The zero-intercept analysis for overhead conductor, underground conductor, and line transformers are included in Seelye Exhibits 25, 26, and 27.

Q. Please summarize the results of the electric cost of service study.

A. The following table (Table 1) summarizes the rates of return for each customer class before and after reflecting the rate adjustments proposed by LG&E. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the pro-forma adjustments discussed in Mr. Rives' testimony. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 1 Electric Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return**
Residential Rate - RS	3.19%	5.86%
General Service - GS	9.12%	12.62%
Power Service - PS		
- Primary	4.86%	8.47%
- Secondary	6.62%	10.13%
Commercial Time of Day		
-Commercial TOD Secondary - CTODS	4.42%	8.00%
-Commercial TOD Primary - CTODP	4.47%	8.72%
Industrial Time of Day		
- Industrial TOD Secondary - ITODS	5.27%	9.28%
- Industrial TOD Primary - ITODP	3.31%	6.97%
Retail Transmission Service - RTS	2.91%	6.53%
Lighting	8.80%	11.17%
Special Contracts	-0.19%	2.51%
Total System	4.77%	7.89%

Determination of the actual adjusted and proposed rates of return are detailed in Seelye Exhibit 24, pages 49-51 and pages 55-57, respectively.

VIII. NATURAL GAS COST OF SERVICE STUDY

Q. Did you prepare a cost of service study for LG&E's gas operations based on financial and operating results for the 12 months ended October 31, 2009?

A. Yes. I supervised and participated in the preparation of a fully allocated, time-differentiated, embedded cost of service study for gas operations for the 12 months ended October 31, 2009, based on LG&E's accounting costs per books, adjusted for known and measurable changes to test year operating results. The cost of service study corresponds to the pro-forma financial exhibits included in the testimony of Mr.

Rives. As with the electric cost of service study, the objective in performing the gas cost of service study is to determine the rate of return on rate base that LG&E is earning from each customer class, which provides an indication as to whether LG&E's gas service rates reflect the cost of providing service to each customer class.

Q. Generally, were the procedures used in performing the gas cost of service study the same as those that you described above for the electric cost of service study?

A. Yes, with the exception that the study was not time differentiated. The cost of service study was 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; and then (3) costs were allocated to LG&E's rate classes. These steps are depicted in the following diagram (Figure 3). This is a standard approach utilized in the preparation of embedded cost of service studies for gas utilities.

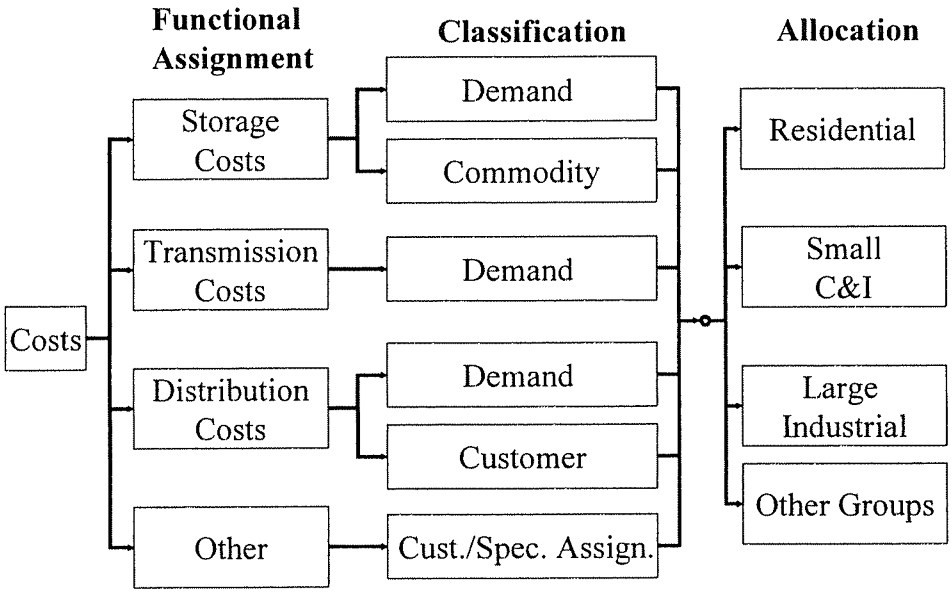


Figure 3

Q. What functional groups were used in the natural gas cost of service study?

A. The following standard functional groups were identified in the cost of service study: (1) Procurement, (2) Storage, (3) Transmission, (4) Distribution Commodity, (5) Distribution Structures and Equipment, (6) Distribution Mains – Low- and Medium-Pressure, (7) Distribution Mains – High-Pressure, (8) Services, (9) Meters, (10) Customer Accounts, and (11) Customer Service Expense.

Q. How were costs classified as commodity related, demand related or customer related?

A. Classification provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. Costs classified as *commodity related* tend to vary with the quantity of gas delivered, such as gas supply and the operation of compressors. Since gas supply costs were removed from the cost of service study, it was not necessary to classify gas supply costs. Costs classified as *demand related* are costs related to facilities installed to meet design-day usage requirements. Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of gas purchased or the peak requirements of the customers. All transmission plant costs were classified as demand related and are allocated on the same basis as storage. Unlike other local gas distribution companies ("LDCs"), LG&E's transmission system is used primarily to get gas in and out of its gas storage fields. Distribution Structures and Equipment costs were classified as demand-related. As will be discussed later in my testimony, costs related to Distribution Mains were functionally assigned as either low and medium pressure mains or high-pressure mains and then classified as demand-related and customer-related using the zero-intercept methodology. Services, Meters, Customer Accounts, and Customer Service Expenses were classified as customer-related.

Q. Have you prepared an exhibit showing the results of the functional assignment and classification steps of the cost of service study?

A. Yes. Seelye Exhibit 28 shows the results of the first two steps of the natural gas cost of service study, functional assignment and classification.

Q. Please describe the allocation factors used in the gas cost of service study.

A. The following allocation factors were used in the gas cost of service study:

- **DEM01** is used to allocate procurement demand-related costs; these costs are the procurement-related expenses that are not recovered through LG&E's Gas Supply

Clause.

- **DEM02** is used to allocate Storage demand-related costs and represents a composite allocation based on extreme winter season requirements and design day demands. The class allocation factor is the sum of (a) the volumes (commodity) withdrawn from storage during the design winter season, and (b) the volumes needed in storage to meet the design-day demands. The calculation of this allocation factor is shown on Seelye Exhibit 30.

- **DEM03** is used to allocate Transmission demand-related costs and is allocated on the same basis as storage demand. Because LG&E's transmission lines are used primarily to either fill the storage fields or remove gas from storage, transmission demand-related costs are allocated on the same basis as storage demand-related costs.

- **DEM04** is used to allocate Distribution Structures and Equipment demand-related costs and represents maximum class demands determined at LG&E's -12° F design day mean temperature. These demands, which are shown in Seelye Exhibit 30, were calculated using base loads and temperature sensitive loads developed for the temperature normalization adjustment. The temperature normalization adjustment is discussed earlier in my testimony.

- **DEM05** is used to allocate the demand-related portion of the cost of high-pressure distribution mains and represents maximum class demands determined at the design day mean temperature of customers served at high-pressure or below. The high-pressure system consists of pipe pressured above 50 psi. All of the gas delivered into the low- and medium-pressure system must first pass through the high- pressure system. Consequently, all customers utilize the high-pressure system.

- **DEM05a** is used to allocate the demand-related portion of the cost of low and medium-pressure distribution mains and represents maximum class demands determined at the design day mean temperature of customers served at medium pressure or low-pressure. The low- and medium- pressure system consists of pipe pressured at 50 psi and below. The demands of customers served at high pressure are not included in the determination of this allocation factor. The low- and medium-pressure system is not used to provide distribution delivery service to customers served at high pressure.

- **COM01** is used to allocate commodity-related procurement expenses and represents annual throughput volumes (including both sales and transportation). Procurement expenses correspond to expenses incurred by LG&E's gas supply department (including labor), which are not recovered through the Gas Supply Clause. This department not only purchases gas for sales customers but also administers LG&E's transportation service schedules.

- **COM02** is used to allocate Storage commodity-related costs and represents actual customer class deliveries during the winter withdrawal season (defined as the months of November through March.)

- **COM03** is used to allocate Transmission commodity-related costs and represents actual customer class deliveries during the winter withdrawal season (defined as the months of November through March).

- **COM04** is used to allocate Distribution commodity-related costs and represents annual throughput volumes (including both sales and transportation).

- **CUST01** is used to allocate the customer-related portion of LG&E's high-pressure distribution mains and represents the year-end number of customers served at high pressure and below.

- **CUST01a** is used to allocate the customer-related portion of LG&E's low and medium pressure distribution mains and represents the year-end number of customers at low and medium pressure. The customers served at high pressure are not included in the determination of this allocation factor. The low- and medium-pressure system is not used to provide distribution delivery service to customers served at high pressure.

- **CUST02** is used to allocate Services and is based on the total estimated cost of installing a service line per customer in each customer class weighted by the year-end number of customers in each class.

- **CUST03** is used to allocate Meters and is based on the total cost of meters and meter installation costs per customer in each customer class weighted by the year-end number of customers in each class.

- **CUST04** is used to allocate customer accounts expenses (Accounts 901 through 905) and represents a composite allocation factor.[4]

- **CUST05** is used to allocate customer service expenses using the same customer-weighting factor used to allocate Accounts 901, 902, 903, and 905 as in the calculation of CUST04.

Q. Did you classify the costs of mains between demand and customer costs?

A. Yes. Mains were classified using the zero-intercept methodology, which was described above in connection with the electric cost of service study. The zero-intercept analysis is included in Seelye Exhibit 31.

Q. How were distribution mains functionally separated between high pressure and low and medium pressure categories?

A. The feet of high-pressure mains by size of pipe were identified from LG&E's maps and records. The feet of low- and medium-pressure pipe were determined residually by subtracting the specifically identified high-pressure mains from the total feet for each pipe size. The zero-intercept unit cost of $4.37 was then applied to the high-pressure mains and to the low and medium pressure mains to determine the customer-related portion of the mains.[5] By identifying high-pressure mains from LG&E's

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[4] This allocation factor is determined as follows: First, customer accounts supervision (Account 901), meter reading (Account 902), customer records and collections (Account 903), and miscellaneous customer account expenses (Account 905) were allocated to each customer class using a customer weighting factor based on discussions with LG&E's meter reading, billing and customer service departments. A cost weighting factor of 1.0 was utilized for Residential Gas Service, a cost weighting factor of 1.1 was utilized for Commercial Gas Service, a cost weighting factor of 10 was utilized for Industrial Gas Service, Rate AAGS, and a customer weighting factor of 20 was utilized for Firm Transportation Service Rate FT and special contracts. Using a cost weighting factor of 20 for Rate FT and special contracts, for example, means that the cost of performing the meter reading, billing and customer service functions for customers served under Rate FT is 20 times more than the cost of performing these same services for customers served under Rate RGS.

[5] The cost of service study used the zero intercept results from the detailed analysis that was performed based on plant records as of April 30, 2008.

maps and records, it was determined that LG&E's high-pressure distribution mains represent 12.52% of the total installed cost, with 0.87% corresponding to customer related costs and 11.65% corresponding to demand related costs. The low- and medium-pressure pipe comprises the remaining 87.48% of installed cost, with 12.96% classified as customer related and 74.52% classified as demand related. The breakdown is shown on page 3 of Seelye Exhibit 31.

Q. **Was a similar separation made in the electric cost of service study?**

A. Yes. The electric cost of service study separates distribution conductor between primary voltage conductor and secondary voltage conductor. The functional separation in the gas cost of service study between high-pressure and low- and medium-pressure pipe is analogous to the primary and secondary splits determined in the electric cost of service study. Differences in the pressure in a pipe are often used as an analogy to differences in voltages.

Q. **Please summarize the results of the gas cost of service study.**

A. The following table (Table 2) summarizes the rates of return on net cost rate base for natural gas service for each customer class before and after reflecting the rate adjustments proposed by LG&E. The rates of return shown in Table 2 can be found on pages 12-13 of Seelye Exhibit 29. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the pro-forma adjustments discussed in Mr. Rives' testimony. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 2 Gas Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return**
Residential - RGS	3.90%	6.82%
Commercial - CGS	7.01%	10.01%
Industrial - IGS	4.36%	7.12%
As-Available Service - AAGS	16.85%	17.01%
Firm Transportation Service - FT	25.71%	25.90%
Special Contracts	25.05%	25.25%
Total System	5.06%	7.95%

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

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

The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is a Principal and Senior Analyst with The Prime Group, LLC, that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

W. Steven Seelye
William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 26th day of January 2010.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

Seelye Exhibit 1

Qualifications

QUALIFICATIONS OF WILLIAM STEVEN SEELYE

Summary of Qualifications

Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base.

Employment

Senior Consultant and Principal
The Prime Group, LLC
(July 1996 to Present)

Provides consulting services in the areas of tariff development, regulatory analysis revenue requirements, cost of service, rate design, fuel and power procurement, depreciation studies, lead-lag studies, and mathematical modeling.

Assists utilities with developing strategic marketing plans and implementation of those plans. Provides utility clients assistance regarding regulatory policy and strategy; project management support for utilities involved in complex regulatory proceedings; process audits; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus of rate alternatives for use with customers; performance-based rate development.

Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for numerous of electric and gas utilities. Performed cost of service or rate studies for over 130 utilities throughout North America. Prepared market power analyses in support of market-based rate filings submitted to the FERC for utilities and their marketing affiliates. Performed business practice audits for electric utilities, gas utilities, and independent transmission organizations (ISOs), including audits of production cost modeling, retail utility tariffs, retail utility billing practices, and ISO billing processes and procedures.

Manager of Rates and Other Positions Louisville Gas & Electric Co. (May 1979 to July 1996)	Held various positions in the Rate Department of LG&E. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

Education

Bachelor of Science Degree in Mathematics, University of Louisville, 1979
54 Hours of Graduate Level Course Work in Industrial Engineering and Physics.

Associations

Member of the Society for Industrial and Applied Mathematics

Expert Witness Testimony

Alabama: Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.

Colorado: Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.

FERC: Submitted direct and rebuttal testimony in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment.

Submitted direct and responsive testimony in Docket No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.

Submitted testimony in Docket Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.

Submitted testimony in Docket No. ER08-1468-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER08-1588-000 concerning a generation formula rate for Kentucky Utilities Company.

Submitted testimony in Docket No. ER09-180-000 concerning changes to Vectren Energy's transmission formula rate.

Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.

Illinois: Submitted direct, rebuttal, and surrebuttal testimony in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

Indiana: Submitted direct testimony and testimony in support of a settlement agreement in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Submitted direct and rebuttal testimony in Cause No. 43111 on behalf of Vectren Energy in support of a transmission cost recovery adjustment.

Submitted direct testimony in Cause No. 43773 on behalf of Crawfordsville Electric Light & Power regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Kansas: Submitted direct and rebuttal testimony in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.

Kentucky: Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings.

Submitted direct and rebuttal testimony in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates.

Submitted direct and rebuttal testimony in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan.

Submitted direct and rebuttal testimony in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments in connection with Delta's rate case.

Submitted direct and rebuttal testimony in Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses.

Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program.

Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings.

Submitted direct and rebuttal testimony in Case No. 2003-00433 on behalf of Louisville Gas and Electric Company and in Case No. 2003-00434 on behalf of Kentucky Utilities Company regarding pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design.

Submitted direct and rebuttal testimony in Case No. 2004-00067 on behalf of Delta Natural Gas Company regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design.

Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Testified on behalf of Delta Natural Gas Company in Case No. 2007-00089 concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony on behalf of Big Rivers Electric Corporation and E.ON U.S. LLC in Case No 2007-00455 and Case No. 2007-00460 regarding the design and implementation of a Fuel Adjustment Clause, Environmental Surcharge, Unwind Surcredit, Rebate Adjustment, and Member Rate Stability Mechanism for Big Rivers Electric Corporation in connection with the unwind of a lease and purchase power transaction with E.ON U.S. LLC.

Submitted testimony in Case No. 2008-00251 on behalf of Kentucky Utilities Company and in Case No. 2008-00252 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Submitted testimony in Case No. 2008-00409 on behalf of East Kentucky Power Cooperative, Inc., concerning revenue requirements, pro-forma adjustments, cost of service, and rate design.

	Submitted testimony in Case No. 2009-00040 on behalf of Big Rivers Electric Corporation regarding revenue requirements and rate design.
	Submitted testimony on behalf of Columbia Gas Company of Kentucky in Case No. 2009-00141 regarding the demand side management program costs and cost recovery mechanism.
Nevada:	Submitted direct and rebuttal testimony in Case No. 03-10001 on behalf of Nevada Power Company regarding cash working capital and rate base adjustments.
	Submitted direct and rebuttal testimony in Case No. 03-12002 on behalf of Sierra Pacific Power Company regarding cash working capital.
	Submitted direct and rebuttal testimony in Case No. 05-10003 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.
	Submitted direct and rebuttal testimony in Case No. 05-10005 on behalf of Sierra Pacific Power Company regarding cash working capital for a gas general rate case.
	Submitted direct and rebuttal testimony in Case Nos. 06-11022 and 06-11023 on behalf of Nevada Power Company regarding cash working capital for a gas general rate case.
	Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.
	Submitted direct testimony in Case No. Docket No. 08-12002 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.
Nova Scotia:	Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.
	Submitted testimony in NSUARB – NSPI – P-884 regarding Nova Scotia Power Company's application to approve a demand-side management plan and cost recovery mechanism.
	Submitted testimony in NSUARB – NSPI – P-888 regarding a general rate application filed by Nova Scotia Power Company.

Submitted testimony on behalf of Nova Scotia Power Company in the matter of the approval of backup, top-up and spill service for use in the Wholesale Open Access Market in Nova Scotia.

Submitted testimony in NSUARB – NSPI – P-884 (2) on behalf of Nova Scotia Power Company's regarding a demand-side management cost recovery mechanism.

Virginia: Submitted testimony in Case No. PUE-2008-00076 on behalf of Northern Neck Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00029 on behalf of Old Dominion Power Company regarding class cost of service, jurisdictional separation, allocation of the revenue increase, general rate design, time of use rates, and excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00065 on behalf of Craig-Botetourt Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Seelye Exhibit 2

Residential Electric Unit Cost

Louisville Gas and Electric Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended October 31, 2009

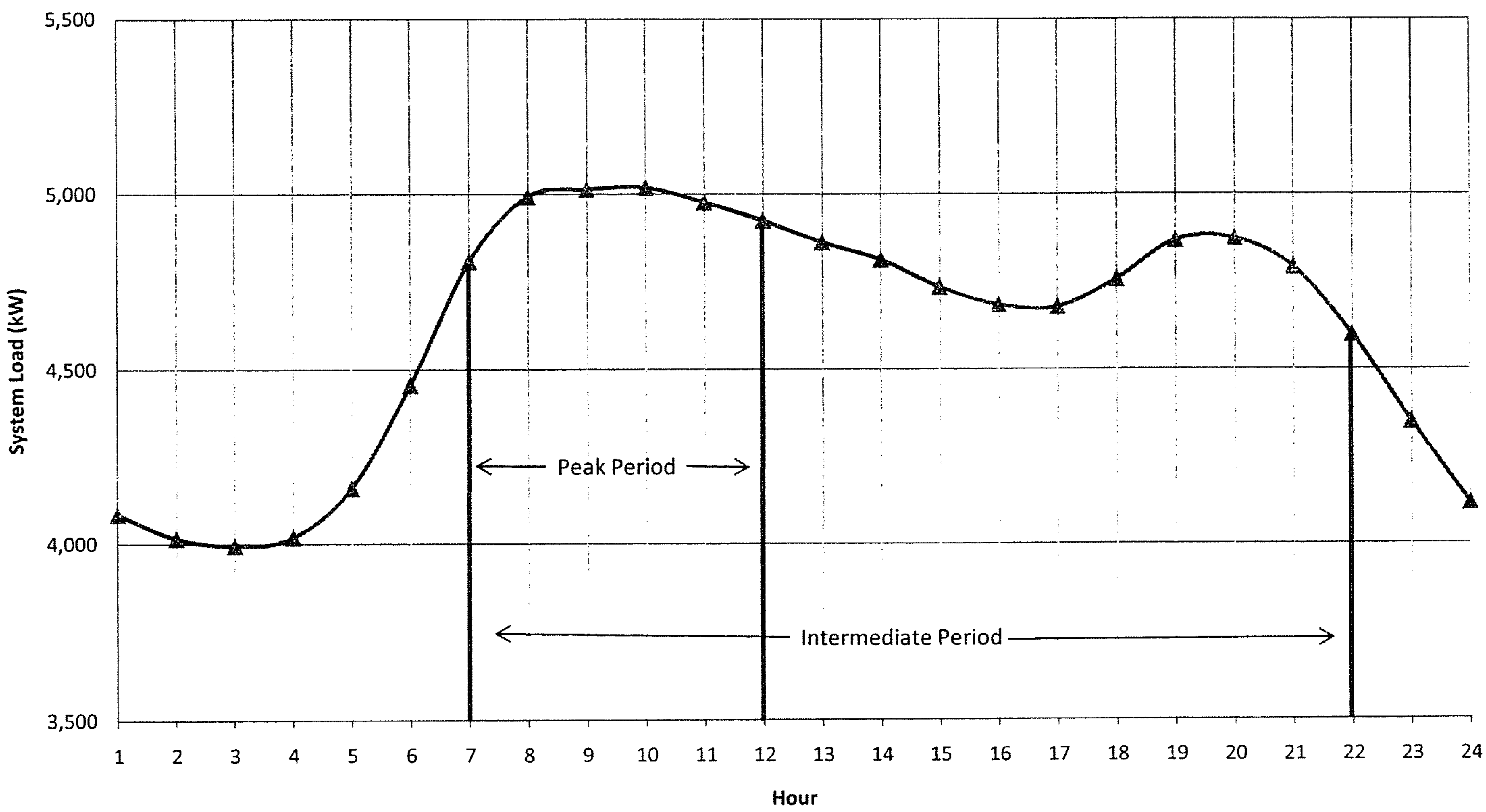
Rate RS

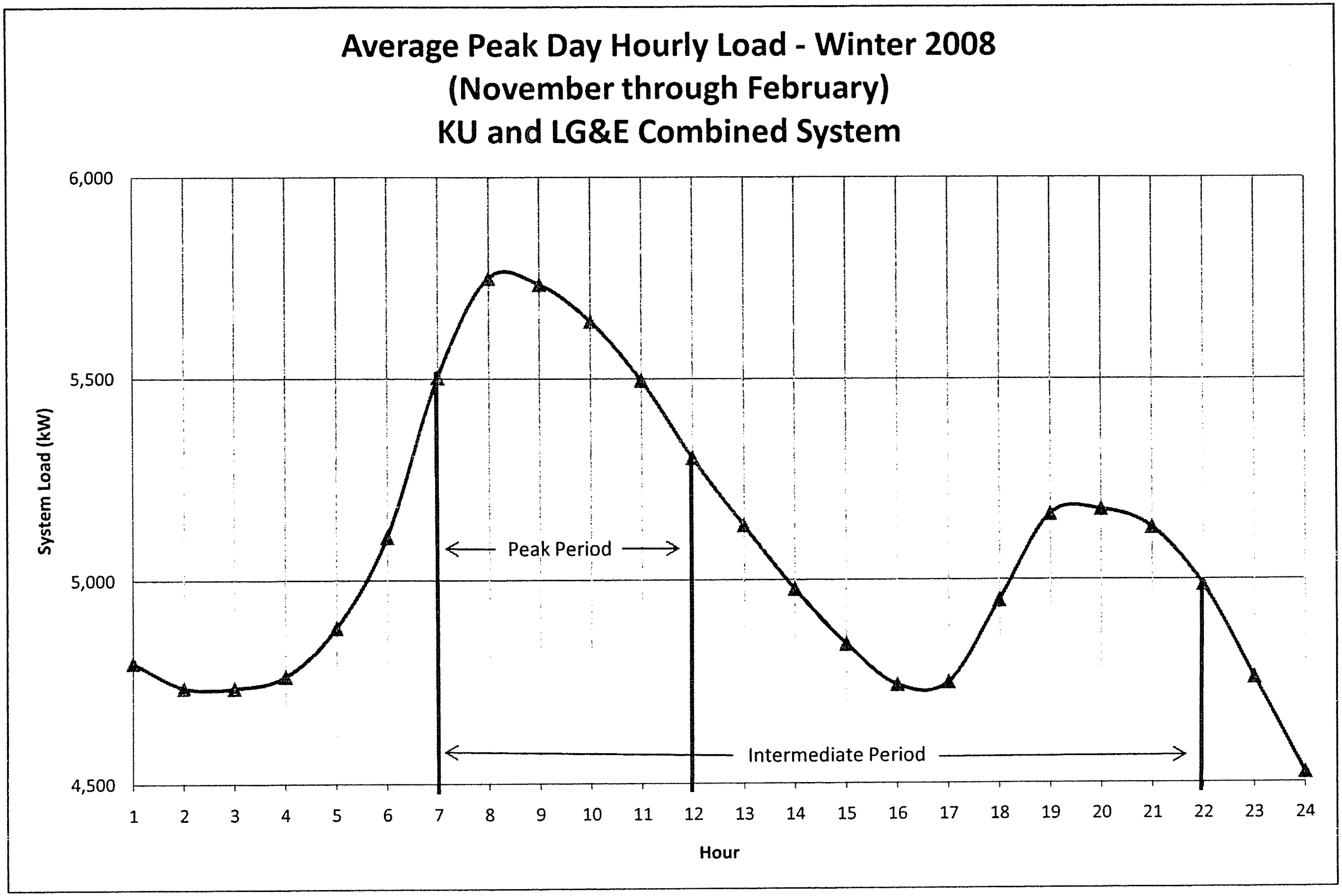
		Production		Transmission	Distribution		Customer Service Expenses	
Description	Amount	Demand-Related	Energy-Related	Demand-Related	Demand-Related	Customer-Related	Customer-Related	Total
(1) Rate Base	$ 870,969,477	$ 507,857,920	$ 18,062,787	$ 58,122,846	$ 120,557,614	$ 163,763,127	$ 2,605,183	$ 870,969,477
(2) Rate Base Adjustments	144,530	84,275	2,997	9,645	20,005	27,175	432	$ 144,530
(3) Rate Base as Adjusted	$ 871,114,007	$ 507,942,194	$ 18,065,785	$ 58,132,491	$ 120,577,619	$ 163,790,302	$ 2,605,615	$ 871,114,007
(4) Rate of Return	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	
(5) Return	$ 51,032,393	$ 29,756,731	$ 1,058,346	$ 3,405,570	$ 7,063,788	$ 9,595,312	$ 152,645	$ 51,032,393
(6) Interest Expenses	$ 22,249,565	$ 12,973,609	$ 461,427	$ 1,484,791	$ 3,079,734	$ 4,183,451	$ 66,551	$ 22,249,565
(7) Net Income	$ 28,782,828	$ 16,783,122	$ 596,919	$ 1,920,779	$ 3,984,054	$ 5,411,861	$ 86,093	$ 28,782,828
(8) Income Taxes	$ 15,474,088	$ 9,022,863	$ 320,913	$ 1,032,640	$ 2,141,888	$ 2,909,499	$ 46,285	$ 15,474,088
(9) Operation and Maintenance Expenses	$ 254,634,222	$ 45,815,866	$ 168,820,783	$ 6,748,185	$ 3,393,333	$ 9,743,783	$ 20,112,274	$ 254,634,222
(10) Depreciation Expenses	49,539,430	$ 32,180,564	$ -	$ 2,303,323	$ 6,398,586	$ 8,656,957	$ -	$ 49,539,430
(11) Other Taxes	9,250,895	$ 5,510,798	$ -	$ 642,777	$ 1,316,357	$ 1,780,963	$ -	$ 9,250,895
(12) Other Depreciation Expenses	2,654,297	$ 1,547,707	$ 55,047	$ 177,131	$ 367,402	$ 499,071	$ 7,939	$ 2,654,297
(13) Curtailable Service Credit	1,148,660	$ 1,148,660	$ -	$ -	$ -	$ -	$ -	$ 1,148,660
(14) Expense Adjustments - Prod. Demand	(5,819,952)	$ (5,819,952)	$ -	$ -	$ -	$ -	$ -	$ (5,819,952)
(15) Expense Adjustments - Energy	(8,082,786)	$ -	$ (8,082,786)	$ -	$ -	$ -	$ -	$ (8,082,786)
(16) Expense Adjustments - Trans. Demand	(238,477)	$ -	$ -	$ (238,477)	$ -	$ -	$ -	$ (238,477)
(17) Expense Adjustments - Distribution	24,965,730	$ -	$ -	$ -	$ 10,585,963	$ 14,379,767	$ -	$ 24,965,730
(18) Expense Adjustments - Other	(2,647,822)	$ (1,543,931)	$ (54,912)	$ (176,698)	$ (366,505)	$ (497,854)	$ (7,920)	$ (2,647,822)
(19) Expense Adjustments - Total	$ 8,176,694	$ (7,363,883)	$ (8,137,698)	$ (415,175)	$ 10,219,458	$ 13,881,913	$ (7,920)	$ 8,176,694
(20) Total Cost of Service	$ 391,910,678	$ 117,619,305	$ 162,117,390	$ 13,894,450	$ 30,900,811	$ 47,067,499	$ 20,311,222	$ 391,910,678
(21) Less: Misc Revenue - Energy	$ (3,667,120)	$ -	$ (3,667,120)	$ -	$ -	$ -	$ -	$ (3,667,120)
(22) Less: Misc Revenue - Other	(70,426,642)	$ (67,174,408)	$ (161,781)	$ (520,581)	$ (1,079,783)	$ (1,466,756)	$ (23,334)	$ (70,426,642)
(23) Less: Misc Revenue - Total	(74,093,762)	$ (67,174,408)	$ (3,828,901)	$ (520,581)	$ (1,079,783)	$ (1,466,756)	$ (23,334)	$ (74,093,762)
(24) Net Cost of Service	$ 317,816,916	$ 50,444,897	$ 158,288,490	$ 13,373,869	$ 29,821,028	$ 45,600,743	$ 20,287,889	$ 317,816,916
(25) Billing Units		4,099,843,486	4,099,843,486	4,099,843,486	4,099,843,486	4,170,876	4,170,876	
(26) Unit Costs		$ 0.01230	$ 0.03861	$ 0.00326	$ 0.00727	$ 10.93	$ 4.86	$ 15.80

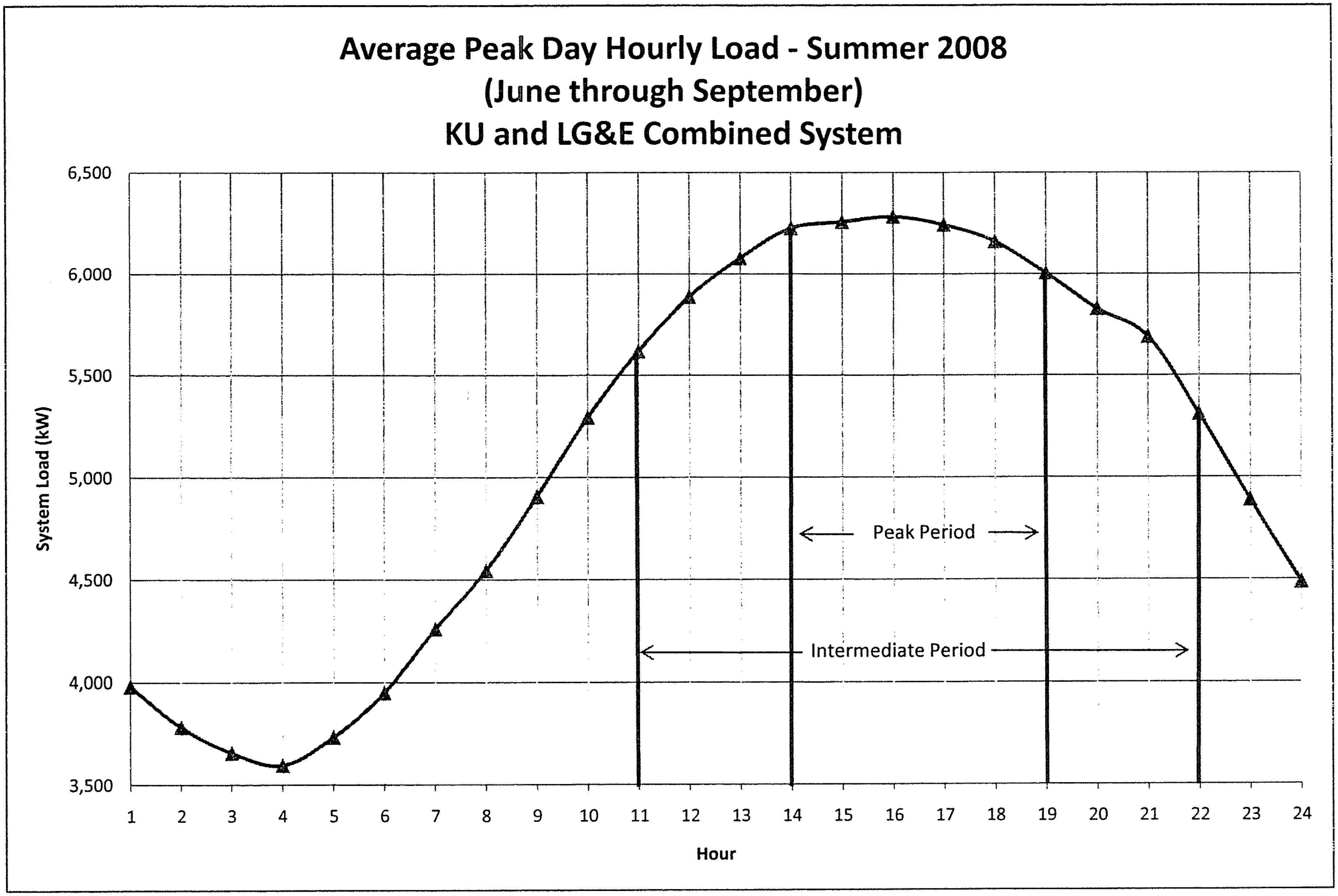
Seelye Exhibit 3

Time of Day Loads

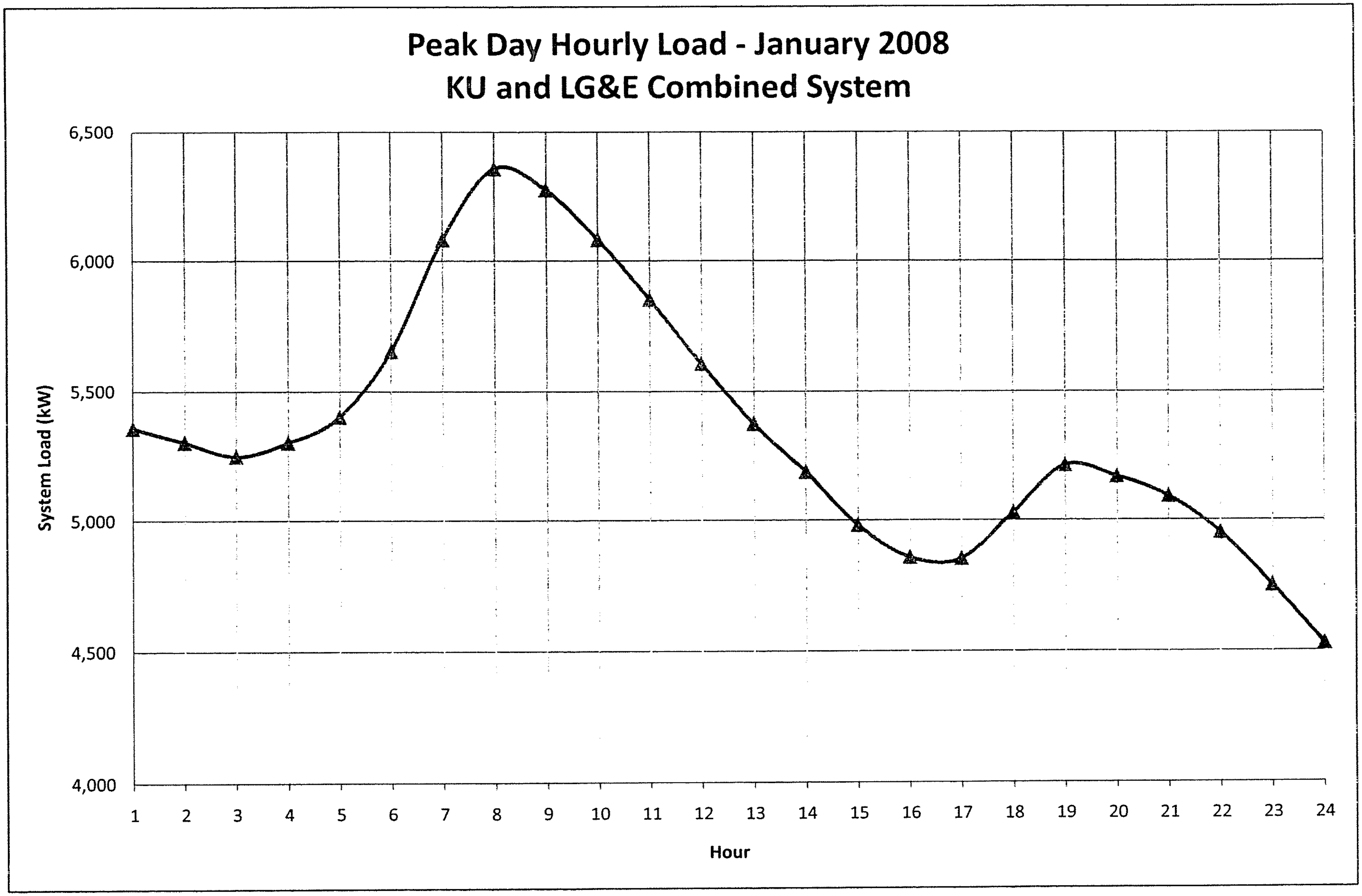
Average Peak Day Hourly Load - Non-Summer 2008
(October through May)
KU and LG&E Combined System

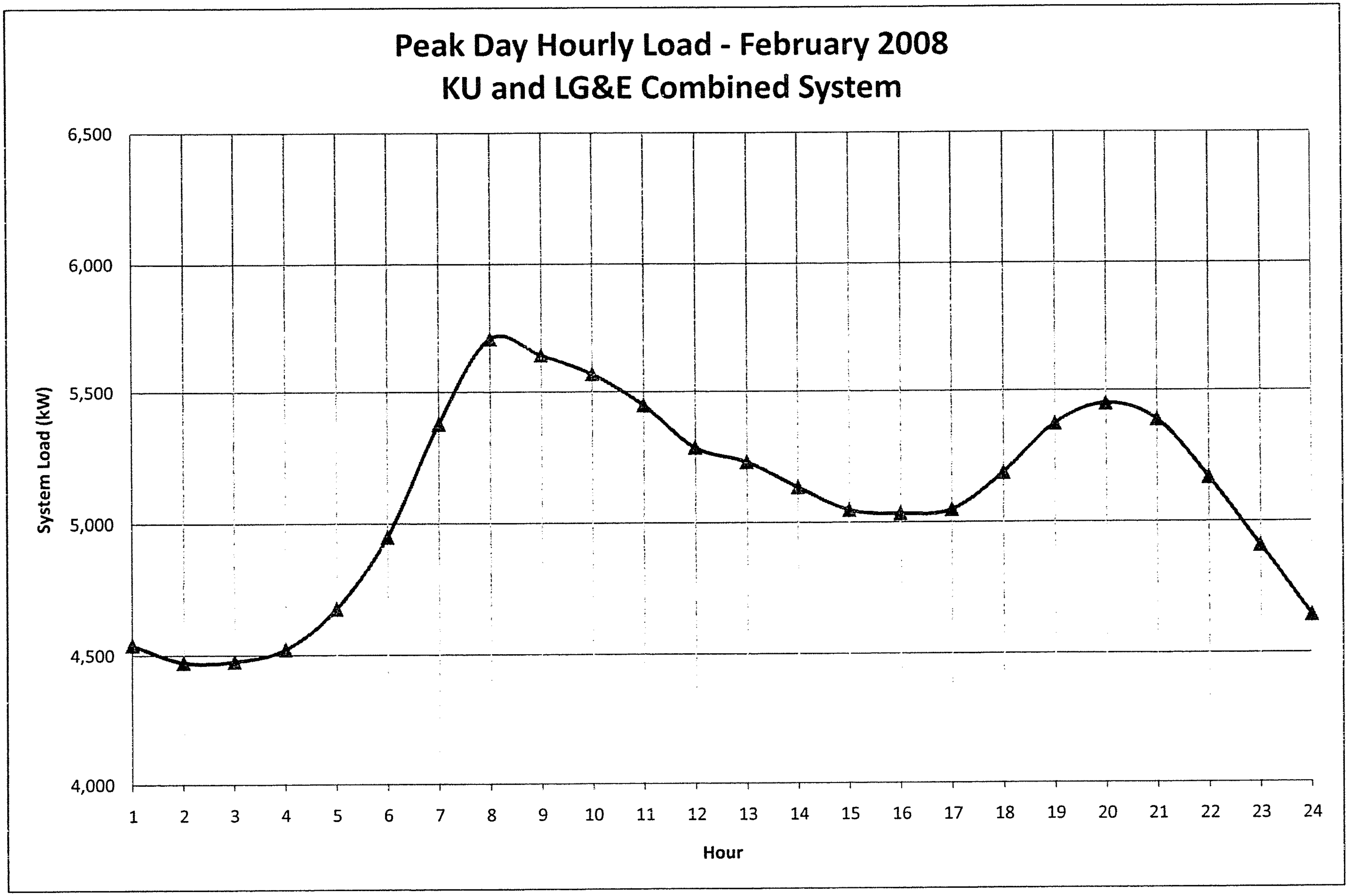



Average Peak Day Hourly Load - Winter 2008
(November through February)
KU and LG&E Combined System
6,000
5,500
5,000
4,500
System Load (kW)
Peak Period
Intermediate Period
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

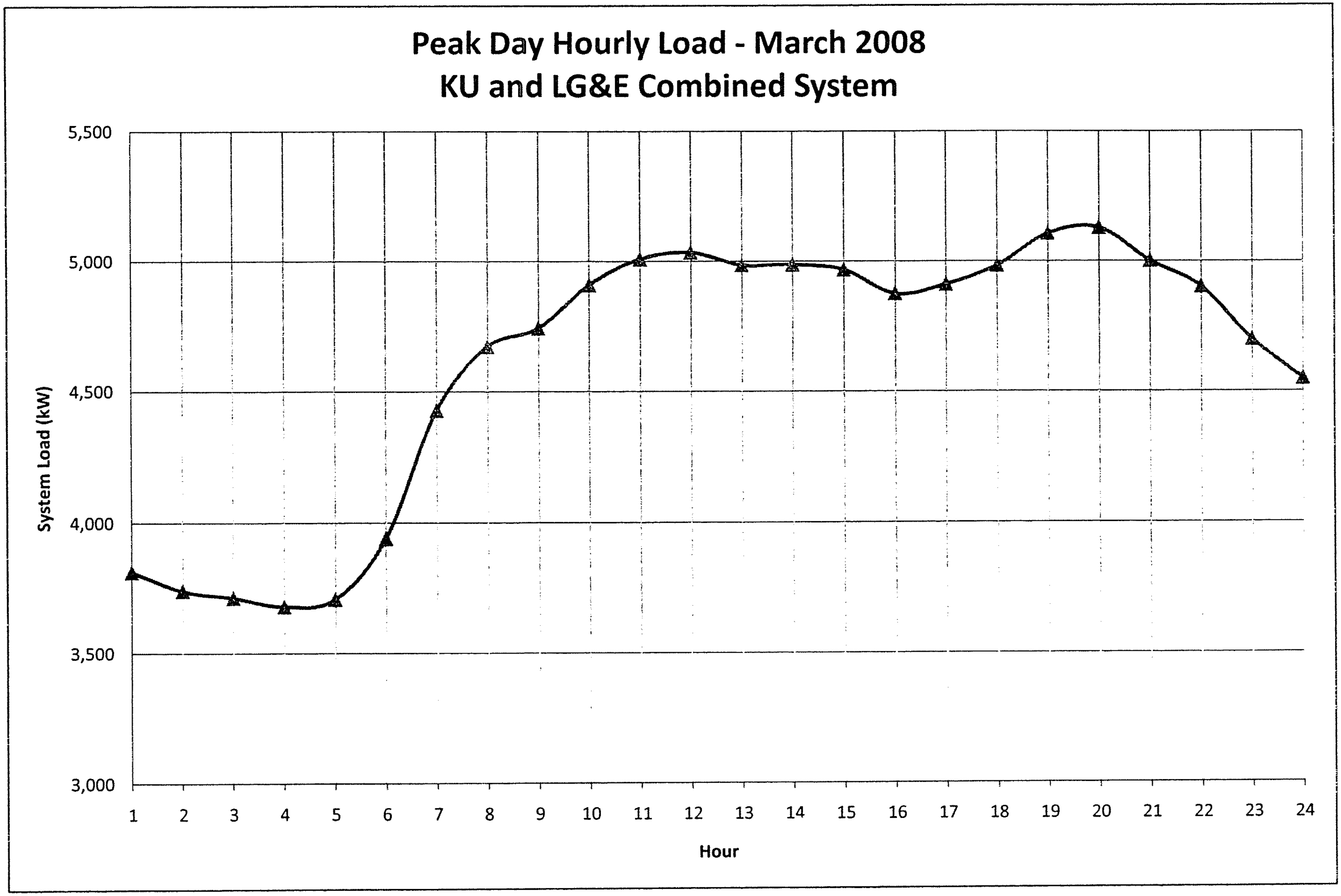


Seelye Exhibit 3
Page 3 of 15


Peak Day Hourly Load - January 2008
KU and LG&E Combined System
System Load (kW)
6,500
6,000
5,500
5,000
4,500
4,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour



Peak Day Hourly Load - February 2008
KU and LG&E Combined System
System Load (kW)
6,500
6,000
5,500
5,000
4,500
4,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


Peak Day Hourly Load - March 2008
KU and LG&E Combined System
System Load (kW)
5,500
5,000
4,500
4,000
3,500
3,000
1
2
3
4
5
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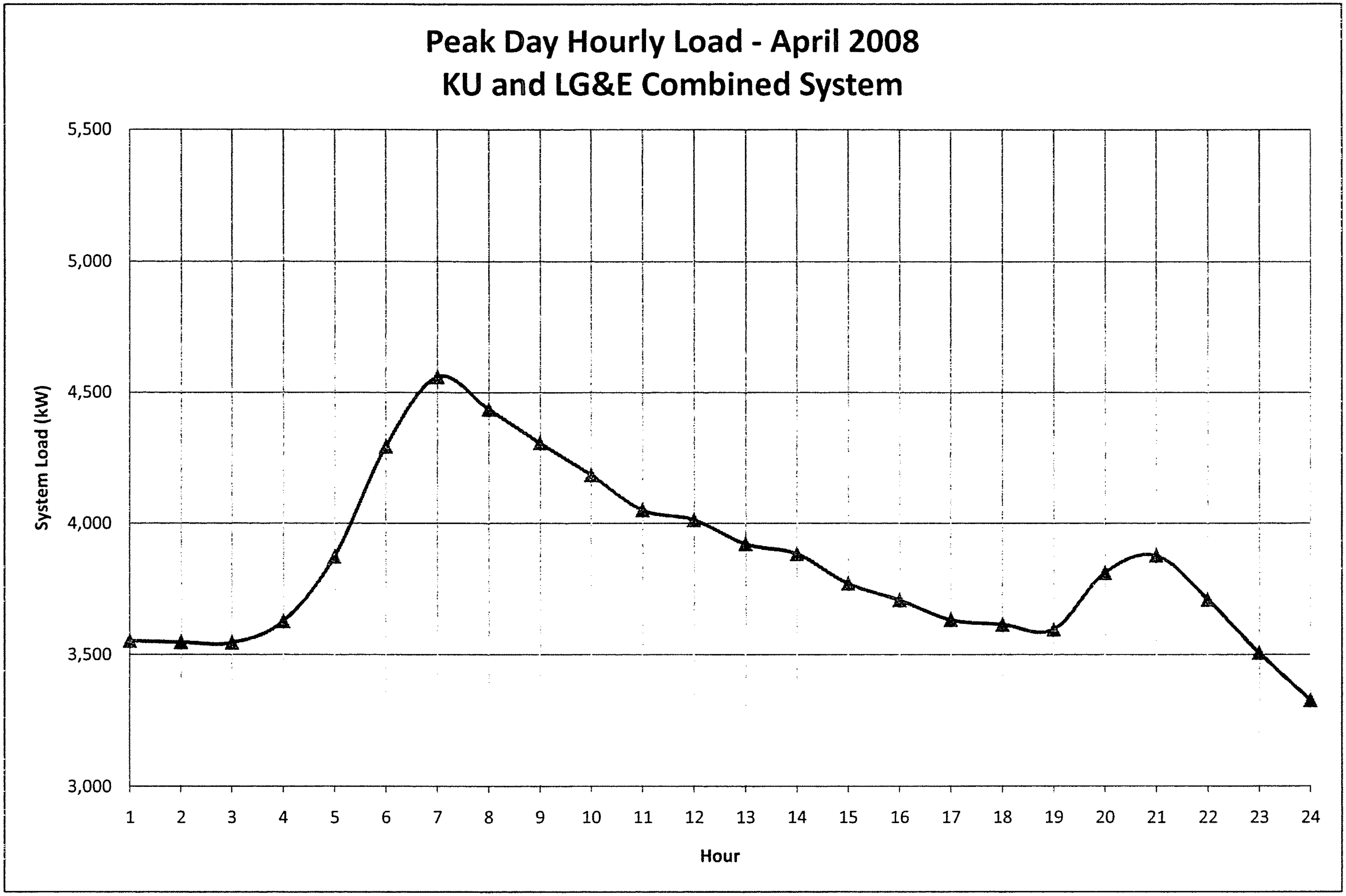
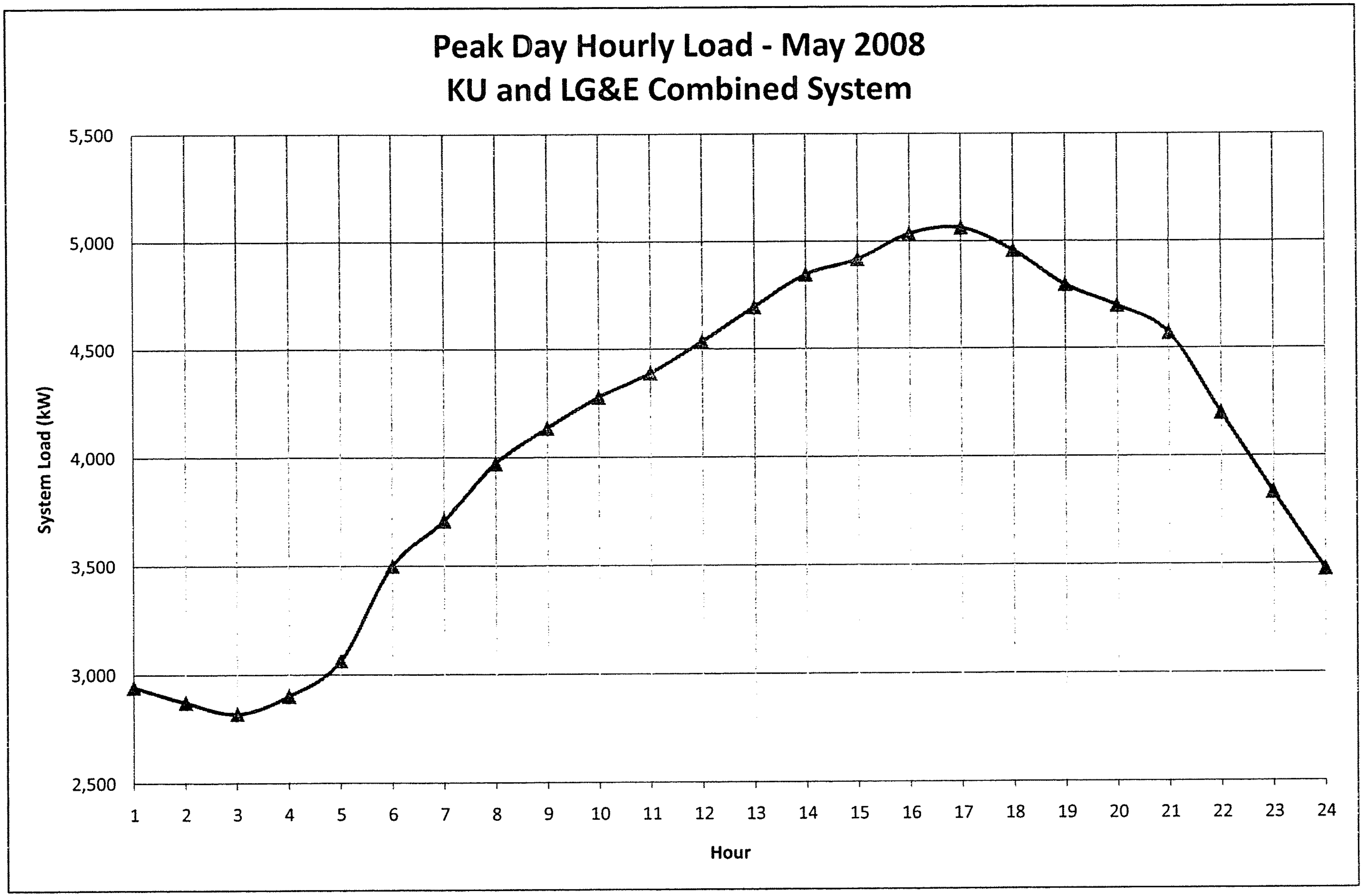
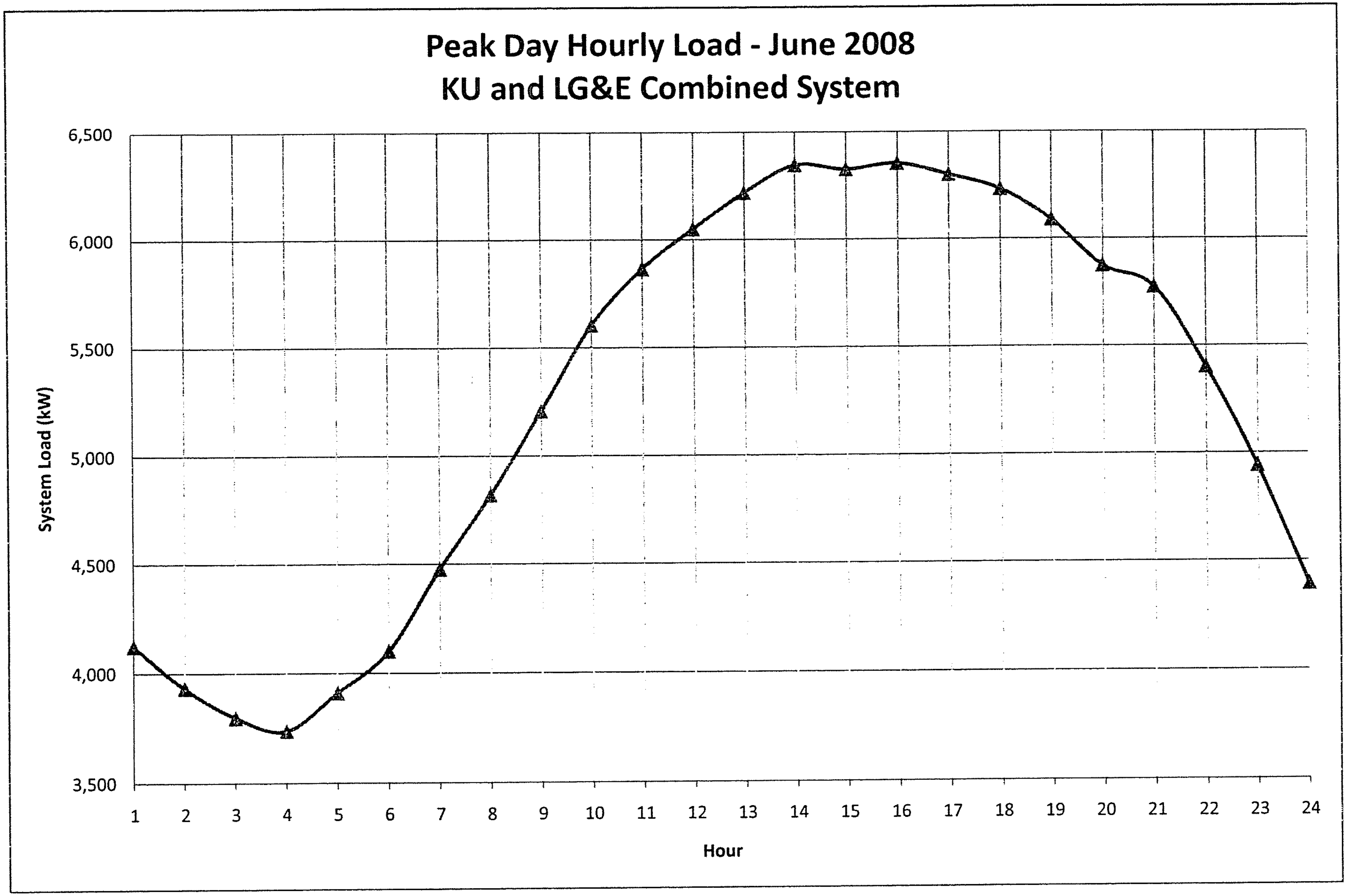
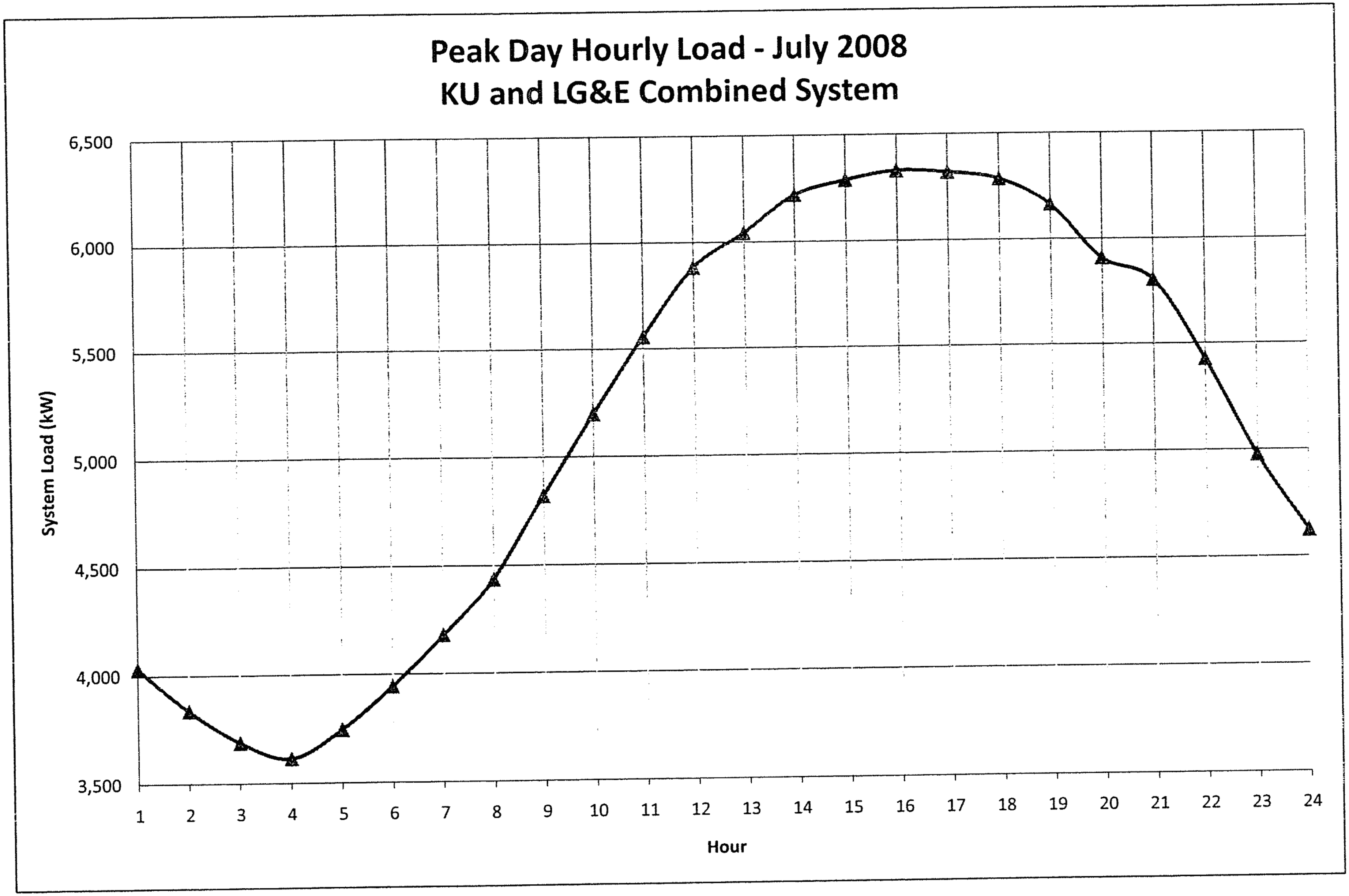
23
24
Hour


Peak Day Hourly Load - April 2008
KU and LG&E Combined System
5,500
5,000
4,500
4,000
3,500
3,000
System Load (kW)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour



Seelye Exhibit 3
Page 8 of 15


Peak Day Hourly Load - June 2008
KU and LG&E Combined System
6,500
6,000
5,500
5,000
4,500
4,000
3,500
System Load (kW)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


Peak Day Hourly Load - July 2008
KU and LG&E Combined System
System Load (kW)
6,500
6,000
5,500
5,000
4,500
4,000
3,500
1
2
3
4
5
6
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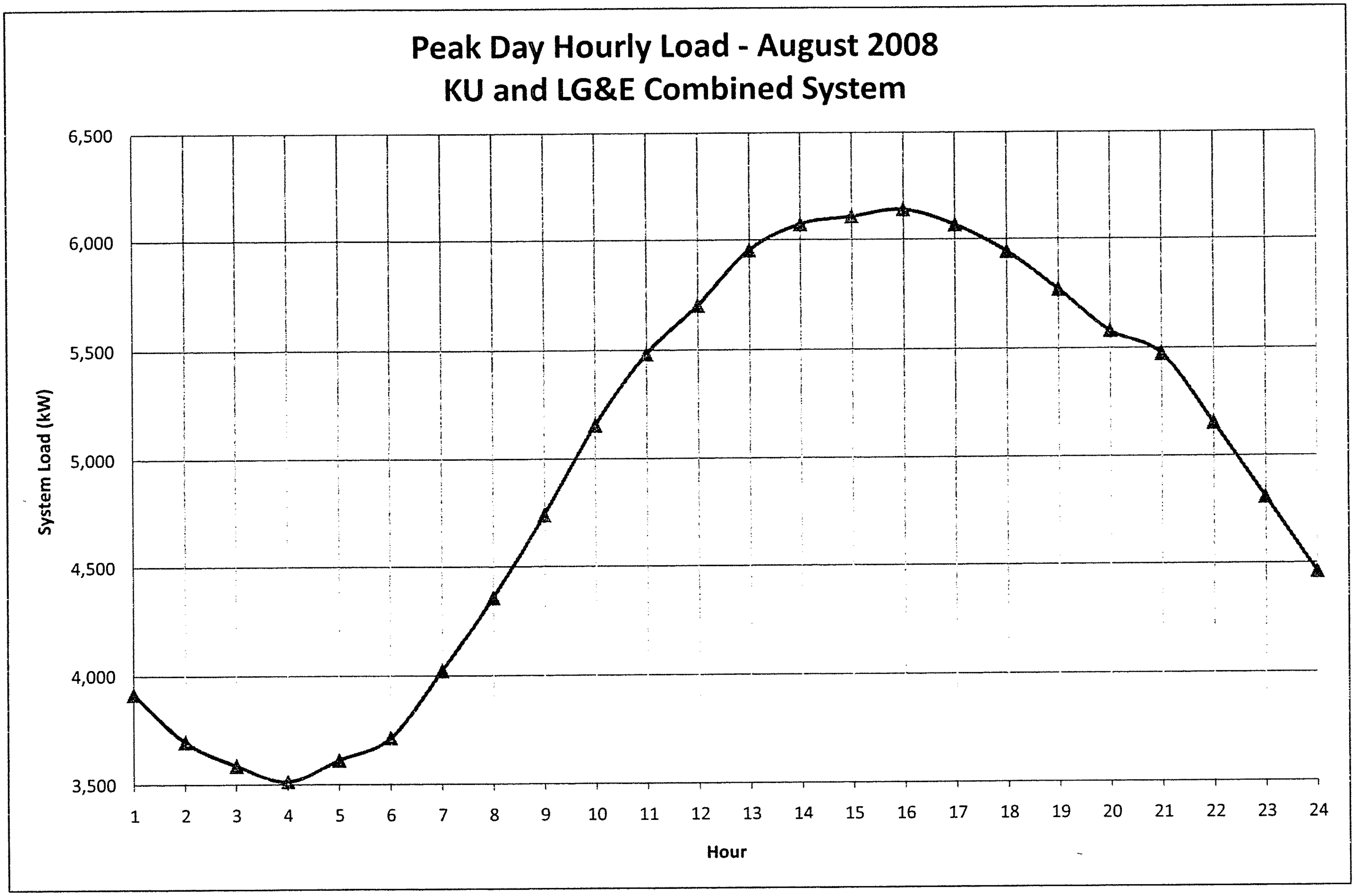
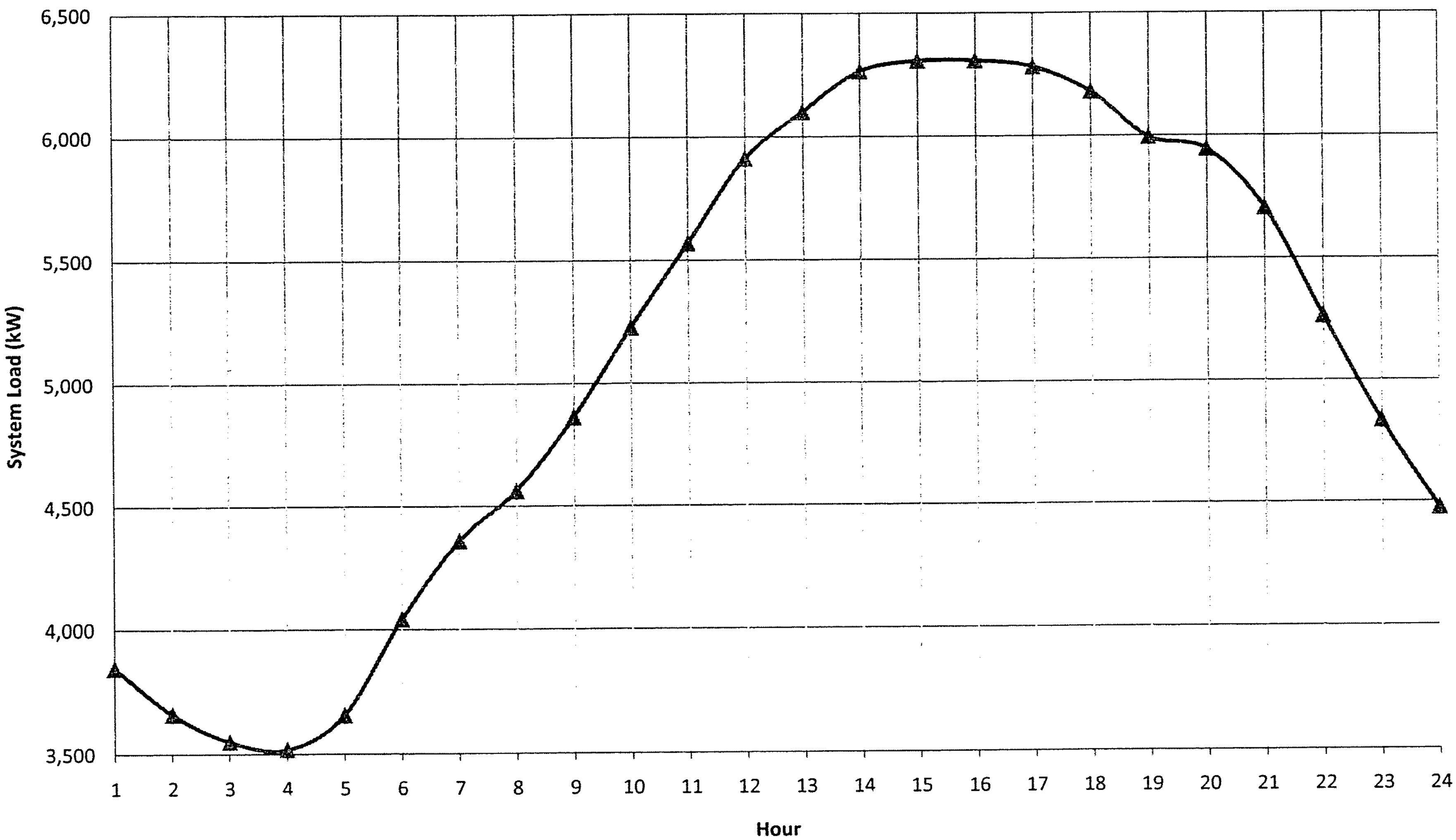
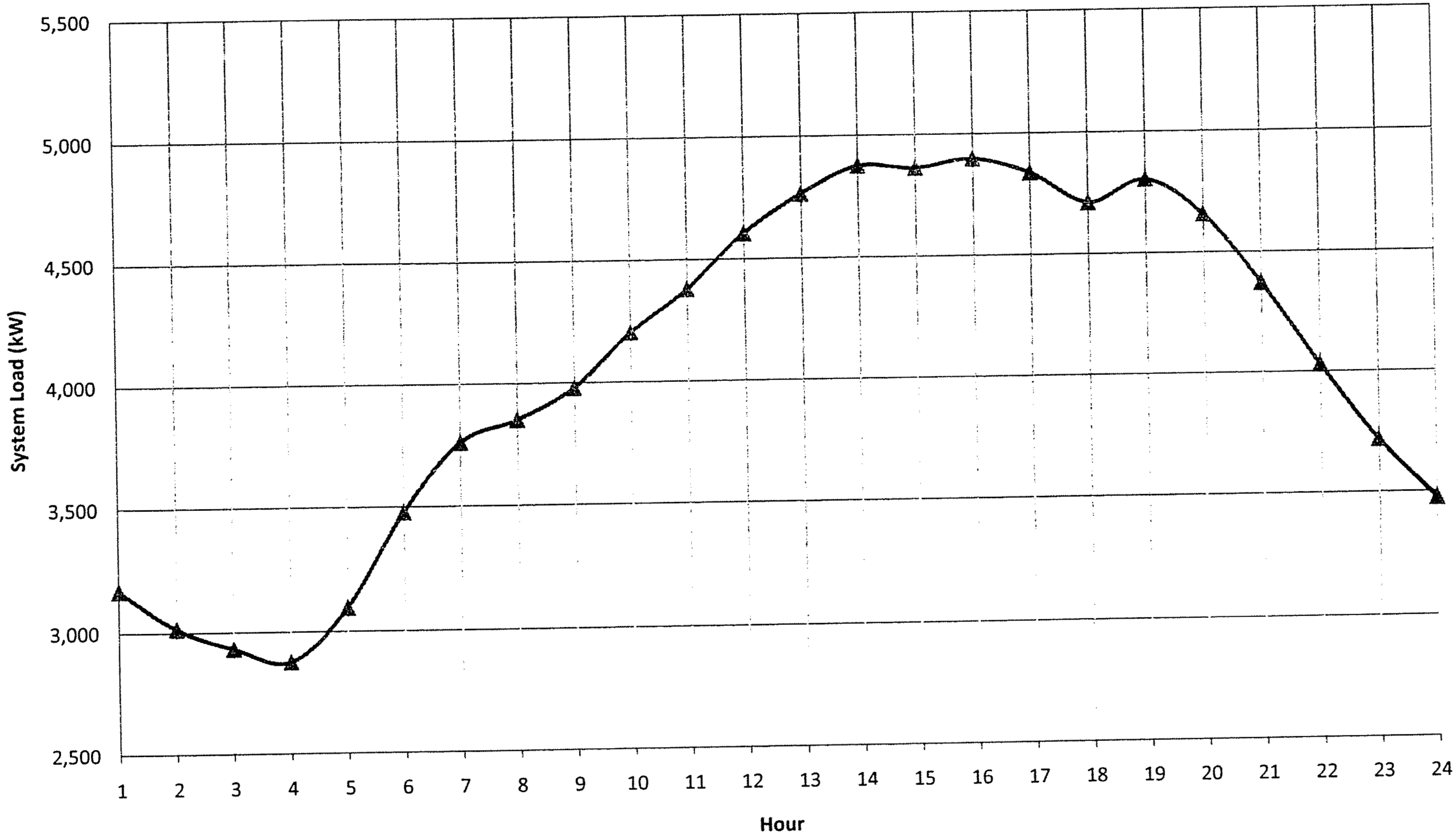
21
22
23
24
Hour

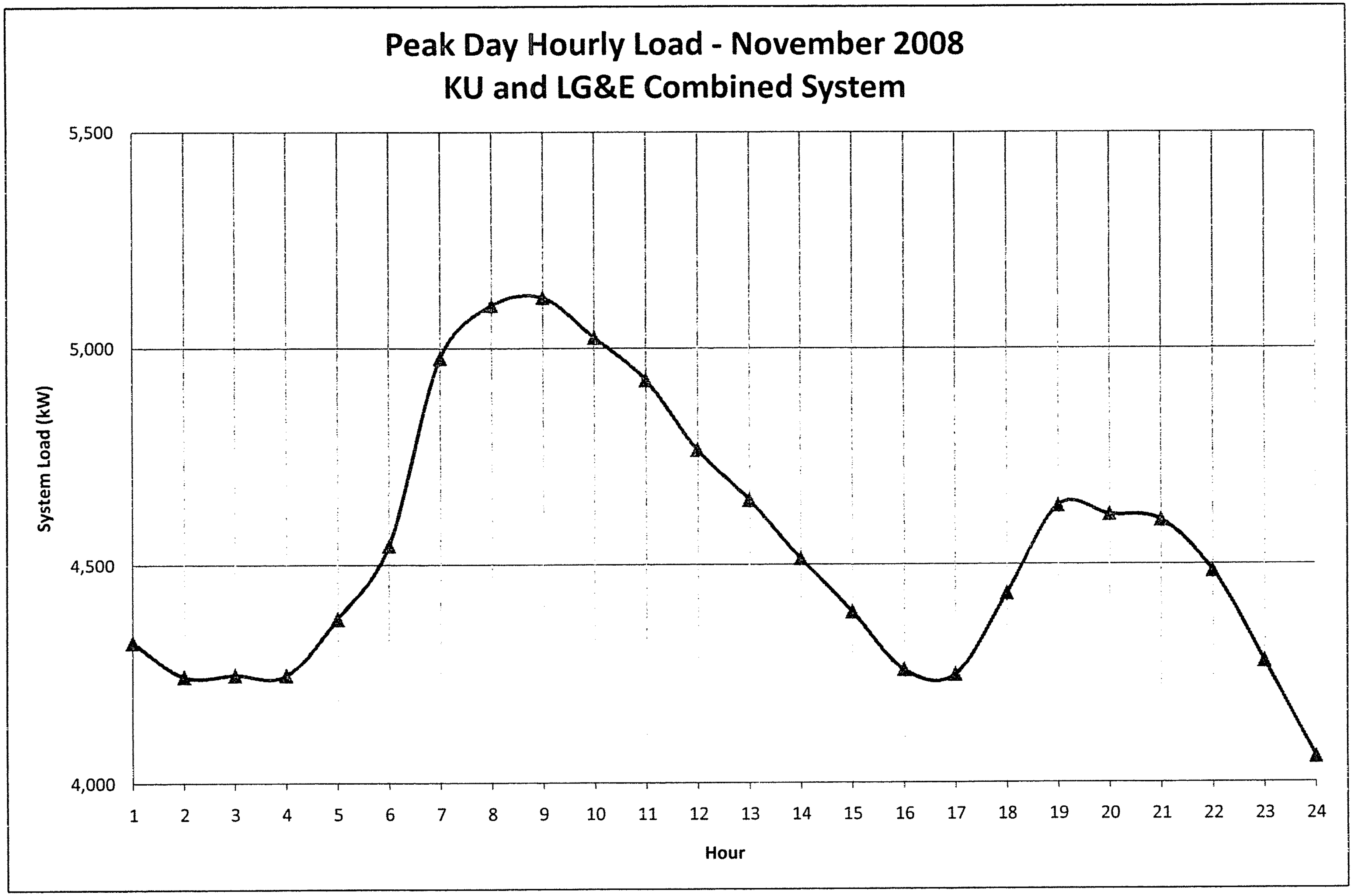

Peak Day Hourly Load - August 2008
KU and LG&E Combined System
System Load (kW)
6,500
6,000
5,500
5,000
4,500
4,000
3,500
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Peak Day Hourly Load - September 2008
KU and LG&E Combined System

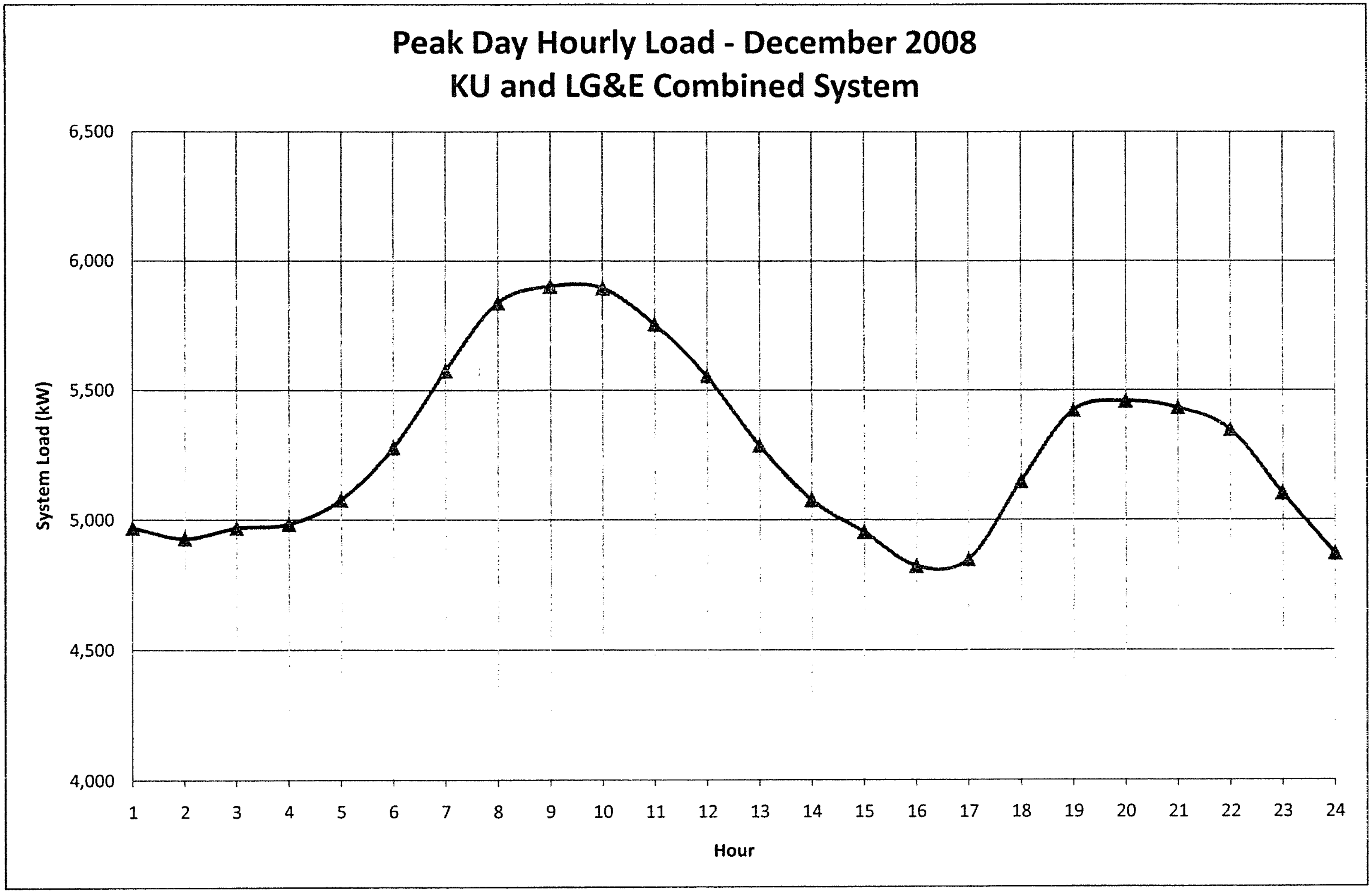


Peak Day Hourly Load - October 2008
KU and LG&E Combined System





Peak Day Hourly Load - November 2008
KU and LG&E Combined System
System Load (kW)
5,500
5,000
4,500
4,000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour



Peak Day Hourly Load - December 2008
KU and LG&E Combined System
System Load (kW)
6,500
6,000
5,500
5,000
4,500
4,000
1
2
3
4
5
6
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16
17
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19
20
21
22
23
24
Hour

Seelye Exhibit 4

Cost Support for New Lighting Rates

Louisville Gas and Electric Company
Cost Support for HPS Contemporary Fixture Only Charges

					HPS CONTEMPORARY FLOOD		
					170 Watt 16,000 Lumen Directional HPS fixture only	287 Watt 28,500 Lumen Directional HPS fixture only	463 Watt 50,000 Lumen Directional HPS fixture only
Estimated Investment per Unit					$785.01	$785.60	$787.43
Fixed Charges @ *	**17.52%**				$137.53	$137.63	$137.95
Energy per kwh **	POL =	$	0.04882	SYSTEM	$33.20	$56.05	$90.41
Operation and Maintenance					$12.35	$14.10	$14.10
Monthly Rate:					**$15.26**	**$17.31**	**$20.21**

Seelye Exhibit 5

Reconstruction of Electric Billing Determinants

Louisville Gas and Electric Company
Reconstruction of Test Year Revenues -- Summary
Twelve Months Ended October 31, 2009

	Revenue As Billed	FAC Billings	DSM Billings	STOD Billings	ECR Billings	Merger Surcredit Billings	CSR Billings	IB Billings	VDT Billings	Actual Net Revenue @ Base Rates	Calculated Net Revenue @ Base Rates	Calculated divided by Actual
Residential Rate												
Residential Service	$ 308,219,040	$ 11,446,903	$ 9,135,486	$ -	$ 3,332,445	$ (1,009,595)	$ -	$ -	$ -	$ 285,313,802	$ 284,842,125	0.998347
Residential Water Heating	858,863	39,316	27,954	-	9,091	(3,058)	-	-	-	785,560	785,331	0.999708
Residential Responsive Pricing	102,814	4,179	3,253	-	1,106	(343)	-	-	-	94,619	94,434	0.998040
Total Residential Service	309,180,717	11,490,398	9,166,692	-	3,342,642	(1,012,997)	-	-	-	286,193,981	285,721,889	0.998350
General Service												
General Service Single Phase	49,367,022	1,377,825	405,094	-	572,587	(105,780)	-	-	-	47,117,296	47,076,529	0.999135
General Service Space Heating	2,220,473	89,891	27,920	-	22,063	(9,971)	-	-	-	2,090,570	2,090,921	1.000168
General Service Water Heating	17,635	730	186	-	194	(47)	-	-	-	16,572	16,583	1.000713
General Service Responsive Pricing	1,059	24	5	-	12	0	-	-	-	1,017	1,018	1.000718
General Service Three Phase	61,561,265	2,678,914	679,489	-	643,665	(209,996)	-	-	(3)	57,769,196	57,727,893	0.999285
General Service Three Phase Primary (moved to rate IPP with P.S.C. 7	101,166	4,093	2,245	-	730	(1,484)	-	-	-	95,582	91,605	0.958395
Total General Service	113,268,618	4,151,478	1,114,940	-	1,239,251	(327,279)	-	-	(3)	107,090,231	107,004,550	0.999200
Large Commercial Rate												
Secondary	127,925,261	5,812,474	1,286,021	65,261	1,412,014	(374,684)	-	-	-	119,724,175	119,729,089	1.000041
Primary	9,731,497	509,549	110,998	5,687	108,592	(27,600)	-	-	-	9,024,272	9,023,424	0.999906
Large Commercial Time of Day Rate												
Secondary	22,095,455	1,113,522	262,652	3,305	243,405	(65,543)	-	-	-	20,538,114	20,523,742	0.999300
Primary	18,367,218	1,050,944	228,895	2,498	202,859	(43,500)	-	-	-	16,925,523	16,989,532	1.003782
Industrial Power Rate												
Secondary	31,677,176	1,484,952	-	-	347,861	(90,022)	-	-	-	29,934,385	29,899,861	0.998847
Primary	6,231,516	333,787	277	-	67,224	(19,135)	-	-	-	5,849,363	5,878,328	1.004952
Industrial Power Time of Day Rate												
Secondary	2,514,177	119,198	-	-	27,981	(6,586)	-	-	-	2,373,584	2,375,054	1.000619
Primary Noninterruptible	66,666,081	3,883,304	-	-	740,980	(173,502)	-	-	-	62,215,299	62,346,269	1.002105
Primary Interruptible	9,673,393	729,310	-	-	112,240	(28,796)	(1,765,763)	110,849	-	10,515,553	10,515,553	1.000000
Transmission Noninterruptible (moved to rate RTS with P.S.C. 7)	3,574,628	171,265	-	-	23,761	(50,620)	-	-	-	3,430,222	3,424,806	0.998421
Transmission Interruptible (moved to rate RTS with P.S.C. 7)	1,885,552	107,202	-	-	13,537	(28,453)	(184,958)	-	-	1,978,225	1,978,225	1.000000
Retail Transmission Service												
Transmission Noninterruptible (moved to rate RTS with P.S.C. 7)	9,476,139	672,487	-	-	125,408	9,497	-	-	-	8,668,748	8,669,671	1.000107
Transmission Interruptible (moved to rate RTS with P.S.C. 7)	4,904,561	307,883	-	-	67,090	9,076	(716,732)	4,788	-	5,232,456	5,232,456	1.000000
Special Contracts												
Fort Knox	10,478,887	657,479	-	-	116,364	(27,098)	-	-	-	9,732,141	9,729,138	0.999691
Louisville Water Company	2,603,901	180,407	-	-	27,425	(9,175)	-	-	-	2,405,243	2,402,969	0.999055
DuPont (moved to rate ITOD-P)	1,263,109	78,703	-	-	8,860	(14,059)	-	-	-	1,189,605	1,189,849	1.000204
Street Lighting Energy Rate	178,739	10,450	-	-	1,850	(954)	-	-	-	167,393	166,626	0.995418
Traffic Lighting Rate	244,878	10,540	-	-	2,611	(1,122)	-	-	-	232,849	230,451	0.989702
Restricted Lighting Service	13,303,082	305,984	-	-	142,217	(38,261)	-	-	-	12,893,142	12,897,874	1.000367
Lighting Service	1,421,007	21,973	-	-	15,454	(3,592)	-	-	-	1,387,173	1,387,921	1.000540
Total	$ 766,665,592	$ 33,203,288	$ 12,170,476	$ 76,751	$ 8,389,626	$ (2,324,406)	$ (2,667,453)	$ 115,637	$ (3)	$ 717,701,676	$ 717,317,276	0.999464

Seelye Exhibit 6

Summary of
Electric Revenue Increase

LOUISVILLE GAS AND ELECTRIC COMPANY

Summary of Proposed Increase
Based on Sales for the 12 months ended October 31, 2009

	Revenue Adjusted to as Billed Basis	To Remove Buy-Through Power Charged	Adjustment to Remove ECR Billings	Adjustment to Renove STOD Program Cost Recovery	Adjustment to Remove DSM Billings	Adjustment to Remove Merger Surcredit Billings	Adjustment to Remove Value Deliven Surcredit	Adjustment to Reflect a Full Year of Base Rate Changes for P.S.C. 7	Adjustment to Reflect a Full Year of Base Rate Changes for FAC Rollin	Adjustment to Reflect FAC Billings for Full Year of the Rollin	Adjustment to Reflect Full Year of Base Rate Changes for ECR Rollin	Adjustment to Reflect ECR Billings for Full Year of the Rollin	Adjustment Reflecting Year-End Number of Customers	Adjustment Reflecting Temperature Normalization	Adjusted Billings at Current Rates	Increase	Percentage Increase
Residential Rate	$ 309,180,717		$ (3,342,642)		$ (9,166,692)	$ 1,012,997	$ -	$ (1,172,720)	$ 9,001,764	$ (9,018,980)	$ 2,294,904	$ 1,013,224	$ (1,624,995)	$ 4,284,606	$ 302,462,182	$ 36,859,770	12.19%
General Service	113,167,453		(1,238,521)		(1,112,695)	325,795	3	801,474	3,216,968	(3,230,702)	2,469,204	444,067	(1,317,520)	475,872	114,001,397	13,879,697	12.18%
Power Service	175,666,617		(1,936,420)	(76,751)	(1,399,542)	512,926	-	(834,920)	6,262,654	(6,334,524)	1,216,642	701,995	2,003,635	283,244	176,065,555	21,442,743	12.18%
Commercial Time of Day Service																	
Commercial Time-of-Day Service Secondary CTODS	22,095,455		(243,405)		(262,652)	65,543	-	(132,729)	859,598	(872,160)	125,043	85,685	3,109,296	40,404	24,870,078		
Commercial Time-of-Day Service Primary CTODS	18,367,218		(202,859)		(228,895)	43,500	-	(103,302)	761,804	(775,638)	108,667	76,528	2,848,181	27,262	20,922,468		
Total Commercial TOD Service	$ 40,462,674		$ (446,264)		$ (491,547)	$ 109,043	$ -	$ (236,030)	$ 1,621,403	$ (1,647,798)	$ 233,711	$ 162,213	$ 5,957,477	$ 67,666	$ 45,792,547	$ 5,576,623	12.18%
Industrial Power Time of Day Service																	
Industrial Time-of-Day Service Secondary ITODS	2,514,177		(27,981)		-	6,586	-	(10,706)	90,116	(94,729)	12,393	11,275	736,101	-	3,237,232		
Industrial Time-of-Day Service Secondary ITODP	79,368,346	(110,849)	(862,079)	-	-	216,357	-	(632,527)	3,480,284	(3,680,287)	384,132	290,751	5,305,802	-	83,759,929		
Total Industrial TOD Service	$ 81,882,523	$ (110,849)	$ (890,060)	$ -	$ -	$ 222,943	$ -	$ (643,233)	$ 3,570,400	$ (3,775,015)	$ 396,526	$ 302,025	$ 6,041,903	$ -	$ 86,997,161	$ 10,596,615	12.18%
Retail Transmission Service	20,742,571		(229,797)		-	60,501	-	(411,843)	961,929	(1,104,581)	128,736	69,923	-	-	20,212,652	2,464,135	12.19%
Special Contracts	13,082,788		(143,789)		-	36,272	-	(46,458)	648,844	(698,026)	85,622	41,419	-	39,835	13,046,506	1,590,095	12.19%
Curtailable Service Rider - Pri	(1,765,763)														(1,765,763)		
Curtailable Service Rider - Tran	(901,690)														(901,690)		
Total Curtailable Service	$ (2,667,453)														$ (2,667,453)		
Street Lighting Energy Rate	178,739		(1,850)		-	954	-	(1,288)	9,626	(8,500)	(450)	675	(4,519)		173,386		
Traffic Lighting Rate	244,878		(2,611)		-	1,122	-	(1,061)	8,986	(7,678)	(436)	976	3,455		247,632		
Restricted Lighting Service	13,303,082		(142,217)		-	38,261	-	(15,020)		(17,523)		5,878	441,193		13,613,655		
Lighting Service	1,421,007		(15,454)		-	3,592	-	-					(284,131)		1,125,014		
	$ 15,147,704		$ (162,133)		$ -	$ 43,930	$ -	$ (17,368)	$ 18,612	$ (33,701)	$ (886)	$ 7,529	$ 155,999	$ -	$ 15,159,687	$ 1,847,743	12.19%
Total (w/o CSR Credits)	$ 766,665,592	$ (110,849)	$ (8,389,626)	$ (76,751)	$ (12,170,476)	$ 2,324,406	$ 3	$ (2,561,098)	$ 25,302,574	$ (25,843,327)	$ 6,824,458	$ 2,742,394	$ 11,216,500	$ 5,151,223	$ 771,070,235	$ 94,257,422	12.22%
Total Forfeited Discounts	5,040,755														5,040,755		
Electric Service Revenues	963,922														963,922		
Rent from Electric Property	2,613,870														2,613,870	313,898	
Oth Misc Elect Rev	1,537,870														1,537,870	882	
Total	$ 776,822,010	$ (110,849)	$ (8,389,626)	$ (76,751)	$ (12,170,476)	$ 2,324,406	$ 3	$ (2,561,098)	$ 25,302,574	$ (25,843,327)	$ 6,824,458	$ 2,742,394	$ 11,216,500	$ 5,151,223	$ 781,226,653	$ 94,572,202	12.11%

Seelye Exhibit 7

Electric Revenue Increase by Rate Schedule

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
RESIDENTIAL RATE RS						
Customer Charges	4,131,523		$ 5.00	$ 20,657,615	$ 15.00	$ 61,972,845
All Energy		4,096,604,929	$ 0.067140	275,046,055	$ 0.06610	270,785,586
Minimum Energy				27,453		30,893
				295,731,123		332,789,324
RATE RRP - RESIDENTIAL RESPONSIVE PRICING						
Customer Charges	1,150		$ 10.00	$ 11,500	$ 20.00	$ 23,000
All Energy		820,070	$ 0.046280	37,953	$ 0.04556	37,365
		433,022	$ 0.058590	25,371	$ 0.05768	24,978
		177,903	$ 0.112780	20,064	$ 0.11103	19,753
		6,151	$ 0.307430	1,891	$ 0.30267	1,862
		1,437,146				
Minimum Energy				1,236		1,366
				98,014		108,323
Total Calculated at Base Rates				$ 295,829,137		$ 332,897,647
Correction Factor				0.998350450		0.998350450
Total After Application of Correction Factor				$ 296,317,929		$ 333,447,686
Fuel Clause Billings - proforma for rollin				$ 2,471,419		2,471,419
ECR Billings - proforma for rollin				1,013,224		1,013,224
Adjustment to Reflect Year-End Customers				(1,624,995)		(1,828,613)
Adjustment to Reflect Temperature Normalization				4,284,606		4,218,237
Total				$ 302,462,183		$ 339,321,953
Proposed Increase						36,859,770
Percentage Increase						12.19%

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
GENERAL SERVICE RATE GS						
Single Phase						
Customer Charges	353,877		$ 10.00	$ 3,538,770	$ 20.00	$ 7,077,540
All Energy		631,688,944	$ 0.075790	47,875,705	$ 0.08117	51,274,192
Minimum Energy				186,138		211,253
				51,600,613		58,562,985
Three Phase						
Customer Charges	139,826		$ 15.00	$ 2,097,390	$ 35.00	$ 4,893,910
All Energy		787,385,925	$ 0.075790	59,675,979	$ 0.08117	63,912,116
Minimum Energy				18,132		20,196
				61,791,501		68,826,221
RATE GRP - GENERAL SERVICE RESPONSIVE PRICING						
Customer Charges	22		$ 20.00	$ 440	$ 30.00	$ 660
All Energy		3,588	$ 0.053180	191	$ 0.05696	204
		3,307	$ 0.068080	225	$ 0.07291	241
		1,484	$ 0.142470	211	$ 0.15258	226
		98	$ 0.308610	30	$ 0.33052	32
		8,477				
Minimum Energy				(54)		(67)
				1,043		1,297
Total Calculated at Base Rates				$ 113,393,157		$ 127,390,503
Correction Factor				0.999199909		0.999199909
Total After Application of Correction Factor				$ 113,483,955		$ 127,492,508
Fuel Clause Billings - proforma for rollin				$ 915,024		915,024
ECR Billings - proforma for rollin				444,067		444,067
Adjustment to Reflect Year-End Customers				(1,317,520)		(1,480,156)
Adjustment to Reflect Temperature Normalization				475,872		509,652
Total				$ 114,001,397		$ 127,881,095
Proposed Increase						13,879,697
Percentage Increase						12.18%

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / kW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
POWER SERVICE PRIMARY RATE PS						
Customer Charges	634		$ 65.00	$ 41,210	$ 90.00	$ 57,060
All Energy		169,859,360	$ 0.029560	5,021,043	$ 0.033230	5,644,427
Demand Summer	144,404		$ 13.15	$ 1,898,913		
Demand Winter	237,702		$ 10.35	$ 2,460,216		
Demand Summer	174,562				$ 13.73	2,396,742
Demand Winter	207,544				$ 11.48	2,382,600
		169,859,360				
Minimum Energy				12,391		7,499
				9,433,772		10,488,328
POWER SERVICE PRIMARY RATE PS						
Customer Charges	526		$ 90.00	$ 47,340	$ 90.00	$ 47,340
All Energy		110,455,845	$ 0.026110	2,884,002	$ 0.033230	3,670,448
Demand Summer	87,394		$ 13.34	$ 1,165,836	$ -	-
Demand Winter	193,112		$ 10.75	$ 2,075,954	$ -	-
Demand Summer	111,774				$ 13.73	1,534,662
Demand Winter	168,732				$ 11.48	1,937,039
		110,455,845				
Minimum Energy				12,889		7,763
				6,186,022		7,197,252
POWER SERVICE SECONDARY RATE PS						
Customer Charges	32,244		$ 65.00	$ 2,095,860	$ 90.00	$ 2,901,960
All Energy		1,962,425,059	$ 0.029560	58,009,285	$ 0.033230	65,211,385
Demand Summer	1,738,193		$ 14.99	$ 26,055,513	$ -	-
Demand Winter	3,206,893		$ 11.93	$ 38,258,233	$ -	-
Demand Summer	2,145,068				$ 15.57	33,398,702
Demand Winter	2,800,018				$ 13.32	37,296,246
		1,962,425,059				
Minimum Energy				105,544		57,780
				124,524,435		138,866,072
INDUSTRIAL POWER SERVICE RATE IPS-Secondary						
Customer Charges	3,902		$ 90.00	$ 351,180	$ 90.00	$ 351,180
All Energy		498,246,495	$ 0.026110	13,009,216	$ 0.033230	16,556,731
Demand Summer	447,704		$ 15.10	$ 6,760,330	$ -	-
Demand Winter	882,709		$ 12.51	$ 11,042,690	$ -	-
Demand Summer	559,146				$ 15.57	8,705,903
Demand Winter	771,267				$ 13.32	10,273,276
		498,246,495				
Minimum Energy				(44,509)		(24,149)
				31,118,907		35,862,942
Total Calculated at Base Rates				$ 171,263,136		$ 192,414,594
Correction Factor				0.999990920		0.999990920
Total After Application of Correction Factor				$ 171,264,691		$ 192,416,341
Fuel Clause Billings - proforma for rollin				$ 1,811,990		1,811,990
ECR Billings - proforma for rollin				701,995		701,995
Adjustment to Reflect Year-End Customers				2,003,635		2,251,090
Adjustment to Reflect Temperature Normalization				283,244		326,882
Total				$ 176,065,555		$ 197,508,297
Proposed Increase						21,442,743
Percentage Increase						12.18%

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / kW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
COMMERCIAL TIME OF DAY PRIMARY RATE CTOD						
Customer Charges	218		$ 90.00	$ 19,620	$ 200.00	$ 43,600
All Energy		340,177,714	$ 0.029600	10,069,260	$ 0.033440	11,375,543
Demand Base	685,951		$ 2.64	$ 1,810,910		
Demand Summer	240,141		$ 10.50	$ 2,521,481		
Demand Winter	432,250		$ 7.70	$ 3,328,325		
Demand Base	692,810				$ 2.99	2,071,502
Demand Intermediate	672,391				$ 4.20	2,824,042
Demand Peak	664,483				$ 5.70	3,787,553
		340,177,714				
Minimum Energy				7,107		5,091
				17,756,702		20,107,331
COMMERCIAL TIME OF DAY SECOMDARY RATE CTOD						
Customer Charges	868		$ 90.00	$ 78,120	$ 200.00	$ 173,600
All Energy		378,424,027	$ 0.029600	11,201,351	$ 0.033440	12,654,499
Demand Base	785,990		$ 3.65	$ 2,868,862		
Demand Summer	283,242		$ 11.29	$ 3,197,802		
Demand Winter	493,809		$ 8.23	$ 4,064,049		
Demand Base	793,850				$ 4.14	3,286,537
Demand Intermediate	777,051				$ 4.28	3,328,887
Demand Peak	767,912				$ 5.81	4,464,641
		378,424,027				
Minimum Energy				(26,574)		(29,675)
				21,383,611		23,878,490
Total Calculated at Base Rates				$ 39,140,313		$ 43,985,821
Correction Factor				1.001324937		1.001324937
Total After Application of Correction Factor				$ 39,088,523		$ 43,927,620
Fuel Clause Billings - proforma for rollin				$ 516,668		516,668
ECR Billings - proforma for rollin				162,213		162,213
Adjustment to Reflect Year-End Customers				5,957,477		6,695,004
Adjustment to Reflect Temperature Normalization				67,666		67,666
Total				$ 45,792,546		$ 51,369,170
Proposed Increase						5,576,623
Percentage Increase						12.18%

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / kW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
INDUSTRIAL TIME OF DAY PRIMARY RATE ITODP						
Customer Charges	503		$ 120.00	$ 60,360	$ 300.00	$ 150,900
All Energy		1,570,265,493	$ 0.026160	41,078,145	$ 0.029360	46,102,995
Demand Base	3,320,227		$ 3.85	$ 12,782,874		
Demand Summer	1,239,053		$ 9.35	$ 11,585,147		
Demand Winter	2,016,530		$ 6.76	$ 13,631,741		
Demand Base (kVA)	3,483,974				$ 4.12	14,353,972
Demand Intermediate (kVa)	3,416,142				$ 3.42	11,683,204
Demand Peak (kVa)	3,375,964				$ 4.92	16,609,743
		1,570,265,493				
Power Factor Correction Revenue-Interruptible				(321,025)		(360,627)
Minimum Energy				(1,525,968)		(1,714,212)
				77,291,276		86,825,976
INDUSTRIAL TIME OF DAY SECOMDARY RATE ITODS						
Customer Charges	161		$ 120.00	$ 19,320	$ 300.00	$ 48,300
All Energy		42,191,442	$ 0.026160	1,103,728	$ 0.029360	1,238,741
Demand Base	105,652		$ 4.91	$ 518,751		
Demand Summer	36,477		$ 10.05	$ 366,594		
Demand Winter	64,426		$ 7.46	$ 480,618		
Demand Base	106,709				$ 5.48	584,763
Demand Intermediate	100,903				$ 4.00	403,612
Demand Peak	99,716				$ 5.50	548,439
		42,191,442				
Power Factor Correction Revenue-Interruptible				-		-
Minimum Energy				(22,154)		(25,134)
				2,466,858		2,798,721
Total Calculated at Base Rates				$ 79,758,133		$ 89,624,697
Correction Factor				1.001763418		1.001763418
Total After Application of Correction Factor				$ 79,617,734		$ 89,466,929
Fuel Clause Billings - proforma for rollin				$ 1,035,499		1,035,499
ECR Billings - proforma for rollin				302,025		302,025
Adjustment to Reflect Year-End Customers				6,041,903		6,789,323
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 86,997,161		$ 97,593,776
Proposed Increase						**10,596,615**
Percentage Increase						12.18%

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / kW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
RETAIL TRANSMISSION SERVICE Rate RTS						
Customer Charges	56		$ 120.00	$ 6,720	$ 500.00	$ 28,000
All Energy		448,436,560	$ 0.026160	11,731,100	$ 0.029360	13,166,097
Demand Base	923,067		$ 2.36	$ 2,178,438		
Demand Summer	331,383		$ 8.15	$ 2,700,771		
Demand Winter	584,639		$ 5.90	$ 3,449,370		
Demand Base	932,298				$ 2.61	2,433,297
Demand Intermediate	916,022				$ 3.05	2,793,867
Demand Peak	905,249				$ 4.55	4,118,881
		448,436,560				
Power Factor Correction Revenue-Interruptible				-		-
Minimum Energy				(76,599)		(86,042)
				19,989,801		22,454,100
Total Calculated at Base Rates				$ 19,989,801		$ 22,454,100
Correction Factor				1.000066440		1.000066440
Total After Application of Correction Factor				$ 19,988,473		$ 22,452,608
Fuel Clause Billings - proforma for rollin				$ 154,256		154,256
ECR Billings - proforma for rollin				69,923		69,923
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 20,212,652		$ 22,676,787
Proposed Increase						2,464,135
Percentage Increase						12.19%

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / kW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
SPECIAL CONTRACT						
Customer Charges	12		$ -	$ -	$ -	$ -
All Energy		221,595,000	$ 0.026190	5,803,573	$ 0.029440	6,523,757
Demand Summer	196,120		$ 12.63	$ 2,477,001	$ 14.04	2,753,530
Demand Winter	228,657		$ 10.44	$ 2,387,179	$ 11.85	2,709,585
		221,595,000				
Power Factor Correction				(324,519)		(364,647)
Minimum Energy				(74,401)		(83,601)
				10,268,833		11,538,625
Total Calculated at Base Rates				$ 10,268,833		$ 11,538,625
Correction Factor				0.999691406		0.999691406
Total After Application of Correction Factor				$ 10,272,003		$ 11,542,187
Fuel Clause Billings - proforma for rollin				$ 115,664		115,664
ECR Billings - proforma for rollin				33,944		33,944
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				39,835		44,778
Total				$ 10,461,446		$ 11,736,574
Proposed Increase						1,275,127
Percentage Increase						12.19%

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / kW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
SPECIAL CONTRACT						
Customer Charges	24		$ -	$ -	$ -	$ -
All Energy		58,159,200	$ 0.026180	1,522,608	$ 0.029410	1,710,462
Demand	115,286		$ 8.92	$ 1,028,351	$ 10.02	1,155,166
		58,159,200				
Power Factor Correction Revenue-Interruptible				-		-
Minimum Energy				16		18
				2,550,975		2,865,645
Total Calculated at Base Rates				$ 2,550,975		$ 2,865,645
Correction Factor				0.999054636		0.999054636
Total After Application of Correction Factor				$ 2,553,389		$ 2,868,357
Fuel Clause Billings - proforma for rollin				$ 24,197		24,197
ECR Billings - proforma for rollin				7,475		7,475
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				-		-
Total				$ 2,585,060		$ 2,900,028
Proposed Increase						314,968
Percentage Increase						12.18%

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / kW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LIGHTING ENERGY SERVICE RATE LE						
Customer Charges	1,329		$ -	$ -	$ -	$ -
All Energy		4,090,864	$ 0.048710	199,266	$ 0.054650	223,566
		4,090,864				
Power Factor Correction Revenue-Interruptible				-		-
Minimum Energy				(24,752)		(27,771)
				174,514		195,795
Total Calculated at Base Rates				$ 174,514		$ 195,795
Correction Factor				0.995418047		0.995418047
Total After Application of Correction Factor				$ 175,317		$ 196,696
TRAFFIC ENERGY SERVICE RATE TE						
Customer Charges	10,476		$ 2.80	$ 29,333	$ 3.14	$ 32,895
All Energy		3,960,610	$ 0.059030	233,795	$ 0.066230	262,311
		3,960,610				
Power Factor Correction Revenue-Interruptible				-		-
Minimum Energy				(25,187)		(28,257)
				237,941		266,948
Total Calculated at Base Rates				$ 237,941		$ 266,948
Correction Factor				0.989702358		0.989702358
Total After Application of Correction Factor				$ 240,416		$ 269,726

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Units		Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
RESTRICTED LIGHTING SERVICE RATE RLS						
OVERHEAD SERVICE:						
Mercury Vapor						
100W MERCURY OUTDOOR LIGHT	542		$ 7.17	$ 3,886	$ 7.17	$ 3,886
175W MERCURY OUTDOOR LIGHT	35,180		$ 8.25	$ 290,235	$ 8.25	$ 290,235
250W MERCURY OUTDOOR LIGHT	57,703		$ 9.57	$ 552,218	$ 9.57	$ 552,218
400W MERCURY OUTDOOR LIGHT	84,377		$ 11.64	$ 982,148	$ 11.64	$ 982,148
400W MERCURY OUTDOOR LIGHT Metal Pole	572		$ 16.15	$ 9,238	$ 16.15	$ 9,238
1000W MERCURY OUTDOOR LIGHT	-		$ 22.12	$ -	$ 22.12	$ -
1000W MERCURY FLOOD LIGHT	90		$ 22.12	$ 1,991	$ 22.12	$ 1,991
High Pressure Sodium						
100W HP SODIUM OUTDOOR LIGHT	206		$ 8.44	$ 1,739	$ 9.82	$ 2,023
150W HP SODIUM OUTDOOR LIGHT	24,727		$ 10.05	$ 248,506	$ 11.70	$ 289,306
150W HP SODIUM FLOOD LIGHT	140		$ 12.10	$ 1,694	$ 14.08	$ 1,971
250W HP SODIUM OUTDOOR LIGHT	29,048		$ 12.02	$ 349,157	$ 13.99	$ 406,382
400W HP SODIUM OUTDOOR LIGHT	46,377		$ 12.92	$ 599,191	$ 15.04	$ 697,510
400W HP SODIUM FLOOD LIGHT	6,238		$ 12.92	$ 80,595	$ 15.04	$ 93,820
UNDERGROUND SERVICE:						
Mercury Vapor						
100W MERCURY LIGHT TOP MOUNT	1,164		$ 11.17	$ 13,002	$ 11.17	$ 13,002
175W MERCURY LIGHT TOP MOUNT	12,443		$ 12.15	$ 151,182	$ 12.15	$ 151,182
175W UG MERCURY LIGHT METAL POLE	1,259		$ 16.18	$ 20,371	$ 16.18	$ 20,371
250W UG MERCURY OUTDOOR LIGHT	12,425		$ 17.54	$ 217,935	$ 17.54	$ 217,935
400W UG MERCURY OUTDOOR LIGHT	8,601		$ 20.85	$ 179,331	$ 20.85	$ 179,331
400W UG MERCURY LIGHT METAL POLE	4,576		$ 20.95	$ 95,867	$ 20.95	$ 95,867
High Pressure Sodium						
100W HP SODIUM LIGHT TOP MOUNT	22,886		$ 12.22	$ 279,667	$ 14.22	$ 325,439
150W UG HP SODIUM OUTDOOR LIGHT	2,376		$ 20.61	$ 48,969	$ 23.99	$ 57,000
250W UG HP SODIUM OUTDOOR LIGHT	6,589		$ 22.01	$ 145,024	$ 25.62	$ 168,810
250W HP SODIUM LIGHTMETAL POLE	2,412		$ 22.01	$ 53,088	$ 25.62	$ 61,795
400W UG HP SODIUM OUTDOOR LIGHT	7,536		$ 23.95	$ 180,487	$ 27.88	$ 210,104
400W HP SODIUM LIGHTMETAL POLE	2,219		$ 23.95	$ 53,145	$ 27.88	$ 61,866
rior to Jan. 1, 1991	369,686			$ 4,558,665.52		$ 4,893,428.55

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Units		Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
OVERHEAD SERVICE:						
Mercury Vapor						
175W MERCURY OUTDOOR LIGHT	9		$ 10.04	$ 90	$ 10.04	$ 90
250W MERCURY OUTDOOR LIGHT	741		$ 11.46	$ 8,492	$ 11.46	$ 8,492
400W MERCURY OUTDOOR LIGHT	152		$ 13.95	$ 2,120	$ 13.95	$ 2,120
400W MERCURY FLOOD LIGHT	43		$ 13.95	$ 600	$ 13.95	$ 600
1000W MERCURY FLOOD LIGHT	91		$ 25.83	$ 2,351	$ 25.83	$ 2,351
High Pressure Sodium						$ -
100W HP SODIUM OUTDOOR LIGHT	4,198		$ 8.44	$ 35,431	$ 9.82	$ 41,224
150W HP SODIUM OUTDOOR LIGHT	6,571		$ 10.05	$ 66,039	$ 11.70	$ 76,881
150W HP SODIUM FLOOD LIGHT	114		$ 10.05	$ 1,146	$ 11.70	$ 1,334
250W HP SODIUM OUTDOOR LIGHT	873		$ 12.02	$ 10,493	$ 13.99	$ 12,213
400W HP SODIUM OUTDOOR LIGHT	5,778		$ 12.92	$ 74,652	$ 15.04	$ 86,901
400W HP SODIUM FLOOD LIGHT	15,881		$ 12.92	$ 205,183	$ 15.04	$ 238,850
1000W HP SODIUM OUTDOOR LIGHT	21		$ 29.05	$ 610	$ 33.81	$ 710
UNDERGROUND SERVICE:						
Mercury Vapor						
100W MERCURY LIGHT TOP MOUNT	-		$ 13.86	$ -	$ 13.86	$ -
175W MERCURY LIGHT TOP MOUNT	429		$ 14.68	$ 6,298	$ 14.68	$ 6,298
175W UG MERCURY LIGHT METAL POLE	-		$ 23.12	$ -	$ 23.12	$ -
250W UG MERCURY OUTDOOR LIGHT	436		$ 24.05	$ 10,486	$ 24.05	$ 10,486
400W UG MERCURY OUTDOOR LIGHT	-		$ 27.09	$ -	$ 27.09	$ -
400W UG MERCURY OUTDOOR LIGHT	-		$ 27.09	$ -	$ 27.09	$ -
High Pressure Sodium						
70W HP SODIUM LIGHT TOP MOUNT	2,274		$ 11.72	$ 26,651	$ 13.64	$ 31,017
100W HP SODIUM LIGHT TOP MOUNT	59,437		$ 12.22	$ 726,320	$ 14.22	$ 845,194
150W UG HP SODIUM LIGHT TOP MOUNT	3,925		$ 17.75	$ 69,669	$ 20.66	$ 81,091
150W UG HP SODIUM OUTDOOR LIGHT	998		$ 20.61	$ 20,569	$ 23.99	$ 23,942
250W UG HP SODIUM OUTDOOR LIGHT	733		$ 22.01	$ 16,133	$ 25.62	$ 18,779
250W HP SODIUM LIGHTMETAL POLE	-		$ 22.01	$ -	$ 25.62	$ -
400W UG HP SODIUM OUTDOOR LIGHT	3,049		$ 23.95	$ 73,024	$ 27.88	$ 85,006
400W HP SODIUM LIGHTMETAL POLE	9		$ 23.95	$ 216	$ 27.88	$ 251
1000W UG HP SODIUM OUTDOOR LIGHT	19		$ 55.30	$ 1,051	$ 64.37	$ 1,223
DECORATIVE LIGHTING FIXTURES:						
Acorn w/ Decorative Baskets						
70W HP SODIUM ACORN/DECO BASKET	123		$ 15.79	$ 1,942	$ 18.38	$ 2,261
100W HP SODIUM ACORN/DECO BASKET	1,421		$ 16.56	$ 23,532	$ 19.28	$ 27,397
8-Sided Coach						
70W HP SODIUM 8-SIDED COACH	415		$ 15.98	$ 6,632	$ 18.60	$ 7,719
100W HP SODIUM 8-SIDED COACH	88		$ 17.09	$ 1,504	$ 19.89	$ 1,750
Other Restricted Lighting	-					
400 W MERCURY VAPOR UP	73		$ 16.11	$ 1,176	$ 16.11	$ 1,176
250 W US HP SODIUM STATE OF KY POLE	562		$ 22.05	$ 12,390	$ 22.05	$ 12,390
400 W UG MV STATE OF KY POLE	22		$ 20.95	$ 461	$ 20.95	$ 461
300 W 6000 LUMEN INCANDESCENT	154		$ 11.89	$ 1,831	$ 11.89	$ 1,831
100 W 1500 LUMEN INCANDESCENT	203		$ 8.35	$ 1,696	$ 8.35	$ 1,696
Total Installed After Dec. 31, 1990	108,842			1,408,784		1,631,734
Total Public Street Linghting Restricted	478,528			$ 5,967,449.97		$ 6,525,162.20

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Units		Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
OVERHEAD SERVICE:						
Mercury Vapor						
100W MERCURY OUTDOOR LIGHT	546		$ 7.89	$ 4,308	$ 7.89	$ 4,308
175W MERCURY OUTDOOR LIGHT	33,873		$ 8.82	$ 298,760	$ 8.82	$ 298,760
250W MERCURY OUTDOOR LIGHT	16,080		$ 10.18	$ 163,694	$ 10.18	$ 163,694
400W MERCURY OUTDOOR LIGHT	10,481		$ 12.54	$ 131,432	$ 12.54	$ 131,432
400W MERCURY FLOOD LIGHT	6,545		$ 12.54	$ 82,074	$ 12.54	$ 82,074
1000W MERCURY OUTDOOR LIGHT	669		$ 23.44	$ 15,681	$ 23.44	$ 15,681
1000W MERCURY FLOOD LIGHT	2,941		$ 23.44	$ 68,937	$ 23.44	$ 68,937
High Pressure Sodium				$ -		
100W HP SODIUM OUTDOOR LIGHT	2,412		$ 8.71	$ 21,009	$ 10.14	$ 24,458
150W HP SODIUM OUTDOOR LIGHT	6,147		$ 11.02	$ 67,740	$ 12.83	$ 78,866
150W HP SODIUM FLOOD LIGHT	1,016		$ 11.02	$ 11,196	$ 12.83	$ 13,035
250W HP SODIUM OUTDOOR LIGHT	4,611		$ 13.00	$ 59,943	$ 15.13	$ 69,764
400W HP SODIUM OUTDOOR LIGHT	9,732		$ 14.13	$ 137,513	$ 16.45	$ 160,091
400W HP SODIUM FLOOD LIGHT	36,118		$ 14.13	$ 510,347	$ 16.45	$ 594,141
UNDERGROUND SERVICE:				$ -		
Mercury Vapor				$ -		
100W MERCURY LIGHT TOP MOUNT	323		$ 13.13	$ 4,241	$ 13.13	$ 4,241
175W MERCURY LIGHT TOP MOUNT	5,601		$ 13.91	$ 77,910	$ 13.91	$ 77,910
High Pressure Sodium						
70W HP SODIUM LIGHT TOP MOUNT	-		$ 11.65	$ -	$ 13.56	$ -
100W HP SODIUM LIGHT TOP MOUNT	14,459		$ 15.31	$ 221,367	$ 17.82	$ 257,659
150W HP SODIUM OUTDOOR LIGHT	-		$ 20.63	$ -	$ 24.01	$ -
250W UG HP SODIUM OUTDOOR LIGHT	276		$ 23.72	$ 6,547	$ 27.61	$ 7,620
400W UG HP SODIUM OUTDOOR LIGHT	506		$ 26.44	$ 13,379	$ 30.78	$ 15,575
Total Installed Prior to Jan. 1, 1991	152,336			$ 1,896,078		$ 2,068,248

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Units		Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
RESTRICTED LIGHTING SERVICE RATE RLS						
OVERHEAD SERVICE:						
Mercury Vapor						
175W MERCURY OUTDOOR LIGHT	1,138		$ 10.22	$ 11,630	$ 10.22	$ 11,630
250W MERCURY	671		$ 11.65	$ 7,817	$ 11.65	$ 7,817
400W MERCURY	508		$ 14.15	$ 7,188	$ 14.15	$ 7,188
400W MERCURY FLOOD LIGHT	2,055		$ 14.15	$ 29,078	$ 14.15	$ 29,078
1000W MERCURY OUTDOOR LIGHT	196		$ 26.08	$ 5,112	$ 26.08	$ 5,112
1000W MERCURY FLOOD LIGHT	3,934		$ 26.21	$ 103,110	$ 26.21	$ 103,110
High Pressure Sodium						
100W HP SODIUM	21,576		$ 8.71	$ 187,927	$ 10.14	$ 218,781
150W HP SODIUM OUTDOOR LIGHT	15,387		$ 11.02	$ 169,565	$ 12.83	$ 197,415
150W HP SODIUM FLOOD LIGHT	2,675		$ 11.02	$ 29,479	$ 12.83	$ 34,320
250W HP SODIUM OUTDOOR LIGHT	4,556		$ 13.00	$ 59,228	$ 15.13	$ 68,932
400W HP SODIUM OUTDOOR LIGHT	19,433		$ 14.13	$ 274,588	$ 16.45	$ 319,673
400W HP SODIUM FLOOD LIGHT	86,568		$ 14.13	$ 1,223,206	$ 16.45	$ 1,424,044
1000W HP SODIUM OUTDOOR LIGHT	151		$ 32.96	$ 4,977	$ 38.37	$ 5,794
UNDERGROUND SERVICE:						
Mercury Vapor						
100W MERCURY LIGHT TOP MOUNT	-		$ 13.12	$ -	$ 13.12	$ -
175W MERCURY LIGHT TOP MOUNT	2,534		$ 14.88	$ 37,706	$ 14.88	$ 37,706
High Pressure Sodium	-		$ -			
70W HP SODIUM LIGHT TOP MOUNT	14,301		$ 11.65	$ 166,607	$ 13.56	$ 193,922
100W HP SODIUM LIGHT TOP MOUNT	110,948		$ 15.47	$ 1,716,366	$ 18.01	$ 1,998,173
150W UG HP SODIUM LIGHT TOP MOUNT	10,830		$ 18.48	$ 200,138	$ 21.51	$ 232,953
150W HP SODIUM OUTDOOR LIGHT	4,830		$ 20.63	$ 99,643	$ 24.01	$ 115,968
250W UG HP SODIUM OUTDOOR LIGHT	5,958		$ 23.72	$ 141,324	$ 27.61	$ 164,500
400W UG HP SODIUM OUTDOOR LIGHT	17,811		$ 26.44	$ 470,923	$ 30.78	$ 548,223
1000W UG HP SODIUM OUTDOOR LIGHT	280		$ 59.20	$ 16,576	$ 68.91	$ 19,295
DECORATIVE LIGHTING FIXTURES:						
Acorn w/ Decorative Baskets						
70W HP SODIUM ACORN/DECO BASKET	420		$ 16.19	$ 6,800	$ 18.85	$ 7,917
100W HP SODIUM ACORN/DECO BASKET	1,583		$ 17.06	$ 27,006	$ 19.86	$ 31,438
8-Sided Coach						
70W HP SODIUM 8-SIDED COACH	852		$ 16.35	$ 13,930	$ 19.03	$ 16,214
100W HP SODIUM 8-SIDED COACH	889		$ 17.24	$ 15,326	$ 20.07	$ 17,842
Additional Poles	90,647		$ 1.75	$ 158,632	$ 2.04	$ 184,920
Poles						$ -
10' Smooth	2,464		$ 9.20	$ 22,669	$ 10.71	$ 26,389
10' Fluted	2,915		$ 10.98	$ 32,007	$ 12.78	$ 37,254
Bases						
Old Town/Manchester	1,120		$ 2.95	$ 3,304	$ 3.43	$ 3,842
Chesapeake/Franklin	1,651		$ 3.17	$ 5,234	$ 3.69	$ 6,092
Jefferson/Westchester	2,118		$ 3.19	$ 6,756	$ 3.71	$ 7,858
Norfolk/Essex	1,256		$ 3.36	$ 4,220	$ 3.91	$ 4,911
Total Installed After Dec. 31, 1990				5,258,071		6,088,312
Total Outdoor Lighintg Rate RLS				7,154,150		8,156,559
Billings for partial month installations				61,115		61,115
Total Restricted Lighting Service						
Total Calculated at Base Rates				13,182,715		14,742,837
Correction Factor				1.000367016		1.000367016
Total After Application of Correction Factor				$ 13,177,878		$ 14,737,428

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Units		Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
LIGHTING SERVICE RATE LS						
Served Underground						
High Pressure Sodium						
4 SIDED COLONIAL 6300L	1,199		$ 16.38	$ 19,640	$ 19.07	$ 22,865
4 SIDED COLONIAL 9500L	13,276		$ 16.88	$ 224,099	$ 19.65	$ 260,873
4 SIDED COLONIAL 16000L	1,659		$ 17.84	$ 29,597	$ 20.77	$ 34,457
ACORN 6300L	395		$ 16.71	$ 6,600	$ 19.45	$ 7,683
ACORN 9500L	12,959		$ 18.65	$ 241,685	$ 21.71	$ 281,340
ACORN 9500L BRONZE POLE	399		$ 19.60	$ 7,820	$ 22.81	$ 9,101
ACORN 16000L	1,190		$ 19.52	$ 23,229	$ 22.72	$ 27,037
ACORN 16000L BRONZE POLE	669		$ 20.41	$ 13,654	$ 23.76	$ 15,895
CONTEMPORARY 16000L	399		$ 24.88	$ 9,927	$ 28.96	$ 11,555
CONTEMPORARY 28500L	1,661		$ 27.66	$ 45,943	$ 32.20	$ 53,484
CONTEMPORARY 50000L	3,192		$ 31.49	$ 100,516	$ 36.65	$ 116,987
CONTEMPORARY 16000L Fixture Only					$ 15.26	
CONTEMPORARY 28500L Fixture Only					$ 17.31	
CONTEMPORARY 50000L Fixture Only					$ 20.21	
COBRA HEAD 16000L UGHPS	125		$ 21.86	$ 2,733	$ 25.45	$ 3,181
COBRA HEAD 28500L UGHPS	11		$ 23.91	$ 263	$ 27.83	$ 306
COBRA HEAD 50000L UGHPS	178		$ 27.78	$ 4,945	$ 32.34	$ 5,757
LONDON (10' SMOOTH POLE) 6300L	232		$ 27.81	$ 6,452	$ 32.37	$ 7,510
LONDON (10' FLUTED POLE) 6300L	152		$ 29.49	$ 4,482	$ 34.33	$ 5,218
LONDON (10' SMOOTH POLE) 9500L	691		$ 28.46	$ 19,666	$ 33.13	$ 22,893
LONDON (10' FLUTED POLE) 9500L	1,647		$ 30.15	$ 49,657	$ 35.09	$ 57,793
VICTORIAN (10' SMOOTH POLE) 6300L	28		$ 26.99	$ 756	$ 31.42	$ 880
VICTORIAN (10' FLUTED POLE) 6300L	163		$ 27.56	$ 4,492	$ 32.08	$ 5,229
VICTORIAN (10' SMOOTH POLE) 9500L	82		$ 28.67	$ 2,351	$ 33.37	$ 2,736
VICTORIAN (10' FLUTED POLE) 9500L	1,038		$ 29.23	$ 30,341	$ 34.02	$ 35,313
Mercury Vapor				$ -		
4 SIDED COLONIAL 4000L UGMV	11		$ 16.35	$ 180	$ 16.35	$ 180
4 SIDED COLONIAL 8000L UGMV	397		$ 17.92	$ 7,114	$ 17.92	$ 7,114
COBRA HEAD 8000L UGMV	-		$ 21.89	$ -	$ 21.89	$ -
COBRA HEAD 13000L UGMV	11		$ 23.31	$ 256	$ 23.31	$ 256
COBRA HEAD 25000L UGMV	83		$ 26.69	$ 2,215	$ 26.69	$ 2,215
Bases	-			$ -		$ -
Old Town/Manchester	-		$ 2.49	$ -	$ 2.90	$ -
Chesapeake/Franklin	435		$ 2.49	$ 1,083	$ 2.90	$ 1,262
Jefferson/Westchester	179		$ 2.49	$ 446	$ 2.90	$ 519
Norfolk/Essex	42		$ 2.64	$ 111	$ 3.07	$ 129
Served Overhead				$ -		
High Pressure Sodium				$ -		
COBRA HEAD 16000L OHHP	4,459		$ 10.13	$ 45,170	$ 11.79	$ 52,572
COBRA HEAD 28500L OHHP	3,602		$ 12.19	$ 43,908	$ 14.19	$ 51,112
COBRA HEAD 50000L OHHP	3,152		$ 16.06	$ 50,621	$ 18.69	$ 58,911
DIRECTIONAL FLOOD 16000L OHHP	905		$ 11.55	$ 10,453	$ 13.44	$ 12,163
DIRECTIONAL FLOOD 50000L OHHP	15,521		$ 16.91	$ 262,460	$ 19.68	$ 305,453
OPEN BOTTOM 9500L OHHP	5,254		$ 8.99	$ 47,233	$ 10.46	$ 54,957
Mercury Vapor				$ -		$ -
COBRA HEAD 8000L MV	58		$ 10.16	$ 589	$ 10.16	$ 589
COBRA HEAD 13000L MV	170		$ 11.59	$ 1,970	$ 11.59	$ 1,970
COBRA HEAD 25000L MV	508		$ 14.96	$ 7,600	$ 14.96	$ 7,600
DIRECTIONAL FLOOD 25000L MV	2,029		$ 16.31	$ 33,093	$ 16.31	$ 33,093
OPEN BOTTOM 8000L MV	204		$ 9.90	$ 2,020	$ 9.90	$ 2,020

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations of proposed Rate Increase
Based on Sales for the 12 moths ended October 31, 2009

Metal Halide			$ -		
Directional Fixture Only, 12,000 Lumen		$ 10.39		$ 12.09	
Directional Fixture with Wood Pole, 12,000 Lumen		$ 12.33		$ 14.35	
Directional Fixture with Direct Burial Metal Pole, 12,000 Lumen		$ 18.68		$ 21.74	
Directional Fixture Only, 32,000 Lumen	1	$ 14.93	$ 15	$ 17.38	$ 17
Directional Fixture with Wood Pole, 32,000 Lumen		$ 16.88		$ 19.65	
Directional Fixture with Direct Burial Metal Pole, 32,000 Lumen		$ 23.23		$ 27.04	
Directional Fixture Only, 107,800 Lumen		$ 30.90		$ 35.97	
Directional Fixture with Wood Pole, 107,800 Lumen		$ 33.61		$ 39.12	
Directional Fixture with Direct Burial Metal Pole, 107,800 Lumen		$ 39.19		$ 45.62	
Contemporary Fixture Only, 12,000 Lumen		$ 11.47		$ 13.35	
Contemporary Fixture with Direct Burial Metal Pole, 12,000 Lumen		$ 19.78		$ 23.02	
Contemprorary Fixture Only, 32,000 Lumen		$ 16.45		$ 19.15	
Contemporary with Metal Pole, 32,000 Lumen		$ 24.75		$ 28.81	
Contemprorary Fixture Only, 107,800 Lumen		$ 33.42		$ 38.90	
Contemporary with Metal Pole, 107,800 Lumen		$ 41.72		$ 48.56	
Poles	2,367	$ 9.62	$ 22,771	$ 11.20	$ 26,510
Total Rate LS	**Total Calculated at Base Rates**		$ 1,388,156		$ 1,606,737
	Correction Factor		1.000539543		1.000539543
	Total After Application of Correction Factor		$ 1,387,408		$ 1,605,870
TOTAL LIGHTING AFTER APPLICATION OF CORRECTION FACTOR			14,981,019		16,809,720
Fuel Clause Billings - proforma for rollin			$ 9,262		9,262
ECR Billings - proforma for rollin			13,407		13,407
Adjustment to Reflect Year-End Customers			155,999		175,041
Adjustment to Reflect Temperature Normalization			-		-
Total Lighting			$ 15,159,687		$ 17,007,430
Proposed Increase					1,847,743
	Percentage Increase				12.19%

Seelye Exhibit 8

Reconstruction of Gas Billing Determinants

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculation to Reconstruct Test Period Billings Determinants
Based on Sales for the 12 months ended October 31, 2009

	(1)	(2)	(3)	(4)	(6)	(7)
	Booked Revenue Adjusted to as Billed Basis	Less: Gas Supply Cost (GSC) Billings	Net Revenue excluding GSC Billings	Less: Demand-Side Mgmt. (DSM) Billings	Less: WNA Billings	**Net Revenue** @ Base Rates
GAS SALES AND TRANSPORTATION						
Residential Gas Service Rate RGS	$ 274,923,042	$ 204,062,442	$ 70,860,599	$ 2,242,152		
Total Residential Gas Service Rate RGS	274,923,042	204,062,442	70,860,599	2,242,152	52,633	68,565,814
Firm Commercial Gas Service Rate CGS	127,247,593	102,813,882	24,433,710	105,755		
Gas Transportation Service/Standby Rider to Ra	42,124	15,773	26,351	166		
Total Firm Commercial Gas Service Rate C	127,289,717	102,829,655	24,460,062	105,921	(20,525)	24,374,666
Firm Industrial Gas Service Rate IGS	10,396,949	8,836,681	1,560,267	-		
Gas Transportation Service/Standby Rider to Ra	135,497	58,390	77,107	-		
Total Firm Industrial Gas Service Rate IGS	10,532,446	8,895,071	1,637,375	-		1,637,375
As Available Gas Service	2,876,103	2,681,995	194,108	913		
Total Rate AAGS	2,876,103	2,681,995	194,108	913		193,195
FT - Cashouts	249,109	249,109	-			-
Firm Transportation Service Rate FT	3,772,566	191,250	3,581,316	7,142		3,574,174
Total Rate FT	4,021,674	440,358	3,581,316	7,142		3,574,174
Pooling Service Rate PS-FT	60,000		60,000			60,000
Intra-Company Special Contract - Sales Custome	6,513,290	3,466,383	3,046,907			3,046,907
Intra-Company Special Contract - FT Customer	1,282,267	19,895	1,262,372			1,262,372
Total Intra-Company	7,795,557	3,486,278	4,309,279	-		4,309,279
Fort Knox Special Contract	294,437	34,668	259,769			259,769
duPont Special Contract	210,171	32,424	177,746			177,746
Ford LAP Special Contracts	883,477		883,477			883,477
Special Contracts	1,388,084	67,093	1,320,992			1,320,992
Total Ultimate Consumers	428,886,623	322,462,892	106,423,731	2,356,128	32,108	104,035,496
Off-System Sales	-	-	-			-
Grand Total	428,886,623	322,462,892	106,423,731	2,356,128	32,108	104,035,496

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculation to Reconstruct Test Period Billings Determinants
Based on Sales for the 12 months ended October 31, 2009

	(1)	(2)	(3)	(4)	(5)	(6)
	Net Revenue Page 1, Col. 7	**Calculated Net Revenue** Pages 3 thru 9	**Column 2 divided by Column 1**	**Mcf** Billed	Less: **Mcf** Cashouts and Off-system sales	**Mcf** Billed at Base Rates
GAS SALES AND TRANSPORTATION						
Residential Gas Service Rate RGS						-
Total Residential Gas Service Rate RGS	68,565,814	68,556,527	0.999865	20,292,001.6		20,292,001.6
Firm Commercial Gas Service Rate CGS				10,412,756.2		10,412,756.2
Gas Transportation Service/Standby Rider to Rat				15,691.0		15,691.0
Total Firm Commercial Gas Service Rate C	24,374,666	24,156,543	0.991051	10,428,447.2		10,428,447.2
Firm Industrial Gas Service Rate IGS				937,873.5		937,873.5
Gas Transportation Service/Standby Rider to Rat				57,640.3		57,640.3
Total Firm Industrial Gas Service Rate IGS	1,637,375	1,639,314	1.001184	995,513.8		995,513.8
As Available Gas Service				291,982.5		291,982.5
Total Rate AAGS	193,195	196,091	1.014987	291,982.5		291,982.5
FT - Cashouts	-			28,822.4	28,822.4	-
Firm Transportation Service Rate FT	3,574,174	3,570,488	0.998969	7,590,002.2		7,590,002.2
Total Rate FT	3,574,174	3,570,488	0.998969	7,618,824.6	28,822.4	7,590,002.2
Pooling Service Rate PS-FT	60,000	60,000	1.000000			
Intra-Company Special Contract - Sales Custome	3,046,907	3,053,936	1.002307	437,214.3		437,214.3
Intra-Company Special Contract - FT Customer	1,262,372	1,271,459	1.007198	13,677.0		13,677.0
Total Intra-Company	4,309,279	4,325,395	1.003740	450,891.3	-	450,891.3
Fort Knox Special Contract	259,769	259,794	1.000096	273,216.7		273,216.7
duPont Special Contract	177,746	177,771	1.000140	194,151.4		194,151.4
Ford LAP Special Contracts	883,477	883,527	1.000057	883,476.7		883,476.7
Special Contracts	1,320,992	1,321,092	1.000076	1,350,845		1,350,844.9
Total Ultimate Consumers	104,035,496	103,825,449	0.997981	41,428,506	28,822	41,399,683.5
Off-System Sales	-	-	-	-	-	-
Grand Total	104,035,496	103,825,449		41,428,505.9	28,822.4	41,399,683.5

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations to Reconstruct Test Period Billing Determinants
12 Months Ended October 31, 2009

Rate Class	Customers 12mos Oct 2009	Peak MCF	Off-Peak MCF	"As Billed Rates" During 12 Month Period: Unit Charges	Calculated Revenue
RATE RGS:					
Residential Gas Service Rate RGS					
Customers for the 12-Month Period					
Customers Nov08-Jan09:	1,038,361			$ 8.50	$ 8,826,069
Customers Feb09-Oct09:	2,445,080			$ 9.50	$ 23,228,260
Distribution Cost Component					
MCF Nov08-Jan09 Rates:		11,597,570.0		$ 1.54700	$ 17,941,441
MCF Feb09-Oct09 Rates:		8,693,970.4		$ 2.13490	$ 18,560,757
Total Rate RGS		**20,291,540.4**			**$ 68,556,527**

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations to Reconstruct Test Period Billing Determinants
12 Months Ended October 31, 2009

Rate Class	Customers 12mos Oct 2009	Peak MCF	Off-Peak MCF	During 12 Month Period Unit Charges	Calculated Revenue
RATE CGS:					
Firm Commercial Gas Service Rate CGS					
Customers for the 12-Month Period					
Meters < 5000 cfh					
Customers Nov08-Jan09:	103,433.00			$ 16.50	$ 1,706,645
Customers Feb09-Oct09:	190,838.00			$ 23.00	$ 4,389,274
Meters 5000 cfh or >					
Customers Nov08-Jan09:	4,158.00			$ 117.00	$ 486,486
Customers Feb09-Oct09:	8,886.00			$ 160.00	$ 1,421,760
Distribution Cost Component					
MCF Nov08-Jan09 Rates:		5,214,546.2		$ 1.49680	$ 7,805,133
MCF Feb09-Oct09 Rates:		4,112,092.1		$ 1.70520	$ 7,011,939
MCF Nov08-Jan09 Rates:			-	$ 0.99680	$ -
MCF Feb09-Oct09 Rates:			1,086,117.9	$ 1.20520	$ 1,308,989
Gas Transportation Service/Standby Rider to Rate CGS					
Administrative Charge-No. Customers					
MCF Nov08-Jan09 Rates:	7			$ 90.00	$ 630
MCF Feb09-Oct09 Rates:	14			$ 153.00	$ 2,142
Distribution Cost Component					
MCF Nov08-Jan09 Rates:		8,153.0		$ 1.49868	$ 12,219
MCF Feb09-Oct09 Rates:		4,483.7		$ 1.70520	$ 7,646
MCF Nov08-Jan09 Rates:			-	$ 0.99680	$ -
MCF Feb09-Oct09 Rates:			3,054.3	$ 1.20520	$ 3,681
Total Rate CGS		9,339,275.0	1,089,172.2		$ 24,156,543

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations to Reconstruct Test Period Billing Determinants
12 Months Ended October 31, 2009

Rate Class	Customers 12mos Oct 2009	Peak MCF	Off-Peak MCF	During 12 Month Period Unit Charges	Calculated Revenue
RATE IGS:					
Firm Industrial Gas Service Rate IGS					
Customers for the 12-Month Period					
Meters < 5000 cfh					
Customers Nov08-Jan09:	444			$ 16.50	$ 7,326
Customers Feb09-Oct09:	926			$ 23.00	$ 21,298
Meters 5000 cfh or >					
Customers Nov08-Jan09:	412			$ 117.00	$ 48,204
Customers Feb09-Oct09:	832			$ 160.00	$ 133,120
Distribution Cost Component					
MCF Nov08-Jan09 Rates:		357,194.5		$ 1.49680	$ 534,649
MCF Feb09-Oct09 Rates:		295,215.8		$ 1.65240	$ 487,815
MCF Nov08-Jan09 Rates:			0.0	$ 0.99680	$ -
MCF Feb09-Oct09 Rates:			285,463.2	$ 1.15240	$ 328,968
			0.0	$ 1,561,379	
Gas Transportation Service/Standby Rider to Rate IGS					
Administrative Charges for the 12-Month Period					
MCF Nov08-Jan09 Rates:	8			$ 90.00	$ 720
MCF Feb09-Oct09 Rates:	24			$ 153.00	$ 3,672
Distribution Cost Component					
MCF Nov08-Jan09 Rates:		9,543.9		$ 1.49868	$ 14,303
MCF Feb09-Oct09 Rates:		7,626.2		$ 1.65240	$ 12,602
MCF Nov08-Jan09 Rates:			0.0	$ 0.99680	$ -
MCF Feb09-Oct09 Rates:			40,470.2	$ 1.15240	$ 46,638
Total Rate IGS		669,580.4	325,933.4		$ 1,639,314

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations to Reconstruct Test Period Billing Determinants
12 Months Ended October 31, 2009

Rate Class	Customers 12mos Oct 2009	Peak MCF	Off-Peak MCF	During 12 Month Period Unit Charges	Calculated Revenue
RATE AAGS:					
As Available Gas Service Rate AAGS					
Customers for the 12-Month Period					
Customers Nov08-Jan09:	50			$ 150.00	$ 7,450
Customers Feb09-Oct09:	128			$ 275.00	$ 35,291
Distribution Cost Component		291,982.5		$ 0.52520	$ 153,349
Total Rate AAGS		**291,982.5**			**$ 196,091**

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations to Reconstruct Test Period Billing Determinants
12 Months Ended October 31, 2009

Rate Class	Customers 12mos Oct 2009	Peak MCF	Off-Peak MCF	During 12 Month Period: Unit Charges	During 12 Month Period: Calculated Revenue
RATE FT:					
Firm Transportation Service (Non-Standby) Rate FT					
Administrative Charges for the 12-Month Period					
MCF Nov08-Jan09 Rates:	220			$ 90.00	$ 19,800
MCF Feb09-Oct09 Rates:	621			$ 230.00	$ 142,830
Distribution Cost Component		7,590,002.2		$ 0.43000	$ 3,263,701
Utilization Charge for Daily Imbalances:					
Daily Storage Charge					
MCF Nov08-Jan09 Rates:		375,391.3		$ 0.1200	$ 45,047
MCF Feb09-Oct09 Rates:		540,697.4		$ 0.1833	$ 99,110
Total Rate FT					**$ 3,570,488**
RATE PS-FT:					
Pooling Service Rate PS - FT					
Administrative Charges	800			$ 75.00	$ 60,000
Total Rate PS-FT		**7,590,002.2**			**$ 60,000**

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations to Reconstruct Test Period Billing Determinants
12 Months Ended October 31, 2009

Rate Class	Customers 12mos Oct 2009	Peak MCF	Off-Peak MCF	During 12 Month Period Unit Charges	Calculated Revenue
INTRA-COMPANY SPECIAL CONTRACTS					
Intra-Company Special Contract - Sales Customers					
Customers for the 12-Month Period					
Customers Nov08-Jan09:	6			$ 68.00	$ 408
Customers Feb09-Oct09:	18			$ 160.00	$ 2,880
Distribution Cost Component		437,214.3		$ 0.2253	$ 98,504
Demand Charge		3,556,800		$ 0.83	$ 2,952,144
					$ 3,053,936
Intra-Company Special Contract - Rate FT Customer					
Customers for the 12-Month Period					
Customers Nov08-Jan09:	3			$ 686.00	$ 2,058
Customers Feb09-Oct09:	9			$ 781.00	$ 7,029
Distribution Cost Component		13,677.0		$ 0.04870	$ 666
Demand Charge		518,400.0		$ 2.43	$ 1,259,712
Sales Gas		1,195.6		$ -	$ -
Utilization Charge for Daily Imbalances:					
Daily Storage Charge					
MCF Nov08-Jan09 Rates:		326.5		$ 0.1200	$ 39
MCF Feb09-Oct09 Rates:		10,662.6		$ 0.1833	$ 1,954
					$ 1,271,459
Total Intra-Company Special Contracts					**$ 4,325,395**

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations to Reconstruct Test Period Billing Determinants
12 Months Ended October 31, 2009

Rate Class	Customers 12mos Oct 2009	Peak MCF	Off-Peak MCF	During 12 Month Period Unit Charges	During 12 Month Period Calculated Revenue
SPECIAL CONTRACTS					
Special Contract					
Transportation Service					
Admin Charge Nov08-Jan09:	3			$ 90.00	$ 270
Admin Charge Feb09-Oct09:	9			$ 230.00	$ 2,070
Distribution Cost Component		591,360.0		$ 0.0487	$ 28,799
Demand Charge		90,000.0		$ 2.43	$ 218,700
Sales Gas		2,469.0		$ -	$ -
Utilization Charge for Daily Imbalances:					
Daily Storage Charge					
MCF Nov08-Jan09 Rates:		38,077.8		$ 0.1200	$ 4,569
MCF Feb09-Oct09 Rates:		29,379.1		$ 0.1833	$ 5,385
					$ 259,794
Special Contract					
Transportation Service					
Admin Charge Nov08-Jan09:	3			$ 90.00	$ 270
Admin Charge Feb09-Oct09:	9			$ 230.00	$ 2,070
Distribution Cost Component		512,570.3		$ 0.1049	$ 53,769
Demand Charge		39,201.6		$2.75	$ 107,804
Sales Gas		3,343.5		$ -	$ -
Utilization Charge for Daily Imbalances:					
Daily Storage Charge					
MCF Nov08-Jan09 Rates:		12,852.9		$ 0.1200	$ 1,542
MCF Feb09-Oct09 Rates:		67,189.9		$ 0.1833	$ 12,316
					$ 177,771
Special Contracts					
Transportation Service					
Admin Charge Nov08-Jan09:	6			$ 90.00	$ 540
Admin Charge Feb09-Oct09:	18			$ 230.00	$ 4,140
Distribution Cost Component		1,710,388.1		$ 0.3200	$ 547,324
Annual Minimum Revenue Requirement					$ 331,523
					$ 883,527
Total Special Contracts					**$ 1,321,092**

Seelye Exhibit 9

Summary of
Gas Revenue Increase

Louisville Gas and Electric Company
Summary of Proposed Rate Increase
Based on Billing Determinants for the 12 Months Ended October 31, 2009

Rate Class	Base Rate Revenue	Temperature Normalization Adjustment	Year-End Adjustment	Rate Switching Adjustment	Base Rate Revenue As Adjusted	GSC Revenue as Adjusted	Total Current Revenue	Increase	Percentage Change
Residential Gas Service - Rate RGS	$ 76,423,451	$ (137,576)	$ 259,367		$ 76,545,242	$ 108,612,983	$ 185,158,225	$ 16,197,217	8.75%
Commercial Gas Service - Rate CGS	26,332,128	(36,646)	1,404,610		27,700,091	58,811,636	86,511,727	5,362,492	6.20%
Industrial Gas Service - Rate IGS	1,715,435	(18,867)	96,963	(34,975)	1,758,556	5,185,788	6,944,344	363,149	5.23%
As-Available Gas Service - Rate AAGS	199,312	(1,740)	-		197,572	1,544,204	1,741,776		
Total Firm Transportation Service (Non-Standby) Rate FT	3,628,793	(13,063)	-	748,206	4,363,936	171,858	4,535,795		
Total Rate PS-FT	60,000				60,000		60,000		
Special Contract - Intra-Company Sales	3,054,488				3,054,488	2,338,834	5,393,323	665,390	12.34%
Special Contract - Intra-Company Transportation	4,326,253				4,326,253		4,326,253		
Special Contract	262,624				262,624		262,624		
Special Contract	179,005				179,005		179,005		
Total Sales to Ultimate Consumers and Inter-Company	$ 116,181,488	$ (207,892)	$ 1,760,940	$ 713,231	$ 118,447,767	$ 176,665,303	$ 295,113,070	$ 22,588,249	7.65%

Seelye Exhibit 10

Gas Revenue Increase by Rate Schedule

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations to Reconstruct Test Period Billing Determinants
12 Months Ended October 31, 209

Rate Class	Customers 12mos Oct 2009	Peak MCF	Off-Peak MCF	"As Billed Rates" During 12 Month Period Unit Charges	"As Billed Rates" During 12 Month Period Calculated Revenue	P.S.C. Gas No. 7 for Full Year Unit Charges	P.S.C. Gas No. 7 for Full Year Calculated Revenue	Proposed Rates Unit Charges	Proposed Rates Calculated Revenue
RATE RGS:									
Residential Gas Service Rate RGS									
Customers for the 12-Month Period									
Customers Nov08-Jan09:	1,038,361			$ 8.50	$ 8,826,069	$ 9.50	$ 9,864,430	$ 26.53	$ 27,547,717
Customers Feb09-Oct09:	2,445,080			$ 9.50	$ 23,228,260	$ 9.50	$ 23,228,260	$ 26.53	64,867,972
Distribution Cost Component									
MCF Nov08-Jan09 Rates:		11,597,570.0		$ 1.54700	$ 17,941,441	$ 2.13490	$ 24,759,652		-
MCF Feb09-Oct09 Rates:		8,693,970.4		$ 2.13490	$ 18,560,757	$ 2.13490	$ 18,560,757		-
Subtotal		**20,291,540.4**			**$ 68,556,527**		**$ 76,413,099**		**$ 92,415,690**
Correction Factor				0.999865		0.999865		0.999865	
Subtotal Rate RGS after application of Correction Factor					**68,565,814**		**76,423,451**		**92,428,209**
Temperature Normalization		(64,441.3)		$ 2.13490	$ (137,576)	$ 2.13490	$ (137,576)	$ -	$ -
Adjustment to Reflect Year-End Customers		76,670.0			259,367		259,367		314,250
GSC at Current (Feb 2010 to Apr 2010) Charges GSC		20,303,769.1		5.3494	$ 108,612,983	5.3494	$ 108,612,983	5.3494	$ 108,612,983
Total Residential Gas Service Rate RGS		20,303,769.1			177,300,588		185,158,225		201,355,442
Proposed Increase in Revenue									16,197,217 8.75%

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations to Reconstruct Test Period Billing Determinants
12 Months Ended October 31, 209

Rate Class	Customers 12mos Oct 2009	Peak MCF	Off-Peak MCF	During 12 Month Period Unit Charges	During 12 Month Period Calculated Revenue	P.S.C. Gas No. 7 for Full Year Unit Charges	P.S.C. Gas No. 7 for Full Year Calculated Revenue	Proposed Rates Unit Charges	Proposed Rates Calculated Revenue
RATE CGS:									
Firm Commercial Gas Service Rate CGS									
Customers for the 12-Month Period									
Meters < 5000 cfh									
Customers Nov08-Jan09:	103,433			$ 16.50	$ 1,706,645	$ 23.00	$ 2,378,959	$ 30.00	$ 3,102,990
Customers Feb09-Oct09:	190,838			$ 23.00	$ 4,389,274	$ 23.00	$ 4,389,274	$ 30.00	$ 5,725,140
Meters 5000 cfh or >									
Customers Nov08-Jan09:	4,158			$ 117.00	$ 486,486	$ 160.00	$ 665,280	$ 170.00	$ 706,860
Customers Feb09-Oct09:	8,886			$ 160.00	$ 1,421,760	$ 160.00	$ 1,421,760	$ 170.00	$ 1,510,620
Distribution Cost Component									
MCF Nov08-Jan09 Rates:		5,214,546.2		$ 1.49680	$ 7,805,133	$ 1.70520	$ 8,891,844	$ 1.9795	$ 10,322,194
MCF Feb09-Oct09 Rates:		4,112,092.1		$ 1.70520	$ 7,011,939	$ 1.70520	$ 7,011,939	$ 1.9795	$ 8,139,886
MCF Nov08-Jan09 Rates:			-	$ 0.99680	$ -	$ 1.20520	$ -	$ 1.4795	
MCF Feb09-Oct09 Rates:			1,086,117.9	$ 1.20520	$ 1,308,989	$ 1.20520	$ 1,308,989	$ 1.4795	$ 1,606,911
Gas Transportation Service/Standby Rider to Rate CGS									
Administrative Charge-No. Customers									
MCF Nov08-Jan09 Rates:	7			$ 90.00	$ 630	$ 153.00	$ 1,071	$ 153.00	$ 1,071
MCF Feb09-Oct09 Rates:	14			$ 153.00	$ 2,142	$ 153.00	$ 2,142	$ 153.00	$ 2,142
Distribution Cost Component									
MCF Nov08-Jan09 Rates:		8,153.0		$ 1.49868	$ 12,219	$ 1.70520	$ 13,902	$ 1.9795	$ 16,139
MCF Feb09-Oct09 Rates:		4,483.7		$ 1.70520	$ 7,646	$ 1.70520	$ 7,646	$ 1.9795	$ 8,875
MCF Nov08-Jan09 Rates:			-	$ 0.99680	$ -	$ 1.20520	$ -	$ 1.4795	
MCF Feb09-Oct09 Rates:			3,054.3	$ 1.20520	$ 3,681	$ 1.20520	$ 3,681	$ 1.4795	$ 4,519
Subtotal		**9,339,275.0**	**1,089,172.2**		**$ 24,156,543**		**$ 26,096,488**		**$ 31,147,348**
Correction Factor				0.991051		0.991051		0.991051	
Subtotal Rate CGS after application of Correction Factor					**24,374,666**		**26,332,128**		**31,428,595**
Temperature Normalization		(21,490.9)		$ 1.70520	$ (36,646)	$ 1.70520	$ (36,646)	$ 1.97950	$ (42,541)
Adjustment to Reflect Year-End Customers		600,620.0			$ 1,404,610		$ 1,404,610		1,676,530
GSC at Current (Feb 2010 to Apr 2010) Charges GSC		10,991,013.9		5.3494	$ 58,795,330	5.3494	$ 58,795,330	5.3494	$ 58,795,330
GSC at Current - Pipeline Suppliers Demand		16,562.4		0.9845	$ 16,306	0.9845	$ 16,306	0.9845	$ 16,306
Total Commercial Gas Service Rate CGS		11,007,576.3			84,554,265		86,511,727		91,874,219
Proposed Increase in Revenue									5,362,492 6.20%

Rate Class	Customers 12mos Oct 2009	Peak MCF	Off-Peak MCF	During 12 Month Period Unit Charges	During 12 Month Period Calculated Revenue	P.S.C. Gas No. 7 for Full Year Unit Charges	P.S.C. Gas No. 7 for Full Year Calculated Revenue	Proposed Rates Unit Charges	Proposed Rates Calculated Revenue
RATE IGS:									
Firm Industrial Gas Service Rate IGS									
Customers for the 12-Month Period									
Meters < 5000 cfh									
Customers Nov08-Jan09:	444			$ 16.50	$ 7,326	$ 23.00	$ 10,212	$ 30.00	$ 13,320
Customers Feb09-Oct09:	926			$ 23.00	$ 21,298	$ 23.00	$ 21,298	$ 30.00	$ 27,780
Meters 5000 cfh or >									
Customers Nov08-Jan09:	412			$ 117.00	$ 48,204	$ 160.00	$ 65,920	$ 170.00	$ 70,040
Customers Feb09-Oct09:	832			$ 160.00	$ 133,120	$ 160.00	$ 133,120	$ 170.00	$ 141,440
Distribution Cost Component									
MCF Nov08-Jan09 Rates:		357,194.5		$ 1.49680	$ 534,649	$ 1.65240	$ 590,228	$ 1.97950	$ 707,067
MCF Feb09-Oct09 Rates:		295,215.8		$ 1.65240	$ 487,815	$ 1.65240	$ 487,815	$ 1.97950	$ 584,380
MCF Nov08-Jan09 Rates:			0.0	$ 0.99680	$ -	$ 1.15240	$ -	$ 1.47950	
MCF Feb09-Oct09 Rates:			285,463.2	$ 1.15240	$ 328,968	$ 1.15240	$ 328,968	$ 1.47950	$ 422,343
Gas Transportation Service/Standby Rider to Rate IGS									
Administrative Charges for the 12-Month Period									
MCF Nov08-Jan09 Rates:	8			$ 90.00	$ 720	$ 153.00	$ 1,224	$ 153.00	$ 1,224
MCF Feb09-Oct09 Rates:	24			$ 153.00	$ 3,672	$ 153.00	$ 3,672	$ 153.00	$ 3,672
Distribution Cost Component									
MCF Nov08-Jan09 Rates:		9,543.9		$ 1.49868	$ 14,303	$ 1.65240	$ 15,770	$ 1.97950	$ 18,892
MCF Feb09-Oct09 Rates:		7,626.2		$ 1.65240	$ 12,602	$ 1.65240	$ 12,602	$ 1.97950	$ 15,096
MCF Nov08-Jan09 Rates:			0.0	$ 0.99680	$ -	$ 1.15240	$ -	$ 1.47950	$ -
MCF Feb09-Oct09 Rates:			40,470.2	$ 1.15240	$ 46,638	$ 1.15240	$ 46,638	$ 1.47950	$ 59,876
Subtotal		**669,580.4**	**325,933.4**		**$ 1,639,314**		**$ 1,717,466**		**$ 2,065,129**
Correction Factor				1.001184		1.001184		1.001184	
Subtotal Rate IGS after application of Correction Factor					**1,637,375**		**1,715,435**		**2,062,686**
Temperature Normalization		(11,417.8)		$ 1.65240	$ (18,866.73)	$ 1.65240	$ (18,866.73)	$ 1.97950	$ (22,601.49)
Adjustment to Reflect Year-End Customers		58,955.0			$ 96,963.00		$ 96,963.00		116,596
Adjustment for Rate Switching									
Customer Chg 12-months	(12)				$ (1,767.97)		$ (1,767.97)		$ (1,767.97)
On-Peak MCF 12-months		(12,950.7)			$ (20,061.22)		$ (20,061.22)		$ (20,061.22)
Off-Peak MCF Apr09-Oct09			(11,407.3)		$ (13,145.77)		$ (13,145.77)		$ (13,145.77)
GSC at Current (Feb 2010 to Apr 2010) Charges GSC		958,300.3		5.3494	$ 5,126,332	5.3494	$ 5,126,332	5.3494	$ 5,126,332
GSC at Current - Pipeline Suppliers Demand		60,392.7		0.9845	$ 59,457	0.9845	$ 59,457	0.9845	$ 59,457
Total Industrial Gas Service Rate IGS		1,018,693.0			6,866,285		6,944,344		7,307,494
Proposed Increase in Revenue									363,149 5.23%

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations to Reconstruct Test Period Billing Determinants
12 Months Ended October 31, 209

Rate Class	Customers 12mos Oct 2009	Peak MCF	Off-Peak MCF	During 12 Month Period Unit Charges	During 12 Month Period Calculated Revenue	P.S.C. Gas No. 7 for Full Year Unit Charges	P.S.C. Gas No. 7 for Full Year Calculated Revenue	Proposed Rates Unit Charges	Proposed Rates Calculated Revenue
RATE AAGS:									
As Available Gas Service Rate AAGS									
Customers for the 12-Month Period									
Customers Nov08-Jan09:	50			$ 150.00	$ 7,450	$ 275.00	$ 13,659	$ 275.00	$ 13,659
Customers Feb09-Oct09:	128			$ 275.00	$ 35,291	$ 275.00	$ 35,291	$ 275.00	$ 35,291
Distribution Cost Component		291,982.5		$ 0.52520	$ 153,349	$ 0.52520	$ 153,349	$ 0.52520	$ 153,349
Subtotal		**291,982.5**			**$ 196,091**		**$ 202,299**		**$ 202,299**
Correction Factor				1.014987		1.014987		1.014987	
Subtotal Rate AAGS after application of Correction Factor					**193,195**		**199,312**		**199,312**
Temperature Normalization		(3,313.8)		$ 0.52520	$ (1,740)	$ 0.52520	$ (1,740)	$ 0.52520	$ (1,740.43)
Adjustment to Reflect Year-End Customers		-			-		-		-
GSC at Current (Feb 2010 to Apr 2010) Charges GSC		288,668.7		5.3494	$ 1,544,204	5.3494	$ 1,544,204	5.3494	$ 1,544,204
GSC at Current - Pipeline Suppliers Demand		-			$ -		$ -		$ -
Total As Available Gas Service Rate AAGS		288,668.7			1,735,659		1,741,776		1,741,776
Proposed Increase in Revenue									0
									0.00%

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations to Reconstruct Test Period Billing Determinants
12 Months Ended October 31, 209

				During 12 Month Period		P.S.C. Gas No. 7 for Full Year		Proposed Rates	
Rate Class	Customers 12mos Oct 2009	Peak MCF	Off-Peak MCF	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue	Unit Charges	Calculated Revenue
RATE FT:									
Firm Transportation Service (Non-Standby) Rate FT									
Administrative Charges for the 12-Month Period									
MCF Nov08-Jan09 Rates:	220			$ 90.00	$ 19,800	$ 230.00	$ 50,600	$ 230.00	$ 50,600
MCF Feb09-Oct09 Rates:	621			$ 230.00	$ 142,830	$ 230.00	$ 142,830	$ 230.00	$ 142,830
Distribution Cost Component		7,590,002.2		$ 0.43000	$ 3,263,701	$ 0.43000	$ 3,263,701	$ 0.43000	$ 3,263,701
Utilization Charge for Daily Imbalances:									
Daily Storage Charge									
MCF Nov08-Jan09 Rates:		375,391.3		$ 0.1200	$ 45,047	$ 0.1833	$ 68,809	$ 0.1833	$ 68,809
MCF Feb09-Oct09 Rates:		540,697.4		$ 0.1833	$ 99,110	$ 0.1833	$ 99,110	$ 0.1833	$ 99,110
Subtotal					**$ 3,570,488**		**$ 3,625,050**		**$ 3,625,050**
Correction Factor				0.998969		0.998969		0.998969	
Subtotal Rate FT after application of Correction Factor					**3,574,174.5**		**3,628,793.1**		**3,628,793.1**
Temperature Normalization		(30,377.9)		$ 0.4300	(13,062.5)	$ 0.4300	$ (13,063)	$ 0.4300	$ (13,063)
Adjustment to Reflect Year-End Customers		-			-		$ -		$ -
Adjustment for Rate Switching									
Admin Chg 12-months	36				$ 2,265		$ 2,265		$ 2,265
On-Peak MCF 12-months		1,734,746.1			745,941		$ 745,941		$ 745,941
UCDI Charge - Daily Demand (current)		916,088.6		$ 0.1876	171,858.2	$ 0.1876	171,858.2	$ 0.1876	171,858.2
Total Firm Transportation (Non-Standby) Rate FT		9,294,370.4			4,481,176		4,535,795		4,535,795
Proposed Increase in Revenue									- 0.00%
Pooling Service Rate PS - FT									
Administrative Charges	800			$ 75.00	$ 60,000	$ 75.00	$ 60,000	$ 75	$ 60,000
Total Rate PS-FT					60,000		60,000		60,000
Proposed Increase in Revenue									- 0.00%

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations to Reconstruct Test Period Billing Determinants
12 Months Ended October 31, 209

Rate Class	Customers 12mos Oct 2009	Peak MCF	Off-Peak MCF	During 12 Month Period: Unit Charges	During 12 Month Period: Calculated Revenue	P.S.C. Gas No. 7 for Full Year: Unit Charges	P.S.C. Gas No. 7 for Full Year: Calculated Revenue	Proposed Rates: Unit Charges	Proposed Rates: Calculated Revenue
INTRA-COMPANY SPECIAL CONTRACTS									
Intra-Company Special Contract - Sales Service									
Customers for the 12-Month Period									
Customers Nov08-Jan09:	6			$ 68.00	$ 408	$ 160.00	$ 960	$ 170.00	$ 1,020
Customers Feb09-Oct09:	18			$ 160.00	$ 2,880	$ 160.00	$ 2,880	$ 170.00	$ 3,060
Distribution Cost Component		437,214.3 Mcf		$ 0.2253	$ 98,504	$ 0.2253	$ 98,504	$ 0.2744	$ 119,982
Demand Charge		3,556,800 Ccfd		$ 0.83	$ 2,952,144	$ 0.83	$ 2,952,144	$ 1.0110	$ 3,595,817
					$ 3,053,936		$ 3,054,488		$ 3,719,878
GSC at Current (Feb 2010 to Apr 2010) Charges GSC		437,214.3		$ 5.3494	$ 2,338,834	$ 5.3494	$ 2,338,834	$ 5.3494	$ 2,338,834
Total Intra-Company Special Contract - Sales Service					$ 5,392,771		$ 5,393,323		$ 6,058,713
Increase									$ 665,390
									12.34%
Intra-Company Special Contract - Rate FT Customer									
Customers for the 12-Month Period									
Customers Nov08-Jan09:	3			$ 686.00	$ 2,058	$ 781.00	$ 2,343	$ 781.00	$ 2,343
Customers Feb09-Oct09:	9			$ 781.00	$ 7,029	$ 781.00	$ 7,029	$ 781.00	$ 7,029
Distribution Cost Component		13,677.0		$ 0.04870	$ 666	$ 0.04870	$ 666	$ 0	$ 666
Demand Charge		518,400.0		$ 2.43	$ 1,259,712	$ 2.43	$ 1,259,712	$ 2	$ 1,259,712
Sales Gas		1,195.6		$ -	$ -	$ -	$ -		
Utilization Charge for Daily Imbalances:									
Daily Storage Charge									
MCF Nov08-Jan09 Rates:		326.5		$ 0.1200	$ 39	$ 0.1833	$ 60	$ 0	$ 60
MCF Feb09-Oct09 Rates:		10,662.6		$ 0.1833	$ 1,954	$ 0.1833	$ 1,954	$ 0	$ 1,954
					$ 1,271,459		$ 1,271,764		$ 1,271,764
Total Intra-Company Special Contracts		452,086.9			$ 4,325,395		$ 4,326,253		$ 4,991,643

LOUISVILLE GAS AND ELECTRIC COMPANY
Calculations to Reconstruct Test Period Billing Determinants
12 Months Ended October 31, 209

Rate Class	Customers 12mos Oct 2009	Peak MCF	Off-Peak MCF	During 12 Month Period Unit Charges	During 12 Month Period Calculated Revenue	P.S.C. Gas No. 7 for Full Year Unit Charges	P.S.C. Gas No. 7 for Full Year Calculated Revenue	Proposed Rates Unit Charges	Proposed Rates Calculated Revenue
SPECIAL CONTRACTS									
Special Contract									
Transportation Service									
Admin Charge Nov08-Jan09:	3			$ 90.00	$ 270	$ 230.00	$ 690		
Admin Charge Feb09-Oct09:	9			$ 230.00	$ 2,070	$ 230.00	$ 2,070		
Distribution Cost Component		591,360.0		$ 0.0487	$ 28,799	$ 0.0487	$ 28,799		
Demand Charge		90,000.0		$ 2.43	$ 218,700	$ 2.43	$ 218,700		
Sales Gas		2,469.0		$ -	$ -	$ -	$ -		
Utilization Charge for Daily Imbalances:									
Daily Storage Charge									
MCF Nov08-Jan09 Rates:		38,077.8		$ 0.1200	$ 4,569	$ 0.1833	$ 6,980		
MCF Feb09-Oct09 Rates:		29,379.1		$ 0.1833	$ 5,385	$ 0.1833	$ 5,385		
					$ 259,794		$ 262,624		
Special Contract									
Transportation Service									
Admin Charge Nov08-Jan09:	3			$ 90.00	$ 270	$ 230.00	$ 690		
Admin Charge Feb09-Oct09:	9			$ 230.00	$ 2,070	$ 230.00	$ 2,070		
Distribution Cost Component		512,570.3		$ 0.1049	$ 53,769	$ 0.1049	$ 53,769		
Demand Charge		39,201.6		$2.75	$ 107,804	$ 2.75	$ 107,804		
Sales Gas		3,343.5		$ -	$ -	$ -	$ -		
Utilization Charge for Daily Imbalances:									
Daily Storage Charge									
MCF Nov08-Jan09 Rates:		12,852.9		$ 0.1200	$ 1,542	$ 0.1833	$ 2,356		
MCF Feb09-Oct09 Rates:		67,189.9		$ 0.1833	$ 12,316	$ 0.1833	$ 12,316		
					$ 177,771		$ 179,005		
Special Contracts									
Transportation Service									
Admin Charge Nov08-Jan09:	6			$ 90.00	$ 540	$ 230.00	$ 1,380		
Admin Charge Feb09-Oct09:	18			$ 230.00	$ 4,140	$ 230.00	$ 4,140		
Distribution Cost Component		1,710,388.1		$ 0.3200	$ 547,324	$ 0.3200	$ 547,324		
Annual Minimum Revenue Requirement					$ 331,523		$ 331,523		
					$ 883,527		$ 884,367		
Total Special Contracts					$ 1,321,092		$ 1,325,996		

Seelye Exhibit 11

Cable TV Attachment Charges

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost		Average Installed Cost	
Weighted Average Bare Pole Cost as of 10/31/2009					
35'	21,992	$	9,895,841	$	449.97
40'	61,023		25,998,372		426.04
	83,015	$	35,894,213	$	432.38
Three-User Poles					
40'	61,023	$	25,998,372	$	426.04
45'	22,136		23,008,391		1,039.41
	83,159	$	49,006,763	$	589.31

	Number of Attachments		Weighted Cost
Two-User Pole Charge			
$432.38 x .1224 Usage Space Factor = $ 52.92			
$ 52.92 x .1843 Annual Carrying Charge = $ 9.76	17,699	$	172,659
Three-User Pole Charge			
$589.31 x .0759 Usage Space Factor = $44.73			
$ 44.73 x .1843 Annual Carrying Charge = $8.24	68,646	$	565,966
Weighted Total	86,345	$	738,625
Weighted Average Monthly Cost		$	8.55

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	8.32%
Depreciation - Sinking Fund	0.54%
Income Tax (1)	3.63%
Property Tax and Insurance	0.22%
Operation and Maintenance (Page 3)	5.73%
Total	18.43%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Common	53.86%	11.50%	6.19%
Preferred	0.00%	0.00%	0.00%
Total Equity	53.86%		6.19%
Debt	46.14%	4.61%	2.13%
Total Capitalization	100.00%		8.32%

Composite Federal and State Income Taxes rate = 36.93%

Income Tax = (0.3693/(1-0.3693) x 0.0619 = 3.63%

LOUISVILLE GAS AND ELECTRIC COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2009

(1) Labor Charged to 592 - Poles, Towers and Fixtures Subaccount	$ 289,969	
- Tree Trimming	225,900	
		$ 515,870
Total Labor		$ 56,166,593
Total Administrative and General Expenses		$ 73,557,685

Assignment of a Portion of A & G Expenses to Poles

($515,870/$56,166,593) x $73,557,685 = $675,600

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$ 1,366,766
Tree Trimming of Electric Distribution Routes 593004	4,775,583
A & G Expenses Assigned to Poles	675,600
Total	$ 6,817,950

Adder to Annual Carrying Charges for O & M Expenses

$$\frac{\$\ 6{,}817{,}950 \quad \text{Expenses Assigned to Poles}}{119{,}084{,}747 \quad \text{Plant in Service - Account 364}} = 5.73\%$$

Seelye Exhibit 12

Excess Facilities Charge
Cost Support

Louisville Gas and Electric Company
Present Value of Replacement Plant as a Percentage of Original Cost
Electric Service

Year (1)	30 Year R2 Iowa Curve Percent Surviving (2)	Annual Replacement Percentage (3)	Cumulative Replacement Percentage (4)	Cost Escalation Factor at a 3.00% Inflation Factor (5)	Nominal Replacement Cost (6)	Present Value Factor at a 7.00% Discount Rate (7)	Present Value of Annual Replacement Cost (8)	Cumulative Present Value of Annual Replaced Cost (9)
					(3) x (5)		(6) x (7)	
0	100.0000							
1	99.6710	0.3290	0.3290	1.0300	0.3389	0.9346	0.3167	0.3167
2	99.3034	0.3676	0.6966	1.0609	0.3900	0.8734	0.3406	0.6573
3	98.8936	0.4098	1.1064	1.0927	0.4478	0.8163	0.3655	1.0229
4	98.4380	0.4556	1.5620	1.1255	0.5128	0.7629	0.3912	1.4141
5	97.9327	0.5053	2.0673	1.1593	0.5858	0.7130	0.4177	1.8317
6	97.3737	0.5590	2.6263	1.1941	0.6675	0.6663	0.4448	2.2765
7	96.7565	0.6172	3.2435	1.2299	0.7591	0.6227	0.4727	2.7492
8	96.0767	0.6798	3.9233	1.2668	0.8612	0.5820	0.5012	3.2504
9	95.3294	0.7473	4.6706	1.3048	0.9751	0.5439	0.5304	3.7808
10	94.5095	0.8199	5.4905	1.3439	1.1019	0.5083	0.5601	4.3409
11	93.6118	0.8977	6.3882	1.3842	1.2426	0.4751	0.5904	4.9313
12	92.6306	0.9812	7.3694	1.4258	1.3990	0.4440	0.6212	5.5524
13	91.5602	1.0704	8.4398	1.4685	1.5719	0.4150	0.6523	6.2047
14	90.3943	1.1659	9.6057	1.5126	1.7635	0.3878	0.6839	6.8886
15	89.1267	1.2676	10.8733	1.5580	1.9749	0.3624	0.7158	7.6044
16	87.7508	1.3759	12.2492	1.6047	2.2079	0.3387	0.7479	8.3523
17	86.2598	1.4910	13.7402	1.6528	2.4644	0.3166	0.7802	9.1325
18	84.6471	1.6127	15.3529	1.7024	2.7455	0.2959	0.8123	9.9448
19	82.9057	1.7414	17.0943	1.7535	3.0536	0.2765	0.8443	10.7891
20	81.0292	1.8765	18.9708	1.8061	3.3892	0.2584	0.8758	11.6649
21	79.0113	2.0179	20.9887	1.8603	3.7539	0.2415	0.9066	12.5716
22	76.8463	2.1650	23.1537	1.9161	4.1484	0.2257	0.9363	13.5079
23	74.5295	2.3168	25.4705	1.9736	4.5724	0.2109	0.9645	14.4724
24	72.0573	2.4722	27.9427	2.0328	5.0255	0.1971	0.9908	15.4632
25	69.4278	2.6295	30.5722	2.0938	5.5056	0.1842	1.0144	16.4776
26	66.6411	2.7867	33.3589	2.1566	6.0098	0.1722	1.0349	17.5124
27	63.7000	2.9411	36.3000	2.2213	6.5330	0.1609	1.0514	18.5638
28	60.6101	3.0899	39.3899	2.2879	7.0695	0.1504	1.0633	19.6271
29	57.3808	3.2293	42.6192	2.3566	7.6101	0.1406	1.0697	20.6968
30	54.0251	3.3557	45.9749	2.4273	8.1452	0.1314	1.0700	21.7668

Present Value of Replacement Plant as a Percentage of Original Cost $\boxed{21.7668}$

Louisville Gas and Electric Company
Excess Facilities Charges
Electric Service

		Assuming Customer Does Not Make Up-Front Payment to Cover Original Cost	Assuming Customer Makes Up-Front Payment to Cover Original Cost
1	Present Value of Replacement Plant as a Percentage of Original Cost	21.77	21.77
2	Original Cost Value	100	-
3	Total Present Value of Original and Replacement Cost Value as a Percentage of Original Cost	121.77	21.77
4	Monthly Carrying Charge Percentage (Levelized Carrying Charge Rate / 12 months)	0.00860	0.00860
5	Applicable Carrying Charge Charge Percentage (Lines 3 x 5)	1.05%	0.19%
6	O&M Percentage	0.68%	0.68%
7	Total Excess Facilities Charge	1.73%	0.87%

Louisville Gas and Electric Company
Levelized Carrying Charge Analysis - Electric
Electric Service

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Debt	46.14%	4.61%	2.13%	37.60%	1.33%
Preferred Equity	0.00%	0.00%	0.00%		0.00%
Common Equity	53.86%	11.50%	6.19%		6.19%
			8.32%		7.52%

Tax Depreciation Table (MACRS)

	5	10	15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%
31	0.000%	0.000%	0.000%	0.000%
31	0.000%	0.000%	0.000%	0.000%

Louisville Gas and Electric Company
Levelized Carrying Charge Analysis
Electric Service

Assumptions:

Investment	$	1,000
Book Life		30
Tax Life		20
Composite Tax Rate		37.6028%
Property Tax Rate		0.00%
Levelized Revenue Requirement Years		35
O&M as Percent of Investment		0.00%

Results:

Present Value Revenue Requirement	$	1,164	
Levelized Revenue Requirement		$103	
Levelized Carrying Charge Rate		10.32%	
Level of Investment that can be Supported b'		9.69	Times Net Revenue

Year	Investment	Book Depreciation	Residual Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 1,000						
1		33	967	38	963	2	2
2		33	933	72	890	15	16
3		33	900	67	824	13	29
4		33	867	62	762	11	39
5		33	833	57	705	9	48
6		33	800	53	652	7	56
7		33	767	49	603	6	62
8		33	733	45	558	4	66
9		33	700	45	513	4	70
10		33	667	45	468	4	75
11		33	633	45	424	4	79
12		33	600	45	379	4	83
13		33	567	45	335	4	87
14		33	533	45	290	4	92
15		33	500	45	245	4	96
16		33	467	45	201	4	100
17		33	433	45	156	4	104
18		33	400	45	112	4	108
19		33	367	45	67	4	113
20		33	333	45	22	4	117
21		33	300	22	(0)	(4)	113
22		33	267	-	(0)	(13)	100
23		33	233	-	(0)	(13)	88
24		33	200	-	(0)	(13)	75
25		33	167	-	(0)	(13)	63
26		33	133	-	(0)	(13)	50
27		33	100	-	(0)	(13)	38
28		33	67	-	(0)	(13)	25
29		33	33	-	(0)	(13)	13
30		33	(0)	-	(0)	(13)	-

Louisville Gas and Electric Company
Levelized Carrying Charge Analysis
Electric Service

Assumptions:

Investment	$	1,000
Book Life		30
Tax Life		20
Composite Tax Rate		37.6028%
Property Tax Rate		0.00%
Levelized Revenue Requirement Years		35
O&M as Percent of Investment		0.00%

Results:

Present Value Revenue Requirement	$	1,164	
Levelized Revenue Requirement		$103	
Levelized Carrying Charge Rate		10.32%	
Level of Investment that can be Supported by Revenue		9.69	Times Net Revenue

Year	Rate Base	Interest	Equity	Income Taxes	Annual Revenue Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0	$ -	-	$ -	-	$ -	1.000000	$ -
1	965	21	60	36	150	1	138
2	917	20	57	34	144	0.852266	123
3	871	19	54	33	138	0.786797	109
4	827	18	51	31	133	0.726357	97
5	785	17	49	29	128	0.670560	86
6	744	16	46	28	123	0.619049	76
7	705	15	44	26	118	0.571495	68
8	667	14	41	25	114	0.527594	60
9	630	13	39	24	109	0.487066	53
10	592	13	37	22	105	0.449651	47
11	555	12	34	21	100	0.415110	42
12	517	11	32	19	96	0.383222	37
13	479	10	30	18	91	0.353784	32
14	442	9	27	16	87	0.326607	28
15	404	9	25	15	82	0.301518	25
16	367	8	23	14	78	0.278356	22
17	329	7	20	12	73	0.256973	19
18	292	6	18	11	68	0.237233	16
19	254	5	16	9	64	0.219009	14
20	216	5	13	8	59	0.202186	12
21	187	4	12	7	56	0.186654	10
22	166	4	10	6	53	0.172316	9
23	146	3	9	5	51	0.159079	8
24	125	3	8	5	48	0.146859	7
25	104	2	6	4	46	0.135578	6
26	83	2	5	3	43	0.125163	5
27	62	1	4	2	41	0.115548	5
28	42	1	3	2	38	0.106672	4
29	21	0	1	1	36	0.098478	4
30	(0)	(0)	(0)	(0)	33	0.090913	3
							$ 1,164

Louisville Gas and Electric Company
Present Value of Replacement Plant as a Percentage of Original Cost
Gas Service

Year (1)	30 Year R2 Iowa Curve Percent Surviving (2)	Annual Replacement Percentage (3)	Cumulative Replacement Percentage (4)	Cost Escalation Factor at a 3.00% Inflation Factor (5)	Nominal Replacement Cost (6)	Present Value Factor at a 7.00% Discount Rate (7)	Present Value of Annual Replacement Cost (8)	Cumulative Present Value of Annual Replaced Cost (9)
					(3) x (5)		(6) x (7)	
0	100.0000							
1	99.6710	0.3290	0.3290	1.0300	0.3389	0.9346	0.3167	0.3167
2	99.3034	0.3676	0.6966	1.0609	0.3900	0.8734	0.3406	0.6573
3	98.8936	0.4098	1.1064	1.0927	0.4478	0.8163	0.3655	1.0229
4	98.4380	0.4556	1.5620	1.1255	0.5128	0.7629	0.3912	1.4141
5	97.9327	0.5053	2.0673	1.1593	0.5858	0.7130	0.4177	1.8317
6	97.3737	0.5590	2.6263	1.1941	0.6675	0.6663	0.4448	2.2765
7	96.7565	0.6172	3.2435	1.2299	0.7591	0.6227	0.4727	2.7492
8	96.0767	0.6798	3.9233	1.2668	0.8612	0.5820	0.5012	3.2504
9	95.3294	0.7473	4.6706	1.3048	0.9751	0.5439	0.5304	3.7808
10	94.5095	0.8199	5.4905	1.3439	1.1019	0.5083	0.5601	4.3409
11	93.6118	0.8977	6.3882	1.3842	1.2426	0.4751	0.5904	4.9313
12	92.6306	0.9812	7.3694	1.4258	1.3990	0.4440	0.6212	5.5524
13	91.5602	1.0704	8.4398	1.4685	1.5719	0.4150	0.6523	6.2047
14	90.3943	1.1659	9.6057	1.5126	1.7635	0.3878	0.6839	6.8886
15	89.1267	1.2676	10.8733	1.5580	1.9749	0.3624	0.7158	7.6044
16	87.7508	1.3759	12.2492	1.6047	2.2079	0.3387	0.7479	8.3523
17	86.2598	1.4910	13.7402	1.6528	2.4644	0.3166	0.7802	9.1325
18	84.6471	1.6127	15.3529	1.7024	2.7455	0.2959	0.8123	9.9448
19	82.9057	1.7414	17.0943	1.7535	3.0536	0.2765	0.8443	10.7891
20	81.0292	1.8765	18.9708	1.8061	3.3892	0.2584	0.8758	11.6649
21	79.0113	2.0179	20.9887	1.8603	3.7539	0.2415	0.9066	12.5716
22	76.8463	2.1650	23.1537	1.9161	4.1484	0.2257	0.9363	13.5079
23	74.5295	2.3168	25.4705	1.9736	4.5724	0.2109	0.9645	14.4724
24	72.0573	2.4722	27.9427	2.0328	5.0255	0.1971	0.9908	15.4632
25	69.4278	2.6295	30.5722	2.0938	5.5056	0.1842	1.0144	16.4776
26	66.6411	2.7867	33.3589	2.1566	6.0098	0.1722	1.0349	17.5124
27	63.7000	2.9411	36.3000	2.2213	6.5330	0.1609	1.0514	18.5638
28	60.6101	3.0899	39.3899	2.2879	7.0695	0.1504	1.0633	19.6271
29	57.3808	3.2293	42.6192	2.3566	7.6101	0.1406	1.0697	20.6968
30	54.0251	3.3557	45.9749	2.4273	8.1452	0.1314	1.0700	21.7668

Present Value of Replacement Plant as a Percentage of Original Cost $\boxed{21.7668}$

3

Louisville Gas and Electric Company
Excess Facilities Charges
Gas Service

		Assuming Customer Does Not Make Up-Front Payment to Cover Original Cost	Assuming Customer Makes Up-Front Payment to Cover Original Cost
1	Present Value of Replacement Plant as a Percentage of Original Cost	21.77	21.77
2	Original Cost Value	100	-
3	Total Present Value of Original and Replacement Cost Value as a Percentage of Original Cost	121.77	21.77
4	Monthly Carrying Charge Percentage (Levelized Carrying Charge Rate / 12 months)	0.00860	0.00860
5	Applicable Carrying Charge Charge Percentage (Lines 3 x 5)	1.05%	0.19%
6	O&M Percentage	0.68%	0.68%
7	Total Excess Facilities Charge	1.73%	0.87%

Louisville Gas and Electric Company
Levelized Carrying Charge Analysis - Electric
Gas Service

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Debt	46.14%	4.61%	2.13%	37.60%	1.33%
Preferred Equity	0.00%	0.00%	0.00%		0.00%
Common Equity	53.86%	11.50%	6.19%		6.19%
			8.32%		7.52%

Tax Depreciation Table (MACRS)

	5	10	15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%
31	0.000%	0.000%	0.000%	0.000%
31	0.000%	0.000%	0.000%	0.000%

Louisville Gas and Electric Company
Levelized Carrying Charge Analysis
Gas Service

Assumptions:

Investment	$	1,000
Book Life		30
Tax Life		20
Composite Tax Rate		37.6028%
Property Tax Rate		0.00%
Levelized Revenue Requirement Years		35
O&M as Percent of Investment		0.00%

Results:

Present Value Revenue Requirement	$	1,164	
Levelized Revenue Requirement		$103	
Levelized Carrying Charge Rate		10.32%	
Level of Investment that can be Supported by		9.69	Times Net Revenue

Year	Investment	Book Depreciation	Residual Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 1,000						
1		33	967	38	963	2	2
2		33	933	72	890	15	16
3		33	900	67	824	13	29
4		33	867	62	762	11	39
5		33	833	57	705	9	48
6		33	800	53	652	7	56
7		33	767	49	603	6	62
8		33	733	45	558	4	66
9		33	700	45	513	4	70
10		33	667	45	468	4	75
11		33	633	45	424	4	79
12		33	600	45	379	4	83
13		33	567	45	335	4	87
14		33	533	45	290	4	92
15		33	500	45	245	4	96
16		33	467	45	201	4	100
17		33	433	45	156	4	104
18		33	400	45	112	4	108
19		33	367	45	67	4	113
20		33	333	45	22	4	117
21		33	300	22	(0)	(4)	113
22		33	267	-	(0)	(13)	100
23		33	233	-	(0)	(13)	88
24		33	200	-	(0)	(13)	75
25		33	167	-	(0)	(13)	63
26		33	133	-	(0)	(13)	50
27		33	100	-	(0)	(13)	38
28		33	67	-	(0)	(13)	25
29		33	33	-	(0)	(13)	13
30		33	(0)	-	(0)	(13)	-

Louisville Gas and Electric Company
Levelized Carrying Charge Analysis
Gas Service

Assumptions:

Investment	$	1,000
Book Life		30
Tax Life		20
Composite Tax Rate		37.6028%
Property Tax Rate		0.00%
Levelized Revenue Requirement Years		35
O&M as Percent of Investment		0.00%

Results:

Present Value Revenue Requirement	$	1,164
Levelized Revenue Requirement		$103
Levelized Carrying Charge Rate		10.32%
Level of Investment that can be Supported by Revenue		9.69 Times Net Revenue

Year	Rate Base	Interest	Equity	Income Taxes	Annual Revenue Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0	$ -	-	$ -	-	$ -	1.000000	$ -
1	965	21	60	36	150	1	138
2	917	20	57	34	144	0.852266	123
3	871	19	54	33	138	0.786797	109
4	827	18	51	31	133	0.726357	97
5	785	17	49	29	128	0.670560	86
6	744	16	46	28	123	0.619049	76
7	705	15	44	26	118	0.571495	68
8	667	14	41	25	114	0.527594	60
9	630	13	39	24	109	0.487066	53
10	592	13	37	22	105	0.449651	47
11	555	12	34	21	100	0.415110	42
12	517	11	32	19	96	0.383222	37
13	479	10	30	18	91	0.353784	32
14	442	9	27	16	87	0.326607	28
15	404	9	25	15	82	0.301518	25
16	367	8	23	14	78	0.278356	22
17	329	7	20	12	73	0.256973	19
18	292	6	18	11	68	0.237233	16
19	254	5	16	9	64	0.219009	14
20	216	5	13	8	59	0.202186	12
21	187	4	12	7	56	0.186654	10
22	166	4	10	6	53	0.172316	9
23	146	3	9	5	51	0.159079	8
24	125	3	8	5	48	0.146859	7
25	104	2	6	4	46	0.135578	6
26	83	2	5	3	43	0.125163	5
27	62	1	4	2	41	0.115548	5
28	42	1	3	2	38	0.106672	4
29	21	0	1	1	36	0.098478	4
30	(0)	(0)	(0)	(0)	33	0.090913	3
							$ 1,164

Seelye Exhibit 13

Meter Relay Pulse Charge Cost Support

Louisville Gas & Electric Company
Meter Pulse Charge

1	Present Value of Replacement Plant as a Percentage of Original Cost		38.55
2	Original Cost Basis (100)		100
3	Total Present Value of Original and Replacement Cost Value as a Percentage of Original Cost		138.55
4	Monthly Carrying Charge Percentage (Levelized Carrying Charge Rate / 12 months)		0.02081
5	Applicable Carrying Charge Charge Percentage (Lines 3 x 5)		2.88%
6	O&M Percentage		0.36%
7	Distribution O&M 12 Months Ended December 31, 2008	$ 55,764,529	
8	Distribution Plant in Service as December 31, 2007	$ 1,277,947,757	
9	Total Monthly Revenue Requirement as Percentage of Original Cost		3.25%
10	Installed Cost of Meter Pulse Equipment		554.65
11	Monthly Charge	$	18.01

Louisville Gas & Electric Company

Present Value of Replacement Plant as a Percentage of Original Cost

Year (1)	5-Year R3 Iowa Curve Percent Surviving (2)	Annual Replacement Percentage (3)	Cumulative Replacement Percentage (4)	Cost Escalation Factor at a 3.00% Inflation Factor (5)	Nominal Replacement Cost (6)	Present Value Factor at a 7.00% Discount Rate (7)	Present Value of Annual Replacement Cost (8)	Cumulative Present Value of Annual Replaced Cost (9)
					(3) x (5)		(6) x (7)	
0	100.0000							
1	99.2989	0.7011	0.7011	1.0300	0.7222	0.9346	0.6749	0.6749
2	96.8953	2.4035	3.1047	1.0609	2.5499	0.8734	2.2272	2.9021
3	90.7990	6.0963	9.2010	1.0927	6.6616	0.8163	5.4379	8.3400
4	78.0273	12.7718	21.9727	1.1255	14.3747	0.7629	10.9664	19.3064
5	54.7415	23.2857	45.2585	1.1593	26.9946	0.7130	19.2468	38.5531

Present Value of Replacement Plant as a Percentage of Original Cost $\boxed{38.5531}$

Louisville Gas & Electric Company
Levelized Carrying Charge Analysis

Capital Structure:

	Amount	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Debt	$ 1,529,999	46.15%	4.61%	2.128%	36.93%	1.34%
Preferred Equity	-	0.00%	0.00%	0.000%		0.00%
Common Equity	1,743,493	53.85%	11.50%	6.193%		6.19%
	$ 3,273,492			8.320%		7.53%

Tax Depreciation Table (MACRS)

	5	10	15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	5.760%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%
31	0.000%	0.000%	0.000%	0.000%
31	0.000%	0.000%	0.000%	0.000%

Louisville Gas & Electric Company
Levelized Carrying Charge Analysis

Assumptions:

Investment	$	1,000
Book Life		5
Tax Life		5
Composite Tax Rate		36.93%
Property Tax Rate		0.00%
Levelized Revenue Requirement Years		5
O&M as Percent of Investment		0.00%

Results:

Present Value Revenue Requirement	$	989	
Levelized Revenue Requirement		$250	
Levelized Carrying Charge Rate		24.97%	
Level of Investment that can be Supported b		4.01	Times Net Revenue

Year	Investment	Book Depreciation	Residual Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 1,000						
1		200	800	200	800	-	-
2		200	600	320	480	44	44
3		200	400	192	288	(3)	41
4		200	200	115	173	(31)	10
5		200	-	115	58	(31)	(21)
6		-	-	58	-	21	-

Louisville Gas & Electric Company
Levelized Carrying Charge Analysis

Assumptions:

Investment	$	1,000
Book Life		5
Tax Life		5
Composite Tax Rate		36.93%
Property Tax Rate		0.00%
Levelized Revenue Requirement Years		5
O&M as Percent of Investment		0.00%

Results:

Present Value Revenue Requirement	$	989	
Levelized Revenue Requirement		$250	
Levelized Carrying Charge Rate		24.97%	
Level of Investment that can be Supported by Revenue		4.01	Times Net Revenue

Year	Rate Base	Interest	Equity	Income Taxes	Annual Revenue Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0	$ -	-	$ -	-	$ -	1.000000	$ -
1	800	17	50	29	296	0.923188	273
2	556	12	34	20	266	0.852277	227
3	359	8	22	13	243	0.786812	191
4	190	4	12	7	223	0.726375	162
5	21	0	1	1	203	0.670581	136
6	-	-	-	-	-	0.619073	-
							$ 989

Louisville Gas & Electric Company
Gas Meter Pulse Charge

1	Present Value of Replacement Plant as a Percentage of Original Cost			38.55	
2	Original Cost Basis (100)			100	
3	Total Present Value of Original and Replacement Cost Value as a Percentage of Original Cost			138.55	
4	Monthly Carrying Charge Percentage (Levelized Carrying Charge Rate / 12 months)			0.02081	
5	Applicable Carrying Charge Charge Percentage (Lines 3 x 5)			2.88%	
6	O&M Percentage			0.40%	
7	Distribution O&M 12 Months Ended December 31, 2008	$ 30,162,627			
8	Distribution Plant in Service as December 31, 2007	$ 627,196,783			
9	Total Monthly Revenue Requirement as Percentage of Original Cost			3.28%	
				Non-FT	FT
10	Installed Cost of Meter Pulse Equipment		$	650	$ 250
11	Monthly Charge		$	21.34	$ 8.21

Louisville Gas & Electric Company
Present Value of Replacement Plant as a Percentage of Original Cost

Year (1)	5-Year R3 Iowa Curve Percent Surviving (2)	Annual Replacement Percentage (3)	Cumulative Replacement Percentage (4)	Cost Escalation Factor at a 3.00% Inflation Factor (5)	Nominal Replacement Cost (6)	Present Value Factor at a 7.00% Discount Rate (7)	Present Value of Annual Replacement Cost (8)	Cumulative Present Value of Annual Replaced Cost (9)
					(3) x (5)		(6) x (7)	
0	100.0000							
1	99.2989	0.7011	0.7011	1.0300	0.7222	0.9346	0.6749	0.6749
2	96.8953	2.4035	3.1047	1.0609	2.5499	0.8734	2.2272	2.9021
3	90.7990	6.0963	9.2010	1.0927	6.6616	0.8163	5.4379	8.3400
4	78.0273	12.7718	21.9727	1.1255	14.3747	0.7629	10.9664	19.3064
5	54.7415	23.2857	45.2585	1.1593	26.9946	0.7130	19.2468	38.5531
			Present Value of Replacement Plant as a Percentage of Original Cost					38.5531

Louisville Gas & Electric Company
Levelized Carrying Charge Analysis

Capital Structure:

		Amount	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Debt	$	1,529,999	46.15%	4.61%	2.128%	36.93%	1.34%
Preferred Equity		-	0.00%	0.00%	0.000%		0.00%
Common Equity		1,743,493	53.85%	11.50%	6.193%		6.19%
	$	3,273,492			8.320%		7.53%

Tax Depreciation Table (MACRS)

	5	10	15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
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5	11.520%	9.220%	6.930%	5.713%
6	5.760%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%
31	0.000%	0.000%	0.000%	0.000%
31	0.000%	0.000%	0.000%	0.000%

Louisville Gas & Electric Company
Levelized Carrying Charge Analysis

Assumptions:

Investment	$	1,000
Book Life		5
Tax Life		5
Composite Tax Rate		36.93%
Property Tax Rate		0.00%
Levelized Revenue Requirement Years		5
O&M as Percent of Investment		0.00%

Results:

Present Value Revenue Requirement	$	989	
Levelized Revenue Requirement		$250	
Levelized Carrying Charge Rate		24.97%	
Level of Investment that can be Supported b;		4.01	Times Net Revenue

Year	Investment	Book Depreciation	Residual Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 1,000						
1		200	800	200	800	-	-
2		200	600	320	480	44	44
3		200	400	192	288	(3)	41
4		200	200	115	173	(31)	10
5		200	-	115	58	(31)	(21)
6		-	-	58	-	21	-

Louisville Gas & Electric Company
Levelized Carrying Charge Analysis

Assumptions:

Investment	$	1,000
Book Life		5
Tax Life		5
Composite Tax Rate		36.93%
Property Tax Rate		0.00%
Levelized Revenue Requirement Years		5
O&M as Percent of Investment		0.00%

Results:

Present Value Revenue Requirement	$	989	
Levelized Revenue Requirement		$250	
Levelized Carrying Charge Rate		24.97%	
Level of Investment that can be Supported by Revenue		4.01	Times Net Revenue

Year	Rate Base	Interest	Equity	Income Taxes	Annual Revenue Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0	$ -	-	$ -	-	$ -	1.000000	$ -
1	800	17	50	29	296	0.923188	273
2	556	12	34	20	266	0.852277	227
3	359	8	22	13	243	0.786812	191
4	190	4	12	7	223	0.726375	162
5	21	0	1	1	203	0.670581	136
6	-	-	-	-	-	0.619073	-
							$ 989

Seelye Exhibit 14

Customer Deposit Requirements

LOUISVILLE GAS AND ELECTRIC COMPANY
Customer Deposit Requirements

	Residential Electric -- Rate RS		
(1)	Proposed Revenue	$	339,321,953
(2)	Customer Months		4,131,523
(3)	Residential Electric Deposit Requirement [(1) / (2)] * 2 months	$	164
(4)	Proposed Deposit Requirement	$	160
	Residential Gas -- Raet RGS		
(5)	Proposed Revenue	$	201,355,442
(6)	Customer Months		3,483,441
(7)	Residential Electric Deposit Requirement [(5) / (6)] * 2 months	$	116
(8)	Proposed Deposit Requirement	$	115
	Combination Residenital Gas and Electric		
(9)	Proposed Deposit Requirement [(4) + (8)]	$	275

Seelye Exhibit 15

Electric Temperature Normalization Bandwidth

Louisville Gas and Electric Company
SDF (30 year normals 1979-2008)
Degree days are based on 65 degrees

Month	Average HDD	Average CDD	Standard Deviation HDD	Standard Deviation CDD	1σ Bandwidth Lower	1σ Bandwidth Upper	Test Year Actual Values		Outside Bandwidth	Departure from Bandwidth Boundary
Jan	943	0	159	0	784	1102	Jan_2009	1080	FALSE	
Feb	759	0	126	1	633	885	Feb_2009	687	FALSE	
Mar	555	6	98	12	457	653	Mar_2009	449	TRUE	8 warmer than normal, adjust sales up
Apr	260	31	73	24	187	333	Apr_2009	259	FALSE	
May	72	123	43	64	59	187	May_2009	113	FALSE	
Jun	5	309	6	65	244	374	Jun_2009	329	FALSE	
Jul	0	439	0	60	379	499	Jul_2009	268	TRUE	111 cooler than normal, adjust sales up
Aug	0	408	2	86	322	494	Aug_2009	339	FALSE	
Sep	31	204	23	67	137	271	Sep_2009	206	FALSE	
Oct	221	40	70	30	10	70	Oct_2009	4	TRUE	6 cooler than normal, adjust sales up
Nov	506	3	100	4	406	606	Nov_2008	578	FALSE	
Dec	837	1	157	2	680	994	Dec_2008	849	FALSE	

σ

Seelye Exhibit 16

Electric Temperature Normalization Coefficients

Louisville Gas and Electric Company
Regression Coefficients and Statistics

Year	Month	Company	Description	Class	HDD65	CDD65	R-sq	T-stat
2008	11	LGE	Residential	1	140154	0	0.955	14.5
2008	12	LGE	Residential	1	118802	0	0.929	16.0
2009	1	LGE	Residential	1	138001	0	0.732	6.2
2009	2	LGE	Residential	1	125021	0	0.932	14.3
2009	3	LGE	Residential	1	113348	0	0.933	13.3
2009	4	LGE	Residential	1	22016	0	0.560	0.7
2009	5	LGE	Residential	1	0	526547	0.890	14.9
2009	6	LGE	Residential	1	0	542554	0.653	6.9
2009	7	LGE	Residential	1	0	561406	0.901	15.6
2009	8	LGE	Residential	1	0	572638	0.946	18.2
2009	9	LGE	Residential	1	0	375250	0.837	9.3
2009	10	LGE	Residential	1	0	98895	0.580	3.1
2008	11	LGE	General Service	100	18883	0	0.814	2.3
2008	12	LGE	General Service	100	24251	0	0.853	5.0
2009	1	LGE	General Service	100	23076	0	0.713	2.9
2009	2	LGE	General Service	100	27650	0	0.913	7.6
2009	3	LGE	General Service	100	17380	0	0.934	5.2
2009	4	LGE	General Service	100	2629	0	0.879	0.5
2009	5	LGE	General Service	100	0	86445	0.933	7.4
2009	6	LGE	General Service	100	0	68296	0.812	6.8
2009	7	LGE	General Service	100	0	53108	0.895	3.7
2009	8	LGE	General Service	100	0	86759	0.968	10.0
2009	9	LGE	General Service	100	0	74647	0.833	5.2
2009	10	LGE	General Service	100	0	40740	0.940	0.7
2008	11	LGE	CPS-Primary	210	162	0	0.699	0.4
2008	12	LGE	CPS-Primary	210	699	0	0.825	3.6
2009	1	LGE	CPS-Primary	210	883	0	0.503	1.4
2009	2	LGE	CPS-Primary	210	841	0	0.816	3.6
2009	3	LGE	CPS-Primary	210	569	0	0.794	2.3
2009	4	LGE	CPS-Primary	210	-1468	0	0.770	-2.2
2009	5	LGE	CPS-Primary	210	0	10410	0.876	9.4
2009	6	LGE	CPS-Primary	210	0	7373	0.708	7.6
2009	7	LGE	CPS-Primary	210	0	6909	0.920	9.8
2009	8	LGE	CPS-Primary	210	0	8337	0.961	22.8
2009	9	LGE	CPS-Primary	210	0	8031	0.856	8.2
2009	10	LGE	CPS-Primary	210	0	10368	0.905	3.2
2008	11	LGE	CPS-Secondary	220	10952	0	0.726	1.6
2008	12	LGE	CPS-Secondary	220	13874	0	0.702	2.9
2009	1	LGE	CPS-Secondary	220	27128	0	0.806	4.6
2009	2	LGE	CPS-Secondary	220	20913	0	0.896	6.4
2009	3	LGE	CPS-Secondary	220	13082	0	0.860	3.7
2009	4	LGE	CPS-Secondary	220	-18706	0	0.785	-2.3
2009	5	LGE	CPS-Secondary	220	0	84049	0.859	8.3
2009	6	LGE	CPS-Secondary	220	0	78870	0.784	7.5
2009	7	LGE	CPS-Secondary	220	0	72821	0.918	10.5
2009	8	LGE	CPS-Secondary	220	0	88664	0.966	13.9

Louisville Gas and Electric Company
Regression Coefficients and Statistics

Year	Month	Company	Description	Class	HDD65	CDD65	R-sq	T-stat
2009	9	LGE	CPS-Secondary	220	0	76765	0.856	5.6
2009	10	LGE	CPS-Secondary	220	0	93399	0.930	2.5
2008	11	LGE	CTOD-Primary	230	0	0		
2008	12	LGE	CTOD-Primary	230	0	0		
2009	1	LGE	CTOD-Primary	230	0	0		
2009	2	LGE	CTOD-Primary	230	0	0		
2009	3	LGE	CTOD-Primary	230	0	0		
2009	4	LGE	CTOD-Primary	230	0	0		
2009	5	LGE	CTOD-Primary	230	0	9833	0.711	4.5
2009	6	LGE	CTOD-Primary	230	0	14818	0.717	7.7
2009	7	LGE	CTOD-Primary	230	0	8301	0.842	6.4
2009	8	LGE	CTOD-Primary	230	0	12807	0.870	5.3
2009	9	LGE	CTOD-Primary	230	0	9080	0.815	5.0
2009	10	LGE	CTOD-Primary	230	0	0		
2008	11	LGE	CTOD-Secondary	240	1121	0	0.725	0.9
2008	12	LGE	CTOD-Secondary	240	2356	0	0.648	2.6
2009	1	LGE	CTOD-Secondary	240	5190	0	0.797	6.8
2009	2	LGE	CTOD-Secondary	240	3036	0	0.920	6.4
2009	3	LGE	CTOD-Secondary	240	1384	0	0.881	2.5
2009	4	LGE	CTOD-Secondary	240	-4284	0	0.809	-3.6
2009	5	LGE	CTOD-Secondary	240	0	11226	0.844	6.0
2009	6	LGE	CTOD-Secondary	240	0	12762	0.791	6.6
2009	7	LGE	CTOD-Secondary	240	0	12194	0.937	10.1
2009	8	LGE	CTOD-Secondary	240	0	13621	0.976	25.3
2009	9	LGE	CTOD-Secondary	240	0	11371	0.853	5.0
2009	10	LGE	CTOD-Secondary	240	0	0		
2008	11	LGE	IPS-Secondary	300	0	0		
2008	12	LGE	IPS-Secondary	300	0	0		
2009	1	LGE	IPS-Secondary	300	0	0		
2009	2	LGE	IPS-Secondary	300	0	0		
2009	3	LGE	IPS-Secondary	300	0	0		
2009	4	LGE	IPS-Secondary	300	0	0		
2009	5	LGE	IPS-Secondary	300	0	0		
2009	6	LGE	IPS-Secondary	300	0	0		
2009	7	LGE	IPS-Secondary	300	0	0		
2009	8	LGE	IPS-Secondary	300	0	0		
2009	9	LGE	IPS-Secondary	300	0	0		
2009	10	LGE	IPS-Secondary	300	0	0		
2008	11	LGE	IPS-Primary	320	0	0		
2008	12	LGE	IPS-Primary	320	0	0		
2009	1	LGE	IPS-Primary	320	0	0		
2009	2	LGE	IPS-Primary	320	0	0		
2009	3	LGE	IPS-Primary	320	0	0		
2009	4	LGE	IPS-Primary	320	0	0		
2009	5	LGE	IPS-Primary	320	0	0		
2009	6	LGE	IPS-Primary	320	0	0		

Louisville Gas and Electric Company
Regression Coefficients and Statistics

Year	Month	Company	Description	Class	HDD65	CDD65	R-sq	T-stat
2009	7	LGE	IPS-Primary	320	0	0		
2009	8	LGE	IPS-Primary	320	0	0		
2009	9	LGE	IPS-Primary	320	0	0		
2009	10	LGE	IPS-Primary	320	0	0		
2008	11	LGE	ITOD-Secondary	400	0	0		
2008	12	LGE	ITOD-Secondary	400	0	0		
2009	1	LGE	ITOD-Secondary	400	0	0		
2009	2	LGE	ITOD-Secondary	400	0	0		
2009	3	LGE	ITOD-Secondary	400	0	0		
2009	4	LGE	ITOD-Secondary	400	0	0		
2009	5	LGE	ITOD-Secondary	400	0	0		
2009	6	LGE	ITOD-Secondary	400	0	0		
2009	7	LGE	ITOD-Secondary	400	0	0		
2009	8	LGE	ITOD-Secondary	400	0	0		
2009	9	LGE	ITOD-Secondary	400	0	0		
2009	10	LGE	ITOD-Secondary	400	0	0		
2008	11	LGE	ITOD-Primary	420	0	0		
2008	12	LGE	ITOD-Primary	420	0	0		
2009	1	LGE	ITOD-Primary	420	0	0		
2009	2	LGE	ITOD-Primary	420	0	0		
2009	3	LGE	ITOD-Primary	420	0	0		
2009	4	LGE	ITOD-Primary	420	0	0		
2009	5	LGE	ITOD-Primary	420	0	0		
2009	6	LGE	ITOD-Primary	420	0	0		
2009	7	LGE	ITOD-Primary	420	0	0		
2009	8	LGE	ITOD-Primary	420	0	0		
2009	9	LGE	ITOD-Primary	420	0	0		
2009	10	LGE	ITOD-Primary	420	0	0		
2008	11	LGE	RTS	600	0	0		
2008	12	LGE	RTS	600	0	0		
2009	1	LGE	RTS	600	0	0		
2009	2	LGE	RTS	600	0	0		
2009	3	LGE	RTS	600	0	0		
2009	4	LGE	RTS	600	0	0		
2009	5	LGE	RTS	600	0	0		
2009	6	LGE	RTS	600	0	0		
2009	7	LGE	RTS	600	0	0		
2009	8	LGE	RTS	600	0	0		
2009	9	LGE	RTS	600	0	0		
2009	10	LGE	RTS	600	0	0		
2008	11	LGE	Louisville H2O	801	0	0		
2008	12	LGE	Louisville H2O	801	0	0		
2009	1	LGE	Louisville H2O	801	0	0		
2009	2	LGE	Louisville H2O	801	0	0		
2009	3	LGE	Louisville H2O	801	0	0		
2009	4	LGE	Louisville H2O	801	0	0		

Louisville Gas and Electric Company
Regression Coefficients and Statistics

Year	Month	Company	Description	Class	HDD65	CDD65	R-sq	T-stat
2009	5	LGE	Louisville H2O	801	0	0		
2009	6	LGE	Louisville H2O	801	0	0		
2009	7	LGE	Louisville H2O	801	0	0		
2009	8	LGE	Louisville H2O	801	0	0		
2009	9	LGE	Louisville H2O	801	0	0		
2009	10	LGE	Louisville H2O	801	0	0		
2008	11	LGE	Ft. Knox	802	2332	0	0.814	3.4
2008	12	LGE	Ft. Knox	802	3153	0	0.874	7.5
2009	1	LGE	Ft. Knox	802	3616	0	0.515	1.7
2009	2	LGE	Ft. Knox	802	3559	0	0.863	7.2
2009	3	LGE	Ft. Knox	802	2723	0	0.915	8.6
2009	4	LGE	Ft. Knox	802	0	0		
2009	5	LGE	Ft. Knox	802	0	10152	0.852	9.8
2009	6	LGE	Ft. Knox	802	0	13793	0.787	9.4
2009	7	LGE	Ft. Knox	802	0	13097	0.885	8.3
2009	8	LGE	Ft. Knox	802	0	13929	0.978	29.5
2009	9	LGE	Ft. Knox	802	0	10778	0.815	5.7
2009	10	LGE	Ft. Knox	802	0	7520	0.865	1.7

Seelye Exhibit 17

Electric Temperature Normalization kWh Adjustments

Louisville Gas and Electric Company
kWh Adjustments

Year	Month	Company	Description	Class	Adjustment (MWh)	Adjustment (MWh)
2008	11	LGE	Residential	1	0	0
2008	12	LGE	Residential	1	0	0
2009	1	LGE	Residential	1	0	0
2009	2	LGE	Residential	1	0	0
2009	3	LGE	Residential	1	907	0
2009	4	LGE	Residential	1	0	0
2009	5	LGE	Residential	1	0	0
2009	6	LGE	Residential	1	0	0
2009	7	LGE	Residential	1	0	62316
2009	8	LGE	Residential	1	0	0
2009	9	LGE	Residential	1	0	0
2009	10	LGE	Residential	1	0	593
2008	11	LGE	General Service	100	0	0
2008	12	LGE	General Service	100	0	0
2009	1	LGE	General Service	100	0	0
2009	2	LGE	General Service	100	0	0
2009	3	LGE	General Service	100	139	0
2009	4	LGE	General Service	100	0	0
2009	5	LGE	General Service	100	0	0
2009	6	LGE	General Service	100	0	0
2009	7	LGE	General Service	100	0	5895
2009	8	LGE	General Service	100	0	0
2009	9	LGE	General Service	100	0	0
2009	10	LGE	General Service	100	0	244
2008	11	LGE	CPS-Primary	210	0	0
2008	12	LGE	CPS-Primary	210	0	0
2009	1	LGE	CPS-Primary	210	0	0
2009	2	LGE	CPS-Primary	210	0	0
2009	3	LGE	CPS-Primary	210	5	0
2009	4	LGE	CPS-Primary	210	0	0
2009	5	LGE	CPS-Primary	210	0	0
2009	6	LGE	CPS-Primary	210	0	0
2009	7	LGE	CPS-Primary	210	0	767
2009	8	LGE	CPS-Primary	210	0	0
2009	9	LGE	CPS-Primary	210	0	0
2009	10	LGE	CPS-Primary	210	0	62
2008	11	LGE	CPS-Secondary	220	0	0
2008	12	LGE	CPS-Secondary	220	0	0
2009	1	LGE	CPS-Secondary	220	0	0
2009	2	LGE	CPS-Secondary	220	0	0
2009	3	LGE	CPS-Secondary	220	105	0
2009	4	LGE	CPS-Secondary	220	0	0
2009	5	LGE	CPS-Secondary	220	0	0
2009	6	LGE	CPS-Secondary	220	0	0
2009	7	LGE	CPS-Secondary	220	0	8083
2009	8	LGE	CPS-Secondary	220	0	0

Louisville Gas and Electric Company
kWh Adjustments

Year	Month	Company	Description	Class	Adjustment (MWh)	Adjustment (MWh)
2009	9	LGE	CPS-Secondary	220	0	0
2009	10	LGE	CPS-Secondary	220	0	560
2008	11	LGE	CTOD-Primary	230		
2008	12	LGE	CTOD-Primary	230		
2009	1	LGE	CTOD-Primary	230		
2009	2	LGE	CTOD-Primary	230		
2009	3	LGE	CTOD-Primary	230		
2009	4	LGE	CTOD-Primary	230		
2009	5	LGE	CTOD-Primary	230	0	0
2009	6	LGE	CTOD-Primary	230	0	0
2009	7	LGE	CTOD-Primary	230	0	921
2009	8	LGE	CTOD-Primary	230	0	0
2009	9	LGE	CTOD-Primary	230	0	0
2009	10	LGE	CTOD-Primary	230		
2008	11	LGE	CTOD-Secondary	240	0	0
2008	12	LGE	CTOD-Secondary	240	0	0
2009	1	LGE	CTOD-Secondary	240	0	0
2009	2	LGE	CTOD-Secondary	240	0	0
2009	3	LGE	CTOD-Secondary	240	11	0
2009	4	LGE	CTOD-Secondary	240	0	0
2009	5	LGE	CTOD-Secondary	240	0	0
2009	6	LGE	CTOD-Secondary	240	0	0
2009	7	LGE	CTOD-Secondary	240	0	1354
2009	8	LGE	CTOD-Secondary	240	0	0
2009	9	LGE	CTOD-Secondary	240	0	0
2009	10	LGE	CTOD-Secondary	240		
2008	11	LGE	IPS-Secondary	300		
2008	12	LGE	IPS-Secondary	300		
2009	1	LGE	IPS-Secondary	300		
2009	2	LGE	IPS-Secondary	300		
2009	3	LGE	IPS-Secondary	300		
2009	4	LGE	IPS-Secondary	300		
2009	5	LGE	IPS-Secondary	300		
2009	6	LGE	IPS-Secondary	300		
2009	7	LGE	IPS-Secondary	300		
2009	8	LGE	IPS-Secondary	300		
2009	9	LGE	IPS-Secondary	300		
2009	10	LGE	IPS-Secondary	300		
2008	11	LGE	IPS-Primary	320		
2008	12	LGE	IPS-Primary	320		
2009	1	LGE	IPS-Primary	320		
2009	2	LGE	IPS-Primary	320		
2009	3	LGE	IPS-Primary	320		
2009	4	LGE	IPS-Primary	320		
2009	5	LGE	IPS-Primary	320		
2009	6	LGE	IPS-Primary	320		

Louisville Gas and Electric Company
kWh Adjustments

Year	Month	Company	Description	Class	Adjustment (MWh)	Adjustment (MWh)
2009	7	LGE	IPS-Primary	320		
2009	8	LGE	IPS-Primary	320		
2009	9	LGE	IPS-Primary	320		
2009	10	LGE	IPS-Primary	320		
2008	11	LGE	ITOD-Secondary	400		
2008	12	LGE	ITOD-Secondary	400		
2009	1	LGE	ITOD-Secondary	400		
2009	2	LGE	ITOD-Secondary	400		
2009	3	LGE	ITOD-Secondary	400		
2009	4	LGE	ITOD-Secondary	400		
2009	5	LGE	ITOD-Secondary	400		
2009	6	LGE	ITOD-Secondary	400		
2009	7	LGE	ITOD-Secondary	400		
2009	8	LGE	ITOD-Secondary	400		
2009	9	LGE	ITOD-Secondary	400		
2009	10	LGE	ITOD-Secondary	400		
2008	11	LGE	ITOD-Primary	420		
2008	12	LGE	ITOD-Primary	420		
2009	1	LGE	ITOD-Primary	420		
2009	2	LGE	ITOD-Primary	420		
2009	3	LGE	ITOD-Primary	420		
2009	4	LGE	ITOD-Primary	420		
2009	5	LGE	ITOD-Primary	420		
2009	6	LGE	ITOD-Primary	420		
2009	7	LGE	ITOD-Primary	420		
2009	8	LGE	ITOD-Primary	420		
2009	9	LGE	ITOD-Primary	420		
2009	10	LGE	ITOD-Primary	420		
2008	11	LGE	RTS	600		
2008	12	LGE	RTS	600		
2009	1	LGE	RTS	600		
2009	2	LGE	RTS	600		
2009	3	LGE	RTS	600		
2009	4	LGE	RTS	600		
2009	5	LGE	RTS	600		
2009	6	LGE	RTS	600		
2009	7	LGE	RTS	600		
2009	8	LGE	RTS	600		
2009	9	LGE	RTS	600		
2009	10	LGE	RTS	600		
2008	11	LGE	Louisville H2O	801		
2008	12	LGE	Louisville H2O	801		
2009	1	LGE	Louisville H2O	801		
2009	2	LGE	Louisville H2O	801		
2009	3	LGE	Louisville H2O	801		
2009	4	LGE	Louisville H2O	801		

Louisville Gas and Electric Company
kWh Adjustments

Year	Month	Company	Description	Class	Adjustment (MWh)	Adjustment (MWh)
2009	5	LGE	Louisville H2O	801		
2009	6	LGE	Louisville H2O	801		
2009	7	LGE	Louisville H2O	801		
2009	8	LGE	Louisville H2O	801		
2009	9	LGE	Louisville H2O	801		
2009	10	LGE	Louisville H2O	801		
2008	11	LGE	Ft. Knox	802	0	0
2008	12	LGE	Ft. Knox	802	0	0
2009	1	LGE	Ft. Knox	802	0	0
2009	2	LGE	Ft. Knox	802	0	0
2009	3	LGE	Ft. Knox	802	22	0
2009	4	LGE	Ft. Knox	802		
2009	5	LGE	Ft. Knox	802	0	0
2009	6	LGE	Ft. Knox	802	0	0
2009	7	LGE	Ft. Knox	802	0	1454
2009	8	LGE	Ft. Knox	802	0	0
2009	9	LGE	Ft. Knox	802	0	0
2009	10	LGE	Ft. Knox	802	0	45

Seelye Exhibit 18

Electric Temperature Normalization
Revenue and Expense Adjustments

LOUISVILLE GAS AND ELECTRIC COMPANY
Adjustment to Reflect Weather Normalized Electric Sales Margins
12 Months Ended October 31, 2009

HDD65 AND CDD65	(1) kiloWatt-Hour Adjustment to Usage	(2) Energy Rate		(3) Revenue Adjustment		(4) Revenue Adjustment
				(2) * (1)		(3)
Residential Rate RS	63,816,000	0.06714	$	4,284,606	$	4,284,606
General Service Rate GS	6,278,000	0.07580	$	475,872	$	475,872
Industrial Power Service IPS	-		$	-	$	-
Secondary	-	0.02611	$	-		
Primary	-	0.02611	$	-		
Commercial Power Service CPS	9,582,000		$	283,244	$	283,244
Secondary	8,748,000	0.02956	$	258,591		
Primary	834,000	0.02956	$	24,653		
Industrial Time-of-Day Service ITOD	-		$	-	$	-
Secondary	-	0.02616	$	-		
Primary	-	0.02616	$	-		
Commercial Time-of-Day Service CTOD	2,286,000		$	67,666	$	67,666
Secondary	1,365,000	0.02960	$	40,404		
Primary	921,000	0.02960	$	27,262		
Retail Transmission Service RTS	-	0.02616	$	-	$	-
Industrial Service IS	-		$	-	$	-
Secondary	-	0.02616	$	-		
Primary	-	0.02616	$	-		
Transmission	-	0.02616	$	-		
Special Contracts	1,521,000		$	39,835	$	39,835
Fort Knox	1,521,000	0.02619	$	39,835		
Louisville Water Company	-	0.02618	$	-		
Total	83,483,000		$	5,151,223	$	5,151,223
Expenses (variable only)	83,483,000	0.02275	$	1,899,644	$	1,899,644
ADJUSTMENT TO NET OPERATING INCOME BEFORE TAXES					$	3,251,579

NOTES: Seasonal Adjustments with Monthly Banding

Louisville Gas and Electric Company
Base Fuel Cost and Variable O&M Expenses
12 Months Ended October 31, 2009

Acct	Description	Test-Year Expenses
512	Maintenance of Boiler Plant	34,630,824
513	Maintenance of Electric Plant	7,280,413
514	Maintenance of Misc Steam Plant	1,572,978
544	Maintenance of Electric Plant - Hydro	200,808
545	Maintenance of Misc Hydro Plant	-
558	Duplicate Charge	(3,972,034)
Total Variable Prod Expenses		39,712,989
Total Sales		18,260,044,674
Variable O&M Expenses per kWh		0.00217
FAC Base		0.02058
Total		0.02275

Seelye Exhibit 19

Gas Temperature Normalization Adjustment

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS TEMPERATURE NORMALIZATION ADJUSTMENT
12 MONTHS ENDED October 31, 2009

SUMMARY

	MCF	Annual Revenue	Less: Revenue Billed under Weather Normalization Clause	Net Adjustment to Revenue
Residential Rate RGS - see page 3	(64,441.3)	$ (137,576)	$ 52,633	$ (190,209)
Commercial Rate CGS - see page 3	(21,490.9)	(36,646)	(20,525)	(16,121)
Industrial Rate IGS - see page 2	(11,417.8)	(18,867)		(18,867)
Rate AAGS - see page 2	(3,313.8)	(1,739)		(1,739)
Rate FT - see page 2	(30,377.9)	(13,063)		(13,063)
Special Contracts - see page 2	(39,871.7)	(8,950)		(8,950)
Total	(170,913.5)	$ (216,840)	$ 32,108	$ (248,948)

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS TEMPERATURE NORMALIZATION ADJUSTMENT
12 MONTHS ENDED October 31, 2009

CUSTOMERS NOT BILLED UNDER WEATHER NORMALIZATION ADJUSTMENT CLAUSE

	Actual	Normal	Normal over (under)Actual
Billing Cycle Heating Degree Days	4,252	4,163	-89
Calendar Month Degree Days	4,279	4,168	-111

	(1) Total MCF Sales & Trans,	(2) Non-Temp Sales & Trans. (Jul - Aug)	(3) Non-Temp Sales & Trans. Full Year	(4) Temp Sensitive Sales & Trans.	(5) Actual Degree Days	(6) Mcf per Degree Day	(7) Normal Degree Days	(8) Departure From Normal	(9) Normal Temp Adjustment	(10) Net Revenue Per Mcf Sold	(11) Net Revenue Adjustment
			col 2 x 6	col 1 - col 3		col 4 / col 5		col 7 - coi 5	col 6 x col 8		col 9 x col 10
Industrial Rate IGS	995,514	75,004	450,026	545,487	4,252	128	4,163	(89)	(11,418)	1.6524	$ (18,867)
As Available Gas Service (AAGS)											
Commercial	93,802	9,325	55,951	37,851	4,279	9	4,168	(111)	(982)	0.5252	(516)
Industrial	198,180	18,047	108,284	89,896	4,279	21	4,168	(111)	(2,332)	0.5252	(1,225)
Total Rate AAGS	291,983	27,373	164,236	127,747	4,279	30			(3,314)		(1,739)
Rate FT	7,590,002	1,069,824	6,418,946	1,171,056	4,279	274	4,168	(111)	(30,378)	0.4300	(13,063)
Special Contracts	3,265,210	288,029	1,728,173	1,537,037	4,279	359	4,168	(111)	(39,872)	0.2245	(8,950)
Fort Knox	591,360	943	5,656	585,704	4,279	137	4,168	(111)	(15,194)	0.0487	(740)
E. I. duPont	512,570	93,431	560,583	(48,013)	4,279	(11)	4,168	(111)	1,245	0.1049	131
Ford Motor (KTP &LAP)	1,710,388	118,821	712,927	997,462	4,279	233	4,168	(111)	(25,875)	0.3200	(8,280)
LG&E (MC/CR)	437,214	70,752	424,509	12,705	4,279	3	4,168	(111)	(330)	0.2253	(74)
LG&E (Paddy's)	13,677	4,083	24,498	(10,821)	4,279	(3)	4,168	(111)	281	0.0487	14
Total Net Temperature Normalization Adjustment for Customers Not Billed Under the WNA											$ (42,618)

Notes:
Non-Temperature Sensitive Sales and Transporation are based on July and August deliveries.

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS TEMPERATURE NORMALIZATION ADJUSTMENT
12 MONTHS ENDED October 31, 2009

CUSTOMERS BILLED UNDER WEATHER NORMALIZATION ADJUSTMENT CLAUSE

			Normal over/(under) Actual	
	Actual	Normal	WNA Months	12 Months
Billing Cycle Degree Days				
12 mos. Ended October 31, 2009	4,252	4,163		(89)
WNA Months - Nov08 Apr09	3,957	3,872	(85)	

Degree Days over Normal for 12 months as compared to WNA Period - 1.0471

	Mcf	Unit Price	Revenue
Residential Rate RGS			
Actual Billing Adustments (Mcf and Revenue) under WNA - 6 mos. (see page 4)	(61,545.1)		$ 52,633
Degree Day Deficiency for 12 months as compared to WNA Period -	1.0471		
Calculated Adjustment (Mcf and Revenue) to Temperature Normalize for 12 months -	(64,441.3)	$ 2.1349	$ (137,576)
Net Adjustment for Residential Rate RGS			$ (190,209)
Commercial Rate CGS			
Actual Billing Adustments (Mcf and Revenue) under WNA - 5 mos. (see page 4)	(20,525.0)		$ (20,525)
Degree Day Deficiency for 12 months as compared to WNA Period -	1.0471		
Calculated Adjustment (Mcf and Revenue) to Temperature Normalize for 12 months -	(21,490.9)	$ 1.7052	$ (36,646)
Net Adjustment for Residential Rate CGS			$ (16,121)
Total Net Temperature Normalization Adjustment for Customers Billed Under the WNA			$ (206,330)

LOUISVILLE GAS AND ELECTRIC COMPANY
GAS TEMPERATURE NORMALIZATION ADJUSTMENT
12 MONTHS ENDED October 31, 2009

SUMMARY OF ACTUAL MONTHLY BILLINGS UNDER THE WEATHER NORMALIZATION ADJUSTMENT CLAUSE

	Nov. 2008	Dec. 2008	Jan. 2009	Feb. 2009	Mar. 2009	Apr. 2009	Total
BILLINGS:							
Rate RGS	$ 23,527	$ (704,711)	$ 158,799	$ (300,006)	$ 422,293	$ 452,731	$ 52,633
Rate CGS	4,413	(312,522)	79,481	(113,757)	174,617	147,243	(20,525)
Total Billings	$ 27,940	$ (1,017,233)	$ 238,280	$ (413,763)	$ 596,910	$ 599,974	$ 32,108
APPLICABLE MCF:							
Rate RGS	15,389.7	(456,488.0)	109,898.8	(140,570.5)	198,382.3	211,842.6	(61,545.1)
Rate CGS	2,951.5	(208,875.8)	53,915.3	(66,716.9)	102,453.8	86,271.4	(30,000.7)
Total Mcf	18,341.2	(665,363.8)	163,814.1	(207,287.4)	300,836.1	298,114.0	(91,545.8)

Note: WNA Billings are included in "Sales"
However, the applicable volumes used to compute the Billings are not included.

Seelye Exhibit 20

Electric Year-End Customer Adjustment

LOUISVILLE GAS AND ELECTRIC COMPANY
Adjustment to Reflect Year End Number of Customers
12 Months Ended October 31, 2009

	(1) Average Number of Customers, 13 Months Ended October 31, 2009	(2) Number of Customers Served at October 31, 2009	(3) Year-End Over/ (Under) Average	(4) Actual kWhs	(5) Average kWh per Customer per year	(6) Year-End kWh Adjustment	(7) Current Rates Net Revenue (Base Rates + FAC)	(8) Average Revenue per kWh	(9) Revenue Adjustment
			(2) - (1)		(4) / (1)	(3) * (5)		(7) / (4)	(8) * (6)
Residential Rate R	345,081	343,459	(1,622)	4,085,835,494	11,840	(19,204,839)	$ 287,101,505	$ 0.0703	$ (1,349,476)
Water Heating Rate WH	4,549	4,188	(361)	12,439,838	2,735	(987,202)	807,211	$ 0.0649	(64,059)
General Service Rate GS	42,008	41,509	(499)	1,418,850,089	33,776	(16,854,080)	108,936,035	$ 0.0768	(1,294,017)
Large Commercial Rate CS									
Secondary	2,688	2,726	38	1,962,425,059	730,069	27,742,616	120,591,259	$ 0.0615	1,704,787
Primary	53	54	1	169,859,360	3,204,894	3,204,894	9,083,924	$ 0.0535	171,395
Secondary Small Time of Day									
Primary Small Time of Day									
Time of Day Commercial Rate CTOD									
Secondary	73	84	11	378,424,027	5,183,891	57,022,799	20,634,419	$ 0.0545	3,109,296
Primary	18	21	3	340,177,714	18,898,762	56,696,286	17,089,089	$ 0.0502	2,848,181
Industrial Service Rate IS									
Secondary	324	337	13	498,246,495	1,537,798	19,991,372	30,105,881	$ 0.0604	1,207,952
Primary	44	36	(8)	110,455,845	2,510,360	(20,082,881)	5,942,743	$ 0.0538	(1,080,499)
Industrial Serivce Time of Day Rate ITOD									
Secondary	13	17	4	42,191,442	3,245,496	12,981,982	2,392,330	$ 0.0567	736,101
Primary	42	45	3	1,570,265,493	37,387,274	112,161,821	74,281,223	$ 0.0473	5,305,802
Transmission									
Retail Transmission Service Rate RTS	5	5	-	448,436,560	89,687,312	-	19,123,112	$ 0.0426	-
Special Contracts									
Fort Knox	1	1	-	221,595,000	221,595,000	-	9,817,386	$ 0.0443	-
duPont									
Louisville Water Company	2	2	-	58,159,200	29,079,600	-	2,412,052	$ 0.0415	-
Street Lighting Energy Rate LE	111	108	(3)	4,090,864	36,855	(110,564)	167,188	$ 0.0409	(4,519)
Traffic Lighting Rate TLE	873	886	13	3,960,610	4,537	58,978	232,001	$ 0.0586	3,455
	Lights	*Lights*						*per Light per Year*	
Restricted Lighting Service Rate RLS	85,417	88,317	2,900	100,979,604	1,182	3,428,367	12,994,973	$ 0.1287	441,193
Lighting Service Rate LS	9,103	7,240	(1,863)	7,133,198	784	(1,459,865)	1,388,321	$ 0.1946	(284,131)
Total	490,405	489,035		11,433,525,892			$ 723,100,653		$ 11,451,462

Expenses at an Operating Ratio of	0.694813015 (see page 2)	7,956,625
ADJUSTMENT TO NET OPERATING INCOME BEFORE TAXES		$ 3,494,837

LOUISVILLE GAS AND ELECTRIC COMPANY
Adjustment to Reflect Year End Number of Customers
12 Months Ended April 30, 2008

CALCULATION OF ELECTRIC OPERATING RATIO

TOTAL ELECTRIC OPERATING EXPENSES	642,626,778
LESS WAGES AND SALARIES	73,443,960
LESS PENSIONS AND BENEFITS	35,363,605
LESS REGULATORY COMMISSION EXPENSE	1,119,103
NET EXPENSES	532,700,110
ECTRIC OPERATIONS REVENUES (AS BILLED)	766,681,249
ATING RATIO	$\boxed{0.69481}$

Seelye Exhibit 21

Gas Year-End
Customer Adjustment

LOUISVILLE GAS AND ELECTRIC COMPANY
ADJUSTMENT TO REFLECT NUMBER OF YEAR-END GAS
CUSTOMERS OVER AVERAGE NUMBER OF CUSTOMERS
13 MONTHS ENDED OCTOBER 31, 2009

	Avg. Number of Customers 13 Months Ended October 31, 2009	Number of Customers Served at October 31, 2009	Year-End Over/(Under) Average (Col. 2 - 1)	Weather Normalized Mcf	Average Mcf per Customer (Col. 4 / 1)	Year-End Mcf Adjustment (Col. 3 x 5)	Net Revenue Adjusted for Temperatures	Average Revenue per Mcf	Revenue Adjustment
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Residential Rate RGS	290,075	291,175	1,100	20,227,560	69.7	76,670	$ 68,428,238	$ 3.3829	259,367
Commercial Rate CGS	25,560	27,035	1,475	10,406,956	407.2	600,620	24,338,020	2.3386	1,404,610
Industrial Rate IGS	217	230	13	984,096	4,535.0	58,955	1,618,508	1.6447	96,963
Rate AAGS	15	15	-	288,669	19,244.6	-	191,456	0.6632	-
Rate FT	70	70	-	7,559,624	107,994.6	-	3,561,112	0.4711	-
Intra-Company	3	3	-	450,842	150,280.8	-	4,309,219	9.5581	-
Fort Knox	1	1	-	258,023	258,023.2	-	259,029	1.0039	-
duPont	1	1	-	195,397	195,396.9	-	177,877	0.9103	-
Ford Motor (KTP & LAP)	1	1	-	857,602	857,601.9	-	875,197	1.0205	-
Special Contracts	3	3	-	1,311,022	437,007.3	-	1,312,103	$ 1.0008	-
						736,245.0	99,449,436.7		1,760,940
TOTAL	315,940	318,528	2,588	40,777,927.6					
Expenses at an Operating Ratio of -		0.3076 (see page 2)							541,722
ADJUSTMENT TO NET OPERATING INCOME BEFORE TAXES									$ 1,219,218

LOUISVILLE GAS AND ELECTRIC COMPANY
ADJUSTMENT TO REFLECT NUMBER OF YEAR-END GAS
CUSTOMERS OVER AVERAGE NUMBER OF CUSTOMERS
13 MONTHS ENDED OCTOBER 31, 2009

CALCULATION OF GAS OPERATING RATIO

TOTAL GAS OPERATING EXPENSES	$	367,152,680
LESS GAS SUPPLY EXPENSES	$	303,885,591
LESS WAGES AND SALARIES	$	21,183,057
LESS PENSIONS AND BENEFITS	$	9,307,982
LESS REGULATORY COMMISSION EXPENSE	$	55,329
NET EXPENSES		32,720,721
TOTAL GAS OPERATIONS REVENUES (AS BILLED)	$	428,839,711
LESS GSC REVENUE	$	322,476,565
NET REVENUE		106,363,146
OPERATING RATIO		0.3076

Seelye Exhibit 22

Base-Intermediate-Peak (BIP) Differentiation

LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY
Assignment of Production and Transmission Demand-Related Costs
Based on the 12 Months Ended October 31, 2009

Combined System Demands

Minimum System Demand	2,287
Winter System Peak Demand	6,555
Summer System Peak Demand	6,367

Assignment of Production and Transmission
Demand-Related Costs to the Costing Periods

Non-Time-Differentiated Capacity Costs

1. Minimum System Demand	2,287	
2. Maximum System Demand	6,555	
3. Non-Time-Differentiated Capacity Factor (Line 1/Line 2)	0.3489	
4. Non-Time-Differentiated Cost (Line 3)		34.89%

Summer Peak Period Costs

5. Maximum Summer System Demand	6,367	
6. Intermediate Peak Period Capacity Factor (Line 5/Line2 - Line 3)	0.6224	
7. Winter Peak Period Hours	2,416	
8. Summer Peak Period Hours	1,308	
9. Total Summer and Winter Peak Period Hours (Line 7 + Line 8)	3,724	
10. Summer Peak Period Costs (Line 7/Line 9 x Line 6)		21.86%

Winter Peak Period Costs

11. Peak Capacity Factor (1.0000 - Line 3 - Line 6)	0.0287	
12. Winter Peak Period Costs (Line 11 + Line 8/Line 9 x Line 6)		43.25%

Seelye Exhibit 23

Electric Cost of Service Study
Functional Assignment

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 31, 2009

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Winter Peak	Production Demand Summer Peak	Production Energy	Transmission Demand Base	Transmission Demand Winter Peak	Transmission Demand Summer Peak
Plant in Service										
Intangible Plant										
301.00 ORGANIZATION	P301	PT&D	$ 2,240	528	654	331	-	56	70	35
302.00 FRANCHISE AND CONSENTS	P301	PT&D	100	24	29	15	-	3	3	2
302.00 SOFTWARE - COMMON	P302	PT&D	44,745,233	10,538,243	13,063,313	6,602,637	-	1,125,019	1,394,585	704,870
301.00 ORGANIZATION - COMMON	P301	PT&D	61,999	14,602	18,100	9,149	-	1,559	1,932	977
302.00 FRANCHISE AND CONSENTS - COMMON	P301	PT&D	3,108	732	907	459	-	78	97	49
Total Intangible Plant	PINT		$ 44,812,680	$ 10,554,128	$ 13,083,004	$ 6,612,589	$ -	$ 1,126,715	$ 1,396,687	$ 705,932
Steam Production Plant										
Total Steam Production Plant	PSTPR	F017	$ 1,993,314,622	695,467,471	862,108,574	435,738,576	-	-	-	-
Hydraulic Production Plant										
Total Hydraulic Production Plant	PHDPR	F017	$ 41,579,243	14,506,998	17,983,023	9,089,223	-	-	-	-
Other Production Plant										
Total Other Production Plant	POTPR	F017	$ 231,249,804	80,683,057	100,015,540	50,551,207	-	-	-	-
Total Production Plant	PPRTL		$ 2,266,143,669	$ 790,657,526	$ 980,107,137	$ 495,379,006	$ -	$ -	$ -	$ -
Transmission										
Total Transmission Plant	PTRAN	F011	$ 241,924,058	-	-	-	-	84,407,304	104,632,155	52,884,599
Distribution										
TOTAL ACCTS 360-362	P362	F001	$ 88,269,208	-	-	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	326,045,484	-	-	-	-	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	178,787,538	-	-	-	-	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	126,200,231	-	-	-	-	-	-	-
369-SERVICES	P369	F006	25,016,081	-	-	-	-	-	-	-
370-METERS	P370	F007	36,346,005	-	-	-	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-	-	-	-	-	-
373-STREET LIGHTING	P373	F008	68,350,905	-	-	-	-	-	-	-
374-ASSET RETIRE OBLIGATIONS DIST PLANT	P373	F003	37,674	-	-	-	-	-	-	-
Total Distribution Plant	PDIST		$ 849,053,126	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Prod, Trans, and Dist Plant	PT&D		$ 3,357,120,852	$ 790,657,526	$ 980,107,137	$ 495,379,006	$ -	$ 84,407,304	$ 104,632,155	$ 52,884,599

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 31, 2009

			Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
Description	Name	Functional Vector	General	Specific	Demand	Customer	Demand	Customer
Plant in Service								
Intangible Plant								
301.00 ORGANIZATION	P301	PT&D	59	-	157	126	25	29
302.00 FRANCHISE AND CONSENTS	P301	PT&D	3	-	7	6	1	1
302.00 SOFTWARE - COMMON	P302	PT&D	1,176,492	-	3,135,771	2,521,272	492,687	579,415
301.00 ORGANIZATION - COMMON	P301	PT&D	1,630	-	4,345	3,493	683	803
302.00 FRANCHISE AND CONSENTS - COMMON	P301	PT&D	82	-	218	175	34	40
Total Intangible Plant	PINT		$ 1,178,266	$ -	$ 3,140,498	$ 2,525,073	$ 493,429	$ 580,289
Steam Production Plant								
Total Steam Production Plant	PSTPR	F017	-	-	-	-	-	-
Hydraulic Production Plant								
Total Hydraulic Production Plant	PHDPR	F017	-	-	-	-	-	-
Other Production Plant								
Total Other Production Plant	POTPR	F017	-	-	-	-	-	-
Total Production Plant	PPRTL			$ -	$ -			
Transmission								
Total Transmission Plant	PTRAN	F011	-	-	-	-	-	-
Distribution								
TOTAL ACCTS 360-362	P362	F001	88,269,208	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	-	-	112,518,297	134,493,762	35,995,421	43,038,004
366 & 367-UNDERGROUND LINES	P367	F004	-	-	122,737,645	54,655,350	965,453	429,090
368-TRANSFORMERS - POWER POOL	P368	F005	-	-	-	-	-	-
369-SERVICES	P369	F006	-	-	-	-	-	-
370-METERS	P370	F007	-	-	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-	-	-	-
373-STREET LIGHTING	P373	F008	-	-	-	-	-	-
374-ASSET RETIRE OBLIGATIONS DIST PLANT	P373	F003	-	-	13,001	15,541	4,159	4,973
Total Distribution Plant	PDIST		$ 88,269,208	$ -	$ 235,268,943	$ 189,164,653	$ 36,965,033	$ 43,472,067
Total Prod, Trans, and Dist Plant	PT&D		$ 88,269,208	$ -	$ 235,268,943	$ 189,164,653	$ 36,965,033	$ 43,472,067

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 31, 2009

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Plant In Service										
Intangible Plant										
301.00 ORGANIZATION	P301	PT&D	46	38	17	24	46	-	-	-
302.00 FRANCHISE AND CONSENTS	P301	PT&D	2	2	1	1	2	-	-	-
302.00 SOFTWARE - COMMON	P302	PT&D	913,860	768,194	333,426	484,436	911,012	-	-	-
301.00 ORGANIZATION - COMMON	P301	PT&D	1,266	1,064	462	671	1,262	-	-	-
302.00 FRANCHISE AND CONSENTS - COMMON	P301	PT&D	63	53	23	34	63	-	-	-
Total Intangible Plant	PINT		$ 915,237	$ 769,352	$ 333,928	$ 485,166	$ 912,385	$ -	$ -	$ -
Steam Production Plant										
Total Steam Production Plant	PSTPR	F017	-	-	-	-	-	-	-	-
Hydraulic Production Plant										
Total Hydraulic Production Plant	PHDPR	F017	-	-	-	-	-	-	-	-
Other Production Plant										
Total Other Production Plant	POTPR	F017	-	-	-	-	-	-	-	-
Total Production Plant	PPRTL		$ -	$ -			$ -	$ -	$ -	$ -
Transmission										
Total Transmission Plant	PTRAN	F011	-	-	-	-	-	-	-	-
Distribution										
TOTAL ACCTS 360-362	P362	F001	-	-	-	-	-	-	-	-
364 & 365-OVERHEAD LINES	P365	F003	-	-	-	-	-	-	-	-
366 & 367-UNDERGROUND LINES	P367	F004	-	-	-	-	-	-	-	-
368-TRANSFORMERS - POWER POOL	P368	F005	68,564,585	57,635,645	-	-	-	-	-	-
369-SERVICES	P369	F006	-	-	25,016,081	-	-	-	-	-
370-METERS	P370	F007	-	-	-	36,346,005	-	-	-	-
371-CUSTOMER INSTALLATION	P371	F008	-	-	-	-	-	-	-	-
373-STREET LIGHTING	P373	F008	-	-	-	-	68,350,905	-	-	-
374-ASSET RETIRE OBLIGATIONS DIST PLANT	P373	F003	-	-	-	-	-	-	-	-
Total Distribution Plant	PDIST		$ 68,564,585	$ 57,635,645	$ 25,016,081	$ 36,346,005	$ 68,350,905	$ -	$ -	$ -
Total Prod, Trans, and Dist Plant	PT&D		$ 68,564,585	$ 57,635,645	$ 25,016,081	$ 36,346,005	$ 68,350,905	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 31, 2009

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Winter Peak	Production Demand Summer Peak	Production Energy	Transmission Demand Base	Transmission Demand Winter Peak	Transmission Demand Summer Peak
Plant in Service (Continued)										
General Plant										
Total General Plant	PGP	PT&D	$ 16,821,680	3,961,784	4,911,068	2,482,218	-	422,944	524,285	264,991
TOTAL COMMON PLANT	PCOM	PT&D	$ 122,360,848	28,818,005	35,723,093	18,055,649	-	3,076,490	3,813,649	1,927,546
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	$ 43,594,015	10,267,112	12,727,217	6,432,762	-	1,096,074	1,358,705	686,735
105.00 PLANT HELD FOR FUTURE USE	P105	PDIST	$ 649,014	-	-	-	-	-	-	-
105.00 PLANT HELD FOR FUTURE USE	P105	F017	$ 4,182,560	1,459,295	1,808,957	914,308	-	-	-	-
PROPERTY HELD UNDER CAPITAL LEASE		F017	$ -	0	0	0	0	0	-	-
OTHER		PDIST	$ -	-	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 3,589,541,649	$ 845,717,850	$ 1,048,360,476	$ 529,876,532	$ -	$ 90,129,526	$ 111,725,480	$ 56,469,804
Construction Work in Progress (CWIP)										
CWIP Production	CWIP1	F017	$ 199,499,749	69,605,462	86,283,642	43,610,645	-	-	-	-
CWIP Transmission	CWIP2	F011	42,811,947	-	-	-	-	14,937,088	18,516,167	9,358,692
CWIP Distribution Plant	CWIP3	PDIST	42,933,163	-	-	-	-	-	-	-
CWIP Common Plant	CWIP4	PT&D	9,249,889	2,178,502	2,700,493	1,364,920	-	232,568	288,293	145,713
Total Construction Work in Progress	TCWIP		$ 294,494,749	$ 71,783,965	$ 88,984,135	$ 44,975,565	$ -	$ 15,169,656	$ 18,804,461	$ 9,504,405
Total Utility Plant			$ 3,884,036,398	$ 917,501,815	$ 1,137,344,611	$ 574,852,097	$ -	$ 105,299,183	$ 130,529,941	$ 65,974,208

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 31, 2009

Description	Name	Functional Vector	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
			General	Specific	Demand	Customer	Demand	Customer
Plant in Service (Continued)								
General Plant								
Total General Plant	PGP	PT&D	442,295	-	1,178,873	947,856	185,222	217,827
TOTAL COMMON PLANT	PCOM	PT&D	3,217,249	-	8,575,118	6,894,702	1,347,307	1,584,476
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	1,146,223	-	3,055,093	2,456,405	480,011	564,508
105.00 PLANT HELD FOR FUTURE USE	P105	PDIST	67,473	-	179,839	144,597	28,256	33,230
105.00 PLANT HELD FOR FUTURE USE	P105	F017	-	-	-	-	-	-
PROPERTY HELD UNDER CAPITAL LEASE		F017	0	0	0	0	0	0
OTHER		PDIST	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 94,320,713	$ -	$ 251,398,364	$ 202,133,286	$ 39,499,259	$ 46,452,398
Construction Work in Progress (CWIP)								
CWIP Production	CWIP1	F017	-	-	-	-	-	-
CWIP Transmission	CWIP2	F011	-	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	4,463,415	-	11,896,594	9,565,287	1,869,171	2,198,206
CWIP Common Plant	CWIP4	PT&D	243,209	-	648,238	521,206	101,850	119,779
Total Construction Work in Progress	TCWIP		$ 4,706,623	$ -	$ 12,544,831	$ 10,086,493	$ 1,971,021	$ 2,317,984
Total Utility Plant			$ 99,027,336	$ -	$ 263,943,195	$ 212,219,779	$ 41,470,280	$ 48,770,382

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 31, 2009

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Plant in Service (Continued)										
General Plant										
Total General Plant	PGP	PT&D	343,560	288,798	125,349	182,121	342,489	-	-	-
TOTAL COMMON PLANT	PCOM	PT&D	2,499,052	2,100,713	911,790	1,324,745	2,491,264	-	-	-
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	890,348	748,430	324,847	471,972	887,573	-	-	-
105.00 PLANT HELD FOR FUTURE USE	P105	PDIST	52,411	44,057	19,122	27,783	52,247	-	-	-
105.00 PLANT HELD FOR FUTURE USE	P105	F017	-	-	-	-	-	-	-	-
PROPERTY HELD UNDER CAPITAL LEASE		F017	0	0	0	0	0	0	0	0
OTHER		PDIST	-	-	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 73,265,193	$ 61,586,994	$ 26,731,118	$ 38,837,792	$ 73,036,864	$ -	$ -	$ -
Construction Work in Progress (CWIP)										
CWIP Production	CWIP1	F017	-	-	-	-	-	-	-	-
CWIP Transmission	CWIP2	F011	-	-	-	-	-	-	-	-
CWIP Distribution Plant	CWIP3	PDIST	3,467,032	2,914,400	1,264,961	1,837,870	3,456,227	-	-	-
CWIP Common Plant	CWIP4	PT&D	188,916	158,804	68,927	100,144	188,328	-	-	-
Total Construction Work in Progress	TCWIP		$ 3,655,949	$ 3,073,204	$ 1,333,888	$ 1,938,014	$ 3,644,555	$ -	$ -	$ -
Total Utility Plant			$ 76,921,142	$ 64,660,198	$ 28,065,006	$ 40,775,806	$ 76,681,419	$ -	$ -	$ -
						$ 875,853,125				

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 31, 2009

Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Winter Peak	Production Demand Summer Peak	Production Energy	Transmission Demand Base	Transmission Demand Winter Peak	Transmission Demand Summer Peak
Rate Base										
Utility Plant										
Plant in Service			$ 3,589,541,649	$ 845,717,850	$ 1,048,360,476	$ 529,876,532	$ -	$ 90,129,526	$ 111,725,480	$ 56,469,804
Construction Work in Progress (CWIP)			294,494,749	71,783,964.53	88,984,134.87	44,975,565.05	-	15,169,656.23	18,804,460.65	9,504,404.85
Total Utility Plant	TUP		$ 3,884,036,398	$ 917,501,815	$ 1,137,344,611	$ 574,852,097	$ -	$ 105,299,183	$ 130,529,941	$ 65,974,208
Less: Accumulated Provision for Depreciation and RWIP										
Production	ADEPREPA	F017	$ 1,132,202,431	395,025,428	489,677,551	247,499,451	-	-	-	-
Transmission	ADEPRTP	PTRAN	132,956,587	-	-	-	-	46,388,553	57,503,724	29,064,310
Distribution	ADEPRD11	PDIST	397,101,732	-	-	-	-	-	-	-
General & Common Plant	ADEPRD12	PT&D	89,953,313	21,185,494	26,261,755	13,273,571	-	2,261,675	2,803,596	1,417,031
Intangible Plant	ADEPRGP	PT&D	-	-	-	-	-	-	-	-
Total Accumulated Depreciation	TADEPR		$ 1,752,214,062	$ 416,210,922	$ 515,939,306	$ 260,773,023	$ -	$ 48,650,228	$ 60,307,319	$ 30,481,341
Net Utility Plant	NTPLANT		$ 2,131,822,336	$ 501,290,892	$ 621,405,305	$ 314,079,074	$ -	$ 56,648,954	$ 70,222,622	$ 35,492,867
Working Capital										
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 70,625,892	4,473,345	5,545,204	2,802,732	50,069,811	724,456	898,042	453,901
Materials and Supplies	M&S	TPIS	78,422,832	18,476,896	22,904,149	11,576,525	-	1,969,113	2,440,932	1,233,729
Prepayments	PREPAY	TPIS	3,236,899	762,633	945,368	477,821	-	81,275	100,749	50,922
Mill Creek Ash Dredging Project		F017	1,028,827	358,958	444,968	224,902	-	-	-	-
Total Working Capital	TWC		$ 153,314,450	$ 24,071,832	$ 29,839,689	$ 15,081,979	$ 50,069,811	$ 2,774,843	$ 3,439,724	$ 1,738,552
Deferred Debits										
Service Pension Cost	PENSCOST	TLB	$ -	-	-	-	-	-	-	-
Other Deferred Debits	DDEBPP	OMSUB2	-	-	-	-	-	-	-	-
Total Deferred Debits			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Customer Advances	CSTDEP	F027	$ 1,848,625	-	-	-	-	-	-	-
Accumulated Deferred Income Taxes										
Accumulated Deferred Income Taxes	DIT	TPIS	$ 338,601,920	79,776,672	98,891,977	49,983,321	-	8,501,930	10,539,079	5,326,804
FAS 109 Deferred Income Taxes	DIT	TPIS	$ 37,321,392	8,793,147	10,900,075	5,509,263	-	937,100	1,161,639	587,131
Asset Retirement Obligation-Net Assets	DIT	TPIS	$ 3,342,267	787,458	976,142	493,375	-	83,921	104,029	52,580
Asset Retirement Obligation-Regulatory Liabilities	DIT	TPIS	$ (703,529)	(165,756)	(205,472)	(103,853)	-	(17,665)	(21,898)	(11,068)
Total Accumulated Deferred Income Tax			$ 378,562,050	$ 89,191,522	$ 110,562,721	$ 55,882,106	$ -	$ 9,505,286	$ 11,782,849	$ 5,955,447
Investment Tax Credits										
Total Production Plant	DIT	F017	$ -	-	-	-	-	-	-	-
Total Transmission Plant	DIT	PTRAN	$ -	-	-	-	-	-	-	-
Total Distribution Plant	DIT	PDIST	$ -	-	-	-	-	-	-	-
Total General Plant	DIT	PT&D	$ -	-	-	-	-	-	-	-
Total Investment Tax Credit			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Rate Base	RB		$ 1,904,726,111	$ 436,171,203	$ 540,682,273	$ 273,278,948	$ 50,069,811	$ 49,918,512	$ 61,879,497	$ 31,275,972

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			Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
Description	Name	Functional Vector	General	Specific	Demand	Customer	Demand	Customer
Rate Base								
Utility Plant								
Plant in Service			$ 94,320,713	$ -	$ 251,398,364	$ 202,133,286	$ 39,499,259	$ 46,452,398
Construction Work in Progress (CWIP)			4,706,623.35	-	12,544,831.05	10,086,493.31	1,971,021.31	2,317,984.39
Total Utility Plant	TUP		$ 99,027,336	$ -	$ 263,943,195	$ 212,219,779	$ 41,470,280	$ 48,770,382
Less: Accumulated Provision for Depreciation and RWIP								
Production	ADEPREPA	F017	-	-	-	-	-	-
Transmission	ADEPRTP	PTRAN	-	-	-	-	-	-
Distribution	ADEPRD11	PDIST	41,283,465	-	110,035,169	88,472,216	17,288,528	20,331,865
General & Common Plant	ADEPRD12	PT&D	2,365,154	-	6,303,979	5,068,625	990,470	1,164,824
Intangible Plant	ADEPRGP	PT&D	-	-	-	-	-	-
Total Accumulated Depreciation	TADEPR		$ 43,648,619	$ -	$ 116,339,149	$ 93,540,841	$ 18,278,998	$ 21,496,689
Net Utility Plant	NTPLANT		$ 55,378,717	$ -	$ 147,604,046	$ 118,678,938	$ 23,191,282	$ 27,273,693
Working Capital								
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	687,976	-	183,750	(56,415)	(56,069)	(69,214)
Materials and Supplies	M&S	TPIS	2,060,680	-	5,492,448	4,416,125	862,964	1,014,873
Prepayments	PREPAY	TPIS	85,054	-	226,701	182,275	35,619	41,889
Mill Creek Ash Dredging Project		F017	-	-	-	-	-	-
Total Working Capital	TWC		$ 2,833,710	$ -	$ 5,902,899	$ 4,541,986	$ 842,513	$ 987,547
Deferred Debits								
Service Pension Cost	PENSCOST	TLB	-	-	-	-	-	-
Other Deferred Debits	DDEBPP	OMSUB2	-	-	-	-	-	-
Total Deferred Debits			$ -	$ -	$ -	$ -	$ -	$ -
Less: Customer Advances	CSTDEP	F027	-	-	861,473	692,637	135,345	159,170
Accumulated Deferred Income Taxes								
Accumulated Deferred Income Taxes	DIT	TPIS	8,897,285	-	23,714,440	19,067,259	3,725,970	4,381,861
FAS 109 Deferred Income Taxes	DIT	TPIS	980,677	-	2,613,854	2,101,632	410,684	482,978
Asset Retirement Obligation-Net Assets	DIT	TPIS	87,823	-	234,080	188,209	36,778	43,252
Asset Retirement Obligation-Regulatory Liabilities	DIT	TPIS	(18,486)	-	(49,273)	(39,617)	(7,742)	(9,104)
Total Accumulated Deferred Income Tax			$ 9,947,299	$ -	$ 26,513,101	$ 21,317,482	$ 4,165,691	$ 4,898,986
Investment Tax Credits								
Total Production Plant	DIT	F017	-	-	-	-	-	-
Total Transmission Plant	DIT	PTRAN	-	-	-	-	-	-
Total Distribution Plant	DIT	PDIST	-	-	-	-	-	-
Total General Plant	DIT	PT&D	-	-	-	-	-	-
Total Investment Tax Credit			$ -	$ -	$ -	$ -	$ -	$ -
Net Rate Base	RB		$ 48,265,129	$ -	$ 126,132,371	$ 101,210,805	$ 19,732,759	$ 23,203,084

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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Rate Base										
Utility Plant										
Plant in Service			$ 73,265,193	$ 61,586,994	$ 26,731,118	$ 38,837,792	$ 73,036,864	$ -	$ -	$ -
Construction Work in Progress (CWIP)			3,655,948.50	3,073,203.90	1,333,888.37	1,938,013.95	3,644,554.82	-	-	-
Total Utility Plant	TUP		$ 76,921,142	$ 64,660,198	$ 28,065,006	$ 40,775,806	$ 76,681,419	$ -	$ -	$ -
Less: Accumulated Provision for Depreciation and RWIP										
Production	ADEPREPA	F017	-	-	-	-	-	-	-	-
Transmission	ADEPRTP	PTRAN	-	-	-	-	-	-	-	-
Distribution	ADEPRD11	PDIST	32,067,623	26,956,163	11,700,009	16,999,009	31,967,685	-	-	-
General & Common Plant	ADEPRD12	PT&D	1,837,173	1,544,334	670,300	973,883	1,831,447	-	-	-
Intangible Plant	ADEPRGP	PT&D	-	-	-	-	-	-	-	-
Total Accumulated Depreciation	TADEPR		$ 33,904,796	$ 28,500,498	$ 12,370,309	$ 17,972,892	$ 33,799,132	$ -	$ -	$ -
Net Utility Plant	NTPLANT		$ 43,016,346	$ 36,159,700	$ 15,694,697	$ 22,802,914	$ 42,882,286	$ -	$ -	$ -
Working Capital										
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	59,479	49,998	31,867	1,492,130	158,750	1,915,203	1,260,946	-
Materials and Supplies	M&S	TPIS	1,600,668	1,345,527	584,010	848,512	1,595,679	-	-	-
Prepayments	PREPAY	TPIS	66,067	55,537	24,105	35,022	65,862	-	-	-
Mill Creek Ash Dredging Project		F017	-	-	-	-	-	-	-	-
Total Working Capital	TWC		$ 1,726,214	$ 1,451,062	$ 639,983	$ 2,375,664	$ 1,820,291	$ 1,915,203	$ 1,260,946	$ -
Deferred Debits										
Service Pension Cost	PENSCOST	TLB	-	-	-	-	-	-	-	-
Other Deferred Debits	DDEBPP	OMSUB2	-	-	-	-	-	-	-	-
Total Deferred Debits			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Customer Advances	CSTDEP	F027	-	-	-	-	-	-	-	-
Accumulated Deferred Income Taxes										
Accumulated Deferred Income Taxes	DIT	TPIS	6,911,115	5,809,509	2,521,550	3,663,574	6,889,577	-	-	-
FAS 109 Deferred Income Taxes	DIT	TPIS	761,757	640,336	277,930	403,807	759,383	-	-	-
Asset Retirement Obligation-Net Assets	DIT	TPIS	68,218	57,344	24,890	36,162	68,006	-	-	-
Asset Retirement Obligation-Regulatory Liabilities	DIT	TPIS	(14,360)	(12,071)	(5,239)	(7,612)	(14,315)	-	-	-
Total Accumulated Deferred Income Tax			$ 7,726,731	$ 6,495,119	$ 2,819,131	$ 4,095,931	$ 7,702,651	$ -	$ -	$ -
Investment Tax Credits										
Total Production Plant	DIT	F017	-	-	-	-	-	-	-	-
Total Transmission Plant	DIT	PTRAN	-	-	-	-	-	-	-	-
Total Distribution Plant	DIT	PDIST	-	-	-	-	-	-	-	-
Total General Plant	DIT	PT&D	-	-	-	-	-	-	-	-
Total Investment Tax Credit			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Rate Base	RB		$ 37,015,830	$ 31,115,644	$ 13,515,549	$ 21,082,647	$ 36,999,926	$ 1,915,203	$ 1,260,946	$ -

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Winter Peak	Production Demand Summer Peak	Production Energy	Transmission Demand Base	Transmission Demand Winter Peak	Transmission Demand Summer Peak
Operation and Maintenance Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	$ 2,317,003	686,682	851,218	430,234	348,868	-	-	-
501 FUEL	OM501	Energy	$ 329,490,255	-	-	-	329,490,255	-	-	-
502 STEAM EXPENSES	OM502	PROFIX	$ 35,809,255	12,493,849	15,487,503	7,827,903	-	-	-	-
505 ELECTRIC EXPENSES	OM505	PROFIX	$ 741,669	258,768	320,772	162,129	-	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	$ 19,305,637	6,735,737	8,349,688	4,220,212	-	-	-	-
507 RENTS	OM507	PROFIX	$ -	-	-	-	-	-	-	-
509 ALLOWANCES	OM509	PROFIX	$ 4,678	1,632	2,023	1,023	-	-	-	-
Total Steam Power Operation Expenses			$ 387,668,496	$ 20,176,668	$ 25,011,204	$ 12,641,501	$ 329,839,123	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	$ 2,638,047	31,571	39,136	19,781	2,547,559	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	$ 2,262,456	789,371	978,512	494,573	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	$ 34,630,824	-	-	-	34,630,824	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	$ 7,280,413	-	-	-	7,280,413	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	$ 1,572,978	-	-	-	1,572,978	-	-	-
Total Steam Power Generation Maintenance Expense			$ 48,384,718	$ 820,942	$ 1,017,648	$ 514,354	$ 46,031,774	$ -	$ -	$ -
Total Steam Power Generation Expense			$ 436,053,214	$ 20,997,611	$ 26,028,852	$ 13,155,855	$ 375,870,897	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses										
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	$ 96,788	33,769	41,861	21,158	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	$ 39,044	13,623	16,887	8,535	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	$ -	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	$ 164,110	57,258	70,978	35,874	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	$ 118,533	41,356	51,265	25,911	-	-	-	-
540 RENTS		PROFIX	$ 378,801	132,164	163,831	82,806	-	-	-	-
Total Hydraulic Power Operation Expenses			$ 797,275	$ 278,169	$ 344,822	$ 174,284	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses										
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	$ 101	14	17	9	61	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	$ 203,930	71,151	88,200	44,579	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	$ 86,506	30,182	37,414	18,910	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	$ 200,808	-	-	-	200,808	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	$ -	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ 491,345	$ 101,347	$ 125,631	$ 63,498	$ 200,869	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ 1,288,620	$ 379,516	$ 470,452	$ 237,782	$ 200,869	$ -	$ -	$ -
Other Power Generation Operation Expense										
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	$ 31,105	10,853	13,453	6,800	-	-	-	-
547 FUEL	OM547	Energy	$ 11,186,602	-	-	-	11,186,602	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	$ 127,492	44,482	55,140	27,870	-	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	$ 41,162	14,361	17,803	8,998	-	-	-	-
550 RENTS	OM550	PROFIX	$ -	-	-	-	-	-	-	-
Total Other Power Generation Expenses			$ 11,386,361	$ 69,696	$ 86,396	$ 43,667	$ 11,186,602	$ -	$ -	$ -

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Description	Name	Functional Vector	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
			General	Specific	Demand	Customer	Demand	Customer
Operation and Maintenance Expenses								
Steam Power Generation Operation Expenses								
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	-	-	-	-	-	-
501 FUEL	OM501	Energy	-	-	-	-	-	-
502 STEAM EXPENSES	OM502	PROFIX	-	-	-	-	-	-
505 ELECTRIC EXPENSES	OM505	PROFIX	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-	-	-	-	-
507 RENTS	OM507	PROFIX	-	-	-	-	-	-
509 ALLOWANCES	OM509	PROFIX	-	-	-	-	-	-
Total Steam Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses								
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses								
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	-	-	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses								
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense								
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	-	-	-	-	-	-
547 FUEL	OM547	Energy	-	-	-	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-	-	-	-
550 RENTS	OM550	PROFIX	-	-	-	-	-	-
Total Other Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -

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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	OM500	LBSUB1	-	-	-	-	-	-	-	-
501 FUEL	OM501	Energy	-	-	-	-	-	-	-	-
502 STEAM EXPENSES	OM502	PROFIX	-	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	OM505	PROFIX	-	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFIX	-	-	-	-	-	-	-	-
507 RENTS	OM507	PROFIX	-	-	-	-	-	-	-	-
509 ALLOWANCES	OM509	PROFIX	-	-	-	-	-	-	-	-
Total Steam Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	LBSUB2	-	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFIX	-	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	-	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	-	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	Energy	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses										
535 OPERATION SUPERVISION & ENGINEERING	OM535	LBSUB3	-	-	-	-	-	-	-	-
536 WATER FOR POWER	OM536	PROFIX	-	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	OM537	PROFIX	-	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	OM538	PROFIX	-	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	OM539	PROFIX	-	-	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses										
541 MAINTENANCE SUPERVISION & ENGINEERING	OM541	LBSUB4	-	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	OM542	PROFIX	-	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	OM543	PROFIX	-	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	OM544	Energy	-	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	OM545	Energy	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Operation Expense										
546 OPERATION SUPERVISION & ENGINEERING	OM546	LBSUB5	-	-	-	-	-	-	-	-
547 FUEL	OM547	Energy	-	-	-	-	-	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	-	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-	-	-	-	-	-
550 RENTS	OM550	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Winter Peak	Production Demand Summer Peak	Production Energy	Transmission Demand Base	Transmission Demand Winter Peak	Transmission Demand Summer Peak
Operation and Maintenance Expenses (Continued)										
Other Power Generation Maintenance Expense										
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	$ 40,120	13,998	17,352	8,770	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	$ 65,277	22,775	28,232	14,270	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	$ 1,480,185	516,437	640,180	323,569	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	$ 161,443	56,327	69,824	35,291	-	-	-	-
Total Other Power Generation Maintenance Expense			$ 1,747,025	$ 609,537	$ 755,588	$ 381,900	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ 13,133,387	$ 679,233	$ 841,984	$ 425,567	$ 11,186,602	$ -	$ -	$ -
Total Station Expense			$ 450,475,221	$ 22,056,360	$ 27,341,289	$ 13,819,204	$ 387,258,367	$ -	$ -	$ -
Other Power Supply Expenses										
555 PURCHASED POWER	OM555	OMPP	$ 77,619,641	3,561,963	4,415,445	2,231,714	67,410,519	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	$ -	-	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	$ -	-	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	$ -	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	$ 1,445,355	504,284	625,116	315,955	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	2,008,235	700,673	868,562	439,000	-	-	-	-
558 DUPLICATE CHARGES	OM558	Energy	(3,972,034)	-	-	-	(3,972,034)	-	-	-
Total Other Power Supply Expenses	TPP		$ 77,101,198	$ 4,766,920	$ 5,909,123	$ 2,986,669	$ 63,438,486	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ 527,576,419	$ 26,823,280	$ 33,250,412	$ 16,805,873	$ 450,696,853	$ -	$ -	$ -
Transmission Expenses										
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 668,364	-	-	-	-	233,192	289,067	146,104
561 LOAD DISPATCHING	OM561	LBTRAN	932,847	-	-	-	-	325,470	403,456	203,920
562 STATION EXPENSES	OM562	LBTRAN	1,257,574	-	-	-	-	438,767	543,901	274,906
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	135,420	-	-	-	-	47,248	58,569	29,603
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	4,130,106	-	-	-	-	1,440,994	1,786,271	902,841
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	3,166,816	-	-	-	-	1,104,902	1,369,648	692,266
567 RENTS	OM567	PTRAN	22,287	-	-	-	-	7,776	9,639	4,872
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	17,207	-	-	-	-	6,003	7,442	3,761
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	1,195,086	-	-	-	-	416,965	516,874	261,246
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	513,643	-	-	-	-	179,210	222,151	112,282
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	1,388	-	-	-	-	484	600	303
575 MARKET FACILITATION, MONITORING AND COMPLIANCE	OM575	LBTRAN	925,090	-	-	-	-	322,764	400,101	202,225
Total Transmission Expenses			$ 12,965,828	$ -	$ -	$ -	$ -	$ 4,523,777	$ 5,607,720	$ 2,834,330

LOUISVILLE GAS AND ELECTRIC COMPANY
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Description	Name	Functional Vector	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
			General	Specific	Demand	Customer	Demand	Customer
Operation and Maintenance Expenses (Continued)								
Other Power Generation Maintenance Expense								
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses								
555 PURCHASED POWER	OM555	OMPP	-	-	-	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-	-	-	-
558 DUPLICATE CHARGES	OM558	Energy	-	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -
Transmission Expenses								
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	-	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	-	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	-	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	-	-	-	-
567 RENTS	OM567	PTRAN	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	-	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	-	-	-	-	-	-
575 MARKET FACILITATION, MONITORING AND COMPLIANCE	OM575	LBTRAN	-	-	-	-	-	-
Total Transmission Expenses			$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)										
Other Power Generation Maintenance Expense										
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	-	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Station Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses										
555 PURCHASED POWER	OM555	OMPP	-	-	-	-	-	-	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	-	-	-	-	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	-	-	-	-	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	-	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	-	-	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	-	-	-	-	-	-	-	-
558 DUPLICATE CHARGES	OM558	Energy	-	-	-	-	-	-	-	-
Total Other Power Supply Expenses	TPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Electric Power Generation Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Expenses										
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	-	-	-	-	-	-	-	-
561 LOAD DISPATCHING	OM561	LBTRAN	-	-	-	-	-	-	-	-
562 STATION EXPENSES	OM562	LBTRAN	-	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	LBTRAN	-	-	-	-	-	-	-	-
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	LBTRAN	-	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	-	-	-	-	-	-
567 RENTS	OM567	PTRAN	-	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	-	-	-	-	-	-	-	-
569 STRUCTURES	OM569	LBTRAN	-	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	LBTRAN	-	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	LBTRAN	-	-	-	-	-	-	-	-
572 UNDERGROUND LINES	OM572	LBTRAN	-	-	-	-	-	-	-	-
573 MISC PLANT	OM573	PTRAN	-	-	-	-	-	-	-	-
575 MARKET FACILITATION, MONITORING AND COMPLIANCE	OM575	LBTRAN	-	-	-	-	-	-	-	-
Total Transmission Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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12 Months Ended
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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Winter Peak	Production Demand Summer Peak	Production Energy	Transmission Demand Base	Transmission Demand Winter Peak	Transmission Demand Summer Peak
Operation and Maintenance Expenses (Continued)										
Distribution Operation Expense										
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	$ 1,850,124	-	-	-	-	-	-	-
581 LOAD DISPATCHING	OM581	P362	384,127	-	-	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	1,009,374	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	(2,166,951)	-	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	331,165	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	10,273	-	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	6,014,922	-	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012		-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	(172,863)	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	2,843,085	-	-	-	-	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	14,163	-	-	-	-	-	-	-
Total Distribution Operation Expense	OMDO		$ 10,117,420	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Maintenance Expense										
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	$ 3,451	-	-	-	-	-	-	-
591 STRUCTURES	OM591	P362	$ 770,034	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	957,159	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	(5,345,079)	-	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	1,623,097	-	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	(487,253)	-	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	508,593	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	290,262	-	-	-	-	-	-	-
Total Distribution Maintenance Expense	OMDM		$ (1,679,735)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			8,437,685	-	-	-	-	-	-	-
Transmission and Distribution Expenses			21,403,513	-	-	-	-	4,523,777	5,607,720	2,834,330
Production, Transmission and Distribution Expenses	OMSUB		$ 548,979,932	$ 26,823,280	$ 33,250,412	$ 16,805,873	$ 450,696,853	$ 4,523,777	$ 5,607,720	$ 2,834,330

LOUISVILLE GAS A. .ECTRIC COMPANY
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Description	Name	Functional Vector	Distribution Substation General	Distribution Primary Lines Specific	Distribution Primary Lines Demand	Distribution Primary Lines Customer	Distribution Sec. Lines Demand	Distribution Sec. Lines Customer
Operation and Maintenance Expenses (Continued)								
Distribution Operation Expense								
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	291,999	-	131,820	87,761	13,128	15,147
581 LOAD DISPATCHING	OM581	P362	384,127	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	1,009,374	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	-	-	(747,815)	(893,867)	(239,231)	(286,037)
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	227,345	101,237	1,788	795
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	(17,971)	-	(47,900)	(38,513)	(7,526)	(8,851)
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	295,573	-	787,807	633,425	123,779	145,568
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-
589 RENTS	OM589	PDIST	1,472	-	3,925	3,156	617	725
Total Distribution Operation Expense	OMDO		$ 1,964,573	$ -	$ 355,181	$ (106,801)	$ (107,445)	$ (132,654)
Distribution Maintenance Expense								
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	1,030	-	1,072	706	104	119
591 STRUCTURES	OM591	P362	770,034	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	957,159	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	-	(1,844,587)	(2,204,845)	(590,097)	(705,550)
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	-	1,114,256	496,181	8,765	3,895
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	30,176	-	80,430	64,669	12,637	14,862
Total Distribution Maintenance Expense	OMDM		$ 1,758,399	$ -	$ (648,827)	$ (1,643,289)	$ (568,591)	$ (686,674)
Total Distribution Operation and Maintenance Expenses			3,722,972	-	(293,646)	(1,750,090)	(676,037)	(819,328)
Transmission and Distribution Expenses			3,722,972	-	(293,646)	(1,750,090)	(676,037)	(819,328)
Production, Transmission and Distribution Expenses	OMSUB		$ 3,722,972	$ -	$ (293,646)	$ (1,750,090)	$ (676,037)	$ (819,328)

LOUISVILLE GAS AND ELECTRIC COMPANY
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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)										
Distribution Operation Expense										
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	39,082	32,853	14,259	1,182,889	41,186	-	-	-
581 LOAD DISPATCHING	OM581	P362	-	-	-	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	-	-	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P373	-	-	-	-	10,273	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-	6,014,922	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	(13,959)	(11,734)	(5,093)	(7,400)	(13,916)	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	229,591	192,995	83,767	121,706	228,875	-	-	-
588 MISC DISTR EXP -- MAPPIN	OM588x	PDIST	-	-	-	-	-	-	-	-
589 RENTS	OM589	PDIST	1,144	961	417	606	1,140	-	-	-
Total Distribution Operation Expense	OMDO		$ 255,858	$ 215,075	$ 93,351	$ 7,312,723	$ 267,559	$ -	$ -	$ -
Distribution Maintenance Expense										
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	141	119	5	7	148	-	-	-
591 STRUCTURES	OM591	P362	-	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	-	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	-	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	(264,724)	(222,528)	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	508,593	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	23,440	19,704	8,552	12,425	23,367	-	-	-
Total Distribution Maintenance Expense	OMDM		$ (241,143)	$ (202,706)	$ 8,557	$ 12,432	$ 532,108	$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			14,715	12,369	101,907	7,325,155	799,667	-	-	-
Transmission and Distribution Expenses			14,715	12,369	101,907	7,325,155	799,667	-	-	-
Production, Transmission and Distribution Expenses	OMSUB		$ 14,715	$ 12,369	$ 101,907	$ 7,325,155	$ 799,667	$ -	$ -	$ -

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Description	Name	Functional Vector	Total System	Production Demand			Production Energy	Transmission Demand		
				Base	Winter Peak	Summer Peak		Base	Winter Peak	Summer Peak
Operation and Maintenance Expenses (Continued)										
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ 800,912	-	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	2,113,947	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	5,314,316	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	2,405,783	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	379,346	-	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ 11,014,304	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense										
907 SUPERVISION	OM907	F026	$ 119,732	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	6,415,901	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	158,029	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	2,330,329	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	7,960	-	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	42,906	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	OM915	F026	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ 9,074,857	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		569,069,092	26,823,280	33,250,412	16,805,873	450,696,853	4,523,777	5,607,720	2,834,330

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12 Months Ended
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Description	Name	Functional Vector	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
			General	Specific	Demand	Customer	Demand	Customer
Operation and Maintenance Expenses (Continued)								
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense								
907 SUPERVISION	OM907	F026	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	OM915	F026	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		3,722,972	-	(293,646)	(1,750,090)	(676,037)	(819,328)

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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)										
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-	-	-	-	800,912	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-	2,113,947	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-	5,314,316	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-	2,405,783	-	-
905 MISC CUST ACCOUNTS	OM903	F025	-	-	-	-	-	379,346	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -	$ 11,014,304	$ -	$ -
Customer Service Expense										
907 SUPERVISION	OM907	F026	-	-	-	-	-	-	119,732	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F026	-	-	-	-	-	-	6,415,901	-
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	F026	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F026	-	-	-	-	-	-	158,029	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F026	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F026	-	-	-	-	-	-	2,330,329	-
911 DEMONSTRATION AND SELLING EXP	OM911	F026	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F026	-	-	-	-	-	-	7,960	-
913 ADVERTISING EXPENSES	OM913	F026	-	-	-	-	-	-	42,906	-
915 MDSE-JOBBING-CONTRACT	OM915	F026	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F026	-	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ -	$ -	$ -	$ -	$ -	$ -	$ 9,074,857	$ -
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		14,715	12,369	101,907	7,325,155	799,667	11,014,304	9,074,857	-

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Winter Peak	Production Demand Summer Peak	Production Energy	Transmission Demand Base	Transmission Demand Winter Peak	Transmission Demand Summer Peak
Operation and Maintenance Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	$ 14,155,874	2,206,933	2,735,737	1,382,733	4,053,889	218,285	270,588	136,764
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	4,344,577	677,329	839,624	424,374	1,244,178	66,994	83,046	41,974
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(2,256,053)	(351,724)	(436,000)	(220,369)	(646,077)	(34,789)	(43,124)	(21,796)
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	5,390,944	840,460	1,041,843	526,583	1,543,832	83,129	103,047	52,084
924 PROPERTY INSURANCE	OM924	TUP	3,341,145	789,258	978,372	494,502	-	90,581	112,285	56,753
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	1,718,338	267,893	332,083	167,846	492,089	26,497	32,846	16,601
926 EMPLOYEE BENEFITS	OM926	LBSUB7	35,363,605	5,513,266	6,834,301	3,454,285	10,127,253	545,310	675,972	341,659
927 FRANCHISE REQUIREMENTS	OM927	TUP	25,547	6,035	7,481	3,781	-	693	859	434
928 REGULATORY COMMISSION FEES	OM928	TUP	1,119,103	264,359	327,702	165,631	-	30,340	37,609	19,009
929 DUPLICATE CHARGES-CR	OM929	LBSUB7	(27,402)	(4,272)	(5,296)	(2,677)	(7,847)	(423)	(524)	(265)
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	1,623,174	253,057	313,692	158,550	464,837	25,029	31,027	15,682
931 RENTS AND LEASES	OM931	PGP	1,387,133	326,693	404,972	204,686	-	34,876	43,233	21,851
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	7,371,700	1,736,157	2,152,158	1,087,773	-	185,345	229,755	116,126
Total Administrative and General Expense	OMAG		$ 73,557,685	$ 12,525,444	$ 15,526,668	$ 7,847,699	$ 17,272,153	$ 1,271,867	$ 1,576,619	$ 796,876
Total Operation and Maintenance Expenses	TOM		$ 642,626,778	$ 39,348,724	$ 48,777,080	$ 24,653,572	$ 467,969,007	$ 5,795,644	$ 7,184,340	$ 3,631,206
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 565,007,137	$ 35,786,761	$ 44,361,635	$ 22,421,857	$ 400,558,487	$ 5,795,644	$ 7,184,340	$ 3,631,206

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Description	Name	Functional Vector	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
			General	Specific	Demand	Customer	Demand	Customer
Operation and Maintenance Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	337,078	-	198,324	131,468	19,514	22,500
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	103,453	-	60,868	40,349	5,989	6,906
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(53,721)	-	(31,607)	(20,952)	(3,110)	(3,586)
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	128,368	-	75,527	50,066	7,432	8,569
924 PROPERTY INSURANCE	OM924	TUP	85,186	-	227,050	182,557	35,674	41,953
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	40,917	-	24,074	15,958	2,369	2,731
926 EMPLOYEE BENEFITS	OM926	LBSUB7	842,074	-	495,445	328,427	48,749	56,209
927 FRANCHISE REQUIREMENTS	OM927	TUP	651	-	1,736	1,396	273	321
928 REGULATORY COMMISSION FEES	OM928	TUP	28,533	-	76,050	61,147	11,949	14,052
929 DUPLICATE CHARGES-CR	OM929	LBSUB7	(652)	-	(384)	(254)	(38)	(44)
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	38,651	-	22,741	15,075	2,238	2,580
931 RENTS AND LEASES	OM931	PGP	36,472	-	97,211	78,161	15,274	17,962
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	193,825	-	516,613	415,375	81,169	95,458
Total Administrative and General Expense	OMAG		$ 1,780,834	$ -	$ 1,763,648	$ 1,298,772	$ 227,481	$ 265,612
Total Operation and Maintenance Expenses	TOM		$ 5,503,806	$ -	$ 1,470,002	$ (451,318)	$ (448,556)	$ (553,716)
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 5,503,806	$ -	$ 1,470,002	$ (451,318)	$ (448,556)	$ (553,716)

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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Operation and Maintenance Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB7	45,390	38,155	12,991	1,049,130	47,748	1,010,957	237,690	-
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB7	13,931	11,710	3,987	321,988	14,654	310,273	72,949	-
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB7	(7,234)	(6,081)	(2,070)	(167,202)	(7,610)	(161,118)	(37,881)	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB7	17,286	14,531	4,947	399,537	18,184	385,000	90,519	-
924 PROPERTY INSURANCE	OM924	TUP	66,169	55,622	24,142	35,076	65,963	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB7	5,510	4,632	1,577	127,351	5,796	122,717	28,852	-
926 EMPLOYEE BENEFITS	OM926	LBSUB7	113,393	95,318	32,453	2,620,891	119,283	2,525,530	593,787	-
927 FRANCHISE REQUIREMENTS	OM927	TUP	506	425	185	268	504	-	-	-
928 REGULATORY COMMISSION FEES	OM928	TUP	22,163	18,630	8,086	11,749	22,094	-	-	-
929 DUPLICATE CHARGES-CR	OM929	LBSUB7	(88)	(74)	(25)	(2,031)	(92)	(1,957)	(460)	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB7	5,205	4,375	1,490	120,298	5,475	115,921	27,255	-
931 RENTS AND LEASES	OM931	PGP	28,330	23,815	10,336	15,018	28,242	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	150,557	126,559	54,931	79,810	150,088	-	-	-
Total Administrative and General Expense	OMAG		$ 461,118	$ 387,618	$ 153,030	$ 4,611,883	$ 470,330	$ 4,307,323	$ 1,012,711	$ -
Total Operation and Maintenance Expenses	TOM		$ 475,833	$ 399,987	$ 254,937	$ 11,937,039	$ 1,269,997	$ 15,321,627	$ 10,087,568	$ -
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 475,833	$ 399,987	$ 254,937	$ 11,937,039	$ 1,269,997	$ 15,321,627	$ 10,087,568	$ -
						$ 18,588,013				

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Winter Peak	Production Demand Summer Peak	Production Energy	Transmission Demand Base	Transmission Demand Winter Peak	Transmission Demand Summer Peak
Labor Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	$ 1,490,340	441,687	547,520	276,735	224,399	-	-	-
501 FUEL	LB501	Energy	$ 2,869,025	-	-	-	2,869,025	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	$ 11,242,697	3,922,577	4,862,466	2,457,653	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	$ 563,732	196,686	243,814	123,232	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$ 4,379,139	1,527,882	1,893,978	957,280	-	-	-	-
507 RENTS	LB507	PROFIX	$ -	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ 20,544,933	$ 6,088,832	$ 7,547,778	$ 3,814,900	$ 3,093,424	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	$ 1,419,243	16,985	21,055	10,642	1,370,562	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$ 282,445	98,545	122,158	61,743	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$ 6,424,675	-	-	-	6,424,675	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$ 1,483,608	-	-	-	1,483,608	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	$ 43,556	-	-	-	43,556	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ 9,653,528	$ 115,530	$ 143,212	$ 72,384	$ 9,322,400	$ -	$ -	$ -
Total Steam Power Generation Expense			$ 30,198,460	$ 6,204,362	$ 7,690,990	$ 3,887,284	$ 12,415,824	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses										
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	$ 76,594	26,724	33,127	16,744	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	$ -	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	$ -	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	$ 135,663	47,333	58,674	29,656	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	$ 9,267	3,233	4,008	2,026	-	-	-	-
540 RENTS		PROFIX	$ -	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ 221,524	$ 77,290	$ 95,809	$ 48,425	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses										
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	$ 76	10	13	7	46	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	$ 22,785	7,950	9,855	4,981	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	$ 49,157	17,151	21,260	10,746	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	$ 110,859	-	-	-	110,859	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	$ -	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ 182,877	$ 25,111	$ 31,128	$ 15,733	$ 110,905	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ 404,401	$ 102,401	$ 126,937	$ 64,158	$ 110,905	$ -	$ -	$ -

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Description	Name	Functional Vector	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
			General	Specific	Demand	Customer	Demand	Customer
Labor Expenses								
Steam Power Generation Operation Expenses								
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-	-	-	-
501 FUEL	LB501	Energy	-	-	-	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses								
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses								
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses								
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -

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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	LB500	F019	-	-	-	-	-	-	-	-
501 FUEL	LB501	Energy	-	-	-	-	-	-	-	-
502 STEAM EXPENSES	LB502	PROFIX	-	-	-	-	-	-	-	-
505 ELECTRIC EXPENSES	LB505	PROFIX	-	-	-	-	-	-	-	-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	-	-	-	-	-	-	-	-
507 RENTS	LB507	PROFIX	-	-	-	-	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	F020	-	-	-	-	-	-	-	-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	-	-	-	-	-	-	-	-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	-	-	-	-	-	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	-	-	-	-	-	-	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	Energy	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Steam Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Operation Expenses										
535 OPERATION SUPERVISION & ENGINEERING	LB535	F021	-	-	-	-	-	-	-	-
536 WATER FOR POWER	LB536	PROFIX	-	-	-	-	-	-	-	-
537 HYDRAULIC EXPENSES	LB537	PROFIX	-	-	-	-	-	-	-	-
538 ELECTRIC EXPENSES	LB538	PROFIX	-	-	-	-	-	-	-	-
539 MISC. HYDRAULIC POWER EXPENSES	LB539	PROFIX	-	-	-	-	-	-	-	-
540 RENTS		PROFIX	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses	LBSUB3		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydraulic Power Generation Maintenance Expenses										
541 MAINTENANCE SUPERVISION & ENGINEERING	LB541	F022	-	-	-	-	-	-	-	-
542 MAINTENANCE OF STRUCTURES	LB542	PROFIX	-	-	-	-	-	-	-	-
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	LB543	PROFIX	-	-	-	-	-	-	-	-
544 MAINTENANCE OF ELECTRIC PLANT	LB544	Energy	-	-	-	-	-	-	-	-
545 MAINTENANCE OF MISC HYDRAULIC PLANT	LB545	Energy	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense	LBSUB4		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Hydraulic Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Winter Peak	Production Demand Summer Peak	Production Energy	Transmission Demand Base	Transmission Demand Winter Peak	Transmission Demand Summer Peak
Labor Expenses (Continued)										
Other Power Generation Operation Expense										
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	$ 22,899	7,990	9,904	5,006	-	-	-	-
547 FUEL	LB547	Energy	$ -	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	$ 77,953	27,198	33,715	17,041	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	$ -	-	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	$ -	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ 100,853	$ 35,188	$ 43,619	$ 22,046	$ -	$ -	$ -	$ -
Other Power Generation Maintenance Expense										
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	$ 38,860	13,558	16,807	8,495	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	$ 48,205	16,819	20,849	10,538	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	$ 215,080	75,041	93,022	47,016	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$ 33,614	11,728	14,538	7,348	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ 335,759	$ 117,146	$ 145,216	$ 73,397	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ 436,612	$ 152,334	$ 188,835	$ 95,443	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ 31,039,473	$ 6,459,096	$ 8,006,762	$ 4,046,886	$ 12,526,729	$ -	$ -	$ -
Purchased Power										
555 PURCHASED POWER	LB555	OMPP	$ -	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	1,033,082	360,442	446,808	225,832	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ 1,033,082	$ 360,442	$ 446,808	$ 225,832	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
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October 31, 2009

Description	Name	Functional Vector	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
			General	Specific	Demand	Customer	Demand	Customer
Labor Expenses (Continued)								
Other Power Generation Operation Expense								
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Maintenance Expense								
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power								
555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -

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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)										
Other Power Generation Operation Expense										
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB5		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Maintenance Expense										
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	-	-	-	-	-	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB6		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Power Generation Expense			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Production Expense	LPREX		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power										
555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	-	-	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	-	-	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Winter Peak	Production Demand Summer Peak	Production Energy	Transmission Demand Base	Transmission Demand Winter Peak	Transmission Demand Summer Peak
Labor Expenses (Continued)										
Transmission Labor Expenses										
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$ 447,371	-	-	-	-	156,088	193,488	97,795
561 LOAD DISPATCHING	LB561	PTRAN	716,320	-	-	-	-	249,924	309,808	156,588
562 STATION EXPENSES	LB562	PTRAN	514,340	-	-	-	-	179,453	222,452	112,435
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	8,700	-	-	-	-	3,035	3,763	1,902
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	141,829	-	-	-	-	49,484	61,341	31,004
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	-	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	233,328	-	-	-	-	81,408	100,914	51,005
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	(130,389)	-	-	-	-	(45,493)	(56,393)	(28,503)
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	1,753	-	-	-	-	612	758	383
Total Transmission Labor Expenses	LBTRAN		$ 1,933,252	$ -	$ -	$ -	$ -	$ 674,511	$ 836,131	$ 422,609
Distribution Operation Labor Expense										
580 OPERATION SUPERVISION AND ENGI	LB580	F023	$ 1,053,694	-	-	-	-	-	-	-
581 LOAD DISPATCHING	LB581	P362	293,653	-	-	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	230,749	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	(159,667)	-	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	73,041	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P373	4,830	-	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	2,521,656	-	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	1,050,099	-	-	-	-	-	-	-
589 RENTS	LB589	PDIST	-	-	-	-	-			
Total Distribution Operation Labor Expense	LBDO		$ 5,068,054	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Description	Name	Functional Vector	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
			General	Specific	Demand	Customer	Demand	Customer
Labor Expenses (Continued)								
Transmission Labor Expenses								
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-	-	-	-
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-	-	-	-
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense								
580 OPERATION SUPERVISION AND ENGI	LB580	F023	166,301	-	75,075	49,982	7,477	8,626
581 LOAD DISPATCHING	LB581	P362	293,653	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	230,749	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	-	-	(55,101)	(65,863)	(17,627)	(21,076)
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	50,143	22,329	394	175
585 STREET LIGHTING EXPENSE	LB585	P373	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	109,170	-	290,978	233,957	45,718	53,766
589 RENTS	LB589	PDIST	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 799,873	$ -	$ 361,094	$ 240,405	$ 35,962	$ 41,491

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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)										
Transmission Labor Expenses										
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-	-	-	-	-	-
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	-	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-	-	-	-	-	-
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	-	-	-	-	-	-	-	-
Total Transmission Labor Expenses	LBTRAN		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense										
580 OPERATION SUPERVISION AND ENGI	LB580	F023	22,258	18,710	8,121	673,686	23,457	-	-	-
581 LOAD DISPATCHING	LB581	P362	-	-	-	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	-	-	-	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	-	-	-	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P373	-	-	-	-	4,830	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-	2,521,656	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P371	-	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	84,800	71,283	30,940	44,952	84,536	-	-	-
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 107,058	$ 89,994	$ 39,061	$ 3,240,295	$ 112,822	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
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12 Months Ended
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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Winter Peak	Production Demand Summer Peak	Production Energy	Transmission Demand Base	Transmission Demand Winter Peak	Transmission Demand Summer Peak
Labor Expenses (Continued)										
Distribution Maintenance Labor Expense										
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	$ (165)	-	-	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	8,520	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	229,427	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	193,562	-	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	254,651	-	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	55,665	-	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	31,774	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	36,714	-	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 810,149	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST	5,878,204	-	-	-	-	-	-	-
Transmission and Distribution Labor Expenses			7,811,455	-	-	-	-	674,511	836,131	422,609
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 39,884,010	$ 6,819,539	$ 8,453,570	$ 4,272,717	$ 12,526,729	$ 674,511	$ 836,131	$ 422,609
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	$ 576,055	-	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	217,099	-	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	2,175,355	-	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	155,402	-	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ 3,123,911	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense										
907 SUPERVISION	LB907	F026	$ 75,060	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	354,392	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	2,004	-	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	303,019	-	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	F026	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ 734,475	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7		43,742,395	6,819,539	8,453,570	4,272,717	12,526,729	674,511	836,131	422,609

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Description	Name	Functional Vector	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
			General	Specific	Demand	Customer	Demand	Customer
Labor Expenses (Continued)								
Distribution Maintenance Labor Expense								
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	(49)	-	(51)	(34)	(5)	(6)
591 MAINTENANCE OF STRUCTURES	LB591	P362	8,520	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	229,427	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	-	-	66,798	79,845	21,369	25,550
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	-	-	174,818	77,847	1,375	611
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	3,817	-	10,173	8,180	1,598	1,880
Total Distribution Maintenance Labor Expense	LBDM		$ 241,715	$ -	$ 251,738	$ 165,837	$ 24,338	$ 28,035
Total Distribution Operation and Maintenance Labor Expenses		PDIST	1,041,589	-	612,832	406,242	60,300	69,527
Transmission and Distribution Labor Expenses			1,041,589	-	612,832	406,242	60,300	69,527
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 1,041,589	$ -	$ 612,832	$ 406,242	$ 60,300	$ 69,527
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	-	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expense								
907 SUPERVISION	LB907	F026	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	F026	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ -	$ -	$ -	$ -	$ -	$ -
Sub-Total Labor Exp	LBSUB7		1,041,589	-	612,832	406,242	60,300	69,527

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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)										
Distribution Maintenance Labor Expense										
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	(7)	(6)	(0)	(0)	(7)	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	P362	-	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	-	-	-	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	-	-	-	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	30,243	25,422	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	31,774	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	2,965	2,492	1,082	1,572	2,956	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 33,201	$ 27,909	$ 1,081	$ 1,571	$ 34,723	$ -	$ -	$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST	140,259	117,902	40,142	3,241,866	147,545	-	-	-
Transmission and Distribution Labor Expenses			140,259	117,902	40,142	3,241,866	147,545	-	-	-
Production, Transmission and Distribution Labor Expenses	LBSUB		$ 140,259	$ 117,902	$ 40,142	$ 3,241,866	$ 147,545	$ -	$ -	$ -
Customer Accounts Expense										
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-	-	-	-	576,055	-	-
902 METER READING EXPENSES	LB902	F025	-	-	-	-	-	217,099	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-	2,175,355	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F025	-	-	-	-	-	155,402	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -	$ 3,123,911	$ -	$ -
Customer Service Expense										
907 SUPERVISION	LB907	F026	-	-	-	-	-	-	75,060	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F026	-	-	-	-	-	-	354,392	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F026	-	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F026	-	-	-	-	-	-	2,004	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F026	-	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F026	-	-	-	-	-	-	303,019	-
911 DEMONSTRATION AND SELLING EXP	LB911	F026	-	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F026	-	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F026	-	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	F026	-	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F026	-	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ -	$ -	$ -	$ -	$ -	$ -	$ 734,475	$ -
Sub-Total Labor Exp	LBSUB7		140,259	117,902	40,142	3,241,866	147,545	3,123,911	734,475	-

LOUISVILLE GAS AND ELECTRIC COMPANY
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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Winter Peak	Production Demand Summer Peak	Production Energy	Transmission Demand Base	Transmission Demand Winter Peak	Transmission Demand Summer Peak
Labor Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	$ 10,964,829	1,709,442	2,119,041	1,071,035	3,140,053	169,079	209,592	105,935
921 OFFICE SUPPLIES AND EXPENSES	LB920	LBSUB7	$ -	-	-	-	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(1,341,699)	(209,174)	(259,294)	(131,056)	(384,229)	(20,689)	(25,646)	(12,963)
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	42,291	6,593	8,173	4,131	12,111	652	808	409
926 EMPLOYEE BENEFITS	LB926	LBSUB7	-	-	-	-	-	-	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-	-	-	-	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB932	PGP	2,758,776	649,737	805,421	407,087	-	69,363	85,983	43,459
Total Administrative and General Expense	LBAG		$ 12,424,197	$ 2,156,598	$ 2,673,341	$ 1,351,196	$ 2,767,935	$ 218,405	$ 270,737	$ 136,840
Total Operation and Maintenance Expenses	TLB		$ 56,166,593	$ 8,976,137	$ 11,126,911	$ 5,623,914	$ 15,294,665	$ 892,916	$ 1,106,868	$ 559,448
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 56,166,593	$ 8,976,137	$ 11,126,911	$ 5,623,914	$ 15,294,665	$ 892,916	$ 1,106,868	$ 559,448

LOUISVILLE GAS AND ELECTRIC COMPANY
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Description	Name	Functional Vector	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
			General	Specific	Demand	Customer	Demand	Customer
Labor Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	261,093	-	153,618	101,832	15,115	17,428
921 OFFICE SUPPLIES AND EXPENSES	LB920	LBSUB7	-	-	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(31,948)	-	(18,797)	(12,461)	(1,850)	(2,133)
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	1,007	-	593	393	58	67
926 EMPLOYEE BENEFITS	LB926	LBSUB7	-	-	-	-	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-	-	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB932	PGP	72,537	-	193,337	155,450	30,377	35,724
Total Administrative and General Expense	LBAG		$ 302,689	$ -	$ 328,749	$ 245,214	$ 43,701	$ 51,087
Total Operation and Maintenance Expenses	TLB		$ 1,344,277	$ -	$ 941,582	$ 651,456	$ 104,000	$ 120,614
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 1,344,277	$ -	$ 941,582	$ 651,456	$ 104,000	$ 120,614

LOUISVILLE GAS AND ELECTRIC COMPANY
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12 Months Ended
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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Labor Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB7	35,158	29,554	10,062	812,633	36,985	783,065	184,109	-
921 OFFICE SUPPLIES AND EXPENSES	LB920	LBSUB7	-	-	-	-	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB7	(4,302)	(3,616)	(1,231)	(99,437)	(4,526)	(95,819)	(22,528)	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB7	-	-	-	-	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	-	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB7	136	114	39	3,134	143	3,020	710	-
926 EMPLOYEE BENEFITS	LB926	LBSUB7	-	-	-	-	-	-	-	-
928 REGULATORY COMMISSION FEES	LB928	TUP	-	-	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB7	-	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB7	-	-	-	-	-	-	-	-
931 RENTS AND LEASES	LB931	PGP	-	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB932	PGP	56,344	47,363	20,557	29,868	56,169	-	-	-
Total Administrative and General Expense	LBAG		$ 87,336	$ 73,415	$ 29,427	$ 746,198	$ 88,770	$ 690,267	$ 162,291	$ -
Total Operation and Maintenance Expenses	TLB		$ 227,595	$ 191,317	$ 69,569	$ 3,988,064	$ 236,315	$ 3,814,177	$ 896,766	$ -
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 227,595	$ 191,317	$ 69,569	$ 3,988,064	$ 236,315	$ 3,814,177	$ 896,766	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
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12 Months Ended
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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Winter Peak	Production Demand Summer Peak	Production Energy	Transmission Demand Base	Transmission Demand Winter Peak	Transmission Demand Summer Peak
Other Expenses										
Depreciation Expenses										
Steam Production	DEPRTP	PPRTL	$ 63,914,070	22,299,619	27,642,835	13,971,616	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	628,648	219,335	271,890	137,422	-	-	-	-
Other Production	DEPRDP2	PPRTL	8,147,104	2,842,525	3,523,622	1,780,957	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	4,973,210	-	-	-	-	1,735,153	2,150,913	1,087,144
Transmission - Virginia Property	DEPRDP4	PTRAN	-	-	-	-	-	-	-	-
Distribution	DEPRDP5	PDIST	21,828,520	-	-	-	-	-	-	-
General & Common Plant	DEPRDP6	PGP	9,666,561	2,276,635	2,822,140	1,426,404	-	243,044	301,280	152,277
Intangible Plant	DEPRAADJ	PINT	-	-	-	-	-	-	-	-
Total Depreciation Expense	TDEPR		$ 109,158,114	27,638,114	34,260,488	17,316,399	-	1,978,197	2,452,193	1,239,421
Regualtory Credits										
Production	RCTNP	F017	$ (1,705,393)	(595,012)	(737,582)	(372,799)	-	-	-	-
Transmission	RCTNT	PTRAN	$ (1,467)	-	-	-	-	(512)	(635)	(321)
Distribution	RDTND	PDIST	$ (16,231)	-	-	-	-	-	-	-
Common	RCTNC	PGP	$ (1,189)	(280)	(347)	(176)	-	(30)	(37)	(19)
Total Regulatory Credits	TRCTN		$ (1,724,281)	$ (595,292)	$ (737,930)	$ (372,974)	$ -	$ (542)	$ (672)	$ (339)
Accretion Expense										
Production	ACRTNP	F017	$ 1,483,472	517,583	641,602	324,287	-	-	-	-
Transmission	ACRTNT	PTRAN	$ 1,395	-	-	-	-	487	603	305
Distribution	ACRTND	PDIST	$ 15,865	-	-	-	-	-	-	-
Common	ACRTNC	PGP	$ 1,163	274	340	172	-	29	36	18
Total Accretion Expense	TACRTN		$ 1,501,895	$ 517,857	$ 641,941	$ 324,459	$ -	$ 516	$ 639	$ 323
Property Taxes & Other	PTAX	TUP	$ 18,568,593	4,386,343	5,437,356	2,748,222	-	503,409	624,031	315,406
Amortization of Investment Tax Credit	OTAX	TUP	$ 1,861,232	439,667	545,016	275,469	-	50,459	62,550	31,615
Gain on Disposition of Allowances	OT	TUP	$ (66,274)	(15,656)	(19,407)	(9,809)	-	(1,797)	(2,227)	(1,126)
Interest	INTLTD	TUP	$ 48,502,810	11,457,518	14,202,856	7,178,600	-	1,314,948	1,630,023	823,868
Other Deductions	DEDUCT	TUP	$ -	-	-	-	-	-	-	-
Total Other Expenses	TOE		$ 177,802,089	$ 43,828,553	$ 54,330,321	$ 27,460,366	$ -	$ 3,845,191	$ 4,766,538	$ 2,409,168
Total Cost of Service (O&M + Other Expenses)			$ 820,428,867	$ 83,177,277	$ 103,107,401	$ 52,113,937	$ 467,969,007	$ 9,640,835	$ 11,950,877	$ 6,040,374

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Description	Name	Functional Vector	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
			General	Specific	Demand	Customer	Demand	Customer
Other Expenses								
Depreciation Expenses								
Steam Production	DEPRTP	PPRTL	-	-	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	-	-	-	-	-	-
Distribution	DEPRDP5	PDIST	2,269,335	-	6,048,588	4,863,282	950,343	1,117,634
General & Common Plant	DEPRDP6	PGP	254,164	-	677,438	544,685	106,438	125,174
Intangible Plant	DEPRAADJ	PINT	-	-	-	-	-	-
Total Depreciation Expense	TDEPR		2,523,499	-	6,726,026	5,407,966	1,056,781	1,242,809
Regualtory Credits								
Production	RCTNP	F017	-	-	-	-	-	-
Transmission	RCTNT	PTRAN	-	-	-	-	-	-
Distribution	RDTND	PDIST	(1,687)	-	(4,498)	(3,616)	(707)	(831)
Common	RCTNC	PGP	(31)	-	(83)	(67)	(13)	(15)
Total Regulatory Credits	TRCTN		$ (1,719)	$ -	$ (4,581)	$ (3,683)	$ (720)	$ (846)
Accretion Expense								
Production	ACRTNP	F017	-	-	-	-	-	-
Transmission	ACRTNT	PTRAN	-	-	-	-	-	-
Distribution	ACRTND	PDIST	1,649	-	4,396	3,535	691	812
Common	ACRTNC	PGP	31	-	82	66	13	15
Total Accretion Expense	TACRTN		$ 1,680	$ -	$ 4,478	$ 3,600	$ 704	$ 827
Property Taxes & Other	PTAX	TUP	473,425	-	1,261,845	1,014,569	198,259	233,159
Amortization of Investment Tax Credit	OTAX	TUP	47,454	-	126,482	101,696	19,873	23,371
Gain on Disposition of Allowances	OT	TUP	(1,690)	-	(4,504)	(3,621)	(708)	(832)
Interest	INTLTD	TUP	1,236,627	-	3,296,052	2,650,144	517,870	609,032
Other Deductions	DEDUCT	TUP	-	-	-	-	-	-
Total Other Expenses	TOE		$ 4,279,276	$ -	$ 11,405,799	$ 9,170,671	$ 1,792,059	$ 2,107,519
Total Cost of Service (O&M + Other Expenses)			$ 9,783,082	$ -	$ 12,875,801	$ 8,719,352	$ 1,343,503	$ 1,553,803

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Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Other Expenses										
Depreciation Expenses										
Steam Production	DEPRTP	PPRTL	-	-	-	-	-	-	-	-
Hydraulic Production	DEPRDP1	PPRTL	-	-	-	-	-	-	-	-
Other Production	DEPRDP2	PPRTL	-	-	-	-	-	-	-	-
Transmission - Kentucky System Property	DEPRDP3	PTRAN	-	-	-	-	-	-	-	-
Transmission - Virginia Property	DEPRDP4	PTRAN	-	-	-	-	-	-	-	-
Distribution	DEPRDP5	PDIST	1,762,744	1,481,769	643,145	934,429	1,757,251	-	-	-
General & Common Plant	DEPRDP6	PGP	197,426	165,957	72,032	104,655	196,811	-	-	-
Intangible Plant	DEPRAADJ	PINT	-	-	-	-	-	-	-	-
Total Depreciation Expense	TDEPR		1,960,170	1,647,727	715,177	1,039,084	1,954,062	-	-	-
Regualtory Credits										
Production	RCTNP	F017	-	-	-	-	-	-	-	-
Transmission	RCTNT	PTRAN	-	-	-	-	-	-	-	-
Distribution	RDTND	PDIST	(1,311)	(1,102)	(478)	(695)	(1,307)	-	-	-
Common	RCTNC	PGP	(24)	(20)	(9)	(13)	(24)	-	-	-
Total Regulatory Credits	TRCTN		$ (1,335)	$ (1,122)	$ (487)	$ (708)	$ (1,331)	$ -	$ -	$ -
Accretion Expense										
Production	ACRTNP	F017	-	-	-	-	-	-	-	-
Transmission	ACRTNT	PTRAN	-	-	-	-	-	-	-	-
Distribution	ACRTND	PDIST	1,281	1,077	467	679	1,277	-	-	-
Common	ACRTNC	PGP	24	20	9	13	24	-	-	-
Total Accretion Expense	TACRTN		$ 1,305	$ 1,097	$ 476	$ 692	$ 1,301	$ -	$ -	$ -
Property Taxes & Other	PTAX	TUP	367,740	309,124	134,172	194,939	366,594	-	-	-
Amortization of Investment Tax Credit	OTAX	TUP	36,861	30,985	13,449	19,540	36,746	-	-	-
Gain on Disposition of Allowances	OT	TUP	(1,313)	(1,103)	(479)	(696)	(1,308)	-	-	-
Interest	INTLTD	TUP	960,571	807,459	350,468	509,197	957,577	-	-	-
Other Deductions	DEDUCT	TUP	-	-	-	-	-	-	-	-
Total Other Expenses	TOE		$ 3,324,000	$ 2,794,166	$ 1,212,775	$ 1,762,048	$ 3,313,640	$ -	$ -	$ -
Total Cost of Service (O&M + Other Expenses)			$ 3,799,832	$ 3,194,153	$ 1,467,713	$ 13,699,087	$ 4,583,637	$ 15,321,627	$ 10,087,568	$ -

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Description	Name	Functional Vector	Total System	Production Demand Base	Production Demand Winter Peak	Production Demand Summer Peak	Production Energy	Transmission Demand Base	Transmission Demand Winter Peak	Transmission Demand Summer Peak
Functional Vectors										
Station Equipment	F001		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Line Transformers	F005		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meter Reading	F009		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		1.000000	0.000000	0.000000	0.000000	0.000000	0.348900	0.432500	0.218600
Load Management	F012		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		1.000000	0.348900	0.432500	0.218600	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Fuel	F018		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		19,054,592.78	5,647,144.56	7,000,258.02	3,538,165.09	2,869,025.10	-	-	-
PROFIX	PROFIX		1.000000	0.348900	0.432500	0.218600	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		8,234,284.27	98,545.21	122,157.65	61,742.57	7,951,838.83	-	-	-
Hydraulic Generation Operation Labor	F021		144,929.38	50,565.86	62,681.96	31,681.56	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		182,801.27	25,100.55	31,114.89	15,726.51	110,859.32	-	-	-
Distribution Operation Labor	F023		4,014,360.63	-	-	-	-	-	-	-
Distribution Maintenance Labor	F024		810,314.01	-	-	-	-	-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		504,833,022	-	-	-	-	-	-	-
Purchase Power Demand		F017	10,996,878	3,836,811	4,756,150	2,403,918	-	-	-	-
Purchase Power Energy		F018	72,612,048	-	-	-	72,612,048	-	-	-
Purchased Power Expenses	OMPP		$ 83,608,926	3,836,811	4,756,150	2,403,918	72,612,048	-	-	-
Intallations on Customer Premises - Plant in Service	F013		1.00000	-	-	-	-	-	-	-
Intallations on Customer Premises - Accum Depr	F014		1.00000	-	-	-	-	-	-	-
Generators -Energy	F015		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Generators - Demand	F016		1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Internally Generated Functional Vectors										
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.235517	0.291949	0.147561	-	0.025143	0.031167	0.015753
Total Distribution Plant		PDIST	1.000000	-	-	-	-	-	-	-
Total Transmission Plant		PTRAN	1.000000	-	-	-	-	0.348900	0.432500	0.218600
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.063339	0.078515	0.039684	0.708944	0.010258	0.012715	0.006427
Total Plant in Service		TPIS	1.000000	0.235606	0.292060	0.147617	-	0.025109	0.031125	0.015732
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.159813	0.198106	0.100129	0.272309	0.015898	0.019707	0.009961
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.047135	0.058429	0.029532	0.791990	0.007949	0.009854	0.004981
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.296367	0.367379	0.185686	0.150569	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.011968	0.014835	0.007498	0.965699	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	1.000000	0.348900	0.432500	0.218600	-	-	-	-
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	1.000000	0.137311	0.170212	0.086031	0.606447	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	1.000000	0.348900	0.432500	0.218600	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	-	-	0.3489000	0.4325000	0.2186000
Total Distribution Operation Labor Expense		LBDO	1.000000	-	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense		LBDM	1.000000	-	-	-	-	-	-	-
Sub-Total Labor Exp		LBSUB7	1.000000	0.155902	0.193258	0.097679	0.286375	0.015420	0.019115	0.009661
Total General Plant		PGP	1.000000	0.235517	0.291949	0.147561	-	0.025143	0.031167	0.015753
Total Production Plant		PPRTL	1.000000	0.348900	0.432500	0.218600	-	-	-	-
Total Intangible Plant		PINT	1.000000	0.235517	0.291949	0.147561	-	0.025143	0.031167	0.015753

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 31, 2009

Description	Name	Functional Vector	Distribution Substation	Distribution Primary Lines			Distribution Sec. Lines	
			General	Specific	Demand	Customer	Demand	Customer
Functional Vectors								
Station Equipment	F001		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.000000	0.000000	0.345100	0.412500	0.110400	0.132000
Overhead Conductors and Devices	F003		0.000000	0.000000	0.345100	0.412500	0.110400	0.132000
Underground Conductors and Devices	F004		0.000000	0.000000	0.686500	0.305700	0.005400	0.002400
Line Transformers	F005		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production Plant	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-	-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-	-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-	-	-	-
Distribution Operation Labor	F023		633,572.42	-	286,019.28	190,422.48	28,485.07	32,864.96
Distribution Maintenance Labor	F024		241,764.46	-	251,789.52	165,870.93	24,342.80	28,041.16
Customer Accounts Expense	F025		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Advances	F027		-	-	235,255,941	189,149,113	36,960,874	43,467,094
Purchase Power Demand		F017	-	-	-	-	-	-
Purchase Power Energy		F018	-	-	-	-	-	-
Purchased Power Expenses	OMPP		-	-	-	-	-	-
Intallations on Customer Premises - Plant in Service	F013		-	-	-	-	-	-
Intallations on Customer Premises - Accum Depr	F014		-	-	-	-	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Generators - Demand	F016		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Internally Generated Functional Vectors								
Total Prod, Trans, and Dist Plant		PT&D	0.026293	-	0.070081	0.056347	0.011011	0.012949
Total Distribution Plant		PDIST	0.103962	-	0.277096	0.222795	0.043537	0.051201
Total Transmission Plant		PTRAN	-	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.009741	-	0.002602	(0.000799)	(0.000794)	(0.000980)
Total Plant in Service		TPIS	0.026277	-	0.070036	0.056312	0.011004	0.012941
Total Operation and Maintenance Expenses (Labor)		TLB	0.023934	-	0.016764	0.011599	0.001852	0.002147
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.006542	-	(0.000516)	(0.003075)	(0.001188)	(0.001440)
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	-	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	0.157826	-	0.071249	0.047435	0.007096	0.008187
Total Distribution Maintenance Labor Expense		LBDM	0.298359	-	0.310731	0.204700	0.030041	0.034605
Sub-Total Labor Exp		LBSUB7	0.023812	-	0.014010	0.009287	0.001379	0.001589
Total General Plant		PGP	0.026293	-	0.070081	0.056347	0.011011	0.012949
Total Production Plant		PPRTL	-	-	-	-	-	-
Total Intangible Plant		PINT	0.026293	-	0.070081	0.056347	0.011011	0.012949

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
October 31, 2009

Description	Name	Functional Vector	Distribution Line Trans. Demand	Distribution Line Trans. Customer	Distribution Services Customer	Distribution Meters	Distribution St. & Cust. Lighting	Customer Accounts Expense	Customer Service & Info.	Sales Expense
Functional Vectors										
Station Equipment	F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Line Transformers	F005		0.543300	0.456700	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Transmission	F011		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Production Plant	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Provar	PROVAR		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Fuel	F018		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Operation Labor	F019		-	-	-	-	-	-	-	-
PROFIX	PROFIX		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Steam Generation Maintenance Labor	F020		-	-	-	-	-	-	-	-
Hydraulic Generation Operation Labor	F021		-	-	-	-	-	-	-	-
Hydraulic Generation Maintenance Labor	F022		-	-	-	-	-	-	-	-
Distribution Operation Labor	F023		84,799.88	71,283.09	30,939.60	2,566,608.59	89,365.26	-	-	-
Distribution Maintenance Labor	F024		33,207.49	27,914.34	1,081.71	1,571.62	34,729.98	-	-	-
Customer Accounts Expense	F025		0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Customer Service Expense	F026		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Customer Advances	F027		-	-	-	-	-	-	-	-
Purchase Power Demand		F017	-	-	-	-	-	-	-	-
Purchase Power Energy		F018	-	-	-	-	-	-	-	-
Purchased Power Expenses	OMPP		-	-	-	-	-	-	-	-
Intallations on Customer Premises - Plant in Service	F013		-	-	-	-	-	1.00000	-	-
Intallations on Customer Premises - Accum Depr	F014		-	-	-	-	-	1.00000	-	-
Generators -Energy	F015		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Generators - Demand	F016		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Energy		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Internally Generated Functional Vectors										
Total Prod, Trans, and Dist Plant		PT&D	0.020424	0.017168	0.007452	0.010827	0.020360	-	-	-
Total Distribution Plant		PDIST	0.080754	0.067882	0.029464	0.042808	0.080503	-	-	-
Total Transmission Plant		PTRAN	-	-	-	-	-	-	-	-
Operation and Maintenance Expenses Less Purchase Power		OMLPP	0.000842	0.000708	0.000451	0.021127	0.002248	0.027118	0.017854	-
Total Plant in Service		TPIS	0.020411	0.017157	0.007447	0.010820	0.020347	-	-	-
Total Operation and Maintenance Expenses (Labor)		TLB	0.004052	0.003406	0.001239	0.071004	0.004207	0.067908	0.015966	-
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	0.000026	0.000022	0.000179	0.012872	0.001405	0.019355	0.015947	-
Total Steam Power Operation Expenses (Labor)		LBSUB1	-	-	-	-	-	-	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	-	-	-	-	-	-	-	-
Total Hydraulic Power Operation Expenses (Labor)		LBSUB3	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation Maint. Expense (Labor)		LBSUB4	-	-	-	-	-	-	-	-
Total Other Power Generation Expenses (Labor)		LBSUB5	-	-	-	-	-	-	-	-
Total Transmission Labor Expenses		LBTRAN	-	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense		LBDO	0.021124	0.017757	0.007707	0.639357	0.022261	-	-	-
Total Distribution Maintenance Labor Expense		LBDM	0.040981	0.034449	0.001335	0.001940	0.042860	-	-	-
Sub-Total Labor Exp		LBSUB7	0.003206	0.002695	0.000918	0.074113	0.003373	0.071416	0.016791	-
Total General Plant		PGP	0.020424	0.017168	0.007452	0.010827	0.020360	-	-	-
Total Production Plant		PPRTL	-	-	-	-	-	-	-	-
Total Intangible Plant		PINT	0.020424	0.017168	0.007452	0.010827	0.020360	-	-	-

Seelye Exhibit 24

Electric Cost of Service Study
Class Allocation

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Plant in Service								
Power Production Plant								
Production Demand - Base	TPIS	PLPPDB	PPBDA	$ 845,717,850	$ 305,094,459	$ 105,468,626	$ 20,428,286	$ 183,113,639
Production Demand - Winter Peak	TPIS	PLPPDI	PPWDA	$ 1,048,360,476	$ 427,257,548	$ 154,590,337	$ 23,931,450	$ 228,825,318
Production Demand - Summer Peak	TPIS	PLPPDP	PPSDA	$ 529,876,532	$ 252,363,410	$ 69,000,445	$ 10,436,347	$ 100,337,542
Production Energy	TPIS	PLPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TPIS	PLPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TPIS	PLPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		PLPPT		$ 2,423,954,858	$ 984,715,417	$ 329,059,408	$ 54,796,083	$ 512,276,499
Transmission Plant								
Transmission Demand - Base	TPIS	PLTRB	PPBDA	$ 90,129,526	$ 32,514,413	$ 11,239,963	$ 2,177,076	$ 19,514,718
Transmission Demand - Inter.	TPIS	PLTRI	PPWDA	$ 111,725,480	$ 45,533,532	$ 16,474,944	$ 2,550,414	$ 24,386,286
Transmission Demand - Peak	TPIS	PLTRP	PPSDA	$ 56,469,804	$ 26,894,779	$ 7,353,490	$ 1,112,218	$ 10,693,135
Total Transmission Plant		PLTRT		$ 258,324,810	$ 104,942,723	$ 35,068,396	$ 5,839,708	$ 54,594,139
Distribution Poles								
Specific	TPIS	PLDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TPIS	PLDSG	NCPP	$ 94,320,713	$ 45,659,904	$ 12,342,139	$ 1,973,332	$ 17,029,940
Distribution Primary & Secondary Lines								
Primary Specific	TPIS	PLDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPP	$ 251,398,364	$ 121,699,941	$ 32,896,205	$ 5,259,634	$ 45,390,869
Primary Customer	TPIS	PLDPLC	YECust08	$ 202,133,286	$ 174,243,234	$ 20,846,143	$ 45,118	$ 1,535,525
Secondary Demand	TPIS	PLDSLD	SICD	$ 39,499,259	$ 25,150,118	$ 8,207,551	$ -	$ 5,005,690
Secondary Customer	TPIS	PLDSLC	YECust07	$ 46,452,398	$ 40,058,762	$ 4,792,557	$ -	$ 353,019
Total Distribution Primary & Secondary Lines		PLDLT		$ 539,483,307	$ 361,152,055	$ 66,742,456	$ 5,304,753	$ 52,285,103
Distribution Line Transformers								
Demand	TPIS	PLDLTD	SICD	$ 73,265,193	$ 46,649,691	$ 15,223,774	$ -	$ 9,284,803
Customer	TPIS	PLDLTC	YECust07	$ 61,586,994	$ 53,110,255	$ 6,354,014	$ -	$ 468,036
Total Distribution Line Transformers		PLDLTT		$ 134,852,187	$ 99,759,946	$ 21,577,788	$ -	$ 9,752,839
Distribution Services								
Customer	TPIS	PLDSC	C02	$ 26,731,118	$ 23,620,703	$ 2,825,938	$ -	$ 208,158
Distribution Meters								
Customer	TPIS	PLDMC	C03	$ 38,837,792	$ 32,665,275	$ 4,298,815	$ 67,064	$ 1,438,377
Distribution Street & Customer Lighting								
Customer	TPIS	PLDSCL	YECust04	$ 73,036,864	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	TPIS	PLCAE	YECust05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	TPIS	PLCSI	YECust06	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	TPIS	PLSEC	YECust06	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 3,589,541,649	$ 1,652,516,024	$ 471,914,940	$ 67,980,939	$ 647,585,055

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Plant in Service								
Power Production Plant								
Production Demand - Base	TPIS	PLPPDB	PPBDA	$ 24,790,832	$ 28,160,848	$ 114,434,869	$ 3,139,723	$ 32,054,674
Production Demand - Winter Peak	TPIS	PLPPDI	PPWDA	$ 22,761,482	$ 32,829,919	$ 100,203,370	$ 3,232,674	$ 28,985,504
Production Demand - Summer Peak	TPIS	PLPPDP	PPSDA	$ 11,720,571	$ 14,799,205	$ 49,069,332	$ 1,674,891	$ 9,980,675
Production Energy	TPIS	PLPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TPIS	PLPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TPIS	PLPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		PLPPT		$ 59,272,886	$ 75,789,972	$ 263,707,571	$ 8,047,289	$ 71,020,853
Transmission Plant								
Transmission Demand - Base	TPIS	PLTRB	PPBDA	$ 2,641,999	$ 3,001,147	$ 12,195,510	$ 334,605	$ 3,416,119
Transmission Demand - Inter.	TPIS	PLTRI	PPWDA	$ 2,425,728	$ 3,498,738	$ 10,678,836	$ 344,511	$ 3,089,032
Transmission Demand - Peak	TPIS	PLTRP	PPSDA	$ 1,249,080	$ 1,577,175	$ 5,229,399	$ 178,496	$ 1,063,657
Total Transmission Plant		PLTRT		$ 6,316,808	$ 8,077,061	$ 28,103,745	$ 857,613	$ 7,568,808
Distribution Poles								
Specific	TPIS	PLDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TPIS	PLDSG	NCPP	$ 2,270,142	$ 2,434,157	$ 9,468,502	$ 302,152	$ -
Distribution Primary & Secondary Lines								
Primary Specific	TPIS	PLDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPP	$ 6,050,738	$ 6,487,896	$ 25,236,937	$ 805,342	$ -
Primary Customer	TPIS	PLDPLC	YECust08	$ 10,528	$ 42,110	$ 22,559	$ 8,522	$ -
Secondary Demand	TPIS	PLDSLD	SICD	$ -	$ 753,464	$ -	$ 104,909	$ -
Secondary Customer	TPIS	PLDSLC	YECust07	$ -	$ 9,681	$ -	$ 1,959	$ -
Total Distribution Primary & Secondary Lines		PLDLT		$ 6,061,265	$ 7,293,152	$ 25,259,496	$ 920,733	$ -
Distribution Line Transformers								
Demand	TPIS	PLDLTD	SICD	$ -	$ 1,397,563	$ -	$ 194,590	$ -
Customer	TPIS	PLDLTC	YECust07	$ -	$ 12,835	$ -	$ 2,598	$ -
Total Distribution Line Transformers		PLDLTT		$ -	$ 1,410,398	$ -	$ 197,188	$ -
Distribution Services								
Customer	TPIS	PLDSC	C02	$ -	$ 5,709	$ -	$ 3,058	$ -
Distribution Meters								
Customer	TPIS	PLDMC	C03	$ 12,004	$ 48,018	$ 137,710	$ 51,339	$ 15,099
Distribution Street & Customer Lighting								
Customer	TPIS	PLDSCL	YECust04	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	TPIS	PLCAE	YECust05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	TPIS	PLCSI	YECust06	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	TPIS	PLSEC	YECust06	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 73,933,105	$ 95,058,466	$ 326,677,023	$ 10,379,371	$ 78,604,760

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Plant in Service								
Power Production Plant								
Production Demand - Base	TPIS	PLPPDB	PPBDA	$ 16,148,985	$ 4,238,414	$ 8,045,336	$ 304,424	$ 294,735
Production Demand - Winter Peak	TPIS	PLPPDI	PPWDA	$ 20,875,660	$ 4,637,890	$ -	$ -	$ 229,323
Production Demand - Summer Peak	TPIS	PLPPDP	PPSDA	$ 9,001,253	$ 1,403,343	$ -	$ -	$ 89,516
Production Energy	TPIS	PLPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TPIS	PLPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TPIS	PLPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		PLPPT		$ 46,025,899	$ 10,279,648	$ 8,045,336	$ 304,424	$ 613,574
Transmission Plant								
Transmission Demand - Base	TPIS	PLTRB	PPBDA	$ 1,721,024	$ 451,695	$ 857,405	$ 32,443	$ 31,410
Transmission Demand - Inter.	TPIS	PLTRI	PPWDA	$ 2,224,753	$ 494,267	$ -	$ -	$ 24,439
Transmission Demand - Peak	TPIS	PLTRP	PPSDA	$ 959,278	$ 149,557	$ -	$ -	$ 9,540
Total Transmission Plant		PLTRT		$ 4,905,055	$ 1,095,519	$ 857,405	$ 32,443	$ 65,390
Distribution Poles								
Specific	TPIS	PLDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TPIS	PLDSG	NCPP	$ 1,521,482	$ 352,882	$ 920,461	$ 31,219	$ 14,401
Distribution Primary & Secondary Lines								
Primary Specific	TPIS	PLDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TPIS	PLDPLD	NCPP	$ 4,055,293	$ 940,557	$ 2,453,356	$ 83,211	$ 38,385
Primary Customer	TPIS	PLDPLC	YECust08	$ 501	$ 1,003	$ 5,322,674	$ 6,016	$ 49,352
Secondary Demand	TPIS	PLDSLD	SICD	$ -	$ -	$ 264,423	$ 8,968	$ 4,137
Secondary Customer	TPIS	PLDSLC	YECust07	$ -	$ -	$ 1,223,690	$ 1,383	$ 11,346
Total Distribution Primary & Secondary Lines		PLDLT		$ 4,055,795	$ 941,560	$ 9,264,143	$ 99,578	$ 103,219
Distribution Line Transformers								
Demand	TPIS	PLDLTD	SICD	$ -	$ -	$ 490,464	$ 16,635	$ 7,674
Customer	TPIS	PLDLTC	YECust07	$ -	$ -	$ 1,622,379	$ 1,834	$ 15,043
Total Distribution Line Transformers		PLDLTT		$ -	$ -	$ 2,112,843	$ 18,469	$ 22,716
Distribution Services								
Customer	TPIS	PLDSC	C02	$ -	$ -	$ -	$ 7,340	$ 60,212
Distribution Meters								
Customer	TPIS	PLDMC	C03	$ 3,260	$ 7,413	$ -	$ 10,150	$ 83,267
Distribution Street & Customer Lighting								
Customer	TPIS	PLDSCL	YECust04	$ -	$ -	$ 73,036,864	$ -	$ -
Customer Accounts Expense								
Customer	TPIS	PLCAE	YECust05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	TPIS	PLCSI	YECust06	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	TPIS	PLSEC	YECust06	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 56,511,490	$ 12,677,021	$ 94,237,052	$ 503,623	$ 962,780

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Net Utility Plant								
Power Production Plant								
Production Demand - Base	NTPLANT	UPPPDB	PPBDA	$ 501,290,892	$ 180,841,723	$ 62,515,485	$ 12,108,664	$ 108,538,799
Production Demand - Winter Peak	NTPLANT	UPPPDI	PPWDA	$ 621,405,305	$ 253,252,687	$ 91,631,894	$ 14,185,130	$ 135,633,944
Production Demand - Summer Peak	NTPLANT	UPPPDP	PPSDA	$ 314,079,074	$ 149,585,916	$ 40,899,332	$ 6,186,042	$ 59,474,086
Production Energy	NTPLANT	UPPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	NTPLANT	UPPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	NTPLANT	UPPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		UPPPT		$ 1,436,775,272	$ 583,680,326	$ 195,046,710	$ 32,479,836	$ 303,646,829
Transmission Plant								
Transmission Demand - Base	NTPLANT	UPTRB	PPBDA	$ 56,648,954	$ 20,436,227	$ 7,064,634	$ 1,368,354	$ 12,265,552
Transmission Demand - Inter.	NTPLANT	UPTRI	PPWDA	$ 70,222,622	$ 28,619,111	$ 10,354,968	$ 1,603,007	$ 15,327,470
Transmission Demand - Peak	NTPLANT	UPTRP	PPSDA	$ 35,492,867	$ 16,904,129	$ 4,621,876	$ 699,061	$ 6,720,938
Total Transmission Plant		UPTRT		$ 162,364,444	$ 65,959,467	$ 22,041,478	$ 3,670,421	$ 34,313,959
Distribution Poles								
Specific	NTPLANT	UPDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	NTPLANT	UPDSG	NCPP	$ 55,378,717	$ 26,808,395	$ 7,246,466	$ 1,158,607	$ 9,998,824
Distribution Primary & Secondary Lines								
Primary Specific	NTPLANT	UPDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPP	$ 147,604,046	$ 71,453,940	$ 19,314,418	$ 3,088,100	$ 26,650,436
Primary Customer	NTPLANT	UPDPLC	YECust08	$ 118,678,938	$ 102,303,794	$ 12,239,439	$ 26,490	$ 901,556
Secondary Demand	NTPLANT	UPDSLD	SICD	$ 23,191,282	$ 14,766,441	$ 4,818,916	$ -	$ 2,939,001
Secondary Customer	NTPLANT	UPDSLC	YECust07	$ 27,273,693	$ 23,519,784	$ 2,813,864	$ -	$ 207,269
Total Distribution Primary & Secondary Lines		UPDLT		$ 316,747,960	$ 212,043,960	$ 39,186,637	$ 3,114,591	$ 30,698,262
Distribution Line Transformers								
Demand	NTPLANT	UPDLTD	SICD	$ 43,016,346	$ 27,389,531	$ 8,938,366	$ -	$ 5,451,406
Customer	NTPLANT	UPDLTC	YECust07	$ 36,159,700	$ 31,182,735	$ 3,730,646	$ -	$ 274,799
Total Distribution Line Transformers		UPDLTT		$ 79,176,046	$ 58,572,266	$ 12,669,012	$ -	$ 5,726,205
Distribution Services								
Customer	NTPLANT	UPDSC	C02	$ 15,694,697	$ 13,868,473	$ 1,659,199	$ -	$ 122,216
Distribution Meters								
Customer	NTPLANT	UPDMC	C03	$ 22,802,914	$ 19,178,831	$ 2,523,972	$ 39,376	$ 844,517
Distribution Street & Customer Lighting								
Customer	NTPLANT	UPDSCL	YECust04	$ 42,882,286	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	NTPLANT	UPCAE	YECust05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	NTPLANT	UPCSI	YECust06	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	NTPLANT	UPSEC	YECust06	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 2,131,822,336	$ 980,111,717	$ 280,373,474	$ 40,462,830	$ 385,350,812

LOUISVILLE GAS AND ELECTRIC COMPANY
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Class Allocation

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Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Net Utility Plant								
Power Production Plant								
Production Demand - Base	NTPLANT	UPPPDB	PPBDA	$ 14,694,521	$ 16,692,064	$ 67,830,137	$ 1,861,040	$ 19,000,091
Production Demand - Winter Peak	NTPLANT	UPPPDI	PPWDA	$ 13,491,643	$ 19,459,610	$ 59,394,557	$ 1,916,136	$ 17,180,871
Production Demand - Summer Peak	NTPLANT	UPPPDP	PPSDA	$ 6,947,253	$ 8,772,083	$ 29,085,361	$ 992,775	$ 5,915,947
Production Energy	NTPLANT	UPPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	NTPLANT	UPPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	NTPLANT	UPPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		UPPPT		$ 35,133,417	$ 44,923,756	$ 156,310,055	$ 4,769,951	$ 42,096,908
Transmission Plant								
Transmission Demand - Base	NTPLANT	UPTRB	PPBDA	$ 1,660,571	$ 1,886,306	$ 7,665,223	$ 210,309	$ 2,147,127
Transmission Demand - Inter.	NTPLANT	UPTRI	PPWDA	$ 1,524,639	$ 2,199,056	$ 6,711,950	$ 216,535	$ 1,941,544
Transmission Demand - Peak	NTPLANT	UPTRP	PPSDA	$ 785,082	$ 991,299	$ 3,286,825	$ 112,190	$ 668,538
Total Transmission Plant		UPTRT		$ 3,970,292	$ 5,076,661	$ 17,663,998	$ 539,034	$ 4,757,210
Distribution Poles								
Specific	NTPLANT	UPDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	NTPLANT	UPDSG	NCPP	$ 1,332,873	$ 1,429,172	$ 5,559,261	$ 177,403	$ -
Distribution Primary & Secondary Lines								
Primary Specific	NTPLANT	UPDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPP	$ 3,552,582	$ 3,809,252	$ 14,817,415	$ 472,842	$ -
Primary Customer	NTPLANT	UPDPLC	YECust08	$ 6,181	$ 24,724	$ 13,245	$ 5,004	$ -
Secondary Demand	NTPLANT	UPDSLD	SICD	$ -	$ 442,383	$ -	$ 61,595	$ -
Secondary Customer	NTPLANT	UPDSLC	YECust07	$ -	$ 5,684	$ -	$ 1,150	$ -
Total Distribution Primary & Secondary Lines		UPDLT		$ 3,558,763	$ 4,282,044	$ 14,830,660	$ 540,592	$ -
Distribution Line Transformers								
Demand	NTPLANT	UPDLTD	SICD	$ -	$ 820,554	$ -	$ 114,250	$ -
Customer	NTPLANT	UPDLTC	YECust07	$ -	$ 7,536	$ -	$ 1,525	$ -
Total Distribution Line Transformers		UPDLTT		$ -	$ 828,090	$ -	$ 115,775	$ -
Distribution Services								
Customer	NTPLANT	UPDSC	C02	$ -	$ 3,352	$ -	$ 1,796	$ -
Distribution Meters								
Customer	NTPLANT	UPDMC	C03	$ 7,048	$ 28,193	$ 80,854	$ 30,143	$ 8,865
Distribution Street & Customer Lighting								
Customer	NTPLANT	UPDSCL	YECust04	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	NTPLANT	UPCAE	YECust05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	NTPLANT	UPCSI	YECust06	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	NTPLANT	UPSEC	YECust06	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 44,002,394	$ 56,571,267	$ 194,444,828	$ 6,174,693	$ 46,862,983

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
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Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Net Utility Plant								
Power Production Plant								
Production Demand - Base	NTPLANT	UPPPDB	PPBDA	$ 9,572,151	$ 2,512,278	$ 4,768,793	$ 180,444	$ 174,701
Production Demand - Winter Peak	NTPLANT	UPPPDI	PPWDA	$ 12,373,841	$ 2,749,063	$ -	$ -	$ 135,929
Production Demand - Summer Peak	NTPLANT	UPPPDP	PPSDA	$ 5,335,404	$ 831,818	$ -	$ -	$ 53,060
Production Energy	NTPLANT	UPPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	NTPLANT	UPPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	NTPLANT	UPPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		UPPPT		$ 27,281,397	$ 6,093,159	$ 4,768,793	$ 180,444	$ 363,690
Transmission Plant								
Transmission Demand - Base	NTPLANT	UPTRB	PPBDA	$ 1,081,712	$ 283,903	$ 538,903	$ 20,391	$ 19,742
Transmission Demand - Inter.	NTPLANT	UPTRI	PPWDA	$ 1,398,320	$ 310,661	$ -	$ -	$ 15,361
Transmission Demand - Peak	NTPLANT	UPTRP	PPSDA	$ 602,933	$ 94,001	$ -	$ -	$ 5,996
Total Transmission Plant		UPTRT		$ 3,082,966	$ 688,565	$ 538,903	$ 20,391	$ 41,099
Distribution Poles								
Specific	NTPLANT	UPDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	NTPLANT	UPDSG	NCPP	$ 893,311	$ 207,188	$ 540,432	$ 18,330	$ 8,455
Distribution Primary & Secondary Lines								
Primary Specific	NTPLANT	UPDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	NTPLANT	UPDPLD	NCPP	$ 2,380,993	$ 552,231	$ 1,440,444	$ 48,856	$ 22,537
Primary Customer	NTPLANT	UPDPLC	YECust08	$ 294	$ 589	$ 3,125,113	$ 3,532	$ 28,976
Secondary Demand	NTPLANT	UPDSLD	SICD	$ -	$ -	$ 155,251	$ 5,266	$ 2,429
Secondary Customer	NTPLANT	UPDSLC	YECust07	$ -	$ -	$ 718,468	$ 812	$ 6,662
Total Distribution Primary & Secondary Lines		UPDLT		$ 2,381,287	$ 552,820	$ 5,439,276	$ 58,466	$ 60,603
Distribution Line Transformers								
Demand	NTPLANT	UPDLTD	SICD	$ -	$ -	$ 287,967	$ 9,767	$ 4,505
Customer	NTPLANT	UPDLTC	YECust07	$ -	$ -	$ 952,551	$ 1,077	$ 8,832
Total Distribution Line Transformers		UPDLTT		$ -	$ -	$ 1,240,518	$ 10,844	$ 13,337
Distribution Services								
Customer	NTPLANT	UPDSC	C02	$ -	$ -	$ -	$ 4,309	$ 35,352
Distribution Meters								
Customer	NTPLANT	UPDMC	C03	$ 1,914	$ 4,352	$ -	$ 5,959	$ 48,889
Distribution Street & Customer Lighting								
Customer	NTPLANT	UPDSCL	YECust04	$ -	$ -	$ 42,882,286	$ -	$ -
Customer Accounts Expense								
Customer	NTPLANT	UPCAE	YECust05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	NTPLANT	UPCSI	YECust06	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	NTPLANT	UPSEC	YECust06	$ -	$ -	$ -	$ -	$ -
Total		UPT		$ 33,640,874	$ 7,546,085	$ 55,410,209	$ 298,744	$ 571,427

LOUISVILLE GAS AND ELECTRIC COMPANY
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12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Net Cost Rate Base								
Power Production Plant								
Production Demand - Base	RB	RBPPDB	PPBDA	$ 436,171,203	$ 157,349,661	$ 54,394,474	$ 10,535,700	$ 94,439,175
Production Demand - Winter Peak	RB	RBPPDI	PPWDA	$ 540,682,273	$ 220,354,151	$ 79,728,545	$ 12,342,425	$ 118,014,553
Production Demand - Summer Peak	RB	RBPPDP	PPSDA	$ 273,278,948	$ 130,154,108	$ 35,586,345	$ 5,382,450	$ 51,748,164
Production Energy	RB	RBPPEB	E01	$ 50,069,811	$ 18,062,787	$ 6,244,156	$ 1,209,435	$ 10,841,045
Production Energy - Not Used	RB	RBPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	RB	RBPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		RBPPT		$ 1,300,202,235	$ 525,920,707	$ 175,953,519	$ 29,470,010	$ 275,042,937
Transmission Plant								
Transmission Demand - Base	RB	RBTRB	PPBDA	$ 49,918,512	$ 18,008,206	$ 6,225,288	$ 1,205,780	$ 10,808,286
Transmission Demand - Inter.	RB	RBTRI	PPWDA	$ 61,879,497	$ 25,218,885	$ 9,124,698	$ 1,412,554	$ 13,506,419
Transmission Demand - Peak	RB	RBTRP	PPSDA	$ 31,275,972	$ 14,895,755	$ 4,072,753	$ 616,006	$ 5,922,425
Total Transmission Plant		RBTRT		$ 143,073,982	$ 58,122,846	$ 19,422,738	$ 3,234,340	$ 30,237,130
Distribution Poles								
Specific	RB	RBDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	RB	RBDSG	NCPP	$ 48,265,129	$ 23,364,764	$ 6,315,632	$ 1,009,780	$ 8,714,441
Distribution Primary & Secondary Lines								
Primary Specific	RB	RBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPP	$ 126,132,371	$ 61,059,674	$ 16,504,787	$ 2,638,880	$ 22,773,648
Primary Customer	RB	RBDPLC	YECust08	$ 101,210,805	$ 87,245,888	$ 10,437,939	$ 22,591	$ 768,858
Secondary Demand	RB	RBDSLD	SICD	$ 19,732,759	$ 12,564,317	$ 4,100,270	$ -	$ 2,500,707
Secondary Customer	RB	RBDSLC	YECust07	$ 23,203,084	$ 20,009,448	$ 2,393,894	$ -	$ 176,334
Total Distribution Primary & Secondary Lines		RBDLT		$ 270,279,020	$ 180,879,326	$ 33,436,889	$ 2,661,472	$ 26,219,547
Distribution Line Transformers								
Demand	RB	RBDLTD	SICD	$ 37,015,830	$ 23,568,859	$ 7,691,519	$ -	$ 4,690,968
Customer	RB	RBDLTC	YECust07	$ 31,115,644	$ 26,832,935	$ 3,210,243	$ -	$ 236,466
Total Distribution Line Transformers		RBDLTT		$ 68,131,474	$ 50,401,794	$ 10,901,762	$ -	$ 4,927,434
Distribution Services								
Customer	RB	RBDSC	C02	$ 13,515,549	$ 11,942,889	$ 1,428,825	$ -	$ 105,247
Distribution Meters								
Customer	RB	RBDMC	C03	$ 21,082,647	$ 17,731,968	$ 2,333,562	$ 36,405	$ 780,806
Distribution Street & Customer Lighting								
Customer	RB	RBDSCL	YECust04	$ 36,999,926	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	RB	RBCAE	YECust05	$ 1,915,203	$ 1,518,234	$ 199,803	$ 3,931	$ 133,795
Customer Service & Info.								
Customer	RB	RBCSI	YECust06	$ 1,260,946	$ 1,086,949	$ 130,041	$ 281	$ 9,579
Sales Expense								
Customer	RB	RBSEC	YECust06	$ -	$ -	$ -	$ -	$ -
Total		RBT		$ 1,904,726,111	$ 870,969,477	$ 250,122,772	$ 36,416,219	$ 346,170,916

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
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Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Net Cost Rate Base								
Power Production Plant								
Production Demand - Base	RB	RBPPDB	PPBDA	$ 12,785,644	$ 14,523,698	$ 59,018,731	$ 1,619,283	$ 16,531,903
Production Demand - Winter Peak	RB	RBPPDI	PPWDA	$ 11,739,025	$ 16,931,729	$ 51,678,967	$ 1,667,222	$ 14,949,007
Production Demand - Summer Peak	RB	RBPPDP	PPSDA	$ 6,044,777	$ 7,632,554	$ 25,307,057	$ 863,810	$ 5,147,441
Production Energy	RB	RBPPEB	E01	$ 1,467,715	$ 1,667,233	$ 6,774,993	$ 185,884	$ 1,897,762
Production Energy - Not Used	RB	RBPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	RB	RBPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		RBPPT		$ 32,037,160	$ 40,755,214	$ 142,779,747	$ 4,336,199	$ 38,526,114
Transmission Plant								
Transmission Demand - Base	RB	RBTRB	PPBDA	$ 1,463,279	$ 1,662,195	$ 6,754,520	$ 185,322	$ 1,892,028
Transmission Demand - Inter.	RB	RBTRI	PPWDA	$ 1,343,497	$ 1,937,787	$ 5,914,506	$ 190,809	$ 1,710,870
Transmission Demand - Peak	RB	RBTRP	PPSDA	$ 691,807	$ 873,523	$ 2,896,318	$ 98,861	$ 589,110
Total Transmission Plant		RBTRT		$ 3,498,583	$ 4,473,505	$ 15,565,344	$ 474,991	$ 4,192,007
Distribution Poles								
Specific	RB	RBDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	RB	RBDSG	NCPP	$ 1,161,661	$ 1,245,589	$ 4,845,155	$ 154,615	$ -
Distribution Primary & Secondary Lines								
Primary Specific	RB	RBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPP	$ 3,035,795	$ 3,255,128	$ 12,661,955	$ 404,059	$ -
Primary Customer	RB	RBDPLC	YECust08	$ 5,271	$ 21,085	$ 11,296	$ 4,267	$ -
Secondary Demand	RB	RBDSLD	SICD	$ -	$ 376,410	$ -	$ 52,410	$ -
Secondary Customer	RB	RBDSLC	YECust07	$ -	$ 4,836	$ -	$ 979	$ -
Total Distribution Primary & Secondary Lines		RBDLT		$ 3,041,066	$ 3,657,459	$ 12,673,250	$ 461,714	$ -
Distribution Line Transformers								
Demand	RB	RBDLTD	SICD	$ -	$ 706,092	$ -	$ 98,313	$ -
Customer	RB	RBDLTC	YECust07	$ -	$ 6,485	$ -	$ 1,312	$ -
Total Distribution Line Transformers		RBDLTT		$ -	$ 712,577	$ -	$ 99,625	$ -
Distribution Services								
Customer	RB	RBDSC	C02	$ -	$ 2,886	$ -	$ 1,546	$ -
Distribution Meters								
Customer	RB	RBDMC	C03	$ 6,516	$ 26,066	$ 74,754	$ 27,869	$ 8,196
Distribution Street & Customer Lighting								
Customer	RB	RBDSCL	YECust04	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	RB	RBCAE	YECust05	$ 1,835	$ 7,338	$ 1,966	$ 743	$ 437
Customer Service & Info.								
Customer	RB	RBCSI	YECust06	$ 66	$ 263	$ 141	$ 53	$ 16
Sales Expense								
Customer	RB	RBSEC	YECust06	$ -	$ -	$ -	$ -	$ -
Total		RBT		$ 39,746,887	$ 50,880,896	$ 175,940,357	$ 5,557,356	$ 42,726,770

LOUISVILLE GAS AND ELECTRIC COMPANY
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12 Months Ended
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Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Net Cost Rate Base								
Power Production Plant								
Production Demand - Base	RB	RBPPDB	PPBDA	$ 8,328,691	$ 2,185,923	$ 4,149,308	$ 157,004	$ 152,007
Production Demand - Winter Peak	RB	RBPPDI	PPWDA	$ 10,766,430	$ 2,391,949	$ -	$ -	$ 118,271
Production Demand - Summer Peak	RB	RBPPDP	PPSDA	$ 4,642,314	$ 723,761	$ -	$ -	$ 46,167
Production Energy	RB	RBPPEB	E01	$ 956,083	$ 250,931	$ 476,315	$ 18,023	$ 17,449
Production Energy - Not Used	RB	RBPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	RB	RBPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		RBPPT		$ 24,693,517	$ 5,552,565	$ 4,625,623	$ 175,027	$ 333,895
Transmission Plant								
Transmission Demand - Base	RB	RBTRB	PPBDA	$ 953,194	$ 250,172	$ 474,876	$ 17,969	$ 17,397
Transmission Demand - Inter.	RB	RBTRI	PPWDA	$ 1,232,186	$ 273,752	$ -	$ -	$ 13,536
Transmission Demand - Peak	RB	RBTRP	PPSDA	$ 531,299	$ 82,832	$ -	$ -	$ 5,284
Total Transmission Plant		RBTRT		$ 2,716,680	$ 606,756	$ 474,876	$ 17,969	$ 36,216
Distribution Poles								
Specific	RB	RBDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	RB	RBDSG	NCPP	$ 778,562	$ 180,574	$ 471,012	$ 15,975	$ 7,369
Distribution Primary & Secondary Lines								
Primary Specific	RB	RBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	RB	RBDPLD	NCPP	$ 2,034,634	$ 471,899	$ 1,230,905	$ 41,749	$ 19,258
Primary Customer	RB	RBDPLC	YECust08	$ 251	$ 502	$ 2,665,133	$ 3,012	$ 24,711
Secondary Demand	RB	RBDSLD	SICD	$ -	$ -	$ 132,098	$ 4,480	$ 2,067
Secondary Customer	RB	RBDSLC	YECust07	$ -	$ -	$ 611,236	$ 691	$ 5,667
Total Distribution Primary & Secondary Lines		RBDLT		$ 2,034,885	$ 472,401	$ 4,639,373	$ 49,932	$ 51,704
Distribution Line Transformers								
Demand	RB	RBDLTD	SICD	$ -	$ -	$ 247,798	$ 8,405	$ 3,877
Customer	RB	RBDLTC	YECust07	$ -	$ -	$ 819,676	$ 926	$ 7,600
Total Distribution Line Transformers		RBDLTT		$ -	$ -	$ 1,067,473	$ 9,331	$ 11,477
Distribution Services								
Customer	RB	RBDSC	C02	$ -	$ -	$ -	$ 3,711	$ 30,444
Distribution Meters								
Customer	RB	RBDMC	C03	$ 1,769	$ 4,024	$ -	$ 5,510	$ 45,201
Distribution Street & Customer Lighting								
Customer	RB	RBDSCL	YECust04	$ -	$ -	$ 36,999,926	$ -	$ -
Customer Accounts Expense								
Customer	RB	RBCAE	YECust05	$ 87	$ 175	$ 46,378	$ 52	$ 430
Customer Service & Info.								
Customer	RB	RBCSI	YECust06	$ 3	$ 6	$ 33,203	$ 38	$ 308
Sales Expense								
Customer	RB	RBSEC	YECust06	$ -	$ -	$ -	$ -	$ -
Total		RBT		$ 30,225,504	$ 6,816,502	$ 48,357,866	$ 277,545	$ 517,043

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Operation and Maintenance Expenses								
Power Production Plant								
Production Demand - Base	TOM	OMPPDB	PPBDA	$ 39,348,724	$ 14,195,133	$ 4,907,140	$ 950,467	$ 8,519,730
Production Demand - Winter Peak	TOM	OMPPDI	PPWDA	$ 48,777,080	$ 19,879,017	$ 7,192,626	$ 1,113,459	$ 10,646,558
Production Demand - Summer Peak	TOM	OMPPDP	PPSDA	$ 24,653,572	$ 11,741,715	$ 3,210,385	$ 485,572	$ 4,668,406
Production Energy	TOM	OMPPEB	E01	$ 467,969,007	$ 168,820,783	$ 58,359,946	$ 11,303,776	$ 101,323,990
Production Energy - Not Used	TOM	OMPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TOM	OMPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OMPPT		$ 580,748,382	$ 214,636,649	$ 73,670,097	$ 13,853,274	$ 125,158,684
Transmission Plant								
Transmission Demand - Base	TOM	OMTRB	PPBDA	$ 5,795,644	$ 2,090,791	$ 722,769	$ 139,994	$ 1,254,865
Transmission Demand - Inter.	TOM	OMTRI	PPWDA	$ 7,184,340	$ 2,927,966	$ 1,059,397	$ 164,001	$ 1,568,124
Transmission Demand - Peak	TOM	OMTRP	PPSDA	$ 3,631,206	$ 1,729,429	$ 472,855	$ 71,520	$ 687,606
Total Transmission Plant		OMTRT		$ 16,611,190	$ 6,748,185	$ 2,255,021	$ 375,514	$ 3,510,594
Distribution Poles								
Specific	TOM	OMDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TOM	OMDSG	NCPP	$ 5,503,806	$ 2,664,348	$ 720,189	$ 115,148	$ 993,732
Distribution Primary & Secondary Lines								
Primary Specific	TOM	OMDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPP	$ 1,470,002	$ 711,616	$ 192,354	$ 30,755	$ 265,414
Primary Customer	TOM	OMDPLC	Cust08	$ (451,318)	$ (388,861)	$ (46,826)	$ (100)	$ (3,408)
Secondary Demand	TOM	OMDSLD	SICD	$ (448,556)	$ (285,606)	$ (93,205)	$ -	$ (56,845)
Secondary Customer	TOM	OMDSLC	Cust07	$ (553,716)	$ (477,275)	$ (57,473)	$ -	$ (4,182)
Total Distribution Primary & Secondary Lines		OMDLT		$ 16,412	$ (440,125)	$ (5,151)	$ 30,655	$ 200,979
Distribution Line Transformers								
Demand	TOM	OMDLTD	SICD	$ 475,833	$ 302,974	$ 98,873	$ -	$ 60,302
Customer	TOM	OMDLTC	Cust07	$ 399,987	$ 344,768	$ 41,517	$ -	$ 3,021
Total Distribution Line Transformers		OMDLTT		$ 875,819	$ 647,742	$ 140,390	$ -	$ 63,323
Distribution Services								
Customer	TOM	OMDSC	C02	$ 254,937	$ 225,273	$ 26,951	$ -	$ 1,985
Distribution Meters								
Customer	TOM	OMDMC	C03	$ 11,937,039	$ 10,039,877	$ 1,321,268	$ 20,613	$ 442,094
Distribution Street & Customer Lighting								
Customer	TOM	OMDSCL	C04	$ 1,269,997	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	TOM	OMCAE	C05	$ 15,321,627	$ 12,127,608	$ 1,606,435	$ 31,226	$ 1,062,717
Customer Service & Info.								
Customer	TOM	OMCSI	C05	$ 10,087,568	$ 7,984,666	$ 1,057,657	$ 20,559	$ 699,680
Sales Expense								
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		OMT		$ 642,626,778	$ 254,634,222	$ 80,792,857	$ 14,446,987	$ 132,133,789

LOUISVILLE GAS AND ELECTRIC COMPANY
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Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Operation and Maintenance Expenses								
Power Production Plant								
Production Demand - Base	TOM	OMPPDB	PPBDA	$ 1,153,443	$ 1,310,240	$ 5,324,312	$ 146,082	$ 1,491,408
Production Demand - Winter Peak	TOM	OMPPDI	PPWDA	$ 1,059,024	$ 1,527,478	$ 4,662,163	$ 150,407	$ 1,348,609
Production Demand - Summer Peak	TOM	OMPPDP	PPSDA	$ 545,323	$ 688,563	$ 2,283,049	$ 77,928	$ 464,371
Production Energy	TOM	OMPPEB	E01	$ 13,717,745	$ 15,582,507	$ 63,321,321	$ 1,737,333	$ 17,737,112
Production Energy - Not Used	TOM	OMPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TOM	OMPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OMPPT		$ 16,475,536	$ 19,108,788	$ 75,590,846	$ 2,111,749	$ 21,041,500
Transmission Plant								
Transmission Demand - Base	TOM	OMTRB	PPBDA	$ 169,890	$ 192,984	$ 784,214	$ 21,516	$ 219,668
Transmission Demand - Inter.	TOM	OMTRI	PPWDA	$ 155,983	$ 224,981	$ 686,687	$ 22,153	$ 198,636
Transmission Demand - Peak	TOM	OMTRP	PPSDA	$ 80,320	$ 101,418	$ 336,269	$ 11,478	$ 68,397
Total Transmission Plant		OMTRT		$ 406,193	$ 519,383	$ 1,807,169	$ 55,147	$ 486,701
Distribution Poles								
Specific	TOM	OMDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TOM	OMDSG	NCPP	$ 132,467	$ 142,038	$ 552,506	$ 17,631	$ -
Distribution Primary & Secondary Lines								
Primary Specific	TOM	OMDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPP	$ 35,380	$ 37,937	$ 147,568	$ 4,709	$ -
Primary Customer	TOM	OMDPLC	Cust08	$ (23)	$ (93)	$ (50)	$ (19)	$ -
Secondary Demand	TOM	OMDSLD	SICD	$ -	$ (8,556)	$ -	$ (1,191)	$ -
Secondary Customer	TOM	OMDSLC	Cust07	$ -	$ (115)	$ -	$ (23)	$ -
Total Distribution Primary & Secondary Lines		OMDLT		$ 35,357	$ 29,172	$ 147,518	$ 3,476	$ -
Distribution Line Transformers								
Demand	TOM	OMDLTD	SICD	$ -	$ 9,077	$ -	$ 1,264	$ -
Customer	TOM	OMDLTC	Cust07	$ -	$ 83	$ -	$ 17	$ -
Total Distribution Line Transformers		OMDLTT		$ -	$ 9,160	$ -	$ 1,281	$ -
Distribution Services								
Customer	TOM	OMDSC	C02	$ -	$ 54	$ -	$ 29	$ -
Distribution Meters								
Customer	TOM	OMDMC	C03	$ 3,690	$ 14,759	$ 42,326	$ 15,779	$ 4,641
Distribution Street & Customer Lighting								
Customer	TOM	OMDSCL	C04	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	TOM	OMCAE	C05	$ 14,572	$ 58,288	$ 31,226	$ 11,796	$ 3,470
Customer Service & Info.								
Customer	TOM	OMCSI	C05	$ 9,594	$ 38,376	$ 20,559	$ 7,767	$ 2,284
Sales Expense								
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		OMT		$ 17,077,409	$ 19,920,018	$ 78,192,150	$ 2,224,655	$ 21,538,596

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Operation and Maintenance Expenses								
Power Production Plant								
Production Demand - Base	TOM	OMPPDB	PPBDA	$ 751,364	$ 197,201	$ 374,325	$ 14,164	$ 13,713
Production Demand - Winter Peak	TOM	OMPPDI	PPWDA	$ 971,282	$ 215,787	$ -	$ -	$ 10,670
Production Demand - Summer Peak	TOM	OMPPDP	PPSDA	$ 418,801	$ 65,293	$ -	$ -	$ 4,165
Production Energy	TOM	OMPPEB	E01	$ 8,935,870	$ 2,345,283	$ 4,451,801	$ 168,451	$ 163,088
Production Energy - Not Used	TOM	OMPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TOM	OMPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OMPPT		$ 11,077,317	$ 2,823,565	$ 4,826,127	$ 182,615	$ 191,635
Transmission Plant								
Transmission Demand - Base	TOM	OMTRB	PPBDA	$ 110,668	$ 29,046	$ 55,134	$ 2,086	$ 2,020
Transmission Demand - Inter.	TOM	OMTRI	PPWDA	$ 143,059	$ 31,783	$ -	$ -	$ 1,572
Transmission Demand - Peak	TOM	OMTRP	PPSDA	$ 61,685	$ 9,617	$ -	$ -	$ 613
Total Transmission Plant		OMTRT		$ 315,412	$ 70,446	$ 55,134	$ 2,086	$ 4,205
Distribution Poles								
Specific	TOM	OMDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TOM	OMDSG	NCPP	$ 88,782	$ 20,591	$ 53,711	$ 1,822	$ 840
Distribution Primary & Secondary Lines								
Primary Specific	TOM	OMDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TOM	OMDPLD	NCPP	$ 23,713	$ 5,500	$ 14,346	$ 487	$ 224
Primary Customer	TOM	OMDPLC	Cust08	$ (1)	$ (2)	$ (11,812)	$ (13)	$ (110)
Secondary Demand	TOM	OMDSLD	SICD	$ -	$ -	$ (3,003)	$ (102)	$ (47)
Secondary Customer	TOM	OMDSLC	Cust07	$ -	$ -	$ (14,497)	$ (16)	$ (134)
Total Distribution Primary & Secondary Lines		OMDLT		$ 23,711	$ 5,497	$ (14,966)	$ 355	$ (66)
Distribution Line Transformers								
Demand	TOM	OMDLTD	SICD	$ -	$ -	$ 3,185	$ 108	$ 50
Customer	TOM	OMDLTC	Cust07	$ -	$ -	$ 10,472	$ 12	$ 97
Total Distribution Line Transformers		OMDLTT		$ -	$ -	$ 13,658	$ 120	$ 147
Distribution Services								
Customer	TOM	OMDSC	C02	$ -	$ -	$ -	$ 70	$ 574
Distribution Meters								
Customer	TOM	OMDMC	C03	$ 1,002	$ 2,278	$ -	$ 3,120	$ 25,593
Distribution Street & Customer Lighting								
Customer	TOM	OMDSCL	C04	$ -	$ -	$ 1,269,997	$ -	$ -
Customer Accounts Expense								
Customer	TOM	OMCAE	C05	$ 694	$ 1,388	$ 368,376	$ 416	$ 3,416
Customer Service & Info.								
Customer	TOM	OMCSI	C05	$ 457	$ 914	$ 242,534	$ 274	$ 2,249
Sales Expense								
Customer	TOM	OMSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		OMT		$ 11,507,375	$ 2,924,679	$ 6,814,570	$ 190,878	$ 228,592

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Labor Expenses								
Power Production Plant								
Production Demand - Base	TLB	LBPPDB	PPBDA	$ 8,976,137	$ 3,238,160	$ 1,119,405	$ 216,818	$ 1,943,501
Production Demand - Winter Peak	TLB	LBPPDI	PPWDA	$ 11,126,911	$ 4,534,754	$ 1,640,765	$ 254,000	$ 2,428,667
Production Demand - Summer Peak	TLB	LBPPDP	PPSDA	$ 5,623,914	$ 2,678,492	$ 732,345	$ 110,768	$ 1,064,946
Production Energy	TLB	LBPPEB	E01	$ 15,294,665	$ 5,517,582	$ 1,907,382	$ 369,442	$ 3,311,579
Production Energy - Not Used	TLB	LBPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TLB	LBPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		LBPPT		$ 41,021,626	$ 15,968,988	$ 5,399,897	$ 951,028	$ 8,748,693
Transmission Plant								
Transmission Demand - Base	TLB	LBTRB	PPBDA	$ 892,916	$ 322,121	$ 111,355	$ 21,568	$ 193,333
Transmission Demand - Inter.	TLB	LBTRI	PPWDA	$ 1,106,868	$ 451,102	$ 163,218	$ 25,267	$ 241,596
Transmission Demand - Peak	TLB	LBTRP	PPSDA	$ 559,448	$ 266,448	$ 72,851	$ 11,019	$ 105,937
Total Transmission Plant		LBTRT		$ 2,559,233	$ 1,039,671	$ 347,424	$ 57,854	$ 540,866
Distribution Poles								
Specific	TLB	LBDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TLB	LBDSG	NCPP	$ 1,344,277	$ 650,754	$ 175,903	$ 28,124	$ 242,714
Distribution Primary & Secondary Lines								
Primary Specific	TLB	LBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TLB	LBDPLD	NCPP	$ 941,582	$ 455,812	$ 123,209	$ 19,699	$ 170,006
Primary Customer	TLB	LBDPLC	Cust08	$ 651,456	$ 561,301	$ 67,591	$ 145	$ 4,919
Secondary Demand	TLB	LBDSLD	SICD	$ 104,000	$ 66,220	$ 21,610	$ -	$ 13,180
Secondary Customer	TLB	LBDSLC	Cust07	$ 120,614	$ 103,963	$ 12,519	$ -	$ 911
Total Distribution Primary & Secondary Lines		LBDLT		$ 1,817,651	$ 1,187,296	$ 224,929	$ 19,844	$ 189,015
Distribution Line Transformers								
Demand	TLB	LBDLTD	SICD	$ 227,595	$ 144,915	$ 47,292	$ -	$ 28,843
Customer	TLB	LBDLTC	Cust07	$ 191,317	$ 164,906	$ 19,858	$ -	$ 1,445
Total Distribution Line Transformers		LBDLTT		$ 418,912	$ 309,821	$ 67,150	$ -	$ 30,288
Distribution Services								
Customer	TLB	LBDSC	C02	$ 69,569	$ 61,474	$ 7,355	$ -	$ 542
Distribution Meters								
Customer	TLB	LBDMC	C03	$ 3,988,064	$ 3,354,238	$ 441,424	$ 6,886	$ 147,700
Distribution Street & Customer Lighting								
Customer	TLB	LBDSCL	C04	$ 236,315	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	TLB	LBCAE	C05	$ 3,814,177	$ 3,019,056	$ 399,907	$ 7,773	$ 264,554
Customer Service & Info.								
Customer	TLB	LBCSI	C05	$ 896,766	$ 709,822	$ 94,024	$ 1,828	$ 62,200
Sales Expense								
Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		LBT		$ 56,166,593	$ 26,301,120	$ 7,158,013	$ 1,073,337	$ 10,226,572

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Labor Expenses								
Power Production Plant								
Production Demand - Base	TLB	LBPPDB	PPBDA	$ 263,121	$ 298,889	$ 1,214,569	$ 33,324	$ 340,216
Production Demand - Winter Peak	TLB	LBPPDI	PPWDA	$ 241,582	$ 348,445	$ 1,063,522	$ 34,310	$ 307,641
Production Demand - Summer Peak	TLB	LBPPDP	PPSDA	$ 124,398	$ 157,073	$ 520,804	$ 17,777	$ 105,931
Production Energy	TLB	LBPPEB	E01	$ 448,338	$ 509,284	$ 2,069,535	$ 56,781	$ 579,703
Production Energy - Not Used	TLB	LBPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TLB	LBPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		LBPPT		$ 1,077,439	$ 1,313,691	$ 4,868,430	$ 142,192	$ 1,333,492
Transmission Plant								
Transmission Demand - Base	TLB	LBTRB	PPBDA	$ 26,174	$ 29,732	$ 120,821	$ 3,315	$ 33,844
Transmission Demand - Inter.	TLB	LBTRI	PPWDA	$ 24,032	$ 34,662	$ 105,796	$ 3,413	$ 30,603
Transmission Demand - Peak	TLB	LBTRP	PPSDA	$ 12,375	$ 15,625	$ 51,808	$ 1,768	$ 10,538
Total Transmission Plant		LBTRT		$ 62,581	$ 80,020	$ 278,425	$ 8,496	$ 74,984
Distribution Poles								
Specific	TLB	LBDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TLB	LBDSG	NCPP	$ 32,355	$ 34,692	$ 134,947	$ 4,306	$ -
Distribution Primary & Secondary Lines								
Primary Specific	TLB	LBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TLB	LBDPLD	NCPP	$ 22,662	$ 24,300	$ 94,522	$ 3,016	$ -
Primary Customer	TLB	LBDPLC	Cust08	$ 34	$ 135	$ 72	$ 27	$ -
Secondary Demand	TLB	LBDSLD	SICD	$ -	$ 1,984	$ -	$ 276	$ -
Secondary Customer	TLB	LBDSLC	Cust07	$ -	$ 25	$ -	$ 5	$ -
Total Distribution Primary & Secondary Lines		LBDLT		$ 22,696	$ 26,443	$ 94,594	$ 3,325	$ -
Distribution Line Transformers								
Demand	TLB	LBDLTD	SICD	$ -	$ 4,341	$ -	$ 604	$ -
Customer	TLB	LBDLTC	Cust07	$ -	$ 40	$ -	$ 8	$ -
Total Distribution Line Transformers		LBDLTT		$ -	$ 4,381	$ -	$ 613	$ -
Distribution Services								
Customer	TLB	LBDSC	C02	$ -	$ 15	$ -	$ 8	$ -
Distribution Meters								
Customer	TLB	LBDMC	C03	$ 1,233	$ 4,931	$ 14,141	$ 5,272	$ 1,550
Distribution Street & Customer Lighting								
Customer	TLB	LBDSCL	C04	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	TLB	LBCAE	C05	$ 3,628	$ 14,510	$ 7,773	$ 2,937	$ 864
Customer Service & Info.								
Customer	TLB	LBCSI	C05	$ 853	$ 3,412	$ 1,828	$ 690	$ 203
Sales Expense								
Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		LBT		$ 1,200,783	$ 1,482,095	$ 5,400,138	$ 167,839	$ 1,411,094

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Labor Expenses								
Power Production Plant								
Production Demand - Base	TLB	LBPPDB	PPBDA	$ 171,399	$ 44,985	$ 85,390	$ 3,231	$ 3,128
Production Demand - Winter Peak	TLB	LBPPDI	PPWDA	$ 221,567	$ 49,225	$ -	$ -	$ 2,434
Production Demand - Summer Peak	TLB	LBPPDP	PPSDA	$ 95,536	$ 14,895	$ -	$ -	$ 950
Production Energy	TLB	LBPPEB	E01	$ 292,052	$ 76,651	$ 145,499	$ 5,505	$ 5,330
Production Energy - Not Used	TLB	LBPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TLB	LBPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		LBPPT		$ 780,554	$ 185,755	$ 230,889	$ 8,737	$ 11,842
Transmission Plant								
Transmission Demand - Base	TLB	LBTRB	PPBDA	$ 17,050	$ 4,475	$ 8,494	$ 321	$ 311
Transmission Demand - Inter.	TLB	LBTRI	PPWDA	$ 22,041	$ 4,897	$ -	$ -	$ 242
Transmission Demand - Peak	TLB	LBTRP	PPSDA	$ 9,504	$ 1,482	$ -	$ -	$ 95
Total Transmission Plant		LBTRT		$ 48,595	$ 10,853	$ 8,494	$ 321	$ 648
Distribution Poles								
Specific	TLB	LBDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TLB	LBDSG	NCPP	$ 21,684	$ 5,029	$ 13,119	$ 445	$ 205
Distribution Primary & Secondary Lines								
Primary Specific	TLB	LBDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TLB	LBDPLD	NCPP	$ 15,189	$ 3,523	$ 9,189	$ 312	$ 144
Primary Customer	TLB	LBDPLC	Cust08	$ 2	$ 3	$ 17,050	$ 19	$ 158
Secondary Demand	TLB	LBDSLD	SICD	$ -	$ -	$ 696	$ 24	$ 11
Secondary Customer	TLB	LBDSLC	Cust07	$ -	$ -	$ 3,158	$ 4	$ 29
Total Distribution Primary & Secondary Lines		LBDLT		$ 15,190	$ 3,526	$ 30,092	$ 358	$ 342
Distribution Line Transformers								
Demand	TLB	LBDLTD	SICD	$ -	$ -	$ 1,524	$ 52	$ 24
Customer	TLB	LBDLTC	Cust07	$ -	$ -	$ 5,009	$ 6	$ 46
Total Distribution Line Transformers		LBDLTT		$ -	$ -	$ 6,533	$ 57	$ 70
Distribution Services								
Customer	TLB	LBDSC	C02	$ -	$ -	$ -	$ 19	$ 157
Distribution Meters								
Customer	TLB	LBDMC	C03	$ 335	$ 761	$ -	$ 1,042	$ 8,550
Distribution Street & Customer Lighting								
Customer	TLB	LBDSCL	C04	$ -	$ -	$ 236,315	$ -	$ -
Customer Accounts Expense								
Customer	TLB	LBCAE	C05	$ 173	$ 345	$ 91,704	$ 104	$ 850
Customer Service & Info.								
Customer	TLB	LBCSI	C05	$ 41	$ 81	$ 21,561	$ 24	$ 200
Sales Expense								
Customer	TLB	LBSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		LBT		$ 866,571	$ 206,352	$ 638,706	$ 11,108	$ 22,865

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Depreciation Expenses								
Power Production Plant								
Production Demand - Base	TDEPR	DEPPDB	PPBDA	$ 27,638,114	$ 9,970,507	$ 3,446,722	$ 667,598	$ 5,984,166
Production Demand - Winter Peak	TDEPR	DEPPDI	PPWDA	$ 34,260,488	$ 13,962,804	$ 5,052,022	$ 782,081	$ 7,478,026
Production Demand - Summer Peak	TDEPR	DEPPDP	PPSDA	$ 17,316,399	$ 8,247,253	$ 2,254,939	$ 341,061	$ 3,279,037
Production Energy	TDEPR	DEPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TDEPR	DEPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TDEPR	DEPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		DEPPT		$ 79,215,002	$ 32,180,564	$ 10,753,683	$ 1,790,740	$ 16,741,229
Transmission Plant								
Transmission Demand - Base	TDEPR	DETRB	PPBDA	$ 1,978,197	$ 713,639	$ 246,699	$ 47,783	$ 428,316
Transmission Demand - Inter.	TDEPR	DETRI	PPWDA	$ 2,452,193	$ 999,387	$ 361,598	$ 55,977	$ 535,239
Transmission Demand - Peak	TDEPR	DETRP	PPSDA	$ 1,239,421	$ 590,297	$ 161,397	$ 24,411	$ 234,697
Total Transmission Plant		DETRT		$ 5,669,811	$ 2,303,323	$ 769,694	$ 128,172	$ 1,198,253
Distribution Poles								
Specific	TDEPR	DEDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TDEPR	DEDSG	NCPP	$ 2,523,499	$ 1,221,606	$ 330,207	$ 52,795	$ 455,627
Distribution Primary & Secondary Lines								
Primary Specific	TDEPR	DEDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TDEPR	DEDPLD	NCPP	$ 6,726,026	$ 3,256,016	$ 880,120	$ 140,719	$ 1,214,408
Primary Customer	TDEPR	DEDPLC	Cust08	$ 5,407,966	$ 4,659,563	$ 561,100	$ 1,200	$ 40,831
Secondary Demand	TDEPR	DEDSLD	SICD	$ 1,056,781	$ 672,878	$ 219,589	$ -	$ 133,925
Secondary Customer	TDEPR	DEDSLC	Cust07	$ 1,242,809	$ 1,071,237	$ 128,997	$ -	$ 9,387
Total Distribution Primary & Secondary Lines		DEDLT		$ 14,433,582	$ 9,659,694	$ 1,789,806	$ 141,918	$ 1,398,550
Distribution Line Transformers								
Demand	TDEPR	DEDLTD	SICD	$ 1,960,170	$ 1,248,087	$ 407,304	$ -	$ 248,410
Customer	TDEPR	DEDLTC	Cust07	$ 1,647,727	$ 1,420,256	$ 171,026	$ -	$ 12,445
Total Distribution Line Transformers		DEDLTT		$ 3,607,897	$ 2,668,343	$ 578,330	$ -	$ 260,855
Distribution Services								
Customer	TDEPR	DEDSC	C02	$ 715,177	$ 631,959	$ 75,606	$ -	$ 5,569
Distribution Meters								
Customer	TDEPR	DEDMC	C03	$ 1,039,084	$ 873,942	$ 115,012	$ 1,794	$ 38,483
Distribution Street & Customer Lighting								
Customer	TDEPR	DEDSCL	C04	$ 1,954,062	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	TDEPR	DECSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	TDEPR	DESEC	C06	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 109,158,114	$ 49,539,430	$ 14,412,339	$ 2,115,420	$ 20,098,567

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Depreciation Expenses								
Power Production Plant								
Production Demand - Base	TDEPR	DEPPDB	PPBDA	$ 810,166	$ 920,298	$ 3,739,739	$ 102,606	$ 1,047,549
Production Demand - Winter Peak	TDEPR	DEPPDI	PPWDA	$ 743,847	$ 1,072,884	$ 3,274,653	$ 105,644	$ 947,248
Production Demand - Summer Peak	TDEPR	DEPPDP	PPSDA	$ 383,029	$ 483,639	$ 1,603,589	$ 54,736	$ 326,169
Production Energy	TDEPR	DEPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TDEPR	DEPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TDEPR	DEPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		DEPPT		$ 1,937,042	$ 2,476,821	$ 8,617,981	$ 262,986	$ 2,320,966
Transmission Plant								
Transmission Demand - Base	TDEPR	DETRB	PPBDA	$ 57,988	$ 65,870	$ 267,672	$ 7,344	$ 74,978
Transmission Demand - Inter.	TDEPR	DETRI	PPWDA	$ 53,241	$ 76,792	$ 234,383	$ 7,561	$ 67,799
Transmission Demand - Peak	TDEPR	DETRP	PPSDA	$ 27,415	$ 34,616	$ 114,777	$ 3,918	$ 23,346
Total Transmission Plant		DETRT		$ 138,644	$ 177,278	$ 616,832	$ 18,823	$ 166,123
Distribution Poles								
Specific	TDEPR	DEDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TDEPR	DEDSG	NCPP	$ 60,736	$ 65,125	$ 253,325	$ 8,084	$ -
Distribution Primary & Secondary Lines								
Primary Specific	TDEPR	DEDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TDEPR	DEDPLD	NCPP	$ 161,884	$ 173,580	$ 675,201	$ 21,546	$ -
Primary Customer	TDEPR	DEDPLC	Cust08	$ 280	$ 1,120	$ 600	$ 227	$ -
Secondary Demand	TDEPR	DEDSLD	SICD	$ -	$ 20,159	$ -	$ 2,807	$ -
Secondary Customer	TDEPR	DEDSLC	Cust07	$ -	$ 257	$ -	$ 52	$ -
Total Distribution Primary & Secondary Lines		DEDLT		$ 162,164	$ 195,116	$ 675,800	$ 24,632	$ -
Distribution Line Transformers								
Demand	TDEPR	DEDLTD	SICD	$ -	$ 37,391	$ -	$ 5,206	$ -
Customer	TDEPR	DEDLTC	Cust07	$ -	$ 341	$ -	$ 69	$ -
Total Distribution Line Transformers		DEDLTT		$ -	$ 37,732	$ -	$ 5,275	$ -
Distribution Services								
Customer	TDEPR	DEDSC	C02	$ -	$ 153	$ -	$ 82	$ -
Distribution Meters								
Customer	TDEPR	DEDMC	C03	$ 321	$ 1,285	$ 3,684	$ 1,374	$ 404
Distribution Street & Customer Lighting								
Customer	TDEPR	DEDSCL	C04	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	TDEPR	DECSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	TDEPR	DESEC	C06	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 2,298,907	$ 2,953,510	$ 10,167,622	$ 321,256	$ 2,487,493

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Depreciation Expenses								
Power Production Plant								
Production Demand - Base	TDEPR	DEPPDB	PPBDA	$ 527,750	$ 138,512	$ 262,922	$ 9,949	$ 9,632
Production Demand - Winter Peak	TDEPR	DEPPDI	PPWDA	$ 682,218	$ 151,567	$ -	$ -	$ 7,494
Production Demand - Summer Peak	TDEPR	DEPPDP	PPSDA	$ 294,162	$ 45,861	$ -	$ -	$ 2,925
Production Energy	TDEPR	DEPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TDEPR	DEPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TDEPR	DEPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		DEPPT		$ 1,504,129	$ 335,940	$ 262,922	$ 9,949	$ 20,052
Transmission Plant								
Transmission Demand - Base	TDEPR	DETRB	PPBDA	$ 37,774	$ 9,914	$ 18,819	$ 712	$ 689
Transmission Demand - Inter.	TDEPR	DETRI	PPWDA	$ 48,830	$ 10,848	$ -	$ -	$ 536
Transmission Demand - Peak	TDEPR	DETRP	PPSDA	$ 21,055	$ 3,283	$ -	$ -	$ 209
Total Transmission Plant		DETRT		$ 107,658	$ 24,045	$ 18,819	$ 712	$ 1,435
Distribution Poles								
Specific	TDEPR	DEDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TDEPR	DEDSG	NCPP	$ 40,706	$ 9,441	$ 24,626	$ 835	$ 385
Distribution Primary & Secondary Lines								
Primary Specific	TDEPR	DEDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TDEPR	DEDPLD	NCPP	$ 108,497	$ 25,164	$ 65,638	$ 2,226	$ 1,027
Primary Customer	TDEPR	DEDPLC	Cust08	$ 13	$ 27	$ 141,534	$ 160	$ 1,312
Secondary Demand	TDEPR	DEDSLD	SICD	$ -	$ -	$ 7,074	$ 240	$ 111
Secondary Customer	TDEPR	DEDSLC	Cust07	$ -	$ -	$ 32,539	$ 37	$ 302
Total Distribution Primary & Secondary Lines		DEDLT		$ 108,510	$ 25,191	$ 246,785	$ 2,663	$ 2,752
Distribution Line Transformers								
Demand	TDEPR	DEDLTD	SICD	$ -	$ -	$ 13,122	$ 445	$ 205
Customer	TDEPR	DEDLTC	Cust07	$ -	$ -	$ 43,140	$ 49	$ 400
Total Distribution Line Transformers		DEDLTT		$ -	$ -	$ 56,262	$ 494	$ 605
Distribution Services								
Customer	TDEPR	DEDSC	C02	$ -	$ -	$ -	$ 196	$ 1,611
Distribution Meters								
Customer	TDEPR	DEDMC	C03	$ 87	$ 198	$ -	$ 272	$ 2,228
Distribution Street & Customer Lighting								
Customer	TDEPR	DEDSCL	C04	$ -	$ -	$ 1,954,062	$ -	$ -
Customer Accounts Expense								
Customer	TDEPR	DECAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	TDEPR	DECSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	TDEPR	DESEC	C06	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 1,761,092	$ 394,815	$ 2,563,477	$ 15,121	$ 29,068

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Regulatory Credits								
Power Production Plant								
Production Demand - Base	TRCTN	RCPDB	PPBDA	$ (595,292)	$ (214,753)	$ (74,238)	$ (14,379)	$ (128,892)
Production Demand - Winter Peak	TRCTN	RCPDI	PPWDA	$ (737,930)	$ (300,742)	$ (108,814)	$ (16,845)	$ (161,068)
Production Demand - Summer Peak	TRCTN	RCPDP	PPSDA	$ (372,974)	$ (177,636)	$ (48,569)	$ (7,346)	$ (70,627)
Production Energy	TRCTN	RCPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TRCTN	RCPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TRCTN	RCPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		RCPT		$ (1,706,196)	$ (693,131)	$ (231,621)	$ (38,570)	$ (360,586)
Transmission Plant								
Transmission Demand - Base	TRCTN	RCRB	PPBDA	$ (542)	$ (195)	$ (68)	$ (13)	$ (117)
Transmission Demand - Inter.	TRCTN	RCRI	PPWDA	$ (672)	$ (274)	$ (99)	$ (15)	$ (147)
Transmission Demand - Peak	TRCTN	RCRP	PPSDA	$ (339)	$ (162)	$ (44)	$ (7)	$ (64)
Total Transmission Plant		RCRT		$ (1,553)	$ (631)	$ (211)	$ (35)	$ (328)
Distribution Poles								
Specific	TRCTN	RCPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TRCTN	RCSG	NCPP	$ (1,719)	$ (832)	$ (225)	$ (36)	$ (310)
Distribution Primary & Secondary Lines								
Primary Specific	TRCTN	RCPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TRCTN	RCPLD	NCPP	$ (4,581)	$ (2,218)	$ (599)	$ (96)	$ (827)
Primary Customer	TRCTN	RCPLC	Cust08	$ (3,683)	$ (3,174)	$ (382)	$ (1)	$ (28)
Secondary Demand	TRCTN	RCSLD	SICD	$ (720)	$ (458)	$ (150)	$ -	$ (91)
Secondary Customer	TRCTN	RCSLC	Cust07	$ (846)	$ (730)	$ (88)	$ -	$ (6)
Total Distribution Primary & Secondary Lines		RCLT		$ (9,830)	$ (6,579)	$ (1,219)	$ (97)	$ (953)
Distribution Line Transformers								
Demand	TRCTN	RCLTD	SICD	$ (1,335)	$ (850)	$ (277)	$ -	$ (169)
Customer	TRCTN	RCLTC	Cust07	$ (1,122)	$ (967)	$ (116)	$ -	$ (8)
Total Distribution Line Transformers		RCLTT		$ (2,457)	$ (1,817)	$ (394)	$ -	$ (178)
Distribution Services								
Customer	TRCTN	RCSC	C02	$ (487)	$ (430)	$ (51)	$ -	$ (4)
Distribution Meters								
Customer	TRCTN	RCMC	C03	$ (708)	$ (595)	$ (78)	$ (1)	$ (26)
Distribution Street & Customer Lighting								
Customer	TRCTN	RCSCL	C04	$ (1,331)	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	TRCTN	RCCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	TRCTN	RCCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	TRCTN	RCSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		RCT		$ (1,724,281)	$ (704,015)	$ (233,800)	$ (38,739)	$ (362,385)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Regulatory Credits								
Power Production Plant								
Production Demand - Base	TRCTN	RCPDB	PPBDA	$ (17,450)	$ (19,822)	$ (80,549)	$ (2,210)	$ (22,563)
Production Demand - Winter Peak	TRCTN	RCPDI	PPWDA	$ (16,022)	$ (23,109)	$ (70,532)	$ (2,275)	$ (20,403)
Production Demand - Summer Peak	TRCTN	RCPDP	PPSDA	$ (8,250)	$ (10,417)	$ (34,539)	$ (1,179)	$ (7,025)
Production Energy	TRCTN	RCPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TRCTN	RCPEi	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TRCTN	RCPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		RCPT		$ (41,722)	$ (53,348)	$ (185,621)	$ (5,664)	$ (49,991)
Transmission Plant								
Transmission Demand - Base	TRCTN	RCRB	PPBDA	$ (16)	$ (18)	$ (73)	$ (2)	$ (21)
Transmission Demand - Inter.	TRCTN	RCRI	PPWDA	$ (15)	$ (21)	$ (64)	$ (2)	$ (19)
Transmission Demand - Peak	TRCTN	RCRP	PPSDA	$ (8)	$ (9)	$ (31)	$ (1)	$ (6)
Total Transmission Plant		RCRT		$ (38)	$ (49)	$ (169)	$ (5)	$ (45)
Distribution Poles								
Specific	TRCTN	RCPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TRCTN	RCSG	NCPP	$ (41)	$ (44)	$ (173)	$ (6)	$ -
Distribution Primary & Secondary Lines								
Primary Specific	TRCTN	RCPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TRCTN	RCPLD	NCPP	$ (110)	$ (118)	$ (460)	$ (15)	$ -
Primary Customer	TRCTN	RCPLC	Cust08	$ (0)	$ (1)	$ (0)	$ (0)	$ -
Secondary Demand	TRCTN	RCSLD	SICD	$ -	$ (14)	$ -	$ (2)	$ -
Secondary Customer	TRCTN	RCSLC	Cust07	$ -	$ (0)	$ -	$ (0)	$ -
Total Distribution Primary & Secondary Lines		RCLT		$ (110)	$ (133)	$ (460)	$ (17)	$ -
Distribution Line Transformers								
Demand	TRCTN	RCLTD	SICD	$ -	$ (25)	$ -	$ (4)	$ -
Customer	TRCTN	RCLTC	Cust07	$ -	$ (0)	$ -	$ (0)	$ -
Total Distribution Line Transformers		RCLTT		$ -	$ (26)	$ -	$ (4)	$ -
Distribution Services								
Customer	TRCTN	RCSC	C02	$ -	$ (0)	$ -	$ (0)	$ -
Distribution Meters								
Customer	TRCTN	RCMC	C03	$ (0)	$ (1)	$ (3)	$ (1)	$ (0)
Distribution Street & Customer Lighting								
Customer	TRCTN	RCSCL	C04	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	TRCTN	RCCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	TRCTN	RCCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	TRCTN	RCSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		RCT		$ (41,912)	$ (53,600)	$ (186,425)	$ (5,696)	$ (50,037)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Regulatory Credits								
Power Production Plant								
Production Demand - Base	TRCTN	RCPDB	PPBDA	$ (11,367)	$ (2,983)	$ (5,663)	$ (214)	$ (207)
Production Demand - Winter Peak	TRCTN	RCPDI	PPWDA	$ (14,694)	$ (3,265)	$ -	$ -	$ (161)
Production Demand - Summer Peak	TRCTN	RCPDP	PPSDA	$ (6,336)	$ (988)	$ -	$ -	$ (63)
Production Energy	TRCTN	RCPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TRCTN	RCPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TRCTN	RCPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		RCPT		$ (32,397)	$ (7,236)	$ (5,663)	$ (214)	$ (432)
Transmission Plant								
Transmission Demand - Base	TRCTN	RCRB	PPBDA	$ (10)	$ (3)	$ (5)	$ (0)	$ (0)
Transmission Demand - Inter.	TRCTN	RCRI	PPWDA	$ (13)	$ (3)	$ -	$ -	$ (0)
Transmission Demand - Peak	TRCTN	RCRP	PPSDA	$ (6)	$ (1)	$ -	$ -	$ (0)
Total Transmission Plant		RCRT		$ (29)	$ (7)	$ (5)	$ (0)	$ (0)
Distribution Poles								
Specific	TRCTN	RCPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TRCTN	RCSG	NCPP	$ (28)	$ (6)	$ (17)	$ (1)	$ (0)
Distribution Primary & Secondary Lines								
Primary Specific	TRCTN	RCPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TRCTN	RCPLD	NCPP	$ (74)	$ (17)	$ (45)	$ (2)	$ (1)
Primary Customer	TRCTN	RCPLC	Cust08	$ (0)	$ (0)	$ (96)	$ (0)	$ (1)
Secondary Demand	TRCTN	RCSLD	SICD	$ -	$ -	$ (5)	$ (0)	$ (0)
Secondary Customer	TRCTN	RCSLC	Cust07	$ -	$ -	$ (22)	$ (0)	$ (0)
Total Distribution Primary & Secondary Lines		RCLT		$ (74)	$ (17)	$ (168)	$ (2)	$ (2)
Distribution Line Transformers								
Demand	TRCTN	RCLTD	SICD	$ -	$ -	$ (9)	$ (0)	$ (0)
Customer	TRCTN	RCLTC	Cust07	$ -	$ -	$ (29)	$ (0)	$ (0)
Total Distribution Line Transformers		RCLTT		$ -	$ -	$ (38)	$ (0)	$ (0)
Distribution Services								
Customer	TRCTN	RCSC	C02	$ -	$ -	$ -	$ (0)	$ (1)
Distribution Meters								
Customer	TRCTN	RCMC	C03	$ (0)	$ (0)	$ -	$ (0)	$ (2)
Distribution Street & Customer Lighting								
Customer	TRCTN	RCSCL	C04	$ -	$ -	$ (1,331)	$ -	$ -
Customer Accounts Expense								
Customer	TRCTN	RCCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	TRCTN	RCCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	TRCTN	RCSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		RCT		$ (32,528)	$ (7,266)	$ (7,222)	$ (218)	$ (437)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Accretion Expenses								
Power Production Plant								
Production Demand - Base	TACRTN	ACRPDB	PPBDA	$ 517,857	$ 186,818	$ 64,581	$ 12,509	$ 112,126
Production Demand - Winter Peak	TACRTN	ACRPDI	PPWDA	$ 641,941	$ 261,622	$ 94,660	$ 14,654	$ 140,116
Production Demand - Summer Peak	TACRTN	ACRPDP	PPSDA	$ 324,459	$ 154,529	$ 42,251	$ 6,390	$ 61,440
Production Energy	TACRTN	ACRPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TACRTN	ACRPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TACRTN	ACRPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		ACRPT		$ 1,484,257	$ 602,970	$ 201,493	$ 33,553	$ 313,682
Transmission Plant								
Transmission Demand - Base	TACRTN	ACRRB	PPBDA	$ 516	$ 186	$ 64	$ 12	$ 112
Transmission Demand - Inter.	TACRTN	ACRRI	PPWDA	$ 639	$ 261	$ 94	$ 15	$ 140
Transmission Demand - Peak	TACRTN	ACRRP	PPSDA	$ 323	$ 154	$ 42	$ 6	$ 61
Total Transmission Plant		ACRRT		$ 1,479	$ 601	$ 201	$ 33	$ 312
Distribution Poles								
Specific	TACRTN	ACRPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TACRTN	ACRSG	NCPP	$ 1,680	$ 813	$ 220	$ 35	$ 303
Distribution Primary & Secondary Lines								
Primary Specific	TACRTN	ACRPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TACRTN	ACRPLD	NCPP	$ 4,478	$ 2,168	$ 586	$ 94	$ 808
Primary Customer	TACRTN	ACRPLC	Cust08	$ 3,600	$ 3,102	$ 374	$ 1	$ 27
Secondary Demand	TACRTN	ACRSLD	SICD	$ 704	$ 448	$ 146	$ -	$ 89
Secondary Customer	TACRTN	ACRSLC	Cust07	$ 827	$ 713	$ 86	$ -	$ 6
Total Distribution Primary & Secondary Lines		ACRLT		$ 9,609	$ 6,431	$ 1,192	$ 94	$ 931
Distribution Line Transformers								
Demand	TACRTN	ACRLTD	SICD	$ 1,305	$ 831	$ 271	$ -	$ 165
Customer	TACRTN	ACRLTC	Cust07	$ 1,097	$ 945	$ 114	$ -	$ 8
Total Distribution Line Transformers		ACRLTT		$ 2,402	$ 1,776	$ 385	$ -	$ 174
Distribution Services								
Customer	TACRTN	ACRSC	C02	$ 476	$ 421	$ 50	$ -	$ 4
Distribution Meters								
Customer	TACRTN	ACRMC	C03	$ 692	$ 582	$ 77	$ 1	$ 26
Distribution Street & Customer Lighting								
Customer	TACRTN	ACRSCL	C04	$ 1,301	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	TACRTN	ACRCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	TACRTN	ACRCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	TACRTN	ACRSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		ACRT		$ 1,501,895	$ 613,593	$ 203,617	$ 33,717	$ 315,431

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October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Accretion Expenses								
Power Production Plant								
Production Demand - Base	TACRTN	ACRPDB	PPBDA	$ 15,180	$ 17,244	$ 70,072	$ 1,923	$ 19,628
Production Demand - Winter Peak	TACRTN	ACRPDI	PPWDA	$ 13,938	$ 20,103	$ 61,357	$ 1,979	$ 17,749
Production Demand - Summer Peak	TACRTN	ACRPDP	PPSDA	$ 7,177	$ 9,062	$ 30,047	$ 1,026	$ 6,111
Production Energy	TACRTN	ACRPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TACRTN	ACRPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TACRTN	ACRPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		ACRPT		$ 36,294	$ 46,408	$ 161,476	$ 4,928	$ 43,488
Transmission Plant								
Transmission Demand - Base	TACRTN	ACRRB	PPBDA	$ 15	$ 17	$ 70	$ 2	$ 20
Transmission Demand - Inter.	TACRTN	ACRRI	PPWDA	$ 14	$ 20	$ 61	$ 2	$ 18
Transmission Demand - Peak	TACRTN	ACRRP	PPSDA	$ 7	$ 9	$ 30	$ 1	$ 6
Total Transmission Plant		ACRRT		$ 36	$ 46	$ 161	$ 5	$ 43
Distribution Poles								
Specific	TACRTN	ACRPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TACRTN	ACRSG	NCPP	$ 40	$ 43	$ 169	$ 5	$ -
Distribution Primary & Secondary Lines								
Primary Specific	TACRTN	ACRPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TACRTN	ACRPLD	NCPP	$ 108	$ 116	$ 449	$ 14	$ -
Primary Customer	TACRTN	ACRPLC	Cust08	$ 0	$ 1	$ 0	$ 0	$ -
Secondary Demand	TACRTN	ACRSLD	SICD	$ -	$ 13	$ -	$ 2	$ -
Secondary Customer	TACRTN	ACRSLC	Cust07	$ -	$ 0	$ -	$ 0	$ -
Total Distribution Primary & Secondary Lines		ACRLT		$ 108	$ 130	$ 450	$ 16	$ -
Distribution Line Transformers								
Demand	TACRTN	ACRLTD	SICD	$ -	$ 25	$ -	$ 3	$ -
Customer	TACRTN	ACRLTC	Cust07	$ -	$ 0	$ -	$ 0	$ -
Total Distribution Line Transformers		ACRLTT		$ -	$ 25	$ -	$ 4	$ -
Distribution Services								
Customer	TACRTN	ACRSC	C02	$ -	$ 0	$ -	$ 0	$ -
Distribution Meters								
Customer	TACRTN	ACRMC	C03	$ 0	$ 1	$ 2	$ 1	$ 0
Distribution Street & Customer Lighting								
Customer	TACRTN	ACRSCL	C04	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	TACRTN	ACRCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	TACRTN	ACRCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	TACRTN	ACRSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		ACRT		$ 36,479	$ 46,654	$ 162,258	$ 4,959	$ 43,532

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12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Accretion Expenses								
Power Production Plant								
Production Demand - Base	TACRTN	ACRPDB	PPBDA	$ 9,888	$ 2,595	$ 4,926	$ 186	$ 180
Production Demand - Winter Peak	TACRTN	ACRPDI	PPWDA	$ 12,783	$ 2,840	$ -	$ -	$ 140
Production Demand - Summer Peak	TACRTN	ACRPDP	PPSDA	$ 5,512	$ 859	$ -	$ -	$ 55
Production Energy	TACRTN	ACRPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TACRTN	ACRPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	TACRTN	ACRPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		ACRPT		$ 28,183	$ 6,295	$ 4,926	$ 186	$ 376
Transmission Plant								
Transmission Demand - Base	TACRTN	ACRRB	PPBDA	$ 10	$ 3	$ 5	$ 0	$ 0
Transmission Demand - Inter.	TACRTN	ACRRI	PPWDA	$ 13	$ 3	$ -	$ -	$ 0
Transmission Demand - Peak	TACRTN	ACRRP	PPSDA	$ 5	$ 1	$ -	$ -	$ 0
Total Transmission Plant		ACRRT		$ 28	$ 6	$ 5	$ 0	$ 0
Distribution Poles								
Specific	TACRTN	ACRPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	TACRTN	ACRSG	NCPP	$ 27	$ 6	$ 16	$ 1	$ 0
Distribution Primary & Secondary Lines								
Primary Specific	TACRTN	ACRPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	TACRTN	ACRPLD	NCPP	$ 72	$ 17	$ 44	$ 1	$ 1
Primary Customer	TACRTN	ACRPLC	Cust08	$ 0	$ 0	$ 94	$ 0	$ 1
Secondary Demand	TACRTN	ACRSLD	SICD	$ -	$ -	$ 5	$ 0	$ 0
Secondary Customer	TACRTN	ACRSLC	Cust07	$ -	$ -	$ 22	$ 0	$ 0
Total Distribution Primary & Secondary Lines		ACRLT		$ 72	$ 17	$ 164	$ 2	$ 2
Distribution Line Transformers								
Demand	TACRTN	ACRLTD	SICD	$ -	$ -	$ 9	$ 0	$ 0
Customer	TACRTN	ACRLTC	Cust07	$ -	$ -	$ 29	$ 0	$ 0
Total Distribution Line Transformers		ACRLTT		$ -	$ -	$ 37	$ 0	$ 0
Distribution Services								
Customer	TACRTN	ACRSC	C02	$ -	$ -	$ -	$ 0	$ 1
Distribution Meters								
Customer	TACRTN	ACRMC	C03	$ 0	$ 0	$ -	$ 0	$ 1
Distribution Street & Customer Lighting								
Customer	TACRTN	ACRSCL	C04	$ -	$ -	$ 1,301	$ -	$ -
Customer Accounts Expense								
Customer	TACRTN	ACRCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	TACRTN	ACRCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	TACRTN	ACRSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		ACRT		$ 28,310	$ 6,324	$ 6,450	$ 190	$ 381

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12 Months Ended
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Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Property and Other Taxes								
Power Production Plant								
Production Demand - Base	PTAX	PTPPDB	PPBDA	$ 4,386,343	$ 1,582,382	$ 547,016	$ 105,952	$ 949,725
Production Demand - Winter Peak	PTAX	PTPPDI	PPWDA	$ 5,437,356	$ 2,215,985	$ 801,788	$ 124,121	$ 1,186,810
Production Demand - Summer Peak	PTAX	PTPPDP	PPSDA	$ 2,748,222	$ 1,308,891	$ 357,873	$ 54,128	$ 520,404
Production Energy	PTAX	PTPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	PTAX	PTPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	PTAX	PTPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		PTPPT		$ 12,571,922	$ 5,107,259	$ 1,706,677	$ 284,202	$ 2,656,939
Transmission Plant								
Transmission Demand - Base	PTAX	PTTRB	PPBDA	$ 503,409	$ 181,606	$ 62,780	$ 12,160	$ 108,997
Transmission Demand - Inter.	PTAX	PTTRI	PPWDA	$ 624,031	$ 254,323	$ 92,019	$ 14,245	$ 136,207
Transmission Demand - Peak	PTAX	PTTRP	PPSDA	$ 315,406	$ 150,218	$ 41,072	$ 6,212	$ 59,725
Total Transmission Plant		PTTRT		$ 1,442,845	$ 586,146	$ 195,871	$ 32,617	$ 304,930
Distribution Poles								
Specific	PTAX	PTDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	PTAX	PTDSG	NCPP	$ 473,425	$ 229,181	$ 61,949	$ 9,905	$ 85,478
Distribution Primary & Secondary Lines								
Primary Specific	PTAX	PTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPP	$ 1,261,845	$ 610,849	$ 165,116	$ 26,400	$ 227,831
Primary Customer	PTAX	PTDPLC	Cust08	$ 1,014,569	$ 874,164	$ 105,266	$ 225	$ 7,660
Secondary Demand	PTAX	PTDSLD	SICD	$ 198,259	$ 126,236	$ 41,196	$ -	$ 25,125
Secondary Customer	PTAX	PTDSLC	Cust07	$ 233,159	$ 200,971	$ 24,201	$ -	$ 1,761
Total Distribution Primary & Secondary Lines		PTDLT		$ 2,707,832	$ 1,812,220	$ 335,779	$ 26,625	$ 262,377
Distribution Line Transformers								
Demand	PTAX	PTDLTD	SICD	$ 367,740	$ 234,149	$ 76,413	$ -	$ 46,603
Customer	PTAX	PTDLTC	Cust07	$ 309,124	$ 266,449	$ 32,086	$ -	$ 2,335
Total Distribution Line Transformers		PTDLTT		$ 676,864	$ 500,598	$ 108,498	$ -	$ 48,938
Distribution Services								
Customer	PTAX	PTDSC	C02	$ 134,172	$ 118,560	$ 14,184	$ -	$ 1,045
Distribution Meters								
Customer	PTAX	PTDMC	C03	$ 194,939	$ 163,957	$ 21,577	$ 337	$ 7,220
Distribution Street & Customer Lighting								
Customer	PTAX	PTDSCL	C04	$ 366,594	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	PTAX	PTCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		PTT		$ 18,568,593	$ 8,517,921	$ 2,444,536	$ 353,685	$ 3,366,927

LOUISVILLE GAS AND ELECTRIC COMPANY
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12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Property and Other Taxes								
Power Production Plant								
Production Demand - Base	PTAX	PTPPDB	PPBDA	$ 128,578	$ 146,057	$ 593,520	$ 16,284	$ 166,253
Production Demand - Winter Peak	PTAX	PTPPDI	PPWDA	$ 118,053	$ 170,273	$ 519,708	$ 16,766	$ 150,334
Production Demand - Summer Peak	PTAX	PTPPDP	PPSDA	$ 60,789	$ 76,757	$ 254,500	$ 8,687	$ 51,765
Production Energy	PTAX	PTPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	PTAX	PTPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	PTAX	PTPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		PTPPT		$ 307,421	$ 393,087	$ 1,367,728	$ 41,738	$ 368,352
Transmission Plant								
Transmission Demand - Base	PTAX	PTTRB	PPBDA	$ 14,757	$ 16,763	$ 68,117	$ 1,869	$ 19,080
Transmission Demand - Inter.	PTAX	PTTRI	PPWDA	$ 13,549	$ 19,542	$ 59,645	$ 1,924	$ 17,253
Transmission Demand - Peak	PTAX	PTTRP	PPSDA	$ 6,977	$ 8,809	$ 29,208	$ 997	$ 5,941
Total Transmission Plant		PTTRT		$ 35,282	$ 45,114	$ 156,970	$ 4,790	$ 42,275
Distribution Poles								
Specific	PTAX	PTDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	PTAX	PTDSG	NCPP	$ 11,395	$ 12,218	$ 47,525	$ 1,517	$ -
Distribution Primary & Secondary Lines								
Primary Specific	PTAX	PTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPP	$ 30,371	$ 32,565	$ 126,672	$ 4,042	$ -
Primary Customer	PTAX	PTDPLC	Cust08	$ 53	$ 210	$ 113	$ 43	$ -
Secondary Demand	PTAX	PTDSLD	SICD	$ -	$ 3,782	$ -	$ 527	$ -
Secondary Customer	PTAX	PTDSLC	Cust07	$ -	$ 48	$ -	$ 10	$ -
Total Distribution Primary & Secondary Lines		PTDLT		$ 30,423	$ 36,605	$ 126,784	$ 4,621	$ -
Distribution Line Transformers								
Demand	PTAX	PTDLTD	SICD	$ -	$ 7,015	$ -	$ 977	$ -
Customer	PTAX	PTDLTC	Cust07	$ -	$ 64	$ -	$ 13	$ -
Total Distribution Line Transformers		PTDLTT		$ -	$ 7,079	$ -	$ 990	$ -
Distribution Services								
Customer	PTAX	PTDSC	C02	$ -	$ 29	$ -	$ 15	$ -
Distribution Meters								
Customer	PTAX	PTDMC	C03	$ 60	$ 241	$ 691	$ 258	$ 76
Distribution Street & Customer Lighting								
Customer	PTAX	PTDSCL	C04	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	PTAX	PTCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		PTT		$ 384,580	$ 494,372	$ 1,699,699	$ 53,928	$ 410,703

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12 Months Ended
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Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Property and Other Taxes								
Power Production Plant								
Production Demand - Base	PTAX	PTPPDB	PPBDA	$ 83,757	$ 21,983	$ 41,727	$ 1,579	$ 1,529
Production Demand - Winter Peak	PTAX	PTPPDI	PPWDA	$ 108,272	$ 24,055	$ -	$ -	$ 1,189
Production Demand - Summer Peak	PTAX	PTPPDP	PPSDA	$ 46,685	$ 7,278	$ -	$ -	$ 464
Production Energy	PTAX	PTPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	PTAX	PTPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	PTAX	PTPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		PTPPT		$ 238,715	$ 53,316	$ 41,727	$ 1,579	$ 3,182
Transmission Plant								
Transmission Demand - Base	PTAX	PTTRB	PPBDA	$ 9,613	$ 2,523	$ 4,789	$ 181	$ 175
Transmission Demand - Inter.	PTAX	PTTRI	PPWDA	$ 12,426	$ 2,761	$ -	$ -	$ 137
Transmission Demand - Peak	PTAX	PTTRP	PPSDA	$ 5,358	$ 835	$ -	$ -	$ 53
Total Transmission Plant		PTTRT		$ 27,397	$ 6,119	$ 4,789	$ 181	$ 365
Distribution Poles								
Specific	PTAX	PTDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	PTAX	PTDSG	NCPP	$ 7,637	$ 1,771	$ 4,620	$ 157	$ 72
Distribution Primary & Secondary Lines								
Primary Specific	PTAX	PTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	PTAX	PTDPLD	NCPP	$ 20,355	$ 4,721	$ 12,314	$ 418	$ 193
Primary Customer	PTAX	PTDPLC	Cust08	$ 3	$ 5	$ 26,553	$ 30	$ 246
Secondary Demand	PTAX	PTDSLD	SICD	$ -	$ -	$ 1,327	$ 45	$ 21
Secondary Customer	PTAX	PTDSLC	Cust07	$ -	$ -	$ 6,104	$ 7	$ 57
Total Distribution Primary & Secondary Lines		PTDLT		$ 20,357	$ 4,726	$ 46,299	$ 500	$ 516
Distribution Line Transformers								
Demand	PTAX	PTDLTD	SICD	$ -	$ -	$ 2,462	$ 83	$ 39
Customer	PTAX	PTDLTC	Cust07	$ -	$ -	$ 8,093	$ 9	$ 75
Total Distribution Line Transformers		PTDLTT		$ -	$ -	$ 10,555	$ 93	$ 114
Distribution Services								
Customer	PTAX	PTDSC	C02	$ -	$ -	$ -	$ 37	$ 302
Distribution Meters								
Customer	PTAX	PTDMC	C03	$ 16	$ 37	$ -	$ 51	$ 418
Distribution Street & Customer Lighting								
Customer	PTAX	PTDSCL	C04	$ -	$ -	$ 366,594	$ -	$ -
Customer Accounts Expense								
Customer	PTAX	PTCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	PTAX	PTCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	PTAX	PTSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		PTT		$ 294,122	$ 65,969	$ 474,585	$ 2,597	$ 4,970

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12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Amortization of ITC								
Power Production Plant								
Production Demand - Base	OTAX	OTPPDB	PPBDA	$ 439,667	$ 158,611	$ 54,830	$ 10,620	$ 95,196
Production Demand - Winter Peak	OTAX	OTPPDI	PPWDA	$ 545,016	$ 222,120	$ 80,368	$ 12,441	$ 118,960
Production Demand - Summer Peak	OTAX	OTPPDP	PPSDA	$ 275,469	$ 131,197	$ 35,872	$ 5,426	$ 52,163
Production Energy	OTAX	OTPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	OTAX	OTPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	OTAX	OTPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ 1,260,153	$ 511,929	$ 171,070	$ 28,487	$ 266,320
Transmission Plant								
Transmission Demand - Base	OTAX	OTTRB	PPBDA	$ 50,459	$ 18,203	$ 6,293	$ 1,219	$ 10,925
Transmission Demand - Inter.	OTAX	OTTRI	PPWDA	$ 62,550	$ 25,492	$ 9,224	$ 1,428	$ 13,653
Transmission Demand - Peak	OTAX	OTTRP	PPSDA	$ 31,615	$ 15,057	$ 4,117	$ 623	$ 5,987
Total Transmission Plant		OTTRT		$ 144,624	$ 58,753	$ 19,633	$ 3,269	$ 30,565
Distribution Poles								
Specific	OTAX	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	OTAX	OTDSG	NCPP	$ 47,454	$ 22,972	$ 6,209	$ 993	$ 8,568
Distribution Primary & Secondary Lines								
Primary Specific	OTAX	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	OTAX	OTDPLD	NCPP	$ 126,482	$ 61,229	$ 16,550	$ 2,646	$ 22,837
Primary Customer	OTAX	OTDPLC	Cust08	$ 101,696	$ 87,622	$ 10,551	$ 23	$ 768
Secondary Demand	OTAX	OTDSLD	SICD	$ 19,873	$ 12,653	$ 4,129	$ -	$ 2,518
Secondary Customer	OTAX	OTDSLC	Cust07	$ 23,371	$ 20,144	$ 2,426	$ -	$ 177
Total Distribution Primary & Secondary Lines		OTDLT		$ 271,421	$ 181,649	$ 33,657	$ 2,669	$ 26,299
Distribution Line Transformers								
Demand	OTAX	OTDLTD	SICD	$ 36,861	$ 23,470	$ 7,659	$ -	$ 4,671
Customer	OTAX	OTDLTC	Cust07	$ 30,985	$ 26,708	$ 3,216	$ -	$ 234
Total Distribution Line Transformers		OTDLTT		$ 67,846	$ 50,178	$ 10,875	$ -	$ 4,905
Distribution Services								
Customer	OTAX	OTDSC	C02	$ 13,449	$ 11,884	$ 1,422	$ -	$ 105
Distribution Meters								
Customer	OTAX	OTDMC	C03	$ 19,540	$ 16,434	$ 2,163	$ 34	$ 724
Distribution Street & Customer Lighting								
Customer	OTAX	OTDSCL	C04	$ 36,746	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	OTAX	OTCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ 1,861,232	$ 853,798	$ 245,029	$ 35,452	$ 337,485

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12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Amortization of ITC								
Power Production Plant								
Production Demand - Base	OTAX	OTPPDB	PPBDA	$ 12,888	$ 14,640	$ 59,492	$ 1,632	$ 16,664
Production Demand - Winter Peak	OTAX	OTPPDI	PPWDA	$ 11,833	$ 17,067	$ 52,093	$ 1,681	$ 15,069
Production Demand - Summer Peak	OTAX	OTPPDP	PPSDA	$ 6,093	$ 7,694	$ 25,510	$ 871	$ 5,189
Production Energy	OTAX	OTPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	OTAX	OTPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	OTAX	OTPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ 30,814	$ 39,401	$ 137,095	$ 4,184	$ 36,922
Transmission Plant								
Transmission Demand - Base	OTAX	OTTRB	PPBDA	$ 1,479	$ 1,680	$ 6,828	$ 187	$ 1,913
Transmission Demand - Inter.	OTAX	OTTRI	PPWDA	$ 1,358	$ 1,959	$ 5,979	$ 193	$ 1,729
Transmission Demand - Peak	OTAX	OTTRP	PPSDA	$ 699	$ 883	$ 2,928	$ 100	$ 595
Total Transmission Plant		OTTRT		$ 3,536	$ 4,522	$ 15,734	$ 480	$ 4,237
Distribution Poles								
Specific	OTAX	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	OTAX	OTDSG	NCPP	$ 1,142	$ 1,225	$ 4,764	$ 152	$ -
Distribution Primary & Secondary Lines								
Primary Specific	OTAX	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	OTAX	OTDPLD	NCPP	$ 3,044	$ 3,264	$ 12,697	$ 405	$ -
Primary Customer	OTAX	OTDPLC	Cust08	$ 5	$ 21	$ 11	$ 4	$ -
Secondary Demand	OTAX	OTDSLD	SICD	$ -	$ 379	$ -	$ 53	$ -
Secondary Customer	OTAX	OTDSLC	Cust07	$ -	$ 5	$ -	$ 1	$ -
Total Distribution Primary & Secondary Lines		OTDLT		$ 3,049	$ 3,669	$ 12,708	$ 463	$ -
Distribution Line Transformers								
Demand	OTAX	OTDLTD	SICD	$ -	$ 703	$ -	$ 98	$ -
Customer	OTAX	OTDLTC	Cust07	$ -	$ 6	$ -	$ 1	$ -
Total Distribution Line Transformers		OTDLTT		$ -	$ 710	$ -	$ 99	$ -
Distribution Services								
Customer	OTAX	OTDSC	C02	$ -	$ 3	$ -	$ 2	$ -
Distribution Meters								
Customer	OTAX	OTDMC	C03	$ 6	$ 24	$ 69	$ 26	$ 8
Distribution Street & Customer Lighting								
Customer	OTAX	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	OTAX	OTCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ 38,549	$ 49,554	$ 170,370	$ 5,406	$ 41,167

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Amortization of ITC								
Power Production Plant								
Production Demand - Base	OTAX	OTPPDB	PPBDA	$ 8,395	$ 2,203	$ 4,183	$ 158	$ 153
Production Demand - Winter Peak	OTAX	OTPPDI	PPWDA	$ 10,853	$ 2,411	$ -	$ -	$ 119
Production Demand - Summer Peak	OTAX	OTPPDP	PPSDA	$ 4,680	$ 730	$ -	$ -	$ 47
Production Energy	OTAX	OTPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	OTAX	OTPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	OTAX	OTPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ 23,928	$ 5,344	$ 4,183	$ 158	$ 319
Transmission Plant								
Transmission Demand - Base	OTAX	OTTRB	PPBDA	$ 964	$ 253	$ 480	$ 18	$ 18
Transmission Demand - Inter.	OTAX	OTTRI	PPWDA	$ 1,246	$ 277	$ -	$ -	$ 14
Transmission Demand - Peak	OTAX	OTTRP	PPSDA	$ 537	$ 84	$ -	$ -	$ 5
Total Transmission Plant		OTTRT		$ 2,746	$ 613	$ 480	$ 18	$ 37
Distribution Poles								
Specific	OTAX	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	OTAX	OTDSG	NCPP	$ 765	$ 178	$ 463	$ 16	$ 7
Distribution Primary & Secondary Lines								
Primary Specific	OTAX	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	OTAX	OTDPLD	NCPP	$ 2,040	$ 473	$ 1,234	$ 42	$ 19
Primary Customer	OTAX	OTDPLC	Cust08	$ 0	$ 1	$ 2,662	$ 3	$ 25
Secondary Demand	OTAX	OTDSLD	SICD	$ -	$ -	$ 133	$ 5	$ 2
Secondary Customer	OTAX	OTDSLC	Cust07	$ -	$ -	$ 612	$ 1	$ 6
Total Distribution Primary & Secondary Lines		OTDLT		$ 2,041	$ 474	$ 4,641	$ 50	$ 52
Distribution Line Transformers								
Demand	OTAX	OTDLTD	SICD	$ -	$ -	$ 247	$ 8	$ 4
Customer	OTAX	OTDLTC	Cust07	$ -	$ -	$ 811	$ 1	$ 8
Total Distribution Line Transformers		OTDLTT		$ -	$ -	$ 1,058	$ 9	$ 11
Distribution Services								
Customer	OTAX	OTDSC	C02	$ -	$ -	$ -	$ 4	$ 30
Distribution Meters								
Customer	OTAX	OTDMC	C03	$ 2	$ 4	$ -	$ 5	$ 42
Distribution Street & Customer Lighting								
Customer	OTAX	OTDSCL	C04	$ -	$ -	$ 36,746	$ -	$ -
Customer Accounts Expense								
Customer	OTAX	OTCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	OTAX	OTCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	OTAX	OTSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ 29,481	$ 6,612	$ 47,570	$ 260	$ 498

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Other Expenses								
Power Production Plant								
Production Demand - Base	OT	OTPPDB	PPBDA	$ (15,656)	$ (5,648)	$ (1,952)	$ (378)	$ (3,390)
Production Demand - Winter Peak	OT	OTPPDI	PPWDA	$ (19,407)	$ (7,909)	$ (2,862)	$ (443)	$ (4,236)
Production Demand - Summer Peak	OT	OTPPDP	PPSDA	$ (9,809)	$ (4,672)	$ (1,277)	$ (193)	$ (1,857)
Production Energy	OT	OTPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	OT	OTPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	OT	OTPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ (44,871)	$ (18,229)	$ (6,091)	$ (1,014)	$ (9,483)
Transmission Plant								
Transmission Demand - Base	OT	OTTRB	PPBDA	$ (1,797)	$ (648)	$ (224)	$ (43)	$ (389)
Transmission Demand - Inter.	OT	OTTRI	PPWDA	$ (2,227)	$ (908)	$ (328)	$ (51)	$ (486)
Transmission Demand - Peak	OT	OTTRP	PPSDA	$ (1,126)	$ (536)	$ (147)	$ (22)	$ (213)
Total Transmission Plant		OTTRT		$ (5,150)	$ (2,092)	$ (699)	$ (116)	$ (1,088)
Distribution Poles								
Specific	OT	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	OT	OTDSG	NCPP	$ (1,690)	$ (818)	$ (221)	$ (35)	$ (305)
Distribution Primary & Secondary Lines								
Primary Specific	OT	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	OT	OTDPLD	NCPP	$ (4,504)	$ (2,180)	$ (589)	$ (94)	$ (813)
Primary Customer	OT	OTDPLC	Cust08	$ (3,621)	$ (3,120)	$ (376)	$ (1)	$ (27)
Secondary Demand	OT	OTDSLD	SICD	$ (708)	$ (451)	$ (147)	$ -	$ (90)
Secondary Customer	OT	OTDSLC	Cust07	$ (832)	$ (717)	$ (86)	$ -	$ (6)
Total Distribution Primary & Secondary Lines		OTDLT		$ (9,665)	$ (6,468)	$ (1,198)	$ (95)	$ (936)
Distribution Line Transformers								
Demand	OT	OTDLTD	SICD	$ (1,313)	$ (836)	$ (273)	$ -	$ (166)
Customer	OT	OTDLTC	Cust07	$ (1,103)	$ (951)	$ (115)	$ -	$ (8)
Total Distribution Line Transformers		OTDLTT		$ (2,416)	$ (1,787)	$ (387)	$ -	$ (175)
Distribution Services								
Customer	OT	OTDSC	C02	$ (479)	$ (423)	$ (51)	$ -	$ (4)
Distribution Meters								
Customer	OT	OTDMC	C03	$ (696)	$ (585)	$ (77)	$ (1)	$ (26)
Distribution Street & Customer Lighting								
Customer	OT	OTDSCL	C04	$ (1,308)	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	OT	OTCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	OT	OTCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	OT	OTSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ (66,274)	$ (30,402)	$ (8,725)	$ (1,262)	$ (12,017)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Other Expenses								
Power Production Plant								
Production Demand - Base	OT	OTPPDB	PPBDA	$ (459)	$ (521)	$ (2,118)	$ (58)	$ (593)
Production Demand - Winter Peak	OT	OTPPDI	PPWDA	$ (421)	$ (608)	$ (1,855)	$ (60)	$ (537)
Production Demand - Summer Peak	OT	OTPPDP	PPSDA	$ (217)	$ (274)	$ (908)	$ (31)	$ (185)
Production Energy	OT	OTPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	OT	OTPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	OT	OTPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ (1,097)	$ (1,403)	$ (4,882)	$ (149)	$ (1,315)
Transmission Plant								
Transmission Demand - Base	OT	OTTRB	PPBDA	$ (53)	$ (60)	$ (243)	$ (7)	$ (68)
Transmission Demand - Inter.	OT	OTTRI	PPWDA	$ (48)	$ (70)	$ (213)	$ (7)	$ (62)
Transmission Demand - Peak	OT	OTTRP	PPSDA	$ (25)	$ (31)	$ (104)	$ (4)	$ (21)
Total Transmission Plant		OTTRT		$ (126)	$ (161)	$ (560)	$ (17)	$ (151)
Distribution Poles								
Specific	OT	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	OT	OTDSG	NCPP	$ (41)	$ (44)	$ (170)	$ (5)	$ -
Distribution Primary & Secondary Lines								
Primary Specific	OT	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	OT	OTDPLD	NCPP	$ (108)	$ (116)	$ (452)	$ (14)	$ -
Primary Customer	OT	OTDPLC	Cust08	$ (0)	$ (1)	$ (0)	$ (0)	$ -
Secondary Demand	OT	OTDSLD	SICD	$ -	$ (13)	$ -	$ (2)	$ -
Secondary Customer	OT	OTDSLC	Cust07	$ -	$ (0)	$ -	$ (0)	$ -
Total Distribution Primary & Secondary Lines		OTDLT		$ (109)	$ (131)	$ (453)	$ (16)	$ -
Distribution Line Transformers								
Demand	OT	OTDLTD	SICD	$ -	$ (25)	$ -	$ (3)	$ -
Customer	OT	OTDLTC	Cust07	$ -	$ (0)	$ -	$ (0)	$ -
Total Distribution Line Transformers		OTDLTT		$ -	$ (25)	$ -	$ (4)	$ -
Distribution Services								
Customer	OT	OTDSC	C02	$ -	$ (0)	$ -	$ (0)	$ -
Distribution Meters								
Customer	OT	OTDMC	C03	$ (0)	$ (1)	$ (2)	$ (1)	$ (0)
Distribution Street & Customer Lighting								
Customer	OT	OTDSCL	C04	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	OT	OTCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	OT	OTCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	OT	OTSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ (1,373)	$ (1,764)	$ (6,066)	$ (192)	$ (1,466)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Other Expenses								
Power Production Plant								
Production Demand - Base	OT	OTPPDB	PPBDA	$ (299)	$ (78)	$ (149)	$ (6)	$ (5)
Production Demand - Winter Peak	OT	OTPPDI	PPWDA	$ (386)	$ (86)	$ -	$ -	$ (4)
Production Demand - Summer Peak	OT	OTPPDP	PPSDA	$ (167)	$ (26)	$ -	$ -	$ (2)
Production Energy	OT	OTPPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	OT	OTPPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	OT	OTPPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		OTPPT		$ (852)	$ (190)	$ (149)	$ (6)	$ (11)
Transmission Plant								
Transmission Demand - Base	OT	OTTRB	PPBDA	$ (34)	$ (9)	$ (17)	$ (1)	$ (1)
Transmission Demand - Inter.	OT	OTTRI	PPWDA	$ (44)	$ (10)	$ -	$ -	$ (0)
Transmission Demand - Peak	OT	OTTRP	PPSDA	$ (19)	$ (3)	$ -	$ -	$ (0)
Total Transmission Plant		OTTRT		$ (98)	$ (22)	$ (17)	$ (1)	$ (1)
Distribution Poles								
Specific	OT	OTDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	OT	OTDSG	NCPP	$ (27)	$ (6)	$ (16)	$ (1)	$ (0)
Distribution Primary & Secondary Lines								
Primary Specific	OT	OTDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	OT	OTDPLD	NCPP	$ (73)	$ (17)	$ (44)	$ (1)	$ (1)
Primary Customer	OT	OTDPLC	Cust08	$ (0)	$ (0)	$ (95)	$ (0)	$ (1)
Secondary Demand	OT	OTDSLD	SICD	$ -	$ -	$ (5)	$ (0)	$ (0)
Secondary Customer	OT	OTDSLC	Cust07	$ -	$ -	$ (22)	$ (0)	$ (0)
Total Distribution Primary & Secondary Lines		OTDLT		$ (73)	$ (17)	$ (165)	$ (2)	$ (2)
Distribution Line Transformers								
Demand	OT	OTDLTD	SICD	$ -	$ -	$ (9)	$ (0)	$ (0)
Customer	OT	OTDLTC	Cust07	$ -	$ -	$ (29)	$ (0)	$ (0)
Total Distribution Line Transformers		OTDLTT		$ -	$ -	$ (38)	$ (0)	$ (0)
Distribution Services								
Customer	OT	OTDSC	C02	$ -	$ -	$ -	$ (0)	$ (1)
Distribution Meters								
Customer	OT	OTDMC	C03	$ (0)	$ (0)	$ -	$ (0)	$ (1)
Distribution Street & Customer Lighting								
Customer	OT	OTDSCL	C04	$ -	$ -	$ (1,308)	$ -	$ -
Customer Accounts Expense								
Customer	OT	OTCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	OT	OTCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	OT	OTSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		OTT		$ (1,050)	$ (235)	$ (1,694)	$ (9)	$ (18)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Interest Expenses								
Power Production Plant								
Production Demand - Base	INTLTD	INTPDB	PPBDA	$ 11,457,518	$ 4,133,323	$ 1,428,856	$ 276,756	$ 2,480,766
Production Demand - Winter Peak	INTLTD	INTPDI	PPWDA	$ 14,202,856	$ 5,788,350	$ 2,094,341	$ 324,216	$ 3,100,053
Production Demand - Summer Peak	INTLTD	INTPDP	PPSDA	$ 7,178,600	$ 3,418,940	$ 934,796	$ 141,388	$ 1,359,341
Production Energy	INTLTD	INTPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	INTLTD	INTPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	INTLTD	INTPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		INTPT		$ 32,838,974	$ 13,340,613	$ 4,457,993	$ 742,360	$ 6,940,160
Transmission Plant								
Transmission Demand - Base	INTLTD	INTTRB	PPBDA	$ 1,314,948	$ 474,370	$ 163,986	$ 31,763	$ 284,711
Transmission Demand - Inter.	INTLTD	INTTRI	PPWDA	$ 1,630,023	$ 664,313	$ 240,362	$ 37,209	$ 355,785
Transmission Demand - Peak	INTLTD	INTTRP	PPSDA	$ 823,868	$ 392,382	$ 107,284	$ 16,227	$ 156,008
Total Transmission Plant		INTTRT		$ 3,768,839	$ 1,531,066	$ 511,632	$ 85,199	$ 796,503
Distribution Poles								
Specific	INTLTD	INTDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	INTLTD	INTDSG	NCPP	$ 1,236,627	$ 598,641	$ 161,816	$ 25,872	$ 223,277
Distribution Primary & Secondary Lines								
Primary Specific	INTLTD	INDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INDPLD	NCPP	$ 3,296,052	$ 1,595,593	$ 431,298	$ 68,958	$ 595,114
Primary Customer	INTLTD	INDPLC	Cust08	$ 2,650,144	$ 2,283,393	$ 274,964	$ 588	$ 20,009
Secondary Demand	INTLTD	INDSLD	SICD	$ 517,870	$ 329,740	$ 107,608	$ -	$ 65,629
Secondary Customer	INTLTD	INDSLC	Cust07	$ 609,032	$ 524,954	$ 63,214	$ -	$ 4,600
Total Distribution Primary & Secondary Lines		INDLT		$ 7,073,097	$ 4,733,680	$ 877,085	$ 69,546	$ 685,352
Distribution Line Transformers								
Demand	INTLTD	INDLTD	SICD	$ 960,571	$ 611,618	$ 199,597	$ -	$ 121,732
Customer	INTLTD	INDLTC	Cust07	$ 807,459	$ 695,989	$ 83,810	$ -	$ 6,099
Total Distribution Line Transformers		INDLTT		$ 1,768,030	$ 1,307,607	$ 283,407	$ -	$ 127,831
Distribution Services								
Customer	INTLTD	INDSC	C02	$ 350,468	$ 309,688	$ 37,051	$ -	$ 2,729
Distribution Meters								
Customer	INTLTD	INDMC	C03	$ 509,197	$ 428,270	$ 56,361	$ 879	$ 18,858
Distribution Street & Customer Lighting								
Customer	INTLTD	INDSCL	C04	$ 957,577	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	INTLTD	INCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	INTLTD	INCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	INTLTD	INSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 48,502,810	$ 22,249,565	$ 6,385,344	$ 923,856	$ 8,794,711

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Interest Expenses								
Power Production Plant								
Production Demand - Base	INTLTD	INTPDB	PPBDA	$ 335,858	$ 381,514	$ 1,550,327	$ 42,536	$ 434,267
Production Demand - Winter Peak	INTLTD	INTPDI	PPWDA	$ 308,365	$ 444,769	$ 1,357,524	$ 43,795	$ 392,686
Production Demand - Summer Peak	INTLTD	INTPDP	PPSDA	$ 158,787	$ 200,495	$ 664,776	$ 22,691	$ 135,215
Production Energy	INTLTD	INTPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	INTLTD	INTPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	INTLTD	INTPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		INTPT		$ 803,010	$ 1,026,779	$ 3,572,627	$ 109,022	$ 962,168
Transmission Plant								
Transmission Demand - Base	INTLTD	INTTRB	PPBDA	$ 38,546	$ 43,785	$ 177,927	$ 4,882	$ 49,840
Transmission Demand - Inter.	INTLTD	INTTRI	PPWDA	$ 35,390	$ 51,045	$ 155,799	$ 5,026	$ 45,068
Transmission Demand - Peak	INTLTD	INTTRP	PPSDA	$ 18,224	$ 23,010	$ 76,295	$ 2,604	$ 15,518
Total Transmission Plant		INTTRT		$ 92,159	$ 117,841	$ 410,021	$ 12,512	$ 110,425
Distribution Poles								
Specific	INTLTD	INTDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	INTLTD	INTDSG	NCPP	$ 29,764	$ 31,914	$ 124,140	$ 3,961	$ -
Distribution Primary & Secondary Lines								
Primary Specific	INTLTD	INDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INDPLD	NCPP	$ 79,330	$ 85,062	$ 330,878	$ 10,559	$ -
Primary Customer	INTLTD	INDPLC	Cust08	$ 137	$ 549	$ 294	$ 111	$ -
Secondary Demand	INTLTD	INDSLD	SICD	$ -	$ 9,879	$ -	$ 1,375	$ -
Secondary Customer	INTLTD	INDSLC	Cust07	$ -	$ 126	$ -	$ 26	$ -
Total Distribution Primary & Secondary Lines		INDLT		$ 79,468	$ 95,615	$ 331,172	$ 12,071	$ -
Distribution Line Transformers								
Demand	INTLTD	INDLTD	SICD	$ -	$ 18,323	$ -	$ 2,551	$ -
Customer	INTLTD	INDLTC	Cust07	$ -	$ 167	$ -	$ 34	$ -
Total Distribution Line Transformers		INDLTT		$ -	$ 18,491	$ -	$ 2,585	$ -
Distribution Services								
Customer	INTLTD	INDSC	C02	$ -	$ 75	$ -	$ 40	$ -
Distribution Meters								
Customer	INTLTD	INDMC	C03	$ 157	$ 630	$ 1,805	$ 673	$ 198
Distribution Street & Customer Lighting								
Customer	INTLTD	INDSCL	C04	$ -	$ -	$ -	$ -	$ -
Customer Accounts Expense								
Customer	INTLTD	INCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	INTLTD	INCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	INTLTD	INSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 1,004,558	$ 1,291,343	$ 4,439,765	$ 140,865	$ 1,072,791

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Interest Expenses								
Power Production Plant								
Production Demand - Base	INTLTD	INTPDB	PPBDA	$ 218,781	$ 57,421	$ 108,996	$ 4,124	$ 3,993
Production Demand - Winter Peak	INTLTD	INTPDI	PPWDA	$ 282,817	$ 62,833	$ -	$ -	$ 3,107
Production Demand - Summer Peak	INTLTD	INTPDP	PPSDA	$ 121,946	$ 19,012	$ -	$ -	$ 1,213
Production Energy	INTLTD	INTPEB	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	INTLTD	INTPEI	E01	$ -	$ -	$ -	$ -	$ -
Production Energy - Not Used	INTLTD	INTPEP	E01	$ -	$ -	$ -	$ -	$ -
Total Power Production Plant		INTPT		$ 623,544	$ 139,265	$ 108,996	$ 4,124	$ 8,313
Transmission Plant								
Transmission Demand - Base	INTLTD	INTTRB	PPBDA	$ 25,109	$ 6,590	$ 12,509	$ 473	$ 458
Transmission Demand - Inter.	INTLTD	INTTRI	PPWDA	$ 32,458	$ 7,211	$ -	$ -	$ 357
Transmission Demand - Peak	INTLTD	INTTRP	PPSDA	$ 13,995	$ 2,182	$ -	$ -	$ 139
Total Transmission Plant		INTTRT		$ 71,562	$ 15,983	$ 12,509	$ 473	$ 954
Distribution Poles								
Specific	INTLTD	INTDPS	NCPP	$ -	$ -	$ -	$ -	$ -
Distribution Substation								
General	INTLTD	INTDSG	NCPP	$ 19,948	$ 4,627	$ 12,068	$ 409	$ 189
Distribution Primary & Secondary Lines								
Primary Specific	INTLTD	INDPLS	NCPP	$ -	$ -	$ -	$ -	$ -
Primary Demand	INTLTD	INDPLD	NCPP	$ 53,168	$ 12,332	$ 32,166	$ 1,091	$ 503
Primary Customer	INTLTD	INDPLC	Cust08	$ 7	$ 13	$ 69,358	$ 78	$ 643
Secondary Demand	INTLTD	INDSLD	SICD	$ -	$ -	$ 3,467	$ 118	$ 54
Secondary Customer	INTLTD	INDSLC	Cust07	$ -	$ -	$ 15,945	$ 18	$ 148
Total Distribution Primary & Secondary Lines		INDLT		$ 53,175	$ 12,345	$ 120,936	$ 1,305	$ 1,348
Distribution Line Transformers								
Demand	INTLTD	INDLTD	SICD	$ -	$ -	$ 6,430	$ 218	$ 101
Customer	INTLTD	INDLTC	Cust07	$ -	$ -	$ 21,141	$ 24	$ 196
Total Distribution Line Transformers		INDLTT		$ -	$ -	$ 27,571	$ 242	$ 297
Distribution Services								
Customer	INTLTD	INDSC	C02	$ -	$ -	$ -	$ 96	$ 789
Distribution Meters								
Customer	INTLTD	INDMC	C03	$ 43	$ 97	$ -	$ 133	$ 1,092
Distribution Street & Customer Lighting								
Customer	INTLTD	INDSCL	C04	$ -	$ -	$ 957,577	$ -	$ -
Customer Accounts Expense								
Customer	INTLTD	INCAE	C05	$ -	$ -	$ -	$ -	$ -
Customer Service & Info.								
Customer	INTLTD	INCSI	C05	$ -	$ -	$ -	$ -	$ -
Sales Expense								
Customer	INTLTD	INSEC	C06	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 768,272	$ 172,317	$ 1,239,657	$ 6,783	$ 12,982

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Cost of Service Summary -- Unadjusted								
Operating Revenues								
Sales to Ultimate Consumers		REVUC	R01	$ 763,347,083	$ 307,974,525	$ 112,545,511	$ 15,994,645	$ 158,911,598
Intercompany Sales		ICSALES	E01	$ 110,077,528	$ 39,710,695	$ 13,727,658	$ 2,658,919	$ 23,833,831
Off-System Sales		SFRS	OSSALL	$ 59,391,514	$ 22,915,048	$ 7,768,253	$ 1,383,887	$ 12,689,785
Brokered Purchases		BRKS	Energy	$ (3,239)	$ (1,168)	$ (404)	$ (78)	$ (701)
Settled Swap Revenue			Energy	$ 13,437,949	$ 4,847,768	$ 1,675,833	$ 324,593	$ 2,909,566
Settled Swap Expense			Energy	$ (3,269,501)	$ (1,179,479)	$ (407,736)	$ (78,975)	$ (707,908)
Forfeited Discounts		FORDIS	FDIS	$ 5,040,755	$ 3,952,450	$ 746,971	$ 112,640	$ 228,694
Misc Service Revenues		REVMISC	MISCR	$ 963,922	$ 814,598	$ 149,325	$ -	$ -
Rent From Electric Property			RBT	$ 2,613,870	$ 1,195,238	$ 343,245	$ 49,974	$ 475,053
Other Electric Revenue		OTHREV	RBT	$ 4,020,871	$ 1,838,614	$ 528,008	$ 76,875	$ 730,766
Unbilled Revenue		UNBREV	R01	$ 2,871,000	$ 1,158,313	$ 423,291	$ 60,157	$ 597,677
Total Operating Revenues		TOR		$ 958,491,753	$ 383,226,601	$ 137,499,956	$ 20,582,638	$ 199,668,361
Operating Expenses								
Operation and Maintenance Expenses				$ 642,626,778	$ 254,634,222	$ 80,792,857	$ 14,446,987	$ 132,133,789
Depreciation and Amortization Expenses				109,158,114	49,539,430	14,412,339	2,115,420	20,098,567
Regulatory Credits				(1,724,281)	(704,015)	(233,800)	(38,739)	(362,385)
Accretion Expense				1,501,895	613,593	203,617	33,717	315,431
Depreciation for Asset Retirement Costs			DET	222,385	$ 100,925	$ 29,362	$ 4,310	$ 40,946
Amortization Expense			DET	5,626,250	$ 2,553,372	$ 742,844	$ 109,033	$ 1,035,924
Property and Other Taxes			NPT	18,568,593	8,517,921	2,444,536	353,685	3,366,927
Amortization of Investment Tax Credit				1,861,232	853,798	245,029	35,452	337,485
Other Expenses				(66,274)	(30,402)	(8,725)	(1,262)	(12,017)
State and Federal Income Taxes			TAXINC	46,763,814	$ 15,474,088	$ 11,356,741	$ 899,131	$ 11,800,276
Specific Assignment of Interruptible Credit				(2,667,453)	-	-	-	-
Allocation of Interruptible Credits			INTCRE	2,667,453	$ 1,148,660	$ 377,901	$ 58,087	$ 556,334
Total Operating Expenses		TOE		$ 824,538,506	$ 332,701,592	$ 110,362,701	$ 18,015,820	$ 169,311,278
Utility Operating Income		TOM		$ 133,953,247	$ 50,525,009	$ 27,137,255	$ 2,566,818	$ 30,357,083
Net Cost Rate Base				$ 1,904,726,111	$ 870,969,477	$ 250,122,772	$ 36,416,219	$ 346,170,916

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Cost of Service Summary -- Unadjusted								
Operating Revenues								
Sales to Ultimate Consumers		REVUC	R01	$ 18,287,716	$ 21,999,815	$ 77,266,680	$ 2,503,295	$ 19,754,999
Intercompany Sales		ICSALES	E01	$ 3,226,743	$ 3,665,379	$ 14,894,693	$ 408,662	$ 4,172,194
Off-System Sales		SFRS	OSSALL	$ 1,581,830	$ 1,911,128	$ 7,168,069	$ 207,637	$ 1,969,412
Brokered Purchases		BRKS	Energy	$ (95)	$ (108)	$ (438)	$ (12)	$ (123)
Settled Swap Revenue			Energy	$ 393,911	$ 447,459	$ 1,818,301	$ 49,888	$ 509,329
Settled Swap Expense			Energy	$ (95,840)	$ (108,868)	$ (442,399)	$ (12,138)	$ (123,922)
Forfeited Discounts		FORDIS	FDIS	$ -	$ -	$ -	$ -	$ -
Misc Service Revenues		REVMISC	MISCR	$ -	$ -	$ -	$ -	$ -
Rent From Electric Property			RBT	$ 54,545	$ 69,824	$ 241,444	$ 7,626	$ 58,634
Other Electric Revenue		OTHREV	RBT	$ 83,906	$ 107,409	$ 371,410	$ 11,732	$ 90,196
Unbilled Revenue		UNBREV	R01	$ 68,781	$ 82,743	$ 290,605	$ 9,415	$ 74,300
Total Operating Revenues		TOR		$ 23,601,497	$ 28,174,782	$ 101,608,365	$ 3,186,105	$ 26,505,021
Operating Expenses								
Operation and Maintenance Expenses				$ 17,077,409	$ 19,920,018	$ 78,192,150	$ 2,224,655	$ 21,538,596
Depreciation and Amortization Expenses				2,298,907	2,953,510	10,167,622	321,256	2,487,493
Regulatory Credits				(41,912)	(53,600)	(186,425)	(5,696)	(50,037)
Accretion Expense				36,479	46,654	162,258	4,959	43,532
Depreciation for Asset Retirement Costs			DET	$ 4,684	$ 6,017	$ 20,714	$ 654	$ 5,068
Amortization Expense			DET	$ 118,491	$ 152,230	$ 524,062	$ 16,558	$ 128,211
Property and Other Taxes			NPT	384,580	494,372	1,699,699	53,928	410,703
Amortization of Investment Tax Credit				38,549	49,554	170,370	5,406	41,167
Other Expenses				(1,373)	(1,764)	(6,066)	(192)	(1,466)
State and Federal Income Taxes			TAXINC	$ 927,693	$ 1,144,546	$ 2,807,537	$ 146,932	$ 588,833
Specific Assignment of Interruptible Credit				-	-	(1,765,763)	-	(901,690)
Allocation of Interruptible Credits			INTCRE	$ 58,280	$ 80,500	$ 252,293	$ 8,295	$ 65,859
Total Operating Expenses		TOE		$ 20,901,787	$ 24,792,036	$ 92,038,451	$ 2,776,754	$ 24,356,268
Utility Operating Income		TOM		$ 2,699,710	$ 3,382,745	$ 9,569,914	$ 409,351	$ 2,148,753
Net Cost Rate Base				$ 39,746,887	$ 50,880,896	$ 175,940,357	$ 5,557,356	$ 42,726,770

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Cost of Service Summary -- Unadjusted								
Operating Revenues								
Sales to Ultimate Consumers		REVUC	R01	$ 10,433,529	$ 2,592,630	$ 14,660,356	$ 177,965	$ 243,818
Intercompany Sales		ICSALES	E01	$ 2,101,931	$ 551,667	$ 1,047,170	$ 39,624	$ 38,362
Off-System Sales		SFRS	OSSALL	$ 1,130,576	$ 272,412	$ 362,196	$ 13,705	$ 17,575
Brokered Purchases		BRKS	Energy	$ (62)	$ (16)	$ (31)	$ (1)	$ (1)
Settled Swap Revenue			Energy	$ 256,598	$ 67,346	$ 127,836	$ 4,837	$ 4,683
Settled Swap Expense			Energy	$ (62,431)	$ (16,386)	$ (31,103)	$ (1,177)	$ (1,139)
Forfeited Discounts		FORDIS	FDIS	$ -	$ -	$ -	$ -	$ -
Misc Service Revenues		REVMISC	MISCR	$ -	$ -	$ -	$ -	$ -
Rent From Electric Property			RBT	$ 41,479	$ 9,354	$ 66,362	$ 381	$ 710
Other Electric Revenue		OTHREV	RBT	$ 63,806	$ 14,390	$ 102,083	$ 586	$ 1,091
Unbilled Revenue		UNBREV	R01	$ 39,241	$ 9,751	$ 55,139	$ 669	$ 917
Total Operating Revenues		TOR		$ 14,004,666	$ 3,501,148	$ 16,390,008	$ 236,589	$ 306,016
Operating Expenses								
Operation and Maintenance Expenses				$ 11,507,375	$ 2,924,679	$ 6,814,570	$ 190,878	$ 228,592
Depreciation and Amortization Expenses				1,761,092	394,815	2,563,477	15,121	29,068
Regulatory Credits				(32,528)	(7,266)	(7,222)	(218)	(437)
Accretion Expense				28,310	6,324	6,450	190	381
Depreciation for Asset Retirement Costs			DET	$ 3,588	$ 804	$ 5,223	$ 31	$ 59
Amortization Expense			DET	$ 90,771	$ 20,350	$ 132,127	$ 779	$ 1,498
Property and Other Taxes			NPT	294,122	65,969	474,585	2,597	4,970
Amortization of Investment Tax Credit				29,481	6,612	47,570	260	498
Other Expenses				(1,050)	(235)	(1,694)	(9)	(18)
State and Federal Income Taxes			TAXINC	$ (175,173)	$ (33,046)	$ 1,809,256	$ 7,137	$ 9,863
Specific Assignment of Interruptible Credit				-	-	-	-	-
Allocation of Interruptible Credits			INTCRE	$ 50,496	$ 10,211	$ -	$ -	$ 539
Total Operating Expenses		TOE		$ 13,556,484	$ 3,389,216	$ 11,844,340	$ 216,765	$ 275,013
Utility Operating Income		TOM		$ 448,182	$ 111,932	$ 4,545,668	$ 19,824	$ 31,003
Net Cost Rate Base				$ 30,225,504	$ 6,816,502	$ 48,357,866	$ 277,545	$ 517,043

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Taxable Income Unadjusted								
Total Operating Revenue				$ 958,491,753	$ 383,226,601	$ 137,499,956	$ 20,582,638	$ 199,668,361
Operating Expenses				$ 777,774,692	$ 317,227,503	$ 99,005,960	$ 17,116,689	$ 157,511,002
Interest Expense		INTEXP		$ 48,502,810	$ 22,249,565	$ 6,385,344	$ 923,856	$ 8,794,711
Taxable Income		TAXINC		$ 132,214,251	$ 43,749,532	$ 32,108,652	$ 2,542,093	$ 33,362,648

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Taxable Income Unadjusted								
Total Operating Revenue				$ 23,601,497	$ 28,174,782	$ 101,608,365	$ 3,186,105	$ 26,505,021
Operating Expenses				$ 19,974,094	$ 23,647,491	$ 89,230,913	$ 2,629,822	$ 23,767,434
Interest Expense		INTEXP		$ 1,004,558	$ 1,291,343	$ 4,439,765	$ 140,865	$ 1,072,791
Taxable Income		TAXINC		$ 2,622,845	$ 3,235,947	$ 7,937,686	$ 415,419	$ 1,664,795

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Taxable Income Unadjusted								
Total Operating Revenue				$ 14,004,666	$ 3,501,148	$ 16,390,008	$ 236,589	$ 306,016
Operating Expenses				$ 13,731,657	$ 3,422,262	$ 10,035,085	$ 209,629	$ 265,150
Interest Expense		INTEXP		$ 768,272	$ 172,317	$ 1,239,657	$ 6,783	$ 12,982
Taxable Income		TAXINC		$ (495,264)	$ (93,431)	$ 5,115,267	$ 20,178	$ 27,885

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Cost of Service Summary -- Pro-Forma								
Operating Revenues								
Total Operating Revenue -- Actual				$ 958,491,753	$ 383,226,601	$ 137,499,956	$ 20,582,638	$ 199,668,361
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01	$ (2,871,000)	$ (1,158,313)	$ (423,291)	$ (60,157)	$ (597,677)
Mismatch in fuel cost recovery			Energy	(32,833,346)	(11,844,697)	(4,094,614)	(793,088)	(7,109,030)
To Reflect a Full Year of the FAC Roll-In		FACRI	REV01	(3,104,008)	(1,421,315)	971,372	(173,599)	(838,308)
Remove ECR revenues			ECRREV	(8,394,624)	$ (3,345,623)	$ (1,239,000)	$ (175,921)	$ (1,760,923)
To Reflect a Full Year of the ECR Roll-In		ECRRI	ECRREV2	6,853,924	$ 2,304,814	$ 2,479,866	$ 114,151	$ 1,107,744
Remove off-system ECR revenues			OSSALL	(2,033,628)	(784,635)	(265,993)	(47,386)	(434,512)
Eliminate brokered sales			Energy	(10,165,209)	(3,667,120)	(1,267,693)	(245,540)	(2,200,957)
Eliminate DSM Revenue			DSMREV	(12,207,246)	(9,197,044)	(1,115,653)	(111,611)	(1,289,906)
Year End Revenue Adjustment			YREND	11,451,462	8,138,925	973,726	2,107	71,725
Adjustment for Customer Billing and Rate Switching			RS01	(875,110)	-	-	(55,033)	(654,521)
Eliminate ECR, MSR, DSM, FAC, GSC			R01	3,333,166	1,344,775	491,432	69,841	693,890
Weather Normalized electric operating revenues			TREV01	5,151,223	4,284,606	475,872	24,653	258,591
Adjustment for Merger Surcredit			MSCREV	2,323,679	1,012,681	325,693	48,204	464,561
USGC Settlement			PLPPT	(654,600)	(265,927)	(88,864)	(14,798)	(138,343)
VDT Surcredit Revenues			VDTREV	(395)	-	(395)	-	-
Total Pro-Forma Operating Revenue				$ 914,466,041	$ 368,627,726	$ 134,722,415	$ 19,164,460	$ 187,240,694

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Cost of Service Summary -- Pro-Forma								
Operating Revenues								
Total Operating Revenue -- Actual				$ 23,601,497	$ 28,174,782	$ 101,608,365	$ 3,186,105	$ 26,505,021
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01	$ (68,781)	$ (82,743)	$ (290,605)	$ (9,415)	$ (74,300)
Mismatch in fuel cost recovery			Energy	(962,456)	(1,093,290)	(4,442,711)	(121,894)	(1,244,460)
To Reflect a Full Year of the FAC Roll-In		FACRI	REV01	(125,200)	(160,865)	(766,612)	(12,975)	(499,146)
Remove ECR revenues			ECRREV	$ (202,980)	$ (243,550)	$ (862,594)	$ (27,998)	$ (229,933)
To Reflect a Full Year of the ECR Roll-In		ECRRI	ECRREV2	$ 109,136	$ 125,583	$ 385,791	$ 12,447	$ 129,292
Remove off-system ECR revenues			OSSALL	(54,164)	(65,439)	(245,442)	(7,110)	(67,435)
Eliminate brokered sales			Energy	(297,976)	(338,483)	(1,375,464)	(37,738)	(385,285)
Eliminate DSM Revenue			DSMREV	(229,587)	(263,446)	-	-	-
Year End Revenue Adjustment			YREND	492	1,967	1,054	398	117
Adjustment for Customer Billing and Rate Switching			RS01	(71,266)	(94,290)	-	-	-
Eliminate ECR, MSR, DSM, FAC, GSC			R01	79,854	96,063	337,386	10,931	86,260
Weather Normalized electric operating revenues			TREV01	27,262	40,404	-	-	-
Adjustment for Merger Surcredit			MSCREV	43,486	65,523	216,289	6,584	60,481
USGC Settlement			PLPPT	(16,007)	(20,467)	(71,215)	(2,173)	(19,180)
VDT Surcredit Revenues			VDTREV	-	-	-	-	-
Total Pro-Forma Operating Revenue				$ 21,833,310	$ 26,141,748	$ 94,494,241	$ 2,997,161	$ 24,261,433

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Cost of Service Summary -- Pro-Forma								
Operating Revenues								
Total Operating Revenue -- Actual				$ 14,004,666	$ 3,501,148	$ 16,390,008	$ 236,589	$ 306,016
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01	$ (39,241)	$ (9,751)	$ (55,139)	$ (669)	$ (917)
Mismatch in fuel cost recovery			Energy	(626,953)	(164,548)	(312,344)	(11,819)	(11,442)
To Reflect a Full Year of the FAC Roll-In		FACRI	REV01	(34,076)	(22,230)	(18,204)	(1,561)	(1,286)
Remove ECR revenues			ECRREV	$ (116,433)	$ (27,441)	$ (157,765)	$ (1,851)	$ (2,613)
To Reflect a Full Year of the ECR Roll-In		ECRRI	ECRREV2	$ 85,991	$ -	$ (438)	$ (452)	$ -
Remove off-system ECR revenues			OSSALL	(38,712)	(9,328)	(12,402)	(469)	(602)
Eliminate brokered sales			Energy	(194,105)	(50,944)	(96,702)	(3,659)	(3,543)
Eliminate DSM Revenue			DSMREV	-	-	-	-	-
Year End Revenue Adjustment			YREND	23	47	2,237,605	2,529	20,747
Adjustment for Customer Billing and Rate Switching			RS01	-	-	-	-	-
Eliminate ECR, MSR, DSM, FAC, GSC			R01	45,558	11,321	64,015	777	1,065
Weather Normalized electric operating revenues			TREV01	39,835	-	-	-	-
Adjustment for Merger Surcredit			MSCREV	27,090	9,172	41,840	954	1,122
USGC Settlement			PLPPT	(12,430)	(2,776)	(2,173)	(82)	(166)
VDT Surcredit Revenues			VDTREV	-	-	-	-	-
Total Pro-Forma Operating Revenue				$ 13,141,213	$ 3,234,669	$ 18,078,302	$ 220,286	$ 308,381

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Cost of Service Summary -- Pro-Forma								
Operating Expenses								
Operation and Maintenance Expenses				$ 642,626,778	$ 254,634,222	$ 80,792,857	$ 14,446,987	$ 132,133,789
Depreciation and Amortization Expenses				109,158,114	49,539,430	14,412,339	2,115,420	20,098,567
Regulatory Credits				(1,724,281)	(704,015)	(233,800)	(38,739)	(362,385)
Accretion Expense				1,501,895	613,593	203,617	33,717	315,431
Depreciation for Asset Retirement Costs				222,385	100,925	29,362	4,310	40,946
Amortization Expense				5,626,250	2,553,372	742,844	109,033	1,035,924
Property and Other Taxes			NPT	18,568,593	8,517,921	2,444,536	353,685	3,366,927
Amortization of Investment Tax Credit				1,861,232	853,798	245,029	35,452	337,485
Other Expenses				(66,274)	(30,402)	(8,725)	(1,262)	(12,017)
State and Federal Income Taxes			TAXINC	46,763,814	$ 15,474,088	$ 11,356,741	$ 899,131	$ 11,800,276
Specific Assignment of Interruptible Credit				(2,667,453)	-	-	-	-
Allocation of Interruptible Credits			INTCRE	2,667,453	$ 1,148,660	$ 377,901	$ 58,087	$ 556,334
Adjustments to Operating Expenses:								
Eliminate mismatch in fuel cost recovery			Energy	(27,086,657)	$ (9,771,567)	$ (3,377,950)	$ (654,277)	$ (5,864,765)
Remove ECR expenses			ECRREV	(3,707,947)	$ (1,477,778)	$ (547,272)	$ (77,705)	$ (777,809)
Reflect full year of ECR roll-in			ECRREV2	3,377,839	$ 1,135,888	$ 1,222,160	$ 56,257	$ 545,933
Eliminate brokered sales expenses			Energy	(248,375)	$ (89,602)	$ (30,975)	$ (5,999)	$ (53,778)
Eliminate DSM Expenses			DSMREV	(7,314,564)	$ (5,510,855)	$ (668,497)	$ (66,877)	$ (772,910)
Year end Expense adjustment			YREND	7,956,625	$ 5,655,031	$ 676,558	$ 1,464	$ 49,835
Adjustment to annualize depreciation expense			DET	6,204,918	$ 2,815,989	$ 819,246	$ 120,248	$ 1,142,471
Labor adjustment			LBT	1,827,123	$ 855,587	$ 232,853	$ 34,916	$ 332,675
Adjustment for pension and post Ret Exp.			LBT	314,825	$ 147,423	$ 40,122	$ 6,016	$ 57,322
Adjustment for property insurance expenses			UPT	355,686	$ 163,528	$ 46,779	$ 6,751	$ 64,294
Adjustment for liability inusrance increase			UPT	514,962	$ 236,755	$ 67,727	$ 9,774	$ 93,085
Adjustment for Hazard Tree Program			SDALL	1,759,303	$ 1,172,724	$ 228,904	$ 16,098	$ 175,349
Storm damage adjustment			SDALL	(670,600)	$ (447,011)	$ (87,252)	$ (6,136)	$ (66,839)
Adjustment to eliminate advertising expense			REVUC	(404,623)	$ (163,246)	$ (59,656)	$ (8,478)	$ (84,233)
Adjustment for retired mainframe			RBT	(1,048,815)	$ (479,589)	$ (137,727)	$ (20,052)	$ (190,615)
Adjustment for MISO Exit Regulatory Asset			PLTRT	(157,119)	$ (63,829)	$ (21,329)	$ (3,552)	$ (33,205)
Adjustment for 2008 Wind Storm Asset			SDALL	27,630,386	$ 18,417,978	$ 3,595,006	$ 252,828	$ 2,753,913
Adjustment for 2009 Winter Storm Asset			SDALL	8,734,140	$ 5,822,040	$ 1,136,404	$ 79,921	$ 870,529
Adjustment for KCCS Regulatory Asset			PLPPT	343,330	$ 139,476	$ 46,608	$ 7,761	$ 72,559
Adjustment for CMRG Regulatory Asset			PLPPT	(1,940)	$ (788)	$ (263)	$ (44)	$ (410)
Amortization of rate case expenses			OMT	324,253	$ 128,482	$ 40,766	$ 7,290	$ 66,671
Adjustment for SW Power Pool settlement			PLPPT	(583,743)	$ (237,142)	$ (79,245)	$ (13,196)	$ (123,368)
Adjustment for MISO RSG resettlement			PLTRT	(429,911)	$ (174,648)	$ (58,362)	$ (9,719)	$ (90,857)
Adjustment for USGC settlement			PLPPT	480,212	$ 195,083	$ 65,190	$ 10,856	$ 101,488
Adjustment to remove FERC Hydropower program change			PLPPT	(157,135)	$ (63,835)	$ (21,332)	$ (3,552)	$ (33,209)
Adjustment for injuries and damages			UPT	313,993	$ 144,359	$ 41,296	$ 5,960	$ 56,758
Adjustment for Interest rate Swap Amortization			UPT	205,798	$ 94,616	$ 27,066	$ 3,906	$ 37,200
Adjustment to correct Edison Electric Institutue invoice			RBT	62,735	$ 28,687	$ 8,238	$ 1,199	$ 11,402
Adjustment to property tax expense			UPT	815,661	$ 375,003	$ 107,274	$ 15,482	$ 147,440
Adjustment for EKPC settlement charges			Energy	904,386	$ 326,259	$ 112,785	$ 21,845	$ 195,816
Reflect weather normalized electric sales margins			TEXP01	1,899,644	$ 1,452,124	$ 142,855	$ 18,978	$ 199,060
Federal & State Income Tax Adjustment			ITADJ	(24,635,520)	$ (13,175,376)	$ (2,359,977)	$ (456,017)	$ (4,206,133)
Federal & State Income Tax Interest Adjustment			TAXINC	(153,686)	$ (50,855)	$ (37,323)	$ (2,955)	$ (38,781)
Prior income tax true-ups & adjustments			TAXINC	2,641,449	$ 874,052	$ 641,484	$ 50,787	$ 666,537
Adjustment for domestic production activities			TAXINC	(1,259,667)	$ (416,822)	$ (305,914)	$ (24,220)	$ (317,862)
Adjustment for tax basis depreciation reduction			UPT	(87,982)	$ (40,450)	$ (11,571)	$ (1,670)	$ (15,904)
Adjustment for amortization of investment tax credit			UPT	345,849	$ 159,005	$ 45,485	$ 6,564	$ 62,516
Total Expense Adjustments				(935,167)	8,176,694	1,540,161	(619,548)	(4,967,823)
Total Operating Expenses		TOE		$ 823,603,339	$ 340,878,286	$ 111,902,862	$ 17,396,272	$ 164,343,456
Net Operating Income -- Pro-Forma				$ 90,862,702	$ 27,749,441	$ 22,819,553	$ 1,768,188	$ 22,897,238

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Cost of Service Summary -- Pro-Forma								
Operating Expenses								
Operation and Maintenance Expenses				$ 17,077,409	$ 19,920,018	$ 78,192,150	$ 2,224,655	$ 21,538,596
Depreciation and Amortization Expenses				2,298,907	2,953,510	10,167,622	321,256	2,487,493
Regulatory Credits				(41,912)	(53,600)	(186,425)	(5,696)	(50,037)
Accretion Expense				36,479	46,654	162,258	4,959	43,532
Depreciation for Asset Retirement Costs				4,684	6,017	20,714	654	5,068
Amortization Expense				118,491	152,230	524,062	16,558	128,211
Property and Other Taxes			NPT	384,580	494,372	1,699,699	53,928	410,703
Amortization of Investment Tax Credit				38,549	49,554	170,370	5,406	41,167
Other Expenses				(1,373)	(1,764)	(6,066)	(192)	(1,466)
State and Federal Income Taxes			TAXINC	$ 927,693	$ 1,144,546	$ 2,807,537	$ 146,932	$ 588,833
Specific Assignment of Interruptible Credit				-	-	(1,765,763)	-	(901,690)
Allocation of Interruptible Credits			INTCRE	$ 58,280	$ 80,500	$ 252,293	$ 8,295	$ 65,859
Adjustments to Operating Expenses:								
Eliminate mismatch in fuel cost recovery			Energy	$ (794,001)	$ (901,936)	$ (3,665,121)	$ (100,559)	$ (1,026,647)
Remove ECR expenses			ECRREV	$ (89,657)	$ (107,577)	$ (381,012)	$ (12,367)	$ (101,562)
Reflect full year of ECR roll-in			ECRREV2	$ 53,786	$ 61,891	$ 190,130	$ 6,134	$ 63,719
Eliminate brokered sales expenses			Energy	$ (7,281)	$ (8,270)	$ (33,608)	$ (922)	$ (9,414)
Eliminate DSM Expenses			DSMREV	$ (137,568)	$ (157,856)	$ -	$ -	$ -
Year end Expense adjustment			YREND	$ 342	$ 1,367	$ 732	$ 277	$ 81
Adjustment to annualize depreciation expense			DET	$ 130,678	$ 167,888	$ 577,962	$ 18,261	$ 141,398
Labor adjustment			LBT	$ 39,062	$ 48,213	$ 175,669	$ 5,460	$ 45,903
Adjustment for pension and post Ret Exp.			LBT	$ 6,731	$ 8,307	$ 30,269	$ 941	$ 7,909
Adjustment for property insurance expenses			UPT	$ 7,342	$ 9,439	$ 32,442	$ 1,030	$ 7,819
Adjustment for liability inusrance increase			UPT	$ 10,629	$ 13,665	$ 46,970	$ 1,492	$ 11,320
Adjustment for Hazard Tree Program			SDALL	$ 18,428	$ 24,648	$ 76,814	$ 3,148	$ -
Storm damage adjustment			SDALL	$ (7,024)	$ (9,395)	$ (29,280)	$ (1,200)	$ -
Adjustment to eliminate advertising expense			REVUC	$ (9,694)	$ (11,661)	$ (40,956)	$ (1,327)	$ (10,471)
Adjustment for retired mainframe			RBT	$ (21,886)	$ (28,017)	$ (96,879)	$ (3,060)	$ (23,527)
Adjustment for MISO Exit Regulatory Asset			PLTRT	$ (3,842)	$ (4,913)	$ (17,093)	$ (522)	$ (4,604)
Adjustment for 2008 Wind Storm Asset			SDALL	$ 289,419	$ 387,103	$ 1,206,391	$ 49,437	$ -
Adjustment for 2009 Winter Storm Asset			SDALL	$ 91,487	$ 122,366	$ 381,348	$ 15,627	$ -
Adjustment for KCCS Regulatory Asset			PLPPT	$ 8,395	$ 10,735	$ 37,352	$ 1,140	$ 10,059
Adjustment for CMRG Regulatory Asset			PLPPT	$ (47)	$ (61)	$ (211)	$ (6)	$ (57)
Amortization of rate case expenses			OMT	$ 8,617	$ 10,051	$ 39,454	$ 1,123	$ 10,868
Adjustment for SW Power Pool settlement			PLPPT	$ (14,274)	$ (18,252)	$ (63,507)	$ (1,938)	$ (17,103)
Adjustment for MISO RSG resettlement			PLTRT	$ (10,513)	$ (13,442)	$ (46,771)	$ (1,427)	$ (12,596)
Adjustment for USGC settlement			PLPPT	$ 11,743	$ 15,015	$ 52,243	$ 1,594	$ 14,070
Adjustment to remove FERC Hydropower program change			PLPPT	$ (3,842)	$ (4,913)	$ (17,095)	$ (522)	$ (4,604)
Adjustment for injuries and damages			UPT	$ 6,481	$ 8,332	$ 28,639	$ 909	$ 6,902
Adjustment for Interest rate Swap Amortization			UPT	$ 4,248	$ 5,461	$ 18,771	$ 596	$ 4,524
Adjustment to correct Edison Electric Institutue invoice			RBT	$ 1,309	$ 1,676	$ 5,795	$ 183	$ 1,407
Adjustment to property tax expense			UPT	$ 16,836	$ 21,645	$ 74,397	$ 2,363	$ 17,930
Adjustment for EKPC settlement charges			Energy	$ 26,511	$ 30,114	$ 122,373	$ 3,358	$ 34,278
Reflect weather normalized electric sales margins			TEXP01	$ 20,957	$ 31,060	$ -	$ -	$ -
Federal & State Income Tax Adjustment			ITADJ	$ (528,695)	$ (649,254)	$ (2,164,658)	$ (66,262)	$ (524,840)
Federal & State Income Tax Interest Adjustment			TAXINC	$ (3,049)	$ (3,761)	$ (9,227)	$ (483)	$ (1,935)
Prior income tax true-ups & adjustments			TAXINC	$ 52,401	$ 64,650	$ 158,583	$ 8,299	$ 33,260
Adjustment for domestic production activities			TAXINC	$ (24,989)	$ (30,830)	$ (75,626)	$ (3,958)	$ (15,861)
Adjustment for tax basis depreciation reduction			UPT	$ (1,816)	$ (2,335)	$ (8,025)	$ (255)	$ (1,934)
Adjustment for amortization of investment tax credit			UPT	$ 7,139	$ 9,178	$ 31,545	$ 1,002	$ 7,603
Total Expense Adjustments				(845,640)	(899,670)	(3,361,188)	(72,434)	(1,336,104)
Total Operating Expenses		TOE		$ 20,056,147	$ 23,892,366	$ 88,677,263	$ 2,704,320	$ 23,020,164
Net Operating Income -- Pro-Forma				$ 1,777,163	$ 2,249,382	$ 5,816,979	$ 292,842	$ 1,241,269

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Cost of Service Summary -- Pro-Forma								
Operating Expenses								
Operation and Maintenance Expenses				$ 11,507,375	$ 2,924,679	$ 6,814,570	$ 190,878	$ 228,592
Depreciation and Amortization Expenses				1,761,092	394,815	2,563,477	15,121	29,068
Regulatory Credits				(32,528)	(7,266)	(7,222)	(218)	(437)
Accretion Expense				28,310	6,324	6,450	190	381
Depreciation for Asset Retirement Costs				3,588	804	5,223	31	59
Amortization Expense				90,771	20,350	132,127	779	1,498
Property and Other Taxes			NPT	294,122	65,969	474,585	2,597	4,970
Amortization of Investment Tax Credit				29,481	6,612	47,570	260	498
Other Expenses				(1,050)	(235)	(1,694)	(9)	(18)
State and Federal Income Taxes			TAXINC	$ (175,173)	$ (33,046)	$ 1,809,256	$ 7,137	$ 9,863
Specific Assignment of Interruptible Credit				-	-	-	-	-
Allocation of Interruptible Credits			INTCRE	$ 50,496	$ 10,211	$ -	$ -	$ 539
Adjustments to Operating Expenses:								
Eliminate mismatch in fuel cost recovery			Energy	$ (517,220)	$ (135,748)	$ (257,676)	$ (9,750)	$ (9,440)
Remove ECR expenses			ECRREV	$ (51,429)	$ (12,121)	$ (69,686)	$ (818)	$ (1,154)
Reflect full year of ECR roll-in			ECRREV2	$ 42,379	$ -	$ (216)	$ (223)	$ -
Eliminate brokered sales expenses			Energy	$ (4,743)	$ (1,245)	$ (2,363)	$ (89)	$ (87)
Eliminate DSM Expenses			DSMREV	$ -	$ -	$ -	$ -	$ -
Year end Expense adjustment			YREND	$ 16	$ 33	$ 1,554,717	$ 1,757	$ 14,415
Adjustment to annualize depreciation expense			DET	$ 100,106	$ 22,443	$ 145,717	$ 860	$ 1,652
Labor adjustment			LBT	$ 28,190	$ 6,713	$ 20,777	$ 361	$ 744
Adjustment for pension and post Ret Exp.			LBT	$ 4,857	$ 1,157	$ 3,580	$ 62	$ 128
Adjustment for property insurance expenses			UPT	$ 5,613	$ 1,259	$ 9,245	$ 50	$ 95
Adjustment for liability inusrance increase			UPT	$ 8,126	$ 1,823	$ 13,385	$ 72	$ 138
Adjustment for Hazard Tree Program			SDALL	$ 12,336	$ 2,863	$ 27,201	$ 346	$ 444
Storm damage adjustment			SDALL	$ (4,702)	$ (1,091)	$ (10,368)	$ (132)	$ (169)
Adjustment to eliminate advertising expense			REVUC	$ (5,530)	$ (1,374)	$ (7,771)	$ (94)	$ (129)
Adjustment for retired mainframe			RBT	$ (16,643)	$ (3,753)	$ (26,628)	$ (153)	$ (285)
Adjustment for MISO Exit Regulatory Asset			PLTRT	$ (2,983)	$ (666)	$ (521)	$ (20)	$ (40)
Adjustment for 2008 Wind Storm Asset			SDALL	$ 193,745	$ 44,967	$ 427,192	$ 5,440	$ 6,967
Adjustment for 2009 Winter Storm Asset			SDALL	$ 61,244	$ 14,214	$ 135,038	$ 1,720	$ 2,202
Adjustment for KCCS Regulatory Asset			PLPPT	$ 6,519	$ 1,456	$ 1,140	$ 43	$ 87
Adjustment for CMRG Regulatory Asset			PLPPT	$ (37)	$ (8)	$ (6)	$ (0)	$ (0)
Amortization of rate case expenses			OMT	$ 5,806	$ 1,476	$ 3,438	$ 96	$ 115
Adjustment for SW Power Pool settlement			PLPPT	$ (11,084)	$ (2,476)	$ (1,937)	$ (73)	$ (148)
Adjustment for MISO RSG resettlement			PLTRT	$ (8,163)	$ (1,823)	$ (1,427)	$ (54)	$ (109)
Adjustment for USGC settlement			PLPPT	$ 9,118	$ 2,037	$ 1,594	$ 60	$ 122
Adjustment to remove FERC Hydropower program change			PLPPT	$ (2,984)	$ (666)	$ (522)	$ (20)	$ (40)
Adjustment for injuries and damages			UPT	$ 4,955	$ 1,111	$ 8,161	$ 44	$ 84
Adjustment for Interest rate Swap Amortization			UPT	$ 3,248	$ 728	$ 5,349	$ 29	$ 55
Adjustment to correct Edison Electric Institutue invoice			RBT	$ 996	$ 225	$ 1,593	$ 9	$ 17
Adjustment to property tax expense			UPT	$ 12,871	$ 2,887	$ 21,201	$ 114	$ 219
Adjustment for EKPC settlement charges			Energy	$ 17,269	$ 4,532	$ 8,603	$ 326	$ 315
Reflect weather normalized electric sales margins			TEXP01	$ 34,610	$ -	$ -	$ -	$ -
Federal & State Income Tax Adjustment			ITADJ	$ (293,789)	$ (80,121)	$ (119,204)	$ (6,050)	$ (5,145)
Federal & State Income Tax Interest Adjustment			TAXINC	$ 576	$ 109	$ (5,946)	$ (23)	$ (32)
Prior income tax true-ups & adjustments			TAXINC	$ (9,895)	$ (1,867)	$ 102,196	$ 403	$ 557
Adjustment for domestic production activities			TAXINC	$ 4,719	$ 890	$ (48,736)	$ (192)	$ (266)
Adjustment for tax basis depreciation reduction			UPT	$ (1,388)	$ (311)	$ (2,287)	$ (12)	$ (24)
Adjustment for amortization of investment tax credit			UPT	$ 5,458	$ 1,224	$ 8,989	$ 48	$ 93
Total Expense Adjustments				(367,833)	(131,126)	1,943,823	(5,862)	11,383
Total Operating Expenses		TOE		$ 13,188,651	$ 3,258,090	$ 13,788,163	$ 210,903	$ 286,395
Net Operating Income -- Pro-Forma				$ (47,438)	$ (23,421)	$ 4,290,139	$ 9,383	$ 21,986

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Cost of Service Summary -- Pro-Forma								
Net Operating Income -- Pro-Forma				$ 90,862,702	$ 27,749,441	$ 22,819,553	$ 1,768,188	$ 22,897,238
Net Cost Rate Base				$ 1,904,726,111	$ 870,969,477	$ 250,122,772	$ 36,416,219	$ 346,170,916
Less: ECR Rate Base			RBPPT	$ -	$ -	$ -	$ -	$ -
Adjustment to Reflect Depreciation Reserve			DET	$ (6,204,918)	$ (2,815,989)	$ (819,246)	$ (120,248)	$ (1,142,471)
Cash Working Capital			OMLF	$ 6,025,602	$ 2,960,519	$ 773,924	$ 108,439	$ 1,062,922
Adjusted Net Cost Rate Base				$ 1,904,546,796	$ 871,114,007	$ 250,077,449	$ 36,404,410	$ 346,091,368
Rate of Return				4.77%	3.19%	9.12%	4.86%	6.62%

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Cost of Service Summary -- Pro-Forma								
Net Operating Income -- Pro-Forma				$ 1,777,163	$ 2,249,382	$ 5,816,979	$ 292,842	$ 1,241,269
Net Cost Rate Base				$ 39,746,887	$ 50,880,896	$ 175,940,357	$ 5,557,356	$ 42,726,770
Less: ECR Rate Base			RBPPT	$ -	$ -	$ -	$ -	$ -
Adjustment to Reflect Depreciation Reserve			DET	$ (130,678)	$ (167,888)	$ (577,962)	$ (18,261)	$ (141,398)
Cash Working Capital			OMLF	$ 115,907	$ 149,642	$ 513,036	$ 16,812	$ 131,149
Adjusted Net Cost Rate Base				$ 39,732,116	$ 50,862,651	$ 175,875,431	$ 5,555,907	$ 42,716,521
Rate of Return				4.47%	4.42%	3.31%	5.27%	2.91%

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Cost of Service Summary -- Pro-Forma								
Net Operating Income -- Pro-Forma				$ (47,438)	$ (23,421)	$ 4,290,139	$ 9,383	$ 21,986
Net Cost Rate Base				$ 30,225,504	$ 6,816,502	$ 48,357,866	$ 277,545	$ 517,043
Less: ECR Rate Base			RBPPT	$ -	$ -	$ -	$ -	$ -
Adjustment to Reflect Depreciation Reserve			DET	$ (100,106)	$ (22,443)	$ (145,717)	$ (860)	$ (1,652)
Cash Working Capital			OMLF	$ 88,716	$ 19,989	$ 81,514	$ 774	$ 2,260
Adjusted Net Cost Rate Base				$ 30,214,114	$ 6,814,048	$ 48,293,664	$ 277,460	$ 517,651
Rate of Return				-0.16%	-0.34%	8.88%	3.38%	4.25%

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Taxable Income Pro-Forma								
Total Operating Revenue				$ 914,466,041	$ 368,627,726	$ 134,722,415	$ 19,164,460	$ 187,240,694
Operating Expenses				$ 772,715,170	$ 323,453,916	$ 100,007,715	$ 16,422,538	$ 151,828,693
Interest Expense		INTEXP		$ 48,502,810	$ 22,249,565	$ 6,385,344	$ 923,856	$ 8,794,711
Interest Syncronization Adjustment			INTEXP	$ (902,327)	$ (413,922)	$ (118,790)	$ (17,187)	$ (163,613)
Taxable Income		TXINCPF		$ 94,150,387	$ 23,338,168	$ 28,448,147	$ 1,835,253	$ 26,780,903

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Taxable Income Pro-Forma								
Total Operating Revenue				$ 21,833,310	$ 26,141,748	$ 94,494,241	$ 2,997,161	$ 24,261,433
Operating Expenses				$ 19,047,192	$ 22,643,173	$ 85,511,375	$ 2,545,871	$ 22,348,089
Interest Expense		INTEXP		$ 1,004,558	$ 1,291,343	$ 4,439,765	$ 140,865	$ 1,072,791
Interest Syncronization Adjustment			INTEXP	$ (18,688)	$ (24,024)	$ (82,596)	$ (2,621)	$ (19,958)
Taxable Income		TXINCPF		$ 1,800,248	$ 2,231,255	$ 4,625,697	$ 313,046	$ 860,511

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Taxable Income Pro-Forma								
Total Operating Revenue				$ 13,141,213	$ 3,234,669	$ 18,078,302	$ 220,286	$ 308,381
Operating Expenses				$ 13,301,995	$ 3,277,249	$ 11,848,780	$ 203,174	$ 275,413
Interest Expense		INTEXP		$ 768,272	$ 172,317	$ 1,239,657	$ 6,783	$ 12,982
Interest Syncronization Adjustment			INTEXP	$ (14,293)	$ (3,206)	$ (23,062)	$ (126)	$ (242)
Taxable Income		TXINCPF		$ (914,761)	$ (211,691)	$ 5,012,927	$ 10,456	$ 20,229

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Cost of Service Summary -- Pro-Forma (Adjusted for Proposed Increase)								
Operating Revenues								
Total Operating Revenue -- Actual				$ 914,466,041	$ 368,627,726	$ 134,722,415	$ 19,164,460	$ 187,240,694
Pro-Forma Adjustments:								
Proposed Increase				$ 94,257,422	$ 36,859,770	$ 13,879,697	$ 2,092,835	$ 19,349,907
To Reflect Proposed Increase in Miscellaneous Charges			MISCR	$ 314,780	$ 209,827	$ 40,956	$ 2,880	$ 31,374
Total Pro-Forma Operating Revenue				$ 1,009,038,243	$ 405,697,324	$ 148,643,069	$ 21,260,176	$ 206,621,975
					0.62136774			
Operating Expenses								
Total Operating Expenses				$ 824,538,506	$ 332,701,592	$ 110,362,701	$ 18,015,820	$ 169,311,278
Total Pro-Forma Adjustments				(935,167)	8,176,694	1,540,161	(619,548)	(4,967,823)
Incremental Income Taxes				35,172,581	13,786,646	5,177,265	779,423	7,208,140
Total Pro-forma Operating Expenses				$ 858,775,920	$ 354,664,931	$ 117,080,127	$ 18,175,695	$ 171,551,596
Net Operating Income -- Pro-Forma				$ 150,262,323	$ 51,032,393	$ 31,562,942	$ 3,084,481	$ 35,070,379
Net Cost Rate Base				$ 1,904,546,796	$ 871,114,007	$ 250,077,449	$ 36,404,410	$ 346,091,368
Rate of Return				7.89%	5.86%	12.62%	8.47%	10.13%

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Cost of Service Summary -- Pro-Forma (Adjusted for Proposed Increase)								
Operating Revenues								
Total Operating Revenue -- Actual				$ 21,833,310	$ 26,141,748	$ 94,494,241	$ 2,997,161	$ 24,261,433
Pro-Forma Adjustments:								
Proposed Increase				$ 2,682,111	$ 2,894,512	$ 10,242,219	$ 354,396	$ 2,464,135
To Reflect Proposed Increase in Miscellaneous Charges			MISCR	$ 3,297	$ 4,410	$ 13,744	$ 563	$ -
Total Pro-Forma Operating Revenue				$ 24,518,718	$ 29,040,671	$ 104,750,204	$ 3,352,120	$ 26,725,568
Operating Expenses								
Total Operating Expenses				$ 20,901,787	$ 24,792,036	$ 92,038,451	$ 2,776,754	$ 24,356,268
Total Pro-Forma Adjustments				(845,640)	(899,670)	(3,361,188)	(72,434)	(1,336,104)
Incremental Income Taxes				998,737	1,078,145	3,814,320	132,014	916,443
Total Pro-forma Operating Expenses				$ 21,054,884	$ 24,970,512	$ 92,491,583	$ 2,836,333	$ 23,936,607
Net Operating Income -- Pro-Forma				$ 3,463,834	$ 4,070,159	$ 12,258,621	$ 515,787	$ 2,788,961
Net Cost Rate Base				$ 39,732,116	$ 50,862,651	$ 175,875,431	$ 5,555,907	$ 42,716,521
Rate of Return				8.72%	8.00%	6.97%	9.28%	6.53%

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Cost of Service Summary -- Pro-Forma (Adjusted for Proposed Increase)								
Operating Revenues								
Total Operating Revenue -- Actual				$ 13,141,213	$ 3,234,669	$ 18,078,302	$ 220,286	$ 308,381
Pro-Forma Adjustments:								
Proposed Increase				$ 1,275,127	$ 314,968	$ 1,797,054	$ 21,379	$ 29,310
To Reflect Proposed Increase in Miscellaneous Charges			MISCR	$ 2,207	$ 512	$ 4,867	$ 62	$ 79
Total Pro-Forma Operating Revenue				$ 14,418,548	$ 3,550,149	$ 19,880,223	$ 241,727	$ 337,771
Operating Expenses								
Total Operating Expenses				$ 13,556,484	$ 3,389,216	$ 11,844,340	$ 216,765	$ 275,013
Total Pro-Forma Adjustments				(367,833)	(131,126)	1,943,823	(5,862)	11,383
Incremental Income Taxes				475,057	117,331	670,157	7,974	10,930
Total Pro-forma Operating Expenses				$ 13,663,708	$ 3,375,421	$ 14,458,320	$ 218,877	$ 297,326
Net Operating Income -- Pro-Forma				$ 754,840	$ 174,728	$ 5,421,903	$ 22,850	$ 40,445
Net Cost Rate Base				$ 30,214,114	$ 6,814,048	$ 48,293,664	$ 277,460	$ 517,651
Rate of Return				2.50%	2.56%	11.23%	8.24%	7.81%

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Allocation Factors								
Energy Allocation Factors								
Energy Usage by Class		E01	Energy	1.000000	0.360752	0.124709	0.024155	0.216519
Customer Allocation Factors								
Primary Distribution Plant -- Average Number of Custc		C01	Cust08	1.000000	0.86161	0.10375	0.00022	0.00755
Customer Services -- Weighted cost of Services		C02		1.000000	0.883641	0.105717	-	0.007787
Meter Costs -- Weighted Cost of Meters		C03		1.000000	0.841069	0.110686	0.00173	0.037036
Lighting Systems -- Lighting Customers		C04	Cust04	1.000000	-	-	-	-
Meter Reading and Billing -- Weighted Cost		C05	Cust05	1.000000	0.79154	0.10485	0.00204	0.06936
Marketing/Economic Development		C06	Cust06	1.000000	0.86160	0.10375	0.00022	0.00755
Rev		R01		766,665,594	309,313,388	113,034,782	16,064,179	159,602,437
Energy				11,433,525,892	4,099,843,486	1,417,281,935	280,315,205	2,460,671,554
Energy (Loss Adjusted)		Energy		12,111,327,512	4,369,186,348	1,510,391,531	292,548,715	2,622,327,559
O&M Customer Allocators								
Customers (Monthly Bills)				5,898,204	4,194,552	505,104	1,080	36,756
Average Customers (Bills/12)				491,517	349,546	42,092	90	3,063
Average Customers (Lighting = Lights)				491,517	349,546	42,092	90	3,063
Weighted Average Customers (Lighting =9 Lights per		Cust05		441,605	349,546	46,301	900	30,630
Street Lighting		Cust04		96,551				
Average Customers		Cust01		491,517	349,546	42,092	90	3,063
Average Customers (Lighting = 9 Lights per Cust)		Cust06		405,694	349,546	42,092	90	3,063
Average Secondary Customers		Cust07		405,530	349,546	42,092	-	3,063
Average Primary Customers		Cust08		405,689	349,546	42,092	90	3,063
Plant Customer Allocators								
Year End Customers				489,035	347,573	41,583	90	3,063
Year End Customers (Lighting = Lights)				489,035	347,573	41,583	90	3,063
Weighted Year End Customers (Lighting =9 Lights pe		YECust05		438,452	347,573	45,741	900	30,630
Street Lighting (plant in service balance)		YECust04		68,350,905				
Year End Customers		YECust01		489,035	347,573	41,583	90	3,063
Year End Customers (Lighting = 9 Lights per Cust)		YECust06		403,212	347,573	41,583	90	3,063
Year End Secondary Customers		YECust07		403,048	347,573	41,583		3,063
Year End Primary Customers		YECust08		403,207	347,573	41,583	90	3,063
Demand Allocators								
Maximum Class Non-Coincident Peak Demands		NCP		2,645,808	1,243,554	336,140	53,744	463,813
Maximum Class Demands (Primary)		NCPP		2,568,839	1,243,554	336,140	53,744	463,813
Sum of the Individual Customer Demands (Secondary		SICD		3,744,771	2,384,385	778,126	-	474,570
Summer Peak Period Demand Allocator		SCP		2,474,288	1,178,425	322,201	48,733	468,532
Winter Peak Period Demand Allocator		WCP		1,910,903	778,786	281,780	43,621	417,092
Base Demand Allocator		BDEM		1,382,572	498,766	172,419	33,396	299,352

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Allocation Factors								
Energy Allocation Factors								
Energy Usage by Class		E01	Energy	0.029313	0.033298	0.135311	0.003712	0.037902
Customer Allocation Factors								
Primary Distribution Plant -- Average Number of Custo		C01	Cust08	0.00005	0.00021	0.00011	0.00004	-
Customer Services -- Weighted cost of Services		C02		-	0.000214	-	0.000114	-
Meter Costs -- Weighted Cost of Meters		C03		0.00031	0.00124	0.00355	0.00132	0.00039
Lighting Systems -- Lighting Customers		C04	Cust04	-	-	-	-	-
Meter Reading and Billing -- Weighted Cost		C05	Cust05	0.00095	0.00380	0.00204	0.00077	0.00023
Marketing/Economic Development		C06	Cust06	0.00005	0.00021	0.00011	0.00004	0.00001
Rev		R01		18,367,218	22,095,455	77,602,583	2,514,177	19,840,881
Energy				340,177,714	378,424,027	1,570,265,493	42,191,442	448,436,560
Energy (Loss Adjusted)		Energy		355,023,742	403,284,930	1,638,794,983	44,963,246	459,047,442
O&M Customer Allocators								
Customers (Monthly Bills)				252	1,008	540	204	60
Average Customers (Bills/12)				21	84	45	17	5
Average Customers (Lighting = Lights)				21	84	45	17	5
Weighted Average Customers (Lighting =9 Lights per		Cust05		420	1,680	900	340	100
Street Lighting		Cust04			-		-	-
Average Customers		Cust01		21	84	45	17	5
Average Customers (Lighting = 9 Lights per Cust)		Cust06		21	84	45	17	5
Average Secondary Customers		Cust07		-	84	-	17	-
Average Primary Customers		Cust08		21	84	45	17	-
Plant Customer Allocators								
Year End Customers				21	84	45	17	5
Year End Customers (Lighting = Lights)				21	84	45	17	5
Weighted Year End Customers (Lighting =9 Lights pe		YECust05		420	1,680	450	170	100
Street Lighting (plant in service balance)		YECust04			-		-	-
Year End Customers		YECust01		21	84	45	17	5
Year End Customers (Lighting = 9 Lights per Cust)		YECust06		21	84	45	17	5
Year End Secondary Customers		YECust07			84		17	
Year End Primary Customers		YECust08		21	84	45	17	
Demand Allocators								
Maximum Class Non-Coincident Peak Demands		NCP		61,828	66,295	257,876	8,229	76,969
Maximum Class Demands (Primary)		NCPP		61,828	66,295	257,876	8,229	-
Sum of the Individual Customer Demands (Secondary		SICD		-	71,433	-	9,946	-
Summer Peak Period Demand Allocator		SCP		54,730	69,106	229,132	7,821	46,605
Winter Peak Period Demand Allocator		WCP		41,489	59,841	182,646	5,892	52,833
Base Demand Allocator		BDEM		40,528	46,037	187,077	5,133	52,403

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Allocation Factors								
Energy Allocation Factors								
Energy Usage by Class		E01	Energy	0.019095	0.005012	0.009513	0.000360	0.000349
Customer Allocation Factors								
Primary Distribution Plant -- Average Number of Custc		C01	Cust08	0.00000	0.00000	0.02617	0.00003	0.00024
Customer Services -- Weighted cost of Services		C02		-	-	-	0.000275	0.002252
Meter Costs -- Weighted Cost of Meters		C03		0.00008	0.00019	-	0.00026	0.00214
Lighting Systems -- Lighting Customers		C04	Cust04	-	-	1.00000	-	-
Meter Reading and Billing -- Weighted Cost		C05	Cust05	0.00005	0.00009	0.02404	0.00003	0.00022
Marketing/Economic Development		C06	Cust06	0.00000	0.00000	0.02617	0.00003	0.00024
Rev		R01		10,478,887	2,603,901	14,724,089	178,739	244,878
Energy				221,595,000	58,159,200	108,112,802	4,090,864	3,960,610
Energy (Loss Adjusted)		Energy		231,265,844	60,697,382	115,215,369	4,359,617	4,220,806
O&M Customer Allocators								
Customers (Monthly Bills)				12	24	1,146,684	1,296	10,632
Average Customers (Bills/12)				1	2	95,557	108	886
Average Customers (Lighting = Lights)				1	2	95,557	108	886
Weighted Average Customers (Lighting =9 Lights per		Cust05		20	40	10,617	12	98
Street Lighting		Cust04		-	-	95,557	108	886
Average Customers		Cust01		1	2	95,557	108	886
Average Customers (Lighting = 9 Lights per Cust)		Cust06		1	2	10,617	12	98
Average Secondary Customers		Cust07		-	-	10,617	12	98
Average Primary Customers		Cust08		1	2	10,617	12	98
Plant Customer Allocators								
Year End Customers				1	2	95,557	108	886
Year End Customers (Lighting = Lights)				1	2	95,557	108	886
Weighted Year End Customers (Lighting =9 Lights pe		YECust05		20	40	10,617	12	98
Street Lighting (plant in service balance)		YECust04		-	-	68,350,905	-	
Year End Customers		YECust01		1	2	95,557	108	886
Year End Customers (Lighting = 9 Lights per Cust)		YECust06		1	2	10,617	12	98
Year End Secondary Customers		YECust07				10,617	12	98
Year End Primary Customers		YECust08		1	2	10,617	12	98
Demand Allocators								
Maximum Class Non-Coincident Peak Demands		NCP		41,438	9,611	25,069	850	392
Maximum Class Demands (Primary)		NCPP		41,438	9,611	25,069	850	392
Sum of the Individual Customer Demands (Secondary		SICD		-	-	25,069	850	392
Summer Peak Period Demand Allocator		SCP		42,032	6,553	-	-	418
Winter Peak Period Demand Allocator		WCP		38,051	8,454	-	-	418
Base Demand Allocator		BDEM		26,400	6,929	13,152	498	482

LOUISVILLE GAS AND ELECTRIC COMPANY
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Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Allocation Factors (Continued)								
Production Allocation								
Production Residual Winter Demand Allocator		PPWDRA		1,910,903	778,786	281,780	43,621	417,092
Production Winter Demand Costs				$ 48,777,080				
Customer Specific Assignment				$ -		-	$ -	-
Production Winter Demand Residual			PPWDRA	$ 48,777,080	$ 19,879,017	$ 7,192,626	$ 1,113,459	$ 10,646,558
Production Winter Demand Total		PPWDT		$ 48,777,080	$ 19,879,017	$ 7,192,626	$ 1,113,459	$ 10,646,558
Production Winter Demand Allocator		PPWDA	PPWDT	1.000000	0.40755	0.14746	0.02283	0.21827
Production Residual Summer Demand Allocator		PPSDRA		2,474,288	1,178,425	322,201	48,733	468,532
Production Summer Demand Costs				$ 24,653,572				
Customer Specific Assignment				$ -		-	$ -	-
Production Summer Demand Residual			PPSDRA	$ 24,653,572	$ 11,741,715	$ 3,210,385	$ 485,572	$ 4,668,406
Production Summer Demand Total		PPSDT		$ 24,653,572	$ 11,741,715	$ 3,210,385	$ 485,572	$ 4,668,406
Production Summer Demand Allocator		PPSDA	PPSDT	1.000000	0.47627	0.13022	0.01970	0.18936
Production Residual Base Demand Allocator		PPBDRA		1,382,572	498,766	172,419	33,396	299,352
Production Base Demand Costs				$ 39,348,724				
Customer Specific Assignment				$ -		-	$ -	-
Production Base Demand Residual			PPBDRA	$ 39,348,724	$ 14,195,133	$ 4,907,140	$ 950,467	$ 8,519,730
Production Base Demand Total		PPBDT		$ 39,348,724	$ 14,195,133	$ 4,907,140	$ 950,467	$ 8,519,730
Production Base Demand Allocator		PPBDA	PPBDT	1.000000	0.36075	0.12471	0.02415	0.21652

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Allocation Factors (Continued)								
Production Allocation								
Production Residual Winter Demand Allocator		PPWDRA		41,489	59,841	182,646	5,892	52,833
Production Winter Demand Costs								
Customer Specific Assignment				-	-	-	-	-
Production Winter Demand Residual			PPWDRA	$ 1,059,024	$ 1,527,478	$ 4,662,163	$ 150,407	$ 1,348,609
Production Winter Demand Total		PPWDT		$ 1,059,024	$ 1,527,478	$ 4,662,163	$ 150,407	$ 1,348,609
Production Winter Demand Allocator		PPWDA	PPWDT	0.02171	0.03132	0.09558	0.00308	0.02765
Production Residual Summer Demand Allocator		PPSDRA		54,730	69,106	229,132	7,821	46,605
Production Summer Demand Costs								
Customer Specific Assignment				-	-	-	-	-
Production Summer Demand Residual			PPSDRA	$ 545,323	$ 688,563	$ 2,283,049	$ 77,928	$ 464,371
Production Summer Demand Total		PPSDT		$ 545,323	$ 688,563	$ 2,283,049	$ 77,928	$ 464,371
Production Summer Demand Allocator		PPSDA	PPSDT	0.02212	0.02793	0.09261	0.00316	0.01884
Production Residual Base Demand Allocator		PPBDRA		40,528	46,037	187,077	5,133	52,403
Production Base Demand Costs								
Customer Specific Assignment				-	-	-	-	-
Production Base Demand Residual			PPBDRA	$ 1,153,443	$ 1,310,240	$ 5,324,312	$ 146,082	$ 1,491,408
Production Base Demand Total		PPBDT		$ 1,153,443	$ 1,310,240	$ 5,324,312	$ 146,082	$ 1,491,408
Production Base Demand Allocator		PPBDA	PPBDT	0.02931	0.03330	0.13531	0.00371	0.03790

LOUISVILLE GAS AND ELECTRIC COMPANY
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12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Allocation Factors (Continued)								
Production Allocation								
Production Residual Winter Demand Allocator		PPWDRA		38,051	8,454	-	-	418
Production Winter Demand Costs								
Customer Specific Assignment							-	
Production Winter Demand Residual			PPWDRA	$ 971,282	$ 215,787	$ -	$ -	$ 10,670
Production Winter Demand Total		PPWDT		$ 971,282	$ 215,787	$ -	$ -	$ 10,670
Production Winter Demand Allocator		PPWDA	PPWDT	0.01991	0.00442	-	-	0.00022
Production Residual Summer Demand Allocator		PPSDRA		42,032	6,553	-	-	418
Production Summer Demand Costs								
Customer Specific Assignment							-	
Production Summer Demand Residual			PPSDRA	$ 418,801	$ 65,293	$ -	$ -	$ 4,165
Production Summer Demand Total		PPSDT		$ 418,801	$ 65,293	$ -	$ -	$ 4,165
Production Summer Demand Allocator		PPSDA	PPSDT	0.01699	0.00265	-	-	0.00017
Production Residual Base Demand Allocator		PPBDRA		26,400	6,929	13,152	498	482
Production Base Demand Costs								
Customer Specific Assignment							-	
Production Base Demand Residual			PPBDRA	$ 751,364	$ 197,201	$ 374,325	$ 14,164	$ 13,713
Production Base Demand Total		PPBDT		$ 751,364	$ 197,201	$ 374,325	$ 14,164	$ 13,713
Production Base Demand Allocator		PPBDA	PPBDT	0.01910	0.00501	0.00951	0.00036	0.00035

LOUISVILLE GAS AND ELECTRIC COMPANY
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Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	General Service Rate GS	Rate PS Primary	Rate PS Secondary
Allocation Factors (Continued)								
Storm Damage Allocator								
Distribution O&M		SDALL		795,387,324.83	530,192,608.78	103,488,320.36	7,278,084 90	79,276,039.91
Revenue Adjustment Allocators								
Other Electric Revenue								
Revenue related			R01	5,885,915.46	$ 2,374,689	$ 867,801	$ 123,329	$ 1,225,314
Production related			PLPPT	1,451,532	$ 589,675	$ 197,050	$ 32,813	$ 306,765
Transmission related			PLTRT	(981,167)	$ (398,593)	$ (133,197)	$ (22,180)	$ (207,359)
Energy related			Energy	941,245	$ 339,556	$ 117,382	$ 22,736	$ 203,797
Customer related			C01	175,814	$ 151,483	$ 18,241	$ 39	$ 1,327
Specific assignment				3,315	3,315			
Total Other Revenue allocator		OREV		7,476,653	3,060,126	1,067,278	156,737	1,529,845
Forfeited Discounts		FDIS		5,040,755	3,952,450	746,971	112,640	228,694
Misc Revenue Allocator		MISCR		963,922	814,598	149,325	-	-
Off-System Sales Allocator								
Off-System Sales			RBPPT	$ 59,391,514	$ 24,023,360	$ 8,037,323	$ 1,346,151	$ 12,563,597
Less: Adjustment to Reallocate Expenses								
Costs allocated on Energy to be reallocated on RBPPT			Energy	$ (25,339,000)	$ (9,141,096)	$ (3,160,001)	$ (612,063)	$ (5,486,365)
Costs allocated on Energy reallocated on RBPPT			RBPPT	$ 25,339,000	$ 10,249,409	$ 3,429,071	$ 574,326	$ 5,360,176
Net Adjustment				$ -	$ 1,108,313	$ 269,070	$ (37,736)	$ (126,188)
Off-System Sales Allocator		OSSALL		$ 59,391,514	$ 22,915,048	$ 7,768,253	$ 1,383,887	$ 12,689,785
Expense Adjustment Allocators								
Interruptible Credit Allocator (Winter & Summer Peak		INTCRE		1,578,237,008	679,620,958	223,590,783	34,367,797	329,162,860
O&M less fuel		OMLF		174,657,771.12	85,813,439.18	22,432,910.15	3,143,211.15	30,809,799.70
Base Rate Revenue at Current Rates				717,701,676	286,317,323	106,871,307	14,969,217	149,658,560
CSR Avoided Cost								
Interruptible Demands				-				
Avoided Cost per kW								
Avoided Cost				2,667,453				
Revenue and Expense Adjust before IT		ITADJ		$ (66,240,102)	$ (35,426,014)	$ (6,345,518)	$ (1,226,140)	$ (11,309,470)
Full Year Base Rate Change		REV01		(2,561,101)	$ (1,172,720)	$ 801,474	$ (143,236)	$ (691,684)
Temperature Normalization - Revenue		TREV01		5,151,223	$ 4,284,606	$ 475,872	$ 24,653	$ 258,591
Temperature Normalization - Expenses		TEXP01		83,483,000	$ 63,816,000	$ 6,278,000	$ 834,000	$ 8,748,000
VDT Revenue		VDTREV		(3)	$ -	$ (3)	$ -	$ -
Merger Surcredit Revenue		MSCREV		(2,324,405)	$ (1,012,997)	$ (325,795)	$ (48,219)	$ (464,706)
ECR Revenue		ECRREV		8,389,626	$ 3,343,631	$ 1,238,262	$ 175,816	$ 1,759,875
ECR Revenue for Roll-In		ECRREV2		6,824,455	$ 2,294,904	$ 2,469,204	$ 113,660	$ 1,102,981
DSM revenue		DSMREV		12,170,475	$ 9,169,340	$ 1,112,292	$ 111,275	$ 1,286,021
Rate Switching		RS01		30,674	$ -	$ -	$ 1,929	$ 22,942
Year Customers		YREND		489,035	347,573	41,583	90	3,063

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Rate CTOD Primary	Rate CTOD Secondary	Rate ITOD Primary	Rate ITOD Secondary	Rate RTS Transmission
Allocation Factors (Continued)								
Storm Damage Allocator								
Distribution O&M		SDALL		8,331,407.10	11,143,415.43	34,727,997.54	1,423,130.16	-
Revenue Adjustment Allocators								
Other Electric Revenue								
Revenue related			R01	$ 141,010	$ 169,633	$ 595,778	$ 19,302	$ 152,324
Production related			PLPPT	$ 35,494	$ 45,385	$ 157,915	$ 4,819	$ 42,529
Transmission related			PLTRT	$ (23,992)	$ (30,678)	$ (106,743)	$ (3,257)	$ (28,748)
Energy related			Energy	$ 27,591	$ 31,342	$ 127,361	$ 3,494	$ 35,675
Customer related			C01	$ 9	$ 36	$ 20	$ 7	$ -
Specific assignment								
Total Other Revenue allocator		OREV		180,112	215,718	774,330	24,365	201,781
Forfeited Discounts		FDIS		-	-	-	-	-
Misc Revenue Allocator		MISCR		-	-	-	-	-
Off-System Sales Allocator								
Off-System Sales			RBPPT	$ 1,463,415	$ 1,861,644	$ 6,521,989	$ 198,072	$ 1,759,822
Less: Adjustment to Reallocate Expenses								
Costs allocated on Energy to be reallocated on RBPPT			Energy	$ (742,771)	$ (843,742)	$ (3,428,644)	$ (94,071)	$ (960,407)
Costs allocated on Energy reallocated on RBPPT			RBPPT	$ 624,356	$ 794,258	$ 2,782,564	$ 84,506	$ 750,816
Net Adjustment				$ (118,415)	$ (49,484)	$ (646,080)	$ (9,565)	$ (209,591)
Off-System Sales Allocator		OSSALL		$ 1,581,830	$ 1,911,128	$ 7,168,069	$ 207,637	$ 1,969,412
Expense Adjustment Allocators								
Interruptible Credit Allocator (Winter & Summer Peak		INTCRE		34,482,053	47,629,124	149,272,703	4,907,566	38,966,179
O&M less fuel		OMLF		3,359,663.34	4,337,511.24	14,870,829.11	487,322.70	3,801,483.57
Base Rate Revenue at Current Rates				16,925,523	20,538,114	73,920,457	2,373,584	19,309,650
CSR Avoided Cost								
Interruptible Demands								
Avoided Cost per kW								
Avoided Cost						1,765,763		901,690
Revenue and Expense Adjust before IT		ITADJ		$ (1,421,556)	$ (1,745,717)	$ (5,820,342)	$ (178,166)	$ (1,411,192)
Full Year Base Rate Change		REV01		$ (103,302)	$ (132,729)	$ (632,528)	$ (10,706)	$ (411,843)
Temperature Normalization - Revenue		TREV01		$ 27,262	$ 40,404	$ -	$ -	$ -
Temperature Normalization - Expenses		TEXP01		$ 921,000	$ 1,365,000	$ -	$ -	$ -
VDT Revenue		VDTREV		$ -	$ -	$ -	$ -	$ -
Merger Surcredit Revenue		MSCREV		$ (43,500)	$ (65,543)	$ (216,357)	$ (6,586)	$ (60,500)
ECR Revenue		ECRREV		$ 202,859	$ 243,405	$ 862,080	$ 27,981	$ 229,796
ECR Revenue for Roll-In		ECRREV2		$ 108,667	$ 125,043	$ 384,132	$ 12,393	$ 128,736
DSM revenue		DSMREV		$ 228,895	$ 262,652	$ -	$ -	$ -
Rate Switching		RS01		$ 2,498	$ 3,305	$ -	$ -	$ -
Year Customers		YREND		21	84	45	17	5

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
Class Allocation

12 Months Ended
October 31, 2009

Description	Ref	Name	Allocation Vector	Special Contract Cust - Fort Knox	Special Contract Cust - Water Co.	Street Lighting Rate RLS & LS	Street Lighting Rate LE	Traffic Street Lighting Rate TLE
Allocation Factors (Continued)								
Storm Damage Allocator								
Distribution O&M		SDALL		5,577,276.86	1,294,441.82	12,297,447.09	156,606.17	200,548 69
Revenue Adjustment Allocators								
Other Electric Revenue								
Revenue related			R01	$ 80,449	$ 19,991	$ 113,041	$ 1,372	$ 1,880
Production related			PLPPT	$ 27,562	$ 6,156	$ 4,818	$ 182	$ 367
Transmission related			PLTRT	$ (18,630)	$ (4,161)	$ (3,257)	$ (123)	$ (248)
Energy related			Energy	$ 17,973	$ 4,717	$ 8,954	$ 339	$ 328
Customer related			C01	$ 0	$ 1	$ 4,601	$ 5	$ 43
Specific assignment								
Total Other Revenue allocator		OREV		107,354	26,704	128,158	1,775	2,370
Forfeited Discounts		FDIS		-	-	-	-	-
Misc Revenue Allocator		MISCR						
Off-System Sales Allocator								
Off-System Sales			RBPPT	$ 1,127,967	$ 253,634	$ 211,292	$ 7,995	$ 15,252
Less: Adjustment to Reallocate Expenses								
Costs allocated on Energy to be reallocated on RBPPT			Energy	$ (483,848)	$ (126,989)	$ (241,051)	$ (9,121)	$ (8,831)
Costs allocated on Energy reallocated on RBPPT			RBPPT	$ 481,240	$ 108,211	$ 90,146	$ 3,411	$ 6,507
Net Adjustment				$ (2,609)	$ (18,778)	$ (150,904)	$ (5,710)	$ (2,324)
Off-System Sales Allocator		OSSALL		$ 1,130,576	$ 272,412	$ 362,196	$ 13,705	$ 17,575
Expense Adjustment Allocators								
Interruptible Credit Allocator (Winter & Summer Peak		INTCRE		29,876,914	6,041,233	-	-	318,839
O&M less fuel		OMLF		2,571,505.35	579,395.76	2,362,768.40	22,426.83	65,504.64
Base Rate Revenue at Current Rates				9,732,141	2,405,243	14,280,315	167,393	232,849
CSR Avoided Cost								
Interruptible Demands								
Avoided Cost per kW								
Avoided Cost								
Revenue and Expense Adjust before IT		ITADJ		$ (789,940)	$ (215,429)	$ (320,517)	$ (16,267)	$ (13,834)
Full Year Base Rate Change		REV01		$ (28,116)	$ (18,342)	$ (15,020)	$ (1,288)	$ (1,061)
Temperature Normalization - Revenue		TREV01		$ 39,835	$ -	$ -	$ -	$ -
Temperature Normalization - Expenses		TEXP01		$ 1,521,000	$ -	$ -	$ -	$ -
VDT Revenue		VDTREV		$ -	$ -	$ -	$ -	$ -
Merger Surcredit Revenue		MSCREV		$ (27,098)	$ (9,175)	$ (41,853)	$ (954)	$ (1,122)
ECR Revenue		ECRREV		$ 116,364	$ 27,425	$ 157,671	$ 1,850	$ 2,611
ECR Revenue for Roll-In		ECRREV2		$ 85,621	$ -	$ (436)	$ (450)	$ -
DSM revenue		DSMREV		$ -	$ -	$ -	$ -	$ -
Rate Switching		RS01		$ -	$ -	$ -	$ -	$ -
Year Customers		YREND		1	2	95,557	108	886

Seelye Exhibit 25

Zero Intercept
Overhead Conductor

Zero Intercept Analysis
Account 365 -- Overhead Conductor

October 31, 2009

Plant Classification	
Total Number of Units	4,699,122
Zero Intercept	0.7569734
Zero Intercept Cost	$3,557,110
Total Cost of Sample	6,532,475.83
Percentage of Total	0.544527106
Percentage Classified as Customer-Related	54.45%
Percentage Classified as Demand-Related	45.55%

Zero Intercept Analysis
Account 365 -- Overhead Conductor

October 31, 2009

Description	Size	Cost	Quantity	Avg Cost
#12 conductor	6.53	15.15	1,515.00	0.01
#8 conductor	16.51	24.24	1,212.00	0.02
#6 conductor	26.24	3,499.99	18,421.00	0.19
#4 conductor	41.74	21,484.56	89,519.00	0.24
#2 conductor	66.36	650,917.73	971,519.00	0.67
#1 conductor	83.69	116,511.40	88,940.00	1.31
1/0 conductor	105.6	55,059.24	39,898.00	1.38
2/0 conductor	133.1	1,027,450.08	713,507.00	1.44
3/0 conductor	167.8	3,127,499.20	1,954,687.00	1.6
4/0 conductor	211.6	182,934.90	112,230.00	1.63
266 MCM Conductor	266	519,829.20	288,794.00	1.8
266.8 MCM Conductor	266.8	37,486.55	20,263.00	1.85
300 MCM Conductor	300	34,118.49	9,557.00	3.57
350 MCM Conductor	350	3,076.00	769.00	4
397 MCM Conductor	397	228,295.60	265,460.00	0.86
500 MCM Conductor	500	52,201.45	7,511.00	6.95
556 MCM Conductor	556	6,433.00	919.00	7
750 MCM Conductor	750	5,745.00	766.00	7.5
795 MCM Conductor	795	452,816.00	113,204.00	4
954 MCM Conductor	954	1,600.00	100.00	16
1000 MCM Conductor	1000	5,478.05	331.00	16.55

Zero Intercept Analysis
Account 365 -- Overhead Conductor

October 31, 2009

Description	n	y	x	est y	y*n^.5	n^.5	xn^.5
#12 conductor	1,515	0.01000	6.53	0.781	0.389230009	38.92	254.1672
#8 conductor	1,212	0.02000	16.51	0.817	0.696275807	34.81	574.7757
#6 conductor	18,421	0.19000	26.24	0.853	25.78755708	135.72	3561.397
#4 conductor	89,519	0.24000	41.74	0.910	71.80734224	299.20	12488.49
#2 conductor	971,519	0.67000	66.36	1.000	660.3899447	985.66	65408.17
#1 conductor	88,940	1.31000	83.69	1.063	390.6788118	298.23	24958.71
1/0 conductor	39,898	1.38000	105.60	1.143	275.6478754	199.74	21093.05
2/0 conductor	713,507	1.44000	133.10	1.244	1216.358547	844.69	112428.7
3/0 conductor	1,954,687	1.60000	167.80	1.371	2236.96194	1,398.10	234601.4
4/0 conductor	112,230	1.63000	211.60	1.531	546.062164	335.01	70887.58
266 MCM Conductor	288,794	1.80000	266.00	1.730	967.3120283	537.40	142947.2
266.8 MCM Conductor	20,263	1.85000	266.80	1.733	263.3441047	142.35	37978.49
300 MCM Conductor	9,557	3.57000	300.00	1.855	349.0028786	97.76	29327.97
350 MCM Conductor	769	4.00000	350.00	2.038	110.923397	27.73	9705.797
397 MCM Conductor	265,460	0.86000	397.00	2.210	443.0961701	515.23	204545.6
500 MCM Conductor	7,511	6.95000	500.00	2.587	602.3288782	86.67	43333.01
556 MCM Conductor	919	7.00000	556.00	2.792	212.2050895	30.32	16855.15
750 MCM Conductor	766	7.50000	750.00	3.501	207.5752875	27.68	20757.53
795 MCM Conductor	113,204	4.00000	795.00	3.666	1345.832085	336.46	267484.1
954 MCM Conductor	100	16.00000	954.00	4.248	160	10.00	9540
1000 MCM Conductor	331	16.55000	1,000.00	4.416	301.1008593	18.19	18193.41

Louisville Gas and Electric Company
Pri/Sec Splits for Overhead Conductor
As of October 31, 2009

		Customer	Demand
Overhead		54.45%	45.55%
Primary	75.76%	0.4125	0.3451
Secondary	24.24%	0.1320	0.1104

Seelye Exhibit 26

Zero Intercept
Underground Conductor

Zero Intercept Analysis
Account 367 -- Underground Conductor

October 31, 2009

Plant Classification	
Total Number of Units	5,133,562
Zero Intercept	0.4705822
Zero Intercept Cost	$2,415,763
Total Cost of Sample	7,840,407.77
Percentage of Total	0.308117022
Percentage Classified as Customer-Related	30.81%
Percentage Classified as Demand-Related	69.19%

Zero Intercept Analysis
Account 367 -- Underground Conductor

October 31, 2009

	Size	Cost	Quantity	Avg Cost
#12 CABLE	6.53	17,418.71	102,463	0.17
6 COPPER CONDUCTOR	26.24	45,743.60	147,560	0.31
4 COPPER CONDUCTOR	41.74	422.80	1,208	0.35
2 COPPER CONDUCTOR	66.36	1,129,975.00	807,125	1.4
1 CONDUCTOR	83.69	8,630.14	9,181	0.94
1/0 CONDUCTOR	105.6	128,892.60	95,476	1.35
2/0 COPPER CONDUCTOR	133.1	3,986,992.80	2,768,745	1.44
3/0 COPPER CONDUCTOR	167.8	6,817.92	3,392	2.01
4/0 COPPER CONDUCTOR	211.6	2,329,434.00	1,164,717	2
200 MCM COPPER CONDUCTOR	200	220.00	100	2.2
350 MCM COPPER CONDUCTOR	350	59,670.20	20,435	2.92
500 MCM COPPER CONDUCTOR	500	10,900.00	2,180	5
1000 MCM CONDUCTOR	1000	115,290.00	10,980	10.5

Zero Intercept Analysis
Account 367 -- Underground Conductor

October 31, 2009

	n	y	x	est y	y*n^.5	n^.5	xn^.5
#12 CABLE	102,463	0.17000	6.53	0.521	54.4167318	320.10	2090.2427
6 COPPER CONDUCTOR	147,560	0.31000	26.24	0.673	119.0819718	384.14	10079.713
4 COPPER CONDUCTOR	1,208	0.35000	41.74	0.792	12.16470304	34.76	1450.7277
2 COPPER CONDUCTOR	807,125	1.40000	66.36	0.982	1257.761901	898.40	59617.914
1 CONDUCTOR	9,181	0.94000	83.69	1.116	90.06848283	95.82	8018.9695
1/0 CONDUCTOR	95,476	1.35000	105.60	1.285	417.1390775	308.99	32629.546
2/0 COPPER CONDUCTOR	2,768,745	1.44000	133.10	1.496	2396.094663	1,663.95	221472.36
3/0 COPPER CONDUCTOR	3,392	2.01000	167.80	1.764	117.064167	58.24	9772.8195
4/0 COPPER CONDUCTOR	1,164,717	2.00000	211.60	2.102	2158.441104	1,079.22	228363.07
200 MCM COPPER CONDUCTOR	100	2.20000	200.00	2.012	22	10.00	2000
350 MCM COPPER CONDUCTOR	20,435	2.92000	350.00	3.168	417.4170385	142.95	50032.864
500 MCM COPPER CONDUCTOR	2,180	5.00000	500.00	4.324	233.4523506	46.69	23345.235
1000 MCM CONDUCTOR	10,980	10.50000	1,000.00	8.178	1100.247699	104.79	104785.5

Louisville Gas and Electric Company
Pri/Sec Splits for Underground Conductor
As of October 31, 2009

		Customer	Demand
Underground		30.81%	69.19%
Primary	99.22%	0.3057	0.6865
Secondary	0.78%	0.0024	0.0054

Seelye Exhibit 27

Zero Intercept
Transformers

Zero Intercept Analysis
Account 368 - Line Transformers

October 31, 2009

Plant Classification		
Total Number of Units		19,164
Zero Intercept	$	1,520.66
Zero Intercept Cost	$	29,141,903.24
Total Cost of Sample	$	63,805,889.70
Percentage of Total		0.45672748
Percentage Classified as Customer-Related		45.67%
Percentage Classified as Demand-Related		54.33%

Zero Intercept Analysis
Account 368 - Line Transformers

October 31, 2009

	Size	2009 Cost	Quantity	Avg Cost
TRANSFORMERS - OH 1P - 10 KVA	10	40,504.51	50	810.0902727
TRANSFORMERS - OH 1P - 10 KVA	10	48,415.15	7	6916.449314
TRANSFORMERS - OH 1P - 10 KVA	10	12,794.29	2	6397.143406
TRANSFORMERS - OH 1P - 100 KVA	100	15,185.69	15	1012.379661
TRANSFORMERS - OH 1P - 100 KVA	100	61,209.55	23	2661.284986
TRANSFORMERS - OH 1P - 100 KVA	100	156,319.88	124	1260.6442
TRANSFORMERS - OH 1P - 100 KVA	100	94,200.67	24	3925.028071
TRANSFORMERS - OH 1P - 100 KVA	100	180,882.35	54	3349.673196
TRANSFORMERS - OH 1P - 100 KVA	100	68,681.34	20	3434.067089
TRANSFORMERS - OH 1P - 100 KVA	100	95,549.61	45	2123.324634
TRANSFORMERS - OH 1P - 100 KVA	100	285,150.19	90	3168.33544
TRANSFORMERS - OH 1P - 100 KVA	100	322,654.16	13	24819.55064
TRANSFORMERS - OH 1P - 15 KVA	15	113,224.60	118	959.5305299
TRANSFORMERS - OH 1P - 15 KVA	15	122,266.24	125	978.1299341
TRANSFORMERS - OH 1P - 15 KVA	15	175,963.91	334	526.838053
TRANSFORMERS - OH 1P - 15 KVA	15	91,473.80	86	1063.648831
TRANSFORMERS - OH 1P - 15 KVA	15	173,658.69	173	1003.807475
TRANSFORMERS - OH 1P - 15 KVA	15	166,943.21	229	729.009667
TRANSFORMERS - OH 1P - 15 KVA	15	316,718.07	406	780.0937667
TRANSFORMERS - OH 1P - 15 KVA	15	165,490.98	25	6619.639341
TRANSFORMERS - OH 1P - 15 KVA	15	223,385.46	30	7446.181845
TRANSFORMERS - OH 1P - 150 KVA	150	74,089.20	11	6735.381843
TRANSFORMERS - OH 1P - 150 KVA	150	86,828.67	10	8682.866551
TRANSFORMERS - OH 1P - 150 KVA	150	144,041.24	21	6859.106634
TRANSFORMERS - OH 1P - 150 KVA	150	167,254.89	15	11150.32593
TRANSFORMERS - OH 1P - 150 KVA	150	72,644.55	7	10377.79243
TRANSFORMERS - OH 1P - 167 KVA	167	63,034.98	30	2101.166046
TRANSFORMERS - OH 1P - 167 KVA	167	21,516.60	5	4303.319286

Zero Intercept Analysis
Account 368 - Line Transformers

October 31, 2009

	Size	2009 Cost	Quantity	Avg Cost
TRANSFORMERS - OH 1P - 167 KVA	167	80,386.87	75	1071.824998
TRANSFORMERS - OH 1P - 167 KVA	167	32,996.27	6	5499.377635
TRANSFORMERS - OH 1P - 167 KVA	167	66,984.35	15	4465.623538
TRANSFORMERS - OH 1P - 167 KVA	167	472,173.60	88	5365.609086
TRANSFORMERS - OH 1P - 167 KVA	167	25,364.88	9	2818.319546
TRANSFORMERS - OH 1P - 167 KVA	167	167,490.97	37	4526.783083
TRANSFORMERS - OH 1P - 25 KVA	25	469,707.25	247	1901.648782
TRANSFORMERS - OH 1P - 25 KVA	25	486,526.97	264	1842.905181
TRANSFORMERS - OH 1P - 25 KVA	25	473,988.08	647	732.5936301
TRANSFORMERS - OH 1P - 25 KVA	25	189,514.88	113	1677.122796
TRANSFORMERS - OH 1P - 25 KVA	25	363,709.80	247	1472.509314
TRANSFORMERS - OH 1P - 25 KVA	25	368,602.71	289	1275.4419
TRANSFORMERS - OH 1P - 25 KVA	25	341,762.51	337	1014.132063
TRANSFORMERS - OH 1P - 25 KVA	25	983,957.64	925	1063.737993
TRANSFORMERS - OH 1P - 25 KVA	25	390,291.37	47	8304.071666
TRANSFORMERS - OH 1P - 25 KVA	25	770,941.14	75	10279.21525
TRANSFORMERS - OH 1P - 250 KVA	250	69,789.60	20	3489.480193
TRANSFORMERS - OH 1P - 250 KVA	250	20,952.24	3	6984.079407
TRANSFORMERS - OH 1P - 250 KVA	250	36,837.60	4	9209.399595
TRANSFORMERS - OH 1P - 250 KVA	250	47,197.08	3	15732.35992
TRANSFORMERS - OH 1P - 37.5 KVA	37.5	340,067.12	192	1771.182933
TRANSFORMERS - OH 1P - 37.5 KVA	37.5	456,879.10	258	1770.849237
TRANSFORMERS - OH 1P - 37.5 KVA	37.5	506,462.08	486	1042.103054
TRANSFORMERS - OH 1P - 37.5 KVA	37.5	260,446.49	125	2083.571943
TRANSFORMERS - OH 1P - 37.5 KVA	37.5	398,169.00	197	2021.162461
TRANSFORMERS - OH 1P - 37.5 KVA	37.5	377,380.60	231	1633.682263
TRANSFORMERS - OH 1P - 37.5 KVA	37.5	371,505.88	252	1474.22967
TRANSFORMERS - OH 1P - 37.5 KVA	37.5	1,325,901.79	832	1593.63196

Zero Intercept Analysis
Account 368 - Line Transformers

October 31, 2009

	Size	2009 Cost	Quantity	Avg Cost
TRANSFORMERS - OH 1P - 37.5 KVA	37.5	419,217.90	39	10749.17688
TRANSFORMERS - OH 1P - 50 KVA	50	271,301.59	140	1937.868487
TRANSFORMERS - OH 1P - 50 KVA	50	441,591.09	180	2453.283843
TRANSFORMERS - OH 1P - 50 KVA	50	438,594.39	428	1024.753238
TRANSFORMERS - OH 1P - 50 KVA	50	229,983.93	81	2839.307793
TRANSFORMERS - OH 1P - 50 KVA	50	198,736.75	88	2258.372123
TRANSFORMERS - OH 1P - 50 KVA	50	501,751.42	237	2117.094598
TRANSFORMERS - OH 1P - 50 KVA	50	336,835.13	190	1772.816492
TRANSFORMERS - OH 1P - 50 KVA	50	976,292.29	490	1992.433247
TRANSFORMERS - OH 1P - 50 KVA	50	313,518.14	24	13063.25599
TRANSFORMERS - OH 1P - 50 KVA	50	734,870.01	45	16330.44463
TRANSFORMERS - OH 1P - 500 KVA	500	47,182.32	11	4289.302056
TRANSFORMERS - OH 1P - 500 KVA	500	148,454.71	14	10603.90818
TRANSFORMERS - OH 1P - 500 KVA	500	116,587.96	34	3429.057536
TRANSFORMERS - OH 1P - 500 KVA	500	176,974.17	11	16088.56051
TRANSFORMERS - OH 1P - 500 KVA	500	176,874.94	13	13605.76477
TRANSFORMERS - OH 1P - 500 KVA	500	19,592.86	6	3265.476503
TRANSFORMERS - OH 1P - 75 KVA	75	169,501.59	68	2492.670393
TRANSFORMERS - OH 1P - 75 KVA	75	151,530.87	54	2806.127276
TRANSFORMERS - OH 1P - 75 KVA	75	262,123.49	187	1401.729888
TRANSFORMERS - OH 1P - 75 KVA	75	139,374.58	31	4495.954333
TRANSFORMERS - OH 1P - 75 KVA	75	139,821.43	26	5377.747249
TRANSFORMERS - OH 1P - 75 KVA	75	75,111.37	29	2590.047166
TRANSFORMERS - OH 1P - 75 KVA	75	94,337.61	48	1965.366819
TRANSFORMERS - OH 1P - 75 KVA	75	388,930.34	153	2542.02836
TRANSFORMERS - OH 1P - 75 KVA	75	16,762.91	1	16762.90587
TRANSFORMERS - OH 1P - 75 KVA	75	335,695.25	14	23978.23186
TRANSFORMERS - PM 1P - 100 KVA	100	38,851.33	34	1142.686299

Zero Intercept Analysis
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October 31, 2009

	Size	2009 Cost	Quantity	Avg Cost
TRANSFORMERS - PM 1P - 100 KVA	100	137,436.44	43	3196.196383
TRANSFORMERS - PM 1P - 100 KVA	100	355,912.97	124	2870.265918
TRANSFORMERS - PM 1P - 100 KVA	100	70,519.40	15	4701.293137
TRANSFORMERS - PM 1P - 100 KVA	100	183,314.75	44	4166.244287
TRANSFORMERS - PM 1P - 100 KVA	100	317,031.33	78	4064.504168
TRANSFORMERS - PM 1P - 100 KVA	100	275,557.10	69	3993.581135
TRANSFORMERS - PM 1P - 100 KVA	100	481,089.48	138	3486.155625
TRANSFORMERS - PM 1P - 100 KVA	100	216,493.92	9	24054.87946
TRANSFORMERS - PM 1P - 100 KVA	100	58,396.99	2	29198.49601
TRANSFORMERS - PM 1P - 15 KVA	15	3,022.60	3	1007.532674
TRANSFORMERS - PM 1P - 150 KVA	150	83,839.54	40	2095.988594
TRANSFORMERS - PM 1P - 150 KVA	150	96,881.12	19	5099.006119
TRANSFORMERS - PM 1P - 150 KVA	150	153,416.74	36	4261.575999
TRANSFORMERS - PM 1P - 150 KVA	150	77,635.20	9	8626.13379
TRANSFORMERS - PM 1P - 150 KVA	150	65,371.47	13	5028.574643
TRANSFORMERS - PM 1P - 150 KVA	150	185,260.79	19	9750.567781
TRANSFORMERS - PM 1P - 150 KVA	150	15,197.66	3	5065.886783
TRANSFORMERS - PM 1P - 150 KVA	150	368,263.65	35	10521.81866
TRANSFORMERS - PM 1P - 167 KVA	167	457,637.44	133	3440.883023
TRANSFORMERS - PM 1P - 167 KVA	167	205,240.28	6	34206.71256
TRANSFORMERS - PM 1P - 225 KVA	225	35,593.69	15	2372.912679
TRANSFORMERS - PM 1P - 225 KVA	225	142,797.72	13	10984.43963
TRANSFORMERS - PM 1P - 225 KVA	225	43,587.02	6	7264.502627
TRANSFORMERS - PM 1P - 225 KVA	225	102,707.07	10	10270.70656
TRANSFORMERS - PM 1P - 225 KVA	225	135,100.30	11	12281.84545
TRANSFORMERS - PM 1P - 225 KVA	225	196,241.90	19	10328.52099
TRANSFORMERS - PM 1P - 225 KVA	225	32,150.63	4	8037.656457
TRANSFORMERS - PM 1P - 225 KVA	225	293,702.62	26	11296.2548

Zero Intercept Analysis
Account 368 - Line Transformers

October 31, 2009

	Size	2009 Cost	Quantity	Avg Cost
TRANSFORMERS - PM 1P - 25 KVA	25	249,953.89	137	1824.480964
TRANSFORMERS - PM 1P - 25 KVA	25	45,138.52	23	1962.544206
TRANSFORMERS - PM 1P - 25 KVA	25	150,749.55	107	1408.874323
TRANSFORMERS - PM 1P - 25 KVA	25	65,264.08	25	2610.563333
TRANSFORMERS - PM 1P - 25 KVA	25	172,031.07	72	2389.320466
TRANSFORMERS - PM 1P - 25 KVA	25	127,275.67	58	2194.408062
TRANSFORMERS - PM 1P - 25 KVA	25	113,172.94	65	1741.122104
TRANSFORMERS - PM 1P - 25 KVA	25	465.80	12	38.81636977
TRANSFORMERS - PM 1P - 25 KVA	25	205,295.94	109	1883.448994
TRANSFORMERS - PM 1P - 25 KVA	25	26,318.77	2	13159.38252
TRANSFORMERS - PM 1P - 250 KVA	250	203,916.94	11	18537.90362
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	687,855.10	224	3070.781693
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	447,841.61	202	2217.037654
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	539,473.95	285	1892.891068
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	346,727.51	100	3467.275084
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	394,369.16	150	2629.127753
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	615,770.37	237	2598.187232
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	462,096.70	183	2525.118595
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	1,973.49	8	246.6864722
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	256,092.27	117	2188.822824
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	28,747.01	2	14373.50324
TRANSFORMERS - PM 1P - 37.5 KVA	37.5	17,442.98	1	17442.98268
TRANSFORMERS - PM 1P - 50 KVA	50	3,081,402.07	448	6878.129618
TRANSFORMERS - PM 1P - 50 KVA	50	704,378.36	279	2524.653613
TRANSFORMERS - PM 1P - 50 KVA	50	928,732.40	387	2399.825319
TRANSFORMERS - PM 1P - 50 KVA	50	672,476.57	184	3654.763945
TRANSFORMERS - PM 1P - 50 KVA	50	768,940.21	261	2946.131056
TRANSFORMERS - PM 1P - 50 KVA	50	653,866.91	235	2782.412386

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October 31, 2009

	Size	2009 Cost	Quantity	Avg Cost
TRANSFORMERS - PM 1P - 50 KVA	50	935,202.20	320	2922.50688
TRANSFORMERS - PM 1P - 50 KVA	50	376.45	2	188.2261633
TRANSFORMERS - PM 1P - 50 KVA	50	883,734.32	380	2325.616644
TRANSFORMERS - PM 1P - 50 KVA	50	91,675.98	3	30558.65861
TRANSFORMERS - PM 1P - 50 KVA	50	77,012.41	4	19253.10352
TRANSFORMERS - PM 1P - 500 KVA	500	730,431.04	34	21483.26586
TRANSFORMERS - PM 1P - 75 KVA	75	535,872.32	166	3228.146534
TRANSFORMERS - PM 1P - 75 KVA	75	354,145.11	123	2879.228559
TRANSFORMERS - PM 1P - 75 KVA	75	621,249.09	279	2226.69924
TRANSFORMERS - PM 1P - 75 KVA	75	548,737.71	130	4221.059276
TRANSFORMERS - PM 1P - 75 KVA	75	687,503.47	174	3951.169374
TRANSFORMERS - PM 1P - 75 KVA	75	737,441.62	191	3860.95088
TRANSFORMERS - PM 1P - 75 KVA	75	767,699.17	234	3280.76568
TRANSFORMERS - PM 1P - 75 KVA	75	1,421,114.13	481	2954.499239
TRANSFORMERS - PM 1P - 75 KVA	75	208,768.64	11	18978.9673
TRANSFORMERS - PM 1P - 75 KVA	75	46,075.80	2	23037.90165
TRANSFORMERS - PM 3P - 1000 KVA	1000	270,715.25	15	18047.68321
TRANSFORMERS - PM 3P - 1000 KVA	1000	270,128.13	13	20779.08671
TRANSFORMERS - PM 3P - 1000 KVA	1000	462,734.20	24	19280.59154
TRANSFORMERS - PM 3P - 1000 KVA	1000	58,602.50	2	29301.24902
TRANSFORMERS - PM 3P - 1000 KVA	1000	102,802.64	4	25700.65954
TRANSFORMERS - PM 3P - 1000 KVA	1000	260,787.31	11	23707.9373
TRANSFORMERS - PM 3P - 1000 KVA	1000	960,323.49	29	33114.60297
TRANSFORMERS - PM 3P - 150 KVA	150	26,880.69	9	2986.743639
TRANSFORMERS - PM 3P - 150 KVA	150	118,044.83	12	9837.069196
TRANSFORMERS - PM 3P - 150 KVA	150	84,277.40	7	12039.62913
TRANSFORMERS - PM 3P - 150 KVA	150	97,917.01	9	10879.66754
TRANSFORMERS - PM 3P - 150 KVA	150	294,448.68	40	7361.217013

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	Size	2009 Cost	Quantity	Avg Cost
TRANSFORMERS - PM 3P - 150 KVA	150	189,855.49	24	7910.645597
TRANSFORMERS - PM 3P - 1500 KVA	1500	82,421.15	8	10302.64368
TRANSFORMERS - PM 3P - 1500 KVA	1500	306,244.33	7	43749.19061
TRANSFORMERS - PM 3P - 1500 KVA	1500	259,725.24	11	23611.38527
TRANSFORMERS - PM 3P - 1500 KVA	1500	119,681.30	3	39893.76714
TRANSFORMERS - PM 3P - 1500 KVA	1500	150,330.75	6	25055.12564
TRANSFORMERS - PM 3P - 1500 KVA	1500	149,413.74	4	37353.43553
TRANSFORMERS - PM 3P - 1500 KVA	1500	123,548.60	4	30887.15043
TRANSFORMERS - PM 3P - 1500 KVA	1500	360,551.35	10	36055.13516
TRANSFORMERS - PM 3P - 2000 KVA	2000	113,564.91	6	18927.48463
TRANSFORMERS - PM 3P - 2000 KVA	2000	154,134.57	4	38533.64148
TRANSFORMERS - PM 3P - 2000 KVA	2000	221,630.57	7	31661.51025
TRANSFORMERS - PM 3P - 2000 KVA	2000	192,604.45	4	48151.11327
TRANSFORMERS - PM 3P - 2000 KVA	2000	204,570.90	5	40914.17976
TRANSFORMERS - PM 3P - 2000 KVA	2000	70,096.52	2	35048.26226
TRANSFORMERS - PM 3P - 2000 KVA	2000	757,972.49	11	68906.59028
TRANSFORMERS - PM 3P - 225 KVA	225	455.81	2	227.9047706
TRANSFORMERS - PM 3P - 225 KVA	225	19,077.29	2	9538.645837
TRANSFORMERS - PM 3P - 225 KVA	225	12,757.43	1	12757.42656
TRANSFORMERS - PM 3P - 225 KVA	225	21,190.26	2	10595.12767
TRANSFORMERS - PM 3P - 225 KVA	225	85,235.77	9	9470.641574
TRANSFORMERS - PM 3P - 225 KVA	225	214,946.70	19	11312.98432
TRANSFORMERS - PM 3P - 225 KVA	225	148,949.30	15	9929.953062
TRANSFORMERS - PM 3P - 2500 KVA	2500	62,956.55	4	15739.13745
TRANSFORMERS - PM 3P - 2500 KVA	2500	146,537.06	3	48845.68559
TRANSFORMERS - PM 3P - 2500 KVA	2500	98,682.42	4	24670.60484
TRANSFORMERS - PM 3P - 2500 KVA	2500	173,446.34	3	57815.44768
TRANSFORMERS - PM 3P - 2500 KVA	2500	155,629.51	3	51876.50347

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	Size	2009 Cost	Quantity	Avg Cost
TRANSFORMERS - PM 3P - 2500 KVA	2500	51,207.88	1	51207.88082
TRANSFORMERS - PM 3P - 2500 KVA	2500	88,664.85	2	44332.42413
TRANSFORMERS - PM 3P - 2500 KVA	2500	633,538.87	12	52794.90613
TRANSFORMERS - PM 3P - 300 KVA	300	230,056.32	38	6054.113626
TRANSFORMERS - PM 3P - 300 KVA	300	318,629.40	28	11379.62141
TRANSFORMERS - PM 3P - 300 KVA	300	237,920.47	32	7435.014586
TRANSFORMERS - PM 3P - 300 KVA	300	227,511.90	19	11974.31074
TRANSFORMERS - PM 3P - 300 KVA	300	890,003.41	42	21190.55741
TRANSFORMERS - PM 3P - 300 KVA	300	188,267.47	15	12551.16459
TRANSFORMERS - PM 3P - 300 KVA	300	157,381.14	13	12106.24175
TRANSFORMERS - PM 3P - 300 KVA	300	1,002,531.75	78	12852.97113
TRANSFORMERS - PM 3P - 3000 KVA	3000	221,977.14	3	73992.38135
TRANSFORMERS - PM 3P - 3000 KVA	3000	118,498.13	2	59249.06654
TRANSFORMERS - PM 3P - 3000 KVA	3000	150,798.83	2	75399.41744
TRANSFORMERS - PM 3P - 500 KVA	500	83,417.56	13	6416.735028
TRANSFORMERS - PM 3P - 500 KVA	500	281,479.64	13	21652.28037
TRANSFORMERS - PM 3P - 500 KVA	500	177,771.82	20	8888.591244
TRANSFORMERS - PM 3P - 500 KVA	500	133,226.02	7	19032.28906
TRANSFORMERS - PM 3P - 500 KVA	500	151,729.16	8	18966.14468
TRANSFORMERS - PM 3P - 500 KVA	500	584,343.64	33	17707.38293
TRANSFORMERS - PM 3P - 500 KVA	500	223,891.13	16	13993.19561
TRANSFORMERS - PM 3P - 500 KVA	500	379,344.77	33	11495.29621
TRANSFORMERS - PM 3P - 75 KVA	75	41,753.59	5	8350.717984
TRANSFORMERS - PM 3P - 75 KVA	75	24,109.54	3	8036.51371
TRANSFORMERS - PM 3P - 75 KVA	75	19,938.73	7	2848.390094
TRANSFORMERS - PM 3P - 750 KVA	750	560,886.47	33	16996.55983
TRANSFORMERS - PM 3P - 750 KVA	750	244,330.46	16	15270.65362
TRANSFORMERS - PM 3P - 750 KVA	750	416,251.14	27	15416.70873

Zero Intercept Analysis
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	Size	2009 Cost	Quantity	Avg Cost
TRANSFORMERS - PM 3P - 750 KVA	750	325,085.63	11	29553.23896
TRANSFORMERS - PM 3P - 750 KVA	750	193,225.03	8	24153.12877
TRANSFORMERS - PM 3P - 750 KVA	750	169,669.56	7	24238.50883
TRANSFORMERS - PM 3P - 750 KVA	750	329,436.36	19	17338.75595
TRANSFORMERS - PM 3P - 750 KVA	750	1,124,459.10	48	23426.23122

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	n	y	x	est y	y*n^.5	n^.5	xn^.5
TRANSFORMERS - OH 1P - 10 KVA	50	810.09027	10.00	1,733.317	5728.203252	7.07	70.710678
TRANSFORMERS - OH 1P - 10 KVA	7	6,916.44931	10.00	1,733.317	18299.20484	2.65	26.457513
TRANSFORMERS - OH 1P - 10 KVA	2	6,397.14341	10.00	1,733.317	9046.926966	1.41	14.142136
TRANSFORMERS - OH 1P - 100 KVA	15	1,012.37966	100.00	3,647.244	3920.929565	3.87	387.29833
TRANSFORMERS - OH 1P - 100 KVA	23	2,661.28499	100.00	3,647.244	12763.07443	4.80	479.58315
TRANSFORMERS - OH 1P - 100 KVA	124	1,260.64420	100.00	3,647.244	14037.93971	11.14	1113.5529
TRANSFORMERS - OH 1P - 100 KVA	24	3,925.02807	100.00	3,647.244	19228.632	4.90	489.89795
TRANSFORMERS - OH 1P - 100 KVA	54	3,349.67320	100.00	3,647.244	24614.97041	7.35	734.84692
TRANSFORMERS - OH 1P - 100 KVA	20	3,434.06709	100.00	3,647.244	15357.6149	4.47	447.2136
TRANSFORMERS - OH 1P - 100 KVA	45	2,123.32463	100.00	3,647.244	14243.69466	6.71	670.82039
TRANSFORMERS - OH 1P - 100 KVA	90	3,168.33544	100.00	3,647.244	30057.46914	9.49	948.6833
TRANSFORMERS - OH 1P - 100 KVA	13	24,819.55064	100.00	3,647.244	89488.16246	3.61	360.55513
TRANSFORMERS - OH 1P - 15 KVA	118	959.53053	15.00	1,839.646	10423.16952	10.86	162.94171
TRANSFORMERS - OH 1P - 15 KVA	125	978.12993	15.00	1,839.646	10935.82512	11.18	167.7051
TRANSFORMERS - OH 1P - 15 KVA	334	526.83805	15.00	1,839.646	9628.316758	18.28	274.135
TRANSFORMERS - OH 1P - 15 KVA	86	1,063.64883	15.00	1,839.646	9863.873474	9.27	139.10428
TRANSFORMERS - OH 1P - 15 KVA	173	1,003.80748	15.00	1,839.646	13203.02596	13.15	197.2942
TRANSFORMERS - OH 1P - 15 KVA	229	729.00967	15.00	1,839.646	11031.91809	15.13	226.99119
TRANSFORMERS - OH 1P - 15 KVA	406	780.09377	15.00	1,839.646	15718.45386	20.15	302.24163
TRANSFORMERS - OH 1P - 15 KVA	25	6,619.63934	15.00	1,839.646	33098.1967	5.00	75
TRANSFORMERS - OH 1P - 15 KVA	30	7,446.18184	15.00	1,839.646	40784.41764	5.48	82.158384
TRANSFORMERS - OH 1P - 150 KVA	11	6,735.38184	150.00	4,710.536	22338.73439	3.32	497.49372
TRANSFORMERS - OH 1P - 150 KVA	10	8,682.86655	150.00	4,710.536	27457.63492	3.16	474.34165
TRANSFORMERS - OH 1P - 150 KVA	21	6,859.10663	150.00	4,710.536	31432.37535	4.58	687.38635
TRANSFORMERS - OH 1P - 150 KVA	15	11,150.32593	150.00	4,710.536	43185.02665	3.87	580.9475
TRANSFORMERS - OH 1P - 150 KVA	7	10,377.79243	150.00	4,710.536	27457.05793	2.65	396.8627
TRANSFORMERS - OH 1P - 167 KVA	30	2,101.16605	167.00	5,072.056	11508.5604	5.48	914.69667
TRANSFORMERS - OH 1P - 167 KVA	5	4,303.31929	167.00	5,072.056	9622.514453	2.24	373.42335

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	n	y	x	est y	y*n^.5	n^.5	xn^.5
TRANSFORMERS - OH 1P - 167 KVA	75	1,071.82500	167.00	5,072.056	9282.276769	8.66	1446.2624
TRANSFORMERS - OH 1P - 167 KVA	6	5,499.37763	167.00	5,072.056	13470.66911	2.45	409.06479
TRANSFORMERS - OH 1P - 167 KVA	15	4,465.62354	167.00	5,072.056	17295.28559	3.87	646.78822
TRANSFORMERS - OH 1P - 167 KVA	88	5,365.60909	167.00	5,072.056	50333.87483	9.38	1566.5989
TRANSFORMERS - OH 1P - 167 KVA	9	2,818.31955	167.00	5,072.056	8454.958638	3.00	501
TRANSFORMERS - OH 1P - 167 KVA	37	4,526.78308	167.00	5,072.056	27535.34652	6.08	1015.8213
TRANSFORMERS - OH 1P - 25 KVA	247	1,901.64878	25.00	2,052.305	29886.75657	15.72	392.90584
TRANSFORMERS - OH 1P - 25 KVA	264	1,842.90518	25.00	2,052.305	29943.66494	16.25	406.20192
TRANSFORMERS - OH 1P - 25 KVA	647	732.59363	25.00	2,052.305	18634.3942	25.44	635.90487
TRANSFORMERS - OH 1P - 25 KVA	113	1,677.12280	25.00	2,052.305	17828.05987	10.63	265.75365
TRANSFORMERS - OH 1P - 25 KVA	247	1,472.50931	25.00	2,052.305	23142.30042	15.72	392.90584
TRANSFORMERS - OH 1P - 25 KVA	289	1,275.44190	25.00	2,052.305	21682.51229	17.00	425
TRANSFORMERS - OH 1P - 25 KVA	337	1,014.13206	25.00	2,052.305	18616.98995	18.36	458.93899
TRANSFORMERS - OH 1P - 25 KVA	925	1,063.73799	25.00	2,052.305	32352.32804	30.41	760.34532
TRANSFORMERS - OH 1P - 25 KVA	47	8,304.07167	25.00	2,052.305	56929.84712	6.86	171.39137
TRANSFORMERS - OH 1P - 25 KVA	75	10,279.21525	25.00	2,052.305	89020.61537	8.66	216.50635
TRANSFORMERS - OH 1P - 250 KVA	20	3,489.48019	250.00	6,837.122	15605.42983	4.47	1118.034
TRANSFORMERS - OH 1P - 250 KVA	3	6,984.07941	250.00	6,837.122	12096.78038	1.73	433.0127
TRANSFORMERS - OH 1P - 250 KVA	4	9,209.39960	250.00	6,837.122	18418.79919	2.00	500
TRANSFORMERS - OH 1P - 250 KVA	3	15,732.35992	250.00	6,837.122	27249.2467	1.73	433.0127
TRANSFORMERS - OH 1P - 37.5 KVA	192	1,771.18293	37.50	2,318.128	24542.23063	13.86	519.61524
TRANSFORMERS - OH 1P - 37.5 KVA	258	1,770.84924	37.50	2,318.128	28444.05055	16.06	602.33919
TRANSFORMERS - OH 1P - 37.5 KVA	486	1,042.10305	37.50	2,318.128	22973.58667	22.05	826.70279
TRANSFORMERS - OH 1P - 37.5 KVA	125	2,083.57194	37.50	2,318.128	23295.04251	11.18	419.26275
TRANSFORMERS - OH 1P - 37.5 KVA	197	2,021.16246	37.50	2,318.128	28368.367	14.04	526.33758
TRANSFORMERS - OH 1P - 37.5 KVA	231	1,633.68226	37.50	2,318.128	24829.82073	15.20	569.95066
TRANSFORMERS - OH 1P - 37.5 KVA	252	1,474.22967	37.50	2,318.128	23402.6705	15.87	595.29404
TRANSFORMERS - OH 1P - 37.5 KVA	832	1,593.63196	37.50	2,318.128	45967.37398	28.84	1081.6654

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	n	y	x	est y	y*n^.5	n^.5	xn^.5
TRANSFORMERS - OH 1P - 37.5 KVA	39	10,749.17688	37.50	2,318.128	67128.58809	6.24	234.18742
TRANSFORMERS - OH 1P - 50 KVA	140	1,937.86849	50.00	2,583.951	22929.16915	11.83	591.60798
TRANSFORMERS - OH 1P - 50 KVA	180	2,453.28384	50.00	2,583.951	32914.25664	13.42	670.82039
TRANSFORMERS - OH 1P - 50 KVA	428	1,024.75324	50.00	2,583.951	21200.25984	20.69	1034.408
TRANSFORMERS - OH 1P - 50 KVA	81	2,839.30779	50.00	2,583.951	25553.77014	9.00	450
TRANSFORMERS - OH 1P - 50 KVA	88	2,258.37212	50.00	2,583.951	21185.40839	9.38	469.04158
TRANSFORMERS - OH 1P - 50 KVA	237	2,117.09460	50.00	2,583.951	32592.25707	15.39	769.74022
TRANSFORMERS - OH 1P - 50 KVA	190	1,772.81649	50.00	2,583.951	24436.58895	13.78	689.20244
TRANSFORMERS - OH 1P - 50 KVA	490	1,992.43325	50.00	2,583.951	44104.39002	22.14	1106.7972
TRANSFORMERS - OH 1P - 50 KVA	24	13,063.25599	50.00	2,583.951	63996.62309	4.90	244.94897
TRANSFORMERS - OH 1P - 50 KVA	45	16,330.44463	50.00	2,583.951	109547.9529	6.71	335.4102
TRANSFORMERS - OH 1P - 500 KVA	11	4,289.30206	500.00	12,153.584	14226.00553	3.32	1658.3124
TRANSFORMERS - OH 1P - 500 KVA	14	10,603.90818	500.00	12,153.584	39676.19138	3.74	1870.8287
TRANSFORMERS - OH 1P - 500 KVA	34	3,429.05754	500.00	12,153.584	19994.66954	5.83	2915.4759
TRANSFORMERS - OH 1P - 500 KVA	11	16,088.56051	500.00	12,153.584	53359.71864	3.32	1658.3124
TRANSFORMERS - OH 1P - 500 KVA	13	13,605.76477	500.00	12,153.584	49056.2825	3.61	1802.7756
TRANSFORMERS - OH 1P - 500 KVA	6	3,265.47650	500.00	12,153.584	7998.7512	2.45	1224.7449
TRANSFORMERS - OH 1P - 75 KVA	68	2,492.67039	75.00	3,115.598	20555.08664	8.25	618.46584
TRANSFORMERS - OH 1P - 75 KVA	54	2,806.12728	75.00	3,115.598	20620.73994	7.35	551.13519
TRANSFORMERS - OH 1P - 75 KVA	187	1,401.72989	75.00	3,115.598	19168.36793	13.67	1025.6096
TRANSFORMERS - OH 1P - 75 KVA	31	4,495.95433	75.00	3,115.598	25032.41431	5.57	417.58233
TRANSFORMERS - OH 1P - 75 KVA	26	5,377.74725	75.00	3,115.598	27421.23816	5.10	382.42646
TRANSFORMERS - OH 1P - 75 KVA	29	2,590.04717	75.00	3,115.598	13947.83085	5.39	403.88736
TRANSFORMERS - OH 1P - 75 KVA	48	1,965.36682	75.00	3,115.598	13616.46074	6.93	519.61524
TRANSFORMERS - OH 1P - 75 KVA	153	2,542.02836	75.00	3,115.598	31443.15429	12.37	927.69877
TRANSFORMERS - OH 1P - 75 KVA	1	16,762.90587	75.00	3,115.598	16762.90587	1.00	75
TRANSFORMERS - OH 1P - 75 KVA	14	23,978.23186	75.00	3,115.598	89718.32837	3.74	280.6243
TRANSFORMERS - PM 1P - 100 KVA	34	1,142.68630	100.00	3,647.244	6662.948842	5.83	583.09519

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	n	y	x	est y	y*n^.5	n^.5	xn^.5
TRANSFORMERS - PM 1P - 100 KVA	43	3,196.19638	100.00	3,647.244	20958.86129	6.56	655.74385
TRANSFORMERS - PM 1P - 100 KVA	124	2,870.26592	100.00	3,647.244	31961.92857	11.14	1113.5529
TRANSFORMERS - PM 1P - 100 KVA	15	4,701.29314	100.00	3,647.244	18208.03002	3.87	387.29833
TRANSFORMERS - PM 1P - 100 KVA	44	4,166.24429	100.00	3,647.244	27635.73817	6.63	663.32496
TRANSFORMERS - PM 1P - 100 KVA	78	4,064.50417	100.00	3,647.244	35896.72885	8.83	883.17609
TRANSFORMERS - PM 1P - 100 KVA	69	3,993.58114	100.00	3,647.244	33173.17636	8.31	830.66239
TRANSFORMERS - PM 1P - 100 KVA	138	3,486.15563	100.00	3,647.244	40953.05585	11.75	1174.734
TRANSFORMERS - PM 1P - 100 KVA	9	24,054.87946	100.00	3,647.244	72164.63838	3.00	300
TRANSFORMERS - PM 1P - 100 KVA	2	29,198.49601	100.00	3,647.244	41292.90906	1.41	141.42136
TRANSFORMERS - PM 1P - 15 KVA	3	1,007.53267	15.00	1,839.646	1745.097782	1.73	25.980762
TRANSFORMERS - PM 1P - 150 KVA	40	2,095.98859	150.00	4,710.536	13256.19581	6.32	948.6833
TRANSFORMERS - PM 1P - 150 KVA	19	5,099.00612	150.00	4,710.536	22226.05238	4.36	653.83484
TRANSFORMERS - PM 1P - 150 KVA	36	4,261.57600	150.00	4,710.536	25569.456	6.00	900
TRANSFORMERS - PM 1P - 150 KVA	9	8,626.13379	150.00	4,710.536	25878.40137	3.00	450
TRANSFORMERS - PM 1P - 150 KVA	13	5,028.57464	150.00	4,710.536	18130.78372	3.61	540.83269
TRANSFORMERS - PM 1P - 150 KVA	19	9,750.56778	150.00	4,710.536	42501.7396	4.36	653.83484
TRANSFORMERS - PM 1P - 150 KVA	3	5,065.88678	150.00	4,710.536	8774.373293	1.73	259.80762
TRANSFORMERS - PM 1P - 150 KVA	35	10,521.81866	150.00	4,710.536	62247.91868	5.92	887.41197
TRANSFORMERS - PM 1P - 167 KVA	133	3,440.88302	167.00	5,072.056	39682.19884	11.53	1925.938
TRANSFORMERS - PM 1P - 167 KVA	6	34,206.71256	167.00	5,072.056	83788.99155	2.45	409.06479
TRANSFORMERS - PM 1P - 225 KVA	15	2,372.91268	225.00	6,305.475	9190.251287	3.87	871.42125
TRANSFORMERS - PM 1P - 225 KVA	13	10,984.43963	225.00	6,305.475	39604.96033	3.61	811.24904
TRANSFORMERS - PM 1P - 225 KVA	6	7,264.50263	225.00	6,305.475	17794.32467	2.45	551.13519
TRANSFORMERS - PM 1P - 225 KVA	10	10,270.70656	225.00	6,305.475	32478.82592	3.16	711.51247
TRANSFORMERS - PM 1P - 225 KVA	11	12,281.84545	225.00	6,305.475	40734.27308	3.32	746.24058
TRANSFORMERS - PM 1P - 225 KVA	19	10,328.52099	225.00	6,305.475	45020.97924	4.36	980.75226
TRANSFORMERS - PM 1P - 225 KVA	4	8,037.65646	225.00	6,305.475	16075.31291	2.00	450
TRANSFORMERS - PM 1P - 225 KVA	26	11,296.25480	225.00	6,305.475	57599.82368	5.10	1147.2794

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	n	y	x	est y	y*n^.5	n^.5	xn^.5
TRANSFORMERS - PM 1P - 25 KVA	137	1,824.48096	25.00	2,052.305	21355.00218	11.70	292.6175
TRANSFORMERS - PM 1P - 25 KVA	23	1,962.54421	25.00	2,052.305	9412.031369	4.80	119.89579
TRANSFORMERS - PM 1P - 25 KVA	107	1,408.87432	25.00	2,052.305	14573.50932	10.34	258.60201
TRANSFORMERS - PM 1P - 25 KVA	25	2,610.56333	25.00	2,052.305	13052.81666	5.00	125
TRANSFORMERS - PM 1P - 25 KVA	72	2,389.32047	25.00	2,052.305	20274.05645	8.49	212.13203
TRANSFORMERS - PM 1P - 25 KVA	58	2,194.40806	25.00	2,052.305	16712.1139	7.62	190.39433
TRANSFORMERS - PM 1P - 25 KVA	65	1,741.12210	25.00	2,052.305	14037.37518	8.06	201.55644
TRANSFORMERS - PM 1P - 25 KVA	12	38.81637	25.00	2,052.305	134.4638492	3.46	86.60254
TRANSFORMERS - PM 1P - 25 KVA	109	1,883.44899	25.00	2,052.305	19663.78479	10.44	261.00766
TRANSFORMERS - PM 1P - 25 KVA	2	13,159.38252	25.00	2,052.305	18610.17723	1.41	35.355339
TRANSFORMERS - PM 1P - 250 KVA	11	18,537.90362	250.00	6,837.122	61483.27071	3.32	829.1562
TRANSFORMERS - PM 1P - 37.5 KVA	224	3,070.78169	37.50	2,318.128	45959.25202	14.97	561.24861
TRANSFORMERS - PM 1P - 37.5 KVA	202	2,217.03765	37.50	2,318.128	31510.02545	14.21	532.97514
TRANSFORMERS - PM 1P - 37.5 KVA	285	1,892.89107	37.50	2,318.128	31955.67915	16.88	633.07286
TRANSFORMERS - PM 1P - 37.5 KVA	100	3,467.27508	37.50	2,318.128	34672.75084	10.00	375
TRANSFORMERS - PM 1P - 37.5 KVA	150	2,629.12775	37.50	2,318.128	32200.10732	12.25	459.27933
TRANSFORMERS - PM 1P - 37.5 KVA	237	2,598.18723	37.50	2,318.128	39998.58402	15.39	577.30516
TRANSFORMERS - PM 1P - 37.5 KVA	183	2,525.11859	37.50	2,318.128	34159.1712	13.53	507.2906
TRANSFORMERS - PM 1P - 37.5 KVA	8	246.68647	37.50	2,318.128	697.7347092	2.83	106.06602
TRANSFORMERS - PM 1P - 37.5 KVA	117	2,188.82282	37.50	2,318.128	23675.73877	10.82	405.62452
TRANSFORMERS - PM 1P - 37.5 KVA	2	14,373.50324	37.50	2,318.128	20327.20323	1.41	53.033009
TRANSFORMERS - PM 1P - 37.5 KVA	1	17,442.98268	37.50	2,318.128	17442.98268	1.00	37.5
TRANSFORMERS - PM 1P - 50 KVA	448	6,878.12962	50.00	2,583.951	145582.5636	21.17	1058.3005
TRANSFORMERS - PM 1P - 50 KVA	279	2,524.65361	50.00	2,583.951	42170.02924	16.70	835.16465
TRANSFORMERS - PM 1P - 50 KVA	387	2,399.82532	50.00	2,583.951	47210.12099	19.67	983.61578
TRANSFORMERS - PM 1P - 50 KVA	184	3,654.76395	50.00	2,583.951	49575.63017	13.56	678.233
TRANSFORMERS - PM 1P - 50 KVA	261	2,946.13106	50.00	2,583.951	47596.20384	16.16	807.77472
TRANSFORMERS - PM 1P - 50 KVA	235	2,782.41239	50.00	2,583.951	42653.57419	15.33	766.48549

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	n	y	x	est y	y*n^.5	n^.5	xn^.5
TRANSFORMERS - PM 1P - 50 KVA	320	2,922.50688	50.00	2,583.951	52279.39238	17.89	894.42719
TRANSFORMERS - PM 1P - 50 KVA	2	188.22616	50.00	2,583.951	266.1919929	1.41	70.710678
TRANSFORMERS - PM 1P - 50 KVA	380	2,325.61664	50.00	2,583.951	45334.61432	19.49	974.67943
TRANSFORMERS - PM 1P - 50 KVA	3	30,558.65861	50.00	2,583.951	52929.14933	1.73	86.60254
TRANSFORMERS - PM 1P - 50 KVA	4	19,253.10352	50.00	2,583.951	38506.20704	2.00	100
TRANSFORMERS - PM 1P - 500 KVA	34	21,483.26586	500.00	12,153.584	125267.8898	5.83	2915.4759
TRANSFORMERS - PM 1P - 75 KVA	166	3,228.14653	75.00	3,115.598	41591.75865	12.88	966.3074
TRANSFORMERS - PM 1P - 75 KVA	123	2,879.22856	75.00	3,115.598	31932.18945	11.09	831.79024
TRANSFORMERS - PM 1P - 75 KVA	279	2,226.69924	75.00	3,115.598	37193.21003	16.70	1252.747
TRANSFORMERS - PM 1P - 75 KVA	130	4,221.05928	75.00	3,115.598	48127.48054	11.40	855.13157
TRANSFORMERS - PM 1P - 75 KVA	174	3,951.16937	75.00	3,115.598	52119.50363	13.19	989.31795
TRANSFORMERS - PM 1P - 75 KVA	191	3,860.95088	75.00	3,115.598	53359.40278	13.82	1036.5206
TRANSFORMERS - PM 1P - 75 KVA	234	3,280.76568	75.00	3,115.598	50186.06467	15.30	1147.2794
TRANSFORMERS - PM 1P - 75 KVA	481	2,954.49924	75.00	3,115.598	64797.227	21.93	1644.8784
TRANSFORMERS - PM 1P - 75 KVA	11	18,978.96730	75.00	3,115.598	62946.11343	3.32	248.74686
TRANSFORMERS - PM 1P - 75 KVA	2	23,037.90165	75.00	3,115.598	32580.51296	1.41	106.06602
TRANSFORMERS - PM 3P - 1000 KVA	15	18,047.68321	1,000.00	22,786.510	69898.37651	3.87	3872.9833
TRANSFORMERS - PM 3P - 1000 KVA	13	20,779.08671	1,000.00	22,786.510	74920.06259	3.61	3605.5513
TRANSFORMERS - PM 3P - 1000 KVA	24	19,280.59154	1,000.00	22,786.510	94455.22243	4.90	4898.9795
TRANSFORMERS - PM 3P - 1000 KVA	2	29,301.24902	1,000.00	22,786.510	41438.22377	1.41	1414.2136
TRANSFORMERS - PM 3P - 1000 KVA	4	25,700.65954	1,000.00	22,786.510	51401.31908	2.00	2000
TRANSFORMERS - PM 3P - 1000 KVA	11	23,707.93730	1,000.00	22,786.510	78630.33257	3.32	3316.6248
TRANSFORMERS - PM 3P - 1000 KVA	29	33,114.60297	1,000.00	22,786.510	178327.5945	5.39	5385.1648
TRANSFORMERS - PM 3P - 150 KVA	9	2,986.74364	150.00	4,710.536	8960.230917	3.00	450
TRANSFORMERS - PM 3P - 150 KVA	12	9,837.06920	150.00	4,710.536	34076.60729	3.46	519.61524
TRANSFORMERS - PM 3P - 150 KVA	7	12,039.62913	150.00	4,710.536	31853.86455	2.65	396.8627
TRANSFORMERS - PM 3P - 150 KVA	9	10,879.66754	150.00	4,710.536	32639.00263	3.00	450
TRANSFORMERS - PM 3P - 150 KVA	40	7,361.21701	150.00	4,710.536	46556.42422	6.32	948.6833

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	n	y	x	est y	y*n^.5	n^.5	xn^.5
TRANSFORMERS - PM 3P - 150 KVA	24	7,910.64560	150.00	4,710.536	38754.0905	4.90	734.84692
TRANSFORMERS - PM 3P - 1500 KVA	8	10,302.64368	1,500.00	33,419.436	29140.27683	2.83	4242.6407
TRANSFORMERS - PM 3P - 1500 KVA	7	43,749.19061	1,500.00	33,419.436	115749.4784	2.65	3968.627
TRANSFORMERS - PM 3P - 1500 KVA	11	23,611.38527	1,500.00	33,419.436	78310.10572	3.32	4974.9372
TRANSFORMERS - PM 3P - 1500 KVA	3	39,893.76714	1,500.00	33,419.436	69098.03159	1.73	2598.0762
TRANSFORMERS - PM 3P - 1500 KVA	6	25,055.12564	1,500.00	33,419.436	61372.27325	2.45	3674.2346
TRANSFORMERS - PM 3P - 1500 KVA	4	37,353.43553	1,500.00	33,419.436	74706.87106	2.00	3000
TRANSFORMERS - PM 3P - 1500 KVA	4	30,887.15043	1,500.00	33,419.436	61774.30087	2.00	3000
TRANSFORMERS - PM 3P - 1500 KVA	10	36,055.13516	1,500.00	33,419.436	114016.3484	3.16	4743.4165
TRANSFORMERS - PM 3P - 2000 KVA	6	18,927.48463	2,000.00	44,052.362	46362.67947	2.45	4898.9795
TRANSFORMERS - PM 3P - 2000 KVA	4	38,533.64148	2,000.00	44,052.362	77067.28295	2.00	4000
TRANSFORMERS - PM 3P - 2000 KVA	7	31,661.51025	2,000.00	44,052.362	83768.48225	2.65	5291.5026
TRANSFORMERS - PM 3P - 2000 KVA	4	48,151.11327	2,000.00	44,052.362	96302.22654	2.00	4000
TRANSFORMERS - PM 3P - 2000 KVA	5	40,914.17976	2,000.00	44,052.362	91486.88719	2.24	4472.136
TRANSFORMERS - PM 3P - 2000 KVA	2	35,048.26226	2,000.00	44,052.362	49565.72783	1.41	2828.4271
TRANSFORMERS - PM 3P - 2000 KVA	11	68,906.59028	2,000.00	44,052.362	228537.3055	3.32	6633.2496
TRANSFORMERS - PM 3P - 225 KVA	2	227.90477	225.00	6,305.475	322.3060176	1.41	318.19805
TRANSFORMERS - PM 3P - 225 KVA	2	9,538.64584	225.00	6,305.475	13489.68231	1.41	318.19805
TRANSFORMERS - PM 3P - 225 KVA	1	12,757.42656	225.00	6,305.475	12757.42656	1.00	225
TRANSFORMERS - PM 3P - 225 KVA	2	10,595.12767	225.00	6,305.475	14983.77325	1.41	318.19805
TRANSFORMERS - PM 3P - 225 KVA	9	9,470.64157	225.00	6,305.475	28411.92472	3.00	675
TRANSFORMERS - PM 3P - 225 KVA	19	11,312.98432	225.00	6,305.475	49312.15542	4.36	980.75226
TRANSFORMERS - PM 3P - 225 KVA	15	9,929.95306	225.00	6,305.475	38458.54284	3.87	871.42125
TRANSFORMERS - PM 3P - 2500 KVA	4	15,739.13745	2,500.00	54,685.287	31478.27491	2.00	5000
TRANSFORMERS - PM 3P - 2500 KVA	3	48,845.68559	2,500.00	54,685.287	84603.20918	1.73	4330.127
TRANSFORMERS - PM 3P - 2500 KVA	4	24,670.60484	2,500.00	54,685.287	49341.20968	2.00	5000
TRANSFORMERS - PM 3P - 2500 KVA	3	57,815.44768	2,500.00	54,685.287	100139.2928	1.73	4330.127
TRANSFORMERS - PM 3P - 2500 KVA	3	51,876.50347	2,500.00	54,685.287	89852.73972	1.73	4330.127

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	n	y	x	est y	y*n^.5	n^.5	xn^.5
TRANSFORMERS - PM 3P - 2500 KVA	1	51,207.88082	2,500.00	54,685.287	51207.88082	1.00	2500
TRANSFORMERS - PM 3P - 2500 KVA	2	44,332.42413	2,500.00	54,685.287	62695.51546	1.41	3535.5339
TRANSFORMERS - PM 3P - 2500 KVA	12	52,794.90613	2,500.00	54,685.287	182886.9196	3.46	8660.254
TRANSFORMERS - PM 3P - 300 KVA	38	6,054.11363	300.00	7,900.414	37320.06281	6.16	1849.3242
TRANSFORMERS - PM 3P - 300 KVA	28	11,379.62141	300.00	7,900.414	60215.29653	5.29	1587.4508
TRANSFORMERS - PM 3P - 300 KVA	32	7,435.01459	300.00	7,900.414	42058.79385	5.66	1697.0563
TRANSFORMERS - PM 3P - 300 KVA	19	11,974.31074	300.00	7,900.414	52194.81045	4.36	1307.6697
TRANSFORMERS - PM 3P - 300 KVA	42	21,190.55741	300.00	7,900.414	137330.5078	6.48	1944.2222
TRANSFORMERS - PM 3P - 300 KVA	15	12,551.16459	300.00	7,900.414	48610.45142	3.87	1161.895
TRANSFORMERS - PM 3P - 300 KVA	13	12,106.24175	300.00	7,900.414	43649.67537	3.61	1081.6654
TRANSFORMERS - PM 3P - 300 KVA	78	12,852.97113	300.00	7,900.414	113514.3675	8.83	2649.5283
TRANSFORMERS - PM 3P - 3000 KVA	3	73,992.38135	3,000.00	65,318.213	128158.5639	1.73	5196.1524
TRANSFORMERS - PM 3P - 3000 KVA	2	59,249.06654	3,000.00	65,318.213	83790.83346	1.41	4242.6407
TRANSFORMERS - PM 3P - 3000 KVA	2	75,399.41744	3,000.00	65,318.213	106630.8787	1.41	4242.6407
TRANSFORMERS - PM 3P - 500 KVA	13	6,416.73503	500.00	12,153.584	23135.86717	3.61	1802.7756
TRANSFORMERS - PM 3P - 500 KVA	13	21,652.28037	500.00	12,153.584	78068.40711	3.61	1802.7756
TRANSFORMERS - PM 3P - 500 KVA	20	8,888.59124	500.00	12,153.584	39750.98849	4.47	2236.068
TRANSFORMERS - PM 3P - 500 KVA	7	19,032.28906	500.00	12,153.584	50354.70374	2.65	1322.8757
TRANSFORMERS - PM 3P - 500 KVA	8	18,966.14468	500.00	12,153.584	53644.35807	2.83	1414.2136
TRANSFORMERS - PM 3P - 500 KVA	33	17,707.38293	500.00	12,153.584	101721.1706	5.74	2872.2813
TRANSFORMERS - PM 3P - 500 KVA	16	13,993.19561	500.00	12,153.584	55972.78246	4.00	2000
TRANSFORMERS - PM 3P - 500 KVA	33	11,495.29621	500.00	12,153.584	66035.4492	5.74	2872.2813
TRANSFORMERS - PM 3P - 75 KVA	5	8,350.71798	75.00	3,115.598	18672.77307	2.24	167.7051
TRANSFORMERS - PM 3P - 75 KVA	3	8,036.51371	75.00	3,115.598	13919.65006	1.73	129.90381
TRANSFORMERS - PM 3P - 75 KVA	7	2,848.39009	75.00	3,115.598	7536.131825	2.65	198.43135
TRANSFORMERS - PM 3P - 750 KVA	33	16,996.55983	750.00	17,470.047	97637.80271	5.74	4308.422
TRANSFORMERS - PM 3P - 750 KVA	16	15,270.65362	750.00	17,470.047	61082.61449	4.00	3000
TRANSFORMERS - PM 3P - 750 KVA	27	15,416.70873	750.00	17,470.047	80107.56841	5.20	3897.1143

Zero Intercept Analysis
Account 368 - Line Transformers

October 31, 2009

	n	y	x	est y	y*n^.5	n^.5	xn^.5
TRANSFORMERS - PM 3P - 750 KVA	11	29,553.23896	750.00	17,470.047	98017.00497	3.32	2487.4686
TRANSFORMERS - PM 3P - 750 KVA	8	24,153.12877	750.00	17,470.047	68315.36456	2.83	2121.3203
TRANSFORMERS - PM 3P - 750 KVA	7	24,238.50883	750.00	17,470.047	64129.06651	2.65	1984.3135
TRANSFORMERS - PM 3P - 750 KVA	19	17,338.75595	750.00	17,470.047	75577.88497	4.36	3269.1742
TRANSFORMERS - PM 3P - 750 KVA	48	23,426.23122	750.00	17,470.047	162301.6908	6.93	5196.1524

Seelye Exhibit 28

Gas Cost of Service Study
Functional Assignment

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Gas Plant at Original Cost										
Underground Storage Plant										
350-357	Underground Storage Plant	PT350	F003	$ 62,838,253	-	-	62,838,253	-	-	-
358	Asset Retire Obligation Gas Plant	PT350	F003	$ 520,992	-	-	520,992	-	-	-
Total Storage Plant		PTST		$ 63,359,246	$ -	$ -	$ 63,359,246	$ -	$ -	$ -
Transmission Plant										
365-371	Transmission	PT365	F005	$ 13,658,204	-	-	-	-	13,658,204	-
Distribution Plant										
374	Land and Land Rights	PT374	F008	$ 133,743	-	-	-	-	-	-
375	Structures & Improvements	PT375	F008	701,947	-	-	-	-	-	-
376	Mains	PT376	F009	283,965,932	-	-	-	-	-	-
378	Meas. & Reg. Sta. Equip. - General	PT378	F008	9,160,306	-	-	-	-	-	-
379	Meas. & Reg. Sta. Equip. - City Gate	PT379	F008	4,003,923	-	-	-	-	-	-
380	Services	PT380	F010	138,086,721	-	-	-	-	-	-
381	Meters	PT381	F011	34,911,864	-	-	-	-	-	-
382	Meter Installations	PT382	F011	-	-	-	-	-	-	-
383	House Regulators	PT383	F011	13,852,262	-	-	-	-	-	-
384	House Regulator Installations	PT384	F011	-	-	-	-	-	-	-
385	Industrial Meas. & Reg. Equip	PT385	F011	155,769	-	-	-	-	-	-
387	Other Equipment	PT387	F011	51,112	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-City Gate	PT388	F008	364	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	PT388	F009	30,405	-	-	-	-	-	-
Sub-Total Distribution Plant		PTDSUB		$ 485,054,349	$ -	$ -	$ -	$ -	$ -	$ -
U-T-D Subtotal		PTSUB		$ 562,071,799	-	-	63,359,246	-	13,658,204	-
117	Gas Stored Underground/Non-Current	PT117	F003	$ 2,139,990	-	-	2,139,990	-	-	-
301-303	Intangible Plant	PT301	PTSUB	1,187	-	-	134	-	29	-
389-399	General Plant	PT389	PTSUB	9,196,988	-	-	1,036,726	-	223,485	-
	Common Utility Plant	PTCP	PTSUB	58,087,778	-	-	6,547,914	-	1,411,518	-
Total Plant in Service		PTIS		$ 631,497,742	-	-	73,084,009	-	15,293,236	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Gas Plant at Original Cost									
Underground Storage Plant									
350-357	Underground Storage Plant	PT350	F003	-	-	-	-	-	-
358	Asset Retire Obligation Gas Plant	PT350	F003	-	-	-	-	-	-
Total Storage Plant		PTST		$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant									
365-371	Transmission	PT365	F005	-	-	-	-	-	-
Distribution Plant									
374	Land and Land Rights	PT374	F008	-	133,743	-	-	-	-
375	Structures & Improvements	PT375	F008	-	701,947	-	-	-	-
376	Mains	PT376	F009	-	-	211,603,955	36,809,325	33,075,872	2,476,779
378	Meas. & Reg. Sta. Equip. - General	PT378	F008	-	9,160,306	-	-	-	-
379	Meas. & Reg. Sta. Equip. - City Gate	PT379	F008	-	4,003,923	-	-	-	-
380	Services	PT380	F010	-	-	-	-	-	-
381	Meters	PT381	F011	-	-	-	-	-	-
382	Meter Installations	PT382	F011	-	-	-	-	-	-
383	House Regulators	PT383	F011	-	-	-	-	-	-
384	House Regulator Installations	PT384	F011	-	-	-	-	-	-
385	Industrial Meas. & Reg. Equip.	PT385	F011	-	-	-	-	-	-
387	Other Equipment	PT387	F011	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-City Gate	PT388	F008	-	364	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	PT388	F009	-	-	22,657	3,941	3,542	265
Sub-Total Distribution Plant		PTDSUB		$ -	$ 14,000,284	$ 211,626,612	$ 36,813,267	$ 33,079,413	$ 2,477,044
U-T-D Subtotal		PTSUB		-	14,000,284	211,626,612	36,813,267	33,079,413	2,477,044
117	Gas Stored Underground/Non-Current	PT117	F003	-	-	-	-	-	-
301-303	Intangible Plant	PT301	PTSUB	-	30	447	78	70	5
389-399	General Plant	PT389	PTSUB	-	229,082	3,462,774	602,363	541,267	40,531
	Common Utility Plant	PTCP	PTSUB	-	1,446,871	21,870,728	3,804,498	3,418,619	255,992
Total Plant in Service		PTIS		-	15,676,266	236,960,561	41,220,205	37,039,370	2,773,573

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Gas Plant at Original Cost							
Underground Storage Plant							
350-357	Underground Storage Plant	PT350	F003	-	-	-	-
358	Asset Retire Obligation Gas Plant	PT350	F003	-	-	-	-
Total Storage Plant		PTST	$	- $	- $	- $	-
Transmission Plant							
365-371	Transmission	PT365	F005	-	-	-	-
Distribution Plant							
374	Land and Land Rights	PT374	F008	-	-	-	-
375	Structures & Improvements	PT375	F008	-	-	-	-
376	Mains	PT376	F009	-	-	-	-
378	Meas. & Reg. Sta. Equip - General	PT378	F008	-	-	-	-
379	Meas. & Reg. Sta. Equip. - City Gate	PT379	F008	-	-	-	-
380	Services	PT380	F010	138,086,721	-	-	-
381	Meters	PT381	F011	-	34,911,864	-	-
382	Meter Installations	PT382	F011	-	-	-	-
383	House Regulators	PT383	F011	-	13,852,262	-	-
384	House Regulator Installations	PT384	F011	-	-	-	-
385	Industrial Meas. & Reg. Equip.	PT385	F011	-	155,769	-	-
387	Other Equipment	PT387	F011	-	51,112	-	-
388	Asset Retire Obligation Gas Plant-City Gate	PT388	F008	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	PT388	F009	-	-	-	-
Sub-Total Distribution Plant		PTDSUB	$	138,086,721 $	48,971,008 $	- $	-
U-T-D Subtotal		PTSUB		138,086,721	48,971,008	-	-
117	Gas Stored Underground/Non-Current	PT117	F003	-	-	-	-
301-303	Intangible Plant	PT301	PTSUB	292	103	-	-
389-399	General Plant	PT389	PTSUB	2,259,466	801,296	-	-
	Common Utility Plant	PTCP	PTSUB	14,270,687	5,060,950	-	
Total Plant in Service		PTIS		154,617,165	54,833,357	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Gas Plant at Original Cost (Continued)										
Construction Work In Progress										
Underground Storage	CWIPUS	F003	$	4,142,848	-	-	4,142,848	-	-	-
Transmission	CWIPTR	F005		1,250,818	-	-	-	-	1,250,818	-
Distribution Mains	CWIPDM	F009		28,170,630	-	-	-	-	-	-
Other Distribution	CWIPOD	PTDSUB		18,893,204	-	-	-	-	-	-
General	CWIPCO	PTSUB		648,045	-	-	73,051	-	15,747	-
Common		PTSUB		42,241,284	-	-	4,761,626	-	1,026,453	-
Total CWIP	CWIP		$	95,346,829	$ -	$ -	$ 8,977,525	$ -	$ 2,293,018	$ -
Total Gas Plant at Original Cost	PTT		$	726,844,571	-	-	82,061,534	-	17,586,254	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Gas Plant at Original Cost (Continued)								
Construction Work In Progress								
Underground Storage	CWIPUS	F003	-	-	-	-	-	-
Transmission	CWIPTR	F005	-	-	-	-	-	-
Distribution Mains	CWIPDM	F009	-	-	20,992,014	3,651,642	3,281,267	245,707
Other Distribution	CWIPOD	PTDSUB	-	545,321	8,243,004	1,433,902	1,288,466	96,483
General	CWIPCO	PTSUB	-	16,142	243,997	42,444	38,139	2,856
Common		PTSUB	-	1,052,161	15,904,338	2,766,621	2,486,011	186,157
Total CWIP	CWIP	$	-	$ 1,613,623	$ 45,383,352	$ 7,894,609	$ 7,093,884	$ 531,202
Total Gas Plant at Original Cost	PTT		-	17,289,890	282,343,913	49,114,814	44,133,254	3,304,775

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Gas Plant at Original Cost (Continued)						
Construction Work In Progress						
Underground Storage	CWIPUS	F003	-	-	-	-
Transmission	CWIPTR	F005	-	-	-	-
Distribution Mains	CWIPDM	F009	-	-	-	-
Other Distribution	CWIPOD	PTDSUB	5,378,574	1,907,455	-	-
General	CWIPCO	PTSUB	159,208	56,461	-	-
Common		PTSUB	10,377,607	3,680,310	-	-
Total CWIP	CWIP		$ 15,915,389	$ 5,644,226	$ -	$ -
Total Gas Plant at Original Cost	PTT		170,532,554	60,477,583	-	-
				$ 627,196,783		

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Net Cost Rate Base									
Total Gas Utility Plant at Original Cost			$ 726,844,571	$ -	$ -	$ 82,061,534	$ -	$ 17,586,254	$ -
Less:									
Reserve for Depreciation									
Underground Storage	DEPRUS	PTST	$ 32,445,945	-	-	32,445,945	-	-	-
Transmission	DEPTR	F005	12,204,475	-	-	-	-	12,204,475	-
Distribution	DEPRDI	DEPRDIS	174,352,614	-	-	-	-	-	-
General & Intangible	DEPRGE	PT389	6,203,552	-	-	699,292	-	150,745	-
Common	DEPRCO	PTCP	26,723,610	-	-	3,012,405	-	649,377	-
Total Depreciation Reserve	DEPR		$ 251,930,195	$ -	$ -	$ 36,157,641	$ -	$ 13,004,596	$ -
Customer Advances For Construction	CAD	CADAL	$ 7,485,292	-	-	-	-	-	-
Accum. Deferred Income Taxes	DIT	PTSUB	48,874,215	-	-	5,509,320	-	1,187,631	-
FAS 109 Deferred Income taxes		PTSUB	4,053,496	-	-	456,928	-	98,499	-
Asset Retirement Obligation-Net Assets		DEPR	131,229	-	-	18,834	-	6,774	-
Asset Retirement Obligation-Liabilities		DEPR	-	-	-	-	-	-	-
Asset Retirement Obligation-Regulatory Assets		DEPR	-	-	-	-	-	-	-
Asset Retirement Obligation-Regulatory Liabilities		DEPR	(2,353,476)	-	-	(337,777)	-	(121,486)	-
Accum Depre reclassification	ITC	PTSUB	-	-	-	-	-	-	-
PLUS:									
Materials and Supplies	MSP	PTSUB	$ 60,055	-	-	6,770	-	1,459	-
Prepayments	PPY	PTSUB	659,791	-	-	74,375	-	16,033	-
Gas Stored Underground	GSU	F003	66,447,790	-	-	66,447,790	-	-	-
Cash Working Capital	CWC	OMT	7,908,386	16,916	127,172	379,617	1,071,140	210,881	-
Adjustments:									
Unamortized Debt		PTSUB	$ -	-	-	-	-	-	-
Regulatory		PTSUB	-	-	-	-	-	-	-
Customer Advances for Construction		PTSUB	-	-	-	-	-	-	-
Depreciation Adjustment		PTSUB	-						-
Net Cost Rate Base	NCRB		$ 491,799,642	$ 16,916	$ 127,172	$ 107,165,138	$ 1,071,140	$ 3,638,613	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Net Cost Rate Base								
Total Gas Utility Plant at Original Cost		$	- $	17,289,890 $	282,343,913 $	49,114,814 $	44,133,254 $	3,304,775
Less:								
Reserve for Depreciation								
Underground Storage	DEPRUS	PTST	-	-	-	-	-	-
Transmission	DEPTR	F005	-	-	-	-	-	-
Distribution	DEPRDI	DEPRDIS	-	4,212,451	78,410,628	13,639,832	12,256,387	917,780
General & Intangible	DEPRGE	PT389	-	154,520	2,335,710	406,306	365,095	27,339
Common	DEPRCO	PTCP	-	665,641	10,061,752	1,750,281	1,572,755	117,771
Total Depreciation Reserve	DEPR	$	- $	5,032,613 $	90,808,089 $	15,796,418 $	14,194,237 $	1,062,889
Customer Advances For Construction	CAD	CADAL	-	-	3,752,891	652,830	586,615	43,927
Accum. Deferred Income Taxes	DIT	PTSUB	-	1,217,376	18,401,714	3,201,049	2,876,377	215,388
FAS 109 Deferred Income taxes		PTSUB	-	100,966	1,526,189	265,486	238,559	17,864
Asset Retirement Obligation-Net Assets		DEPR	-	2,621	47,301	8,228	7,394	554
Asset Retirement Obligation-Liabilities		DEPR	-	-	-	-	-	-
Asset Retirement Obligation-Regulatory Assets		DEPR	-	-	-	-	-	-
Asset Retirement Obligation-Regulatory Liabilities		DEPR	-	(47,014)	(848,309)	(147,567)	(132,599)	(9,929)
Accum Depre reclassification	ITC	PTSUB	-	-	-	-	-	-
PLUS:								
Materials and Supplies	MSP	PTSUB	-	1,496	22,611	3,933	3,534	265
Prepayments	PPY	PTSUB	-	16,434	248,419	43,213	38,830	2,908
Gas Stored Underground	GSU	F003	-	-	-	-	-	-
Cash Working Capital	CWC	OMT	90,002	346,503	1,865,680	324,542	291,625	21,837
Adjustments:								
Unamortized Debt		PTSUB	-	-	-	-	-	-
Regulatory		PTSUB	-	-	-	-	-	-
Customer Advances for Construction		PTSUB	-	-	-	-	-	-
Depreciation Adjustment		PTSUB	-	-	-	-	-	-
Net Cost Rate Base	NCRB	$	90,002 $	11,347,760 $	170,792,749 $	29,710,058 $	26,696,661 $	1,999,093

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Net Cost Rate Base						
Total Gas Utility Plant at Original Cost			$ 170,532,554	$ 60,477,583	$ -	$ -
Less:						
Reserve for Depreciation						
Underground Storage	DEPRUS	PTST	-	-	-	-
Transmission	DEPTR	F005	-	-	-	-
Distribution	DEPRDI	DEPRDIS	58,378,546	6,536,991	-	-
General & Intangible	DEPRGE	PT389	1,524,055	540,490	-	-
Common	DEPRCO	PTCP	6,565,310	2,328,318	-	-
Total Depreciation Reserve	DEPR		$ 66,467,911	$ 9,405,800	$ -	$ -
Customer Advances For Construction	CAD	CADAL	2,449,030	-	-	-
Accum. Deferred Income Taxes	DIT	PTSUB	12,007,149	4,258,210	-	-
FAS 109 Deferred Income taxes		PTSUB	995,841	353,164	-	-
Asset Retirement Obligation-Net Assets		DEPR	34,623	4,899	-	-
Asset Retirement Obligation-Liabilities		DEPR	-	-	-	-
Asset Retirement Obligation-Regulatory Assets		DEPR	-	-	-	-
Asset Retirement Obligation-Regulatory Liabilities		DEPR	(620,928)	(87,867)	-	-
Accum Depre reclassification	ITC	PTSUB	-	-	-	-
PLUS:						
Materials and Supplies	MSP	PTSUB	14,754	5,232	-	-
Prepayments	PPY	PTSUB	162,094	57,485	-	-
Gas Stored Underground	GSU	F003	-	-	-	-
Cash Working Capital	CWC	OMT	711,612	313,344	1,473,728	663,787
Adjustments:						
Unamortized Debt		PTSUB	-	-	-	-
Regulatory		PTSUB	-	-	-	-
Customer Advances for Construction		PTSUB	-	-	-	-
Depreciation Adjustment		PTSUB	-	-	-	-
Net Cost Rate Base	NCRB		$ 90,087,389	$ 46,919,438	$ 1,473,728	$ 663,787

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Labor Expenses										
807-813	Procurement Expenses	LB807	DMCM	$ 477,017	56,002	421,015	-	-	-	-
Storage Expenses										
Operation										
814	Operations Supervision and Engineer	LB814	OSE	332,069	-	-	82,102	249,967	-	-
815	Maps and Records	LB815	F003	-	-	-	-	-	-	-
816	Well Expenses	LB816	F003	17,775	-	-	17,775	-	-	-
817	Lines Expenses	LB817	F003	254,059	-	-	254,059	-	-	-
818	Compressor Station Exp - Payroll	LB818	F004	337,393	-	-	-	337,393	-	-
819	Compressor Station Fuel and Power	LB819	F004	-	-	-	-	-	-	-
820	Measurement and Regulator Station	LB820	F003	-	-	-	-	-	-	-
821	Purification of Natural Gas	LB821	F004	490,234	-	-	-	490,234	-	-
823	Gas losses	LB823	F004	-	-	-	-	-	-	-
824	Other Expenses	LB824	F004	-	-	-	-	-	-	-
825	Storage Well Royalities	LB825	F003	-	-	-	-	-	-	-
826	Rents	LB826	F003	-	-	-	-	-	-	-
Total Storage Operation Labor		LBSO		$ 1,431,530	$ -	$ -	$ 353,936	$ 1,077,594	$ -	$ -
Storage Expense										
Maintenance										
830	Maintenance Super and Eng.	LB830	MSE	$ 232,292	-	-	83,326	148,966	-	-
831	Maintenance of Structures	LB831	F003	-	-	-	-	-	-	-
832	Maintenance of Resevoirs	LB832	F003	177,940	-	-	177,940	-	-	-
833	Maintenance of Lines	LB833	F003	61,424	-	-	61,424	-	-	-
834	Main of Compressor Station Equipment	LB834	F004	435,341	-	-	-	435,341	-	-
835	Main of Meas and Reg Sta. Equip	LB835	F003	36,483	-	-	36,483	-	-	-
836	Main of Purification Equip	LB836	F004	113,675	-	-	-	113,675	-	-
837	Main of Other Equipment	LB837	F003	31,252	-	-	31,252	-	-	-
Total Maintenance Labor		LBSM		$ 1,088,407	$ -	$ -	$ 390,425	$ 697,981	$ -	$ -
Total Storage Labor		LBS		$ 2,519,937	-	-	744,361	1,775,575	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Labor Expenses									
807-813	Procurement Expenses	LB807	DMCM	-	-	-	-	-	-
Storage Expenses									
Operation									
814	Operations Supervision and Engineer	LB814	OSE	-	-	-	-	-	-
815	Maps and Records	LB815	F003	-	-	-	-	-	-
816	Well Expenses	LB816	F003	-	-	-	-	-	-
817	Lines Expenses	LB817	F003	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	LB818	F004	-	-	-	-	-	-
819	Compressor Station Fuel and Power	LB819	F004	-	-	-	-	-	-
820	Measurement and Regulator Station	LB820	F003	-	-	-	-	-	-
821	Purification of Natural Gas	LB821	F004	-	-	-	-	-	-
823	Gas losses	LB823	F004	-	-	-	-	-	-
824	Other Expenses	LB824	F004	-	-	-	-	-	-
825	Storage Well Royalities	LB825	F003	-	-	-	-	-	-
826	Rents	LB826	F003	-	-	-	-	-	-
Total Storage Operation Labor		LBSO		$ -	$ -	$ -	$ -	$ -	$ -
Storage Expense									
Maintenance									
830	Maintenance Super and Eng.	LB830	MSE	-	-	-	-	-	-
831	Maintenance of Structures	LB831	F003	-	-	-	-	-	-
832	Maintenance of Resevoirs	LB832	F003	-	-	-	-	-	-
833	Maintenance of Lines	LB833	F003	-	-	-	-	-	-
834	Main of Compressor Station Equipment	LB834	F004	-	-	-	-	-	-
835	Main of Meas and Reg Sta. Equip	LB835	F003	-	-	-	-	-	-
836	Main of Purification Equip	LB836	F004	-	-	-	-	-	-
837	Main of Other Equipment	LB837	F003	-	-	-	-	-	-
Total Maintenance Labor		LBSM		$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Labor		LBS		-	-	-	-	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Labor Expenses							
807-813	Procurement Expenses	LB807	DMCM	-	-	-	-
Storage Expenses							
Operation							
814	Operations Supervision and Engineer	LB814	OSE	-	-	-	-
815	Maps and Records	LB815	F003	-	-	-	-
816	Well Expenses	LB816	F003	-	-	-	-
817	Lines Expenses	LB817	F003	-	-	-	-
818	Compressor Station Exp - Payroll	LB818	F004	-	-	-	-
819	Compressor Station Fuel and Power	LB819	F004	-	-	-	-
820	Measurement and Regulator Station	LB820	F003	-	-	-	-
821	Purification of Natural Gas	LB821	F004	-	-	-	-
823	Gas losses	LB823	F004	-	-	-	-
824	Other Expenses	LB824	F004	-	-	-	-
825	Storage Well Royalities	LB825	F003	-	-	-	-
826	Rents	LB826	F003	-	-	-	-
Total Storage Operation Labor		LBSO		$ -	$ -	$ -	$ -
Storage Expense							
Maintenance							
830	Maintenance Super and Eng.	LB830	MSE	-	-	-	-
831	Maintenance of Structures	LB831	F003	-	-	-	-
832	Maintenance of Resevoirs	LB832	F003	-	-	-	-
833	Maintenance of Lines	LB833	F003	-	-	-	-
834	Main of Compressor Station Equipment	LB834	F004	-	-	-	-
835	Main of Meas and Reg Sta. Equip	LB835	F003	-	-	-	-
836	Main of Purification Equip	LB836	F004	-	-	-	-
837	Main of Other Equipment	LB837	F003	-	-	-	-
Total Maintenance Labor		LBSM		$ -	$ -	$ -	$ -
Total Storage Labor		LBS		-	-	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Labor Expenses (Continued)											
Transmission											
850-867	Transmission Expenses	LB850	F005	$	448,209	-	-	-	-	448,209	-
Distribution Expenses											
Operation											
870	Operation Supr and Engr	LB870	DOES	$	-	-	-	-	-	-	-
871	Dist Load Dispatching	LB871	F007		294,287	-	-	-	-	-	-
872	Compr. Station Labor and Exp.	LB872	F007		-	-	-	-	-	-	-
873	Compr. Station Fuel and Power	LB873	F007		-	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	LB874.01	CADAL		553,484	-	-	-	-	-	-
874.02	Leak Survey-Mains	LB874.02	F009		-	-	-	-	-	-	-
874.03	Leak Survey - Service	LB874.03	F010		-	-	-	-	-	-	-
874.04	Locate Main per Request	LB874.04	CADAL		-	-	-	-	-	-	-
874.05	Check Stop Box Access	LB874.05	F010		-	-	-	-	-	-	-
874.06	Patrolling Mains	LB874.06	F009			-	-	-	-	-	-
874.07	Check/Grease Valves	LB874.07	F009		-	-	-	-	-	-	-
874.08	Opr. Odor Equipment	LB874.08	F007		-	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	LB874.09	F009		-	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	LB874.10	F009		-	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	LB875	F008		366,738	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	LB876	F011		177,634	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	LB877	F008		21,164	-	-	-	-	-	-
878	Meter and House Reg. Expense	LB878	F011		7,634	-	-	-	-	-	-
879	Customer Installation Expense	LB879	F011		224,982	-	-	-	-	-	-
880	Other Expenses	LB880	PTDSUB		1,277,222	-	-	-	-	-	-
881	Rents	LB881	PTDSUB		-	-	-	-	-	-	-
Total Operations Distribution Labor		LBDO		$	2,923,145	$ -	$ -	$ -	$ -	$ -	$ -
Total Operations Transmission and Distribution Labor		LBTDO		$	3,371,354	$ -	$ -	$ -	$ -	$ 448,209	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Labor Expenses (Continued)									
Transmission									
850-867	Transmission Expenses	LB850	F005	-	-	-	-	-	-
Distribution Expenses									
Operation									
870	Operation Supr and Engr	LB870	DOES	-	-	-	-	-	-
871	Dist Load Dispatching	LB871	F007	294,287	-	-	-	-	-
872	Compr. Station Labor and Exp.	LB872	F007	-	-	-	-	-	-
873	Compr. Station Fuel and Power	LB873	F007	-	-	-	-	-	-
874.01	Other Mains/Serv Expenses	LB874.01	CADAL	-	-	277,499	48,272	43,376	3,248
874.02	Leak Survey-Mains	LB874.02	F009	-	-	-	-	-	-
874.03	Leak Survey - Service	LB874.03	F010	-	-	-	-	-	-
874.04	Locate Main per Request	LB874.04	CADAL	-	-	-	-	-	-
874.05	Check Stop Box Access	LB874.05	F010	-	-	-	-	-	-
874.06	Patrolling Mains	LB874.06	F009	-	-	-	-	-	-
874.07	Check/Grease Valves	LB874.07	F009	-	-	-	-	-	-
874.08	Opr. Odor Equipment	LB874.08	F007	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	LB874.09	F009	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	LB874.10	F009	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	LB875	F008	-	366,738	-	-	-	-
876	Meas and Reg Station Exp - Industrial	LB876	F011	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	LB877	F008	-	21,164	-	-	-	-
878	Meter and House Reg. Expense	LB878	F011	-	-	-	-	-	-
879	Customer Installation Expense	LB879	F011	-	-	-	-	-	-
880	Other Expenses	LB880	PTDSUB	-	36,865	557,245	96,935	87,103	6,522
881	Rents	LB881	PTDSUB	-	-	-	-	-	-
Total Operations Distribution Labor		LBDO		$ 294,287	$ 424,768	$ 834,744	$ 145,207	$ 130,479	$ 9,771
Total Operations Transmission and Distribution Labor		LBTDO		$ 294,287	$ 424,768	$ 834,744	$ 145,207	$ 130,479	$ 9,771

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Labor Expenses (Continued)							
Transmission							
850-867	Transmission Expenses	LB850	F005	-	-	-	-
Distribution Expenses							
Operation							
870	Operation Supr and Engr	LB870	DOES	-	-	-	-
871	Dist Load Dispatching	LB871	F007	-	-	-	-
872	Compr. Station Labor and Exp.	LB872	F007	-	-	-	-
873	Compr. Station Fuel and Power	LB873	F007	-	-	-	-
874.01	Other Mains/Serv. Expenses	LB874.01	CADAL	181,088	-	-	-
874.02	Leak Survey-Mains	LB874.02	F009	-	-	-	-
874.03	Leak Survey - Service	LB874.03	F010	-	-	-	-
874.04	Locate Main per Request	LB874.04	CADAL	-	-	-	-
874.05	Check Stop Box Access	LB874.05	F010	-	-	-	-
874.06	Patrolling Mains	LB874.06	F009	-	-	-	-
874.07	Check/Grease Valves	LB874.07	F009	-	-	-	-
874.08	Opr. Odor Equipment	LB874.08	F007	-	-	-	-
874.09	Locate and Inspect Valve Boxes	LB874.09	F009	-	-	-	-
874.1	Cut Grass - Right of Way	LB874.10	F009	-	-	-	-
875	Meas and Reg Station Exp.- General	LB875	F008	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	LB876	F011	-	177,634	-	-
877	Meas and Reg Station Exp - City Gate	LB877	F008	-	-	-	-
878	Meter and House Reg. Expense	LB878	F011	-	7,634	-	-
879	Customer Installation Expense	LB879	F011	-	224,982	-	-
880	Other Expenses	LB880	PTDSUB	363,603	128,948	-	-
881	Rents	LB881	PTDSUB	-	-	-	-
Total Operations Distribution Labor		LBDO		$ 544,691	$ 539,198	$ -	$ -
Total Operations Transmission and Distribution Labor		LBTDO		$ 544,691	$ 539,198	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Labor Expenses (Continued)										
Maintenance Expense -- Distribution										
885	Maintenance Supr and Engr	LB885	DMES	$ -	-	-	-	-	-	-
886	Maintenance Structures	LB886	F008	25,478	-	-	-	-	-	-
887	Maintenance Mains	LB887	F009	2,977,274	-	-	-	-	-	-
888	Maintenance Comp. Station Equip.	LB888	F007	-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	LB889	F008	36,857	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	LB890	F011	150,451	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	LB891	F008	143,956	-	-	-	-	-	-
892	Maintenance Services	LB892	F010	574,417	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	LB893	F011	-	-	-	-	-	-	-
894	Maintenance Other Equipment	LB894	PTDSUB	154,778	-	-	-	-	-	-
Total Maintenance Labor		LBDM		$ 4,063,211	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission & Distribution Labor		LBTD		$ 7,434,565	$ -	$ -	$ -	$ -	$ 448,209	$ -
Customer Accounts Expense										
901	Supervision	LB901	F012	$ 471,318	-	-	-	-	-	-
902	Meter Reading	LB902	F012	177,627	-	-	-	-	-	-
903	Customer Records and Collections	LB903	F012	$ 1,779,757	-	-	-	-	-	-
904	Uncollectible Accounts	LB904	F012	-	-	-	-	-	-	-
905	Misc. Cust Account Expenses	LB905	F012	126,229	-	-	-	-	-	-
Total Customer Accounts Labor		LBCA		$ 2,554,931	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expenses										
907-910	Customer Service	LB907	F013	$ 395,379	-	-	-	-	-	-
Sales Expenses										
911-916	Sales Expenses	LB911	F013	$ -	-	-	-	-	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Labor Expenses (Continued)									
Maintenance Expense -- Distribution									
885	Maintenance Supr and Engr	LB885	DMES	-	-	-	-	-	-
886	Maintenance Structures	LB886	F008	-	25,478	-	-	-	-
887	Maintenance Mains	LB887	F009	-	-	2,218,586	385,932	346,788	25,968
888	Maintenance Comp Station Equip	LB888	F007	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	LB889	F008	-	36,857	-	-	-	-
890	Maintenance Meas and Reg - Industrial	LB890	F011	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	LB891	F008	-	143,956	-	-	-	-
892	Maintenance Services	LB892	F010	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	LB893	F011	-	-	-	-	-	-
894	Maintenance Other Equipment	LB894	PTDSUB	-	4,467	67,529	11,747	10,555	790
Total Maintenance Labor		LBDM		$ -	$ 210,759	$ 2,286,115	$ 397,679	$ 357,343	$ 26,758
Total Transmission & Distribution Labor		LBTD		$ 294,287	$ 635,526	$ 3,120,859	$ 542,886	$ 487,822	$ 36,529
Customer Accounts Expense									
901	Supervision	LB901	F012	-	-	-	-	-	-
902	Meter Reading	LB902	F012	-	-	-	-	-	-
903	Customer Records and Collections	LB903	F012	-	-	-	-	-	-
904	Uncollectible Accounts	LB904	F012	-	-	-	-	-	-
905	Misc. Cust Account Expenses	LB905	F012	-	-	-	-	-	-
Total Customer Accounts Labor		LBCA		$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expenses									
907-910	Customer Service	LB907	F013	-	-	-	-	-	-
Sales Expenses									
911-916	Sales Expenses	LB911	F013	-	-	-	-	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Labor Expenses (Continued)							
Maintenance Expense -- Distribution							
885	Maintenance Supr and Engr	LB885	DMES	-	-	-	-
886	Maintenance Structures	LB886	F008	-	-	-	-
887	Maintenance Mains	LB887	F009	-	-	-	-
888	Maintenance Comp. Station Equip	LB888	F007	-	-	-	-
889	Maintenance Meas and Reg. General	LB889	F008	-	-	-	-
890	Maintenance Meas and Reg - Industrial	LB890	F011	-	150,451	-	-
891	Maintenance Meas and Reg.-City Gate	LB891	F008	-	-	-	-
892	Maintenance Services	LB892	F010	574,417	-	-	-
893	Maintenance Meters and House Reg.	LB893	F011	-	-	-	-
894	Maintenance Other Equipment	LB894	PTDSUB	44,063	15,626	-	-
Total Maintenance Labor		LBDM		$ 618,480	$ 166,077	$ -	$ -
Total Transmission & Distribution Labor		LBTD		$ 1,163,171	$ 705,275	$ -	$ -
Customer Accounts Expense							
901	Supervision	LB901	F012	-	-	471,318	-
902	Meter Reading	LB902	F012	-	-	177,627	-
903	Customer Records and Collections	LB903	F012	-	-	1,779,757	-
904	Uncollectible Accounts	LB904	F012	-	-	-	-
905	Misc. Cust Account Expenses	LB905	F012	-	-	126,229	-
Total Customer Accounts Labor		LBCA		$ -	$ -	$ 2,554,931	$ -
Customer Service Expenses							
907-910	Customer Service	LB907	F013	-	-	-	395,379
Sales Expenses							
911-916	Sales Expenses	LB911	F013	-	-	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Labor Expenses (Continued)										
Administrative & General										
920	Admin and General Salaries	LB920	LBSUB	$ 2,577,542	10,787	81,094	143,375	342,003	86,332	-
921	Office Supplies and Expense	LB921	LBSUB	-	-	-	-	-	-	-
922	Admin. Expenses Transferred	LB922	LBSUB	(272,690)	(1,141)	(8,579)	(15,168)	(36,182)	(9,133)	-
923	Outside Services Employed	LB923	LBSUB	-	-	-	-	-	-	-
924	Property Insurance	LB924	PTT	-	-	-	-	-	-	-
925	Injuries and Damages	LB925	LBSUB	6,261	26	197	348	831	210	-
926	Employee Pensions and Benefits	LB926	LBSUB	-	-	-	-	-	-	-
927	Franchise Requirement	LB927	PTT	-	-	-	-	-	-	-
928	Regulatory Commission Fee	LB928	PTT	-	-	-	-	-	-	-
929	Duplicate Charges -Credit	LB929	LBSUB	-	-	-	-	-	-	-
930.1	General Advertising Expense	LB930.1	PTT	-	-	-	-	-	-	-
930.2	Misc. General Expense	LB930.2	LBSUB	-	-	-	-	-	-	-
931	Rents	LB931	PTT	-	-	-	-	-	-	-
935	Maintenance of General Plant	LB935	PT389	968,557	-	-	109,180	-	23,536	-
Total Administrative and General Labor		LBAG		$ 3,279,670	$ 9,672	$ 72,712	$ 237,735	$ 306,651	$ 100,944	$ -
Total Labor Expense		LBTOT		$ 16,661,498	$ 65,674	$ 493,727	$ 982,096	$ 2,082,227	$ 549,153	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Labor Expenses (Continued)									
Administrative & General									
920	Admin and General Salaries	LB920	LBSUB	56,684	122,412	601,124	104,568	93,962	7,036
921	Office Supplies and Expense	LB921	LBSUB	-	-	-	-	-	-
922	Admin. Expenses Transferred	LB922	LBSUB	(5,997)	(12,951)	(63,596)	(11,063)	(9,941)	(744)
923	Outside Services Employed	LB923	LBSUB	-	-	-	-	-	-
924	Property Insurance	LB924	PTT	-	-	-	-	-	-
925	Injuries and Damages	LB925	LBSUB	138	297	1,460	254	228	17
926	Employee Pensions and Benefits	LB926	LBSUB	-	-	-	-	-	-
927	Franchise Requirement	LB927	PTT	-	-	-	-	-	-
928	Regulatory Commission Fee	LB928	PTT	-	-	-	-	-	-
929	Duplicate Charges -Credit	LB929	LBSUB	-	-	-	-	-	-
930.1	General Advertising Expense	LB930.1	PTT	-	-	-	-	-	-
930.2	Misc. General Expense	LB930.2	LBSUB	-	-	-	-	-	-
931	Rents	LB931	PTT	-	-	-	-	-	-
935	Maintenance of General Plant	LB935	PT389	-	24,125	364,673	63,436	57,002	4,268
Total Administrative and General Labor		LBAG		$ 50,825	$ 133,884	$ 903,662	$ 157,195	$ 141,252	$ 10,577
Total Labor Expense		LBTOT		$ 345,112	$ 769,410	$ 4,024,521	$ 700,081	$ 629,074	$ 47,106

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service, Expense Customer
Labor Expenses (Continued)							
Administrative & General							
920	Admin and General Salaries	LB920	LBSUB	224,044	135,847	492,118	76,156
921	Office Supplies and Expense	LB921	LBSUB	-	-	-	-
922	Admin. Expenses Transferred	LB922	LBSUB	(23,703)	(14,372)	(52,064)	(8,057)
923	Outside Services Employed	LB923	LBSUB	-	-	-	-
924	Property Insurance	LB924	PTT	-	-	-	-
925	Injuries and Damages	LB925	LBSUB	544	330	1,195	185
926	Employee Pensions and Benefits	LB926	LBSUB	-	-	-	-
927	Franchise Requirement	LB927	PTT	-	-	-	-
928	Regulatory Commission Fee	LB928	PTT	-	-	-	-
929	Duplicate Charges -Credit	LB929	LBSUB	-	-	-	-
930.1	General Advertising Expense	LB930.1	PTT	-	-	-	-
930.2	Misc. General Expense	LB930.2	LBSUB	-	-	-	-
931	Rents	LB931	PTT	-	-	-	-
935	Maintenance of General Plant	LB935	PT389	237,950	84,386	-	-
Total Administrative and General Labor		LBAG		$ 438,836	$ 206,191	$ 441,250	$ 68,284
Total Labor Expense		LBTOT		$ 1,602,007	$ 911,466	$ 2,996,181	$ 463,663

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Operation & Maintenance Expenses										
807-813	Procurement Expenses	OM807	DMCM	$ 593,600	69,689	523,911	-	-	-	-
Storage Expenses										
Operation										
814	Operations Supervision and Engineer	OM814	OSE	466,755	-	-	115,402	351,353	-	-
815	Maps and Records	OM815	F003	-	-	-	-	-	-	-
816	Well Expenses	OM816	F003	(27,306)	-	-	(27,306)	-	-	-
817	Lines Expenses	OM817	F003	530,675	-	-	530,675	-	-	-
818	Compressor Station Exp - Payroll	OM818	F004	1,549,437	-	-	-	1,549,437	-	-
819	Compressor Station Fuel and Power	OM819	F004	1,064,778	-	-	-	1,064,778	-	-
820	Measurement and Regulator Station	OM820	F003	-	-	-	-	-	-	-
821	Purification of Natural Gas *(1)*	OM821	F004	1,698,551	-	-	-	1,698,551	-	-
823	Gas losses *(2)*	OM823	F004	-	-	-	-	-	-	-
824	Other Expenses	OM824	F004	14,187	-	-	-	14,187	-	-
825	Storage Well Royalities	OM825	F003	42,906	-	-	42,906	-	-	-
826	Rents	OM826	F003	43,171	-	-	43,171	-	-	-
Total Operation Expenses		OMOE		$ 5,383,152	$ -	$ -	$ 704,847	$ 4,678,305	$ -	$ -
Storage Expense										
Maintenance										
830	Maintenance Super and Eng.	OM830	MSE	$ 324,950	-	-	116,564	208,386	-	-
831	Maintenance of Structures	OM831	F003	-	-	-	-	-	-	-
832	Maintenance of Resevoirs	OM832	F003	580,151	-	-	580,151	-	-	-
833	Maintenance of Lines	OM833	F003	172,608	-	-	172,608	-	-	-
834	Main of Compressor Station Equipment	OM834	F004	927,003	-	-	-	927,003	-	-
835	Main of Meas and Reg Sta. Equip	OM835	F003	52,410	-	-	52,410	-	-	-
836	Main of Purification Equip	OM836	F004	464,091	-	-	-	464,091	-	-
837	Main of Other Equipment	OM837	F003	52,201	-	-	52,201	-	-	-
Total Maintenance Expense		OMME		$ 2,573,413	$ -	$ -	$ 973,933	$ 1,599,480	$ -	$ -
Total Storage Expense		OMS		$ 7,956,565	-	-	1,678,780	6,277,786	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Operation & Maintenance Expenses									
807-813	Procurement Expenses	OM807	DMCM	-	-	-	-	-	-
Storage Expenses									
Operation									
814	Operations Supervision and Engineer	OM814	OSE	-	-	-	-	-	-
815	Maps and Records	OM815	F003	-	-	-	-	-	-
816	Well Expenses	OM816	F003	-	-	-	-	-	-
817	Lines Expenses	OM817	F003	-	-	-	-	-	-
818	Compressor Station Exp - Payroll	OM818	F004	-	-	-	-	-	-
819	Compressor Station Fuel and Power	OM819	F004	-	-	-	-	-	-
820	Measurement and Regulator Station	OM820	F003	-	-	-	-	-	-
821	Purification of Natural Gas *(1)*	OM821	F004	-	-	-	-	-	-
823	Gas losses *(2)*	OM823	F004	-	-	-	-	-	-
824	Other Expenses	OM824	F004	-	-	-	-	-	-
825	Storage Well Royalities	OM825	F003	-	-	-	-	-	-
826	Rents	OM826	F003	-	-	-	-	-	-
Total Operation Expenses		OMOE		$ -	$ -	$ -	$ -	$ -	$ -
Storage Expense									
Maintenance									
830	Maintenance Super and Eng.	OM830	MSE	-	-	-	-	-	-
831	Maintenance of Structures	OM831	F003	-	-	-	-	-	-
832	Maintenance of Resevoirs	OM832	F003	-	-	-	-	-	-
833	Maintenance of Lines	OM833	F003	-	-	-	-	-	-
834	Main of Compressor Station Equipment	OM834	F004	-	-	-	-	-	-
835	Main of Meas and Reg Sta. Equip	OM835	F003	-	-	-	-	-	-
836	Main of Purification Equip	OM836	F004	-	-	-	-	-	-
837	Main of Other Equipment	OM837	F003	-	-	-	-	-	-
Total Maintenance Expense		OMME		$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Expense		OMS		-	-	-	-	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses							
807-813	Procurement Expenses	OM807	DMCM	-	-	-	-
Storage Expenses							
Operation							
814	Operations Supervision and Engineer	OM814	OSE	-	-	-	-
815	Maps and Records	OM815	F003	-	-	-	-
816	Well Expenses	OM816	F003	-	-	-	-
817	Lines Expenses	OM817	F003	-	-	-	-
818	Compressor Station Exp - Payroll	OM818	F004	-	-	-	-
819	Compressor Station Fuel and Power	OM819	F004	-	-	-	-
820	Measurement and Regulator Station	OM820	F003	-	-	-	-
821	Purification of Natural Gas *(1)*	OM821	F004	-	-	-	-
823	Gas losses *(2)*	OM823	F004	-	-	-	-
824	Other Expenses	OM824	F004	-	-	-	-
825	Storage Well Royalities	OM825	F003	-	-	-	-
826	Rents	OM826	F003	-	-	-	-
Total Operation Expenses		OMOE		$ -	$ -	$ -	$ -
Storage Expense							
Maintenance							
830	Maintenance Super and Eng.	OM830	MSE	-	-	-	-
831	Maintenance of Structures	OM831	F003	-	-	-	-
832	Maintenance of Resevoirs	OM832	F003	-	-	-	-
833	Maintenance of Lines	OM833	F003	-	-	-	-
834	Main of Compressor Station Equipment	OM834	F004	-	-	-	-
835	Main of Meas and Reg Sta. Equip	OM835	F003	-	-	-	-
836	Main of Purification Equip	OM836	F004	-	-	-	-
837	Main of Other Equipment	OM837	F003	-	-	-	-
Total Maintenance Expense		OMME		$ -	$ -	$ -	$ -
Total Storage Expense		OMS		-	-	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Operation & Maintenance Expenses (Continued)										
Transmission										
850-867	Transmission Expenses	OM850	F005	$ 1,040,622	-	-	-	-	1,040,622	-
Distribution Expenses										
Operation										
870	Operation Supr and Engr	OM870	DOES	$ -	-	-	-	-	-	-
871	Dist Load Dispatching	OM871	F007	374,650	-	-	-	-	-	-
872	Compr. Station Labor and Exp.	OM872	F007	-	-	-	-	-	-	-
873	Compr. Station Fuel and Power	OM873	F007	-	-	-	-	-	-	-
874.01	Other Mains/Serv Expenses	OM874 01	CADAL	3,368,434	-	-	-	-	-	-
874.02	Leak Survey-Mains	OM874 02	F009	-	-	-	-	-	-	-
874.03	Leak Survey - Service	OM874 03	F010	-	-	-	-	-	-	-
874.04	Locate Main per Request	OM874.04	CADAL	-	-	-	-	-	-	-
874.05	Check Stop Box Access	OM874.05	F010	-	-	-	-	-	-	-
874.06	Patrolling Mains	OM874 06	F009	-	-	-	-	-	-	-
874.07	Check/Grease Valves	OM874.07	F009	-	-	-	-	-	-	-
874.08	Opr. Odor Equipment	OM874.08	F007	-	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	OM874 09	F009	-	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	OM874.10	F009	-	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	OM875	F008	644,897	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	OM876	F011	266,889	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	OM877	F008	186,285	-	-	-	-	-	-
878	Meter and House Reg. Expense	OM878	F011	93,528	-	-	-	-	-	-
879	Customer Installation Expense	OM879	F011	406,005	-	-	-	-	-	-
880	Other Expenses	OM880	PTDSUB	3,029,079	-	-	-	-	-	-
881	Rents	OM881	PTDSUB	9,718	-	-	-	-	-	-
Total Operations Distribution Expense		OMDO		$ 8,379,484	-	-	-	-	-	-
Total Transmission and Distribution Oper Exp		OMTDO		$ 9,420,106	$ -	$ -	$ -	$ -	$ 1,040,622	$ -

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LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Operation & Maintenance Expenses (Continued)									
Transmission									
850-867	Transmission Expenses	OM850	F005	-	-	-	-	-	-
Distribution Expenses									
Operation									
870	Operation Supr and Engr	OM870	DOES	-	-	-	-	-	-
871	Dist Load Dispatching	OM871	F007	374,650	-	-	-	-	-
872	Compr. Station Labor and Exp.	OM872	F007	-	-	-	-	-	-
873	Compr. Station Fuel and Power	OM873	F007	-	-	-	-	-	-
874.01	Other Mains/Serv. Expenses	OM874.01	CADAL	-	-	1,688,827	293,778	263,981	19,767
874.02	Leak Survey-Mains	OM874.02	F009	-	-	-	-	-	-
874.03	Leak Survey - Service	OM874.03	F010	-	-	-	-	-	-
874.04	Locate Main per Request	OM874.04	CADAL	-	-	-	-	-	-
874.05	Check Stop Box Access	OM874.05	F010	-	-	-	-	-	-
874.06	Patrolling Mains	OM874.06	F009	-	-	-	-	-	-
874.07	Check/Grease Valves	OM874.07	F009	-	-	-	-	-	-
874.08	Opr. Odor Equipment	OM874.08	F007	-	-	-	-	-	-
874.09	Locate and Inspect Valve Boxes	OM874.09	F009	-	-	-	-	-	-
874.1	Cut Grass - Right of Way	OM874.10	F009	-	-	-	-	-	-
875	Meas and Reg Station Exp.- General	OM875	F008	-	644,897	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	OM876	F011	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	OM877	F008	-	186,285	-	-	-	-
878	Meter and House Reg. Expense	OM878	F011	-	-	-	-	-	-
879	Customer Installation Expense	OM879	F011	-	-	-	-	-	-
880	Other Expenses	OM880	PTDSUB	-	87,429	1,321,571	229,892	206,575	15,469
881	Rents	OM881	PTDSUB	-	280	4,240	738	663	50
Total Operations Distribution Expense		OMDO		374,650	918,892	3,014,638	524,408	471,219	35,286
Total Transmission and Distribution Oper Exp		OMTDO		$ 374,650	$ 918,892	$ 3,014,638	$ 524,408	$ 471,219	$ 35,286

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)							
Transmission							
850-867	Transmission Expenses	OM850	F005	-	-	-	-
Distribution Expenses							
Operation							
870	Operation Supr and Engr	OM870	DOES	-	-	-	-
871	Dist Load Dispatching	OM871	F007	-	-	-	-
872	Compr. Station Labor and Exp.	OM872	F007	-	-	-	-
873	Compr. Station Fuel and Power	OM873	F007	-	-	-	-
874 01	Other Mains/Serv. Expenses	OM874 01	CADAL	1,102,080	-	-	-
874.02	Leak Survey-Mains	OM874.02	F009	-	-	-	-
874.03	Leak Survey - Service	OM874.03	F010	-	-	-	-
874.04	Locate Main per Request	OM874.04	CADAL	-	-	-	-
874 05	Check Stop Box Access	OM874.05	F010	-	-	-	-
874.06	Patrolling Mains	OM874.06	F009	-	-	-	-
874 07	Check/Grease Valves	OM874.07	F009	-	-	-	-
874 08	Opr. Odor Equipment	OM874.08	F007	-	-	-	-
874.09	Locate and Inspect Valve Boxes	OM874.09	F009	-	-	-	-
874.1	Cut Grass - Right of Way	OM874.10	F009	-	-	-	-
875	Meas and Reg Station Exp.- General	OM875	F008	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	OM876	F011	-	266,889	-	-
877	Meas and Reg Station Exp. - City Gate	OM877	F008	-	-	-	-
878	Meter and House Reg. Expense	OM878	F011	-	93,528	-	-
879	Customer Installation Expense	OM879	F011	-	406,005	-	-
880	Other Expenses	OM880	PTDSUB	862,327	305,815	-	-
881	Rents	OM881	PTDSUB	2,766	981	-	-
Total Operations Distribution Expense		OMDO		1,967,174	1,073,218	-	-
Total Transmission and Distribution Oper Exp		OMTDO		$ 1,967,174	$ 1,073,218	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Operation & Maintenance Expenses (Continued)										
Maintenance Expense -- Distribution										
885	Maintenance Supr and Engr	OM885	DMES	$ -	-	-	-	-	-	-
886	Maintenance Structures	OM886	F008	592,928	-	-	-	-	-	-
887	Maintenance Mains	OM887	F009	8,458,381	-	-	-	-	-	-
888	Maintenance Comp. Station Equip.	OM888	F007	-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	OM889	F008	71,202	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	OM890	F011	208,249	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	OM891	F008	280,673	-	-	-	-	-	-
892	Maintenance Services	OM892	F010	1,207,872	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	OM893	F011	-	-	-	-	-	-	-
894	Maintenance Other Equipment	OM894	PTDSUB	353,800	-	-	-	-	-	-
Total Maintenance Expenses		OMME		$ 11,173,106	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission & Distribution Expenses		OMDE		$ 20,593,211	$ -	$ -	$ -	$ -	$ 1,040,622	$ -
Customer Accounts Expense										
901	Supervision	OM901	F012	$ 655,292	-	-	-	-	-	-
902	Meter Reading	OM902	F012	1,729,593	-	-	-	-	-	-
903	Customer Records and Collections	OM903	F012	4,346,793	-	-	-	-	-	-
904	Uncollectible Accounts	OM904	F012	1,517,462	-	-	-	-	-	-
905	Misc. Cust Account Expenses	OM905	F012	270,177	-	-	-	-	-	-
Total Customer Accounts Expense		OMCA		$ 8,519,316	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expenses										
907-910	Customer Service	OM907	F013	$ 4,610,603	-	-	-	-	-	-
Sales Expenses										
911-916	Sales Expenses	OM911	F013	$ 22,308	-	-	-	-	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Operation & Maintenance Expenses (Continued)									
Maintenance Expense -- Distribution									
885	Maintenance Supr and Engr	OM885	DMES	-	-	-	-	-	-
886	Maintenance Structures	OM886	F008	-	592,928	-	-	-	-
887	Maintenance Mains	OM887	F009	-	-	6,302,964	1,096,425	985,218	73,775
888	Maintenance Comp Station Equip	OM888	F007	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	OM889	F008	-	71,202	-	-	-	-
890	Maintenance Meas and Reg - Industrial	OM890	F011	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	OM891	F008	-	280,673	-	-	-	-
892	Maintenance Services	OM892	F010	-	-	-	-	-	-
893	Maintenance Meters and House Reg	OM893	F011	-	-	-	-	-	-
894	Maintenance Other Equipment	OM894	PTDSUB	-	10,212	154,361	26,852	24,128	1,807
Total Maintenance Expenses		OMME		$ -	$ 955,015	$ 6,457,325	$ 1,123,277	$ 1,009,346	$ 75,582
Total Transmission & Distribution Expenses		OMDE		$ 374,650	$ 1,873,908	$ 9,471,962	$ 1,647,684	$ 1,480,565	$ 110,867
Customer Accounts Expense									
901	Supervision	OM901	F012	-	-	-	-	-	-
902	Meter Reading	OM902	F012	-	-	-	-	-	-
903	Customer Records and Collections	OM903	F012	-	-	-	-	-	-
904	Uncollectible Accounts	OM904	F012	-	-	-	-	-	-
905	Misc. Cust Account Expenses	OM905	F012	-	-	-	-	-	-
Total Customer Accounts Expense		OMCA		$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expenses									
907-910	Customer Service	OM907	F013	-	-	-	-	-	-
Sales Expenses									
911-916	Sales Expenses	OM911	F013	-	-	-	-	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)							
Maintenance Expense – Distribution							
885	Maintenance Supr and Engr	OM885	DMES	-	-	-	-
886	Maintenance Structures	OM886	F008	-	-	-	-
887	Maintenance Mains	OM887	F009	-	-	-	-
888	Maintenance Comp. Station Equip.	OM888	F007	-	-	-	-
889	Maintenance Meas and Reg. General	OM889	F008	-	-	-	-
890	Maintenance Meas and Reg - Industrial	OM890	F011	-	208,249	-	-
891	Maintenance Meas and Reg.-City Gate	OM891	F008	-	-	-	-
892	Maintenance Services	OM892	F010	1,207,872	-	-	-
893	Maintenance Meters and House Reg.	OM893	F011	-	-	-	-
894	Maintenance Other Equipment	OM894	PTDSUB	100,721	35,720	-	-
Total Maintenance Expenses		OMME		$ 1,308,593	$ 243,969	$ -	$ -
Total Transmission & Distribution Expenses		OMDE		$ 3,275,767	$ 1,317,187	$ -	$ -
Customer Accounts Expense							
901	Supervision	OM901	F012	-	-	655,292	-
902	Meter Reading	OM902	F012	-	-	1,729,593	-
903	Customer Records and Collections	OM903	F012	-	-	4,346,793	-
904	Uncollectible Accounts	OM904	F012	-	-	1,517,462	-
905	Misc. Cust Account Expenses	OM905	F012	-	-	270,177	-
Total Customer Accounts Expense		OMCA		$ -	$ -	$ 8,519,316	$ -
Customer Service Expenses							
907-910	Customer Service	OM907	F013	-	-	-	4,610,603
Sales Expenses							
911-916	Sales Expenses	OM911	F013	-	-	-	22,308

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Operation & Maintenance Expenses (Continued)										
Administrative & General										
920	Admin and General Salaries	OM920	LBSUB	$ 3,325,921	13,919	104,639	185,004	441,302	111,398	-
921	Office Supplies and Expense	OM921	LBSUB	1,061,002	4,440	33,381	59,018	140,780	35,537	-
922	Admin. Expenses Transferred	OM922	LBSUB	(410,957)	(1,720)	(12,929)	(22,859)	(54,528)	(13,765)	-
923	Outside Services Employed	OM923	LBSUB	1,214,328	5,082	38,205	67,547	161,124	40,673	-
924	Property Insurance	OM924	PTT	147,521	-	-	16,655	-	3,569	-
925	Injuries and Damages	OM925	LBSUB	467,992	1,959	14,724	26,032	62,096	15,675	-
926	Employee Pensions and Benefits	OM926	LBSUB	9,307,982	38,953	292,845	517,754	1,235,035	311,760	-
927	Franchise Requirement	OM927	PTT	524,749	-	-	59,245	-	12,696	-
928	Regulatory Commission Fee	OM928	PTT	55,329	-	-	6,247	-	1,339	-
929	Duplicate Charges -Credit	OM929	LBSUB	(1,086,388)	(4,546)	(34,180)	(60,430)	(144,148)	(36,387)	-
930.1	General Advertising Expense	OM930 1	PTT	127,090	-	-	14,349	-	3,075	-
930.2	Misc. General Expense	OM930 2	LBSUB	215,931	904	6,794	12,011	28,651	7,232	-
931	Rents	OM931	PTT	350,181	-	-	39,536	-	8,473	-
935	Maintenance of General Plant	OM935	PT389	2,562,346	-	-	288,839	-	62,264	-
Total Administrative and General Expense		OMAGT		$ 17,863,024	$ 58,990	$ 443,478	$ 1,208,946	$ 1,870,310	$ 563,540	$ -
Total Operation & Maintenance Expense		OMT		$ 60,158,628	$ 128,678	$ 967,390	$ 2,887,726	$ 8,148,096	$ 1,604,161	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Operation & Maintenance Expenses (Continued)									
Administrative & General									
920	Admin and General Salaries	OM920	LBSUB	73,142	157,954	775,659	134,929	121,243	9,079
921	Office Supplies and Expense	OM921	LBSUB	23,333	50,389	247,443	43,044	38,678	2,896
922	Admin. Expenses Transferred	OM922	LBSUB	(9,038)	(19,517)	(95,842)	(16,672)	(14,981)	(1,122)
923	Outside Services Employed	OM923	LBSUB	26,705	57,671	283,201	49,264	44,267	3,315
924	Property Insurance	OM924	PTT	-	3,509	57,305	9,968	8,957	671
925	Injuries and Damages	OM925	LBSUB	10,292	22,226	109,143	18,986	17,060	1,277
926	Employee Pensions and Benefits	OM926	LBSUB	204,697	442,052	2,170,772	377,614	339,314	25,408
927	Franchise Requirement	OM927	PTT	-	12,483	203,839	35,459	31,862	2,386
928	Regulatory Commission Fee	OM928	PTT	-	1,316	21,493	3,739	3,360	252
929	Duplicate Charges -Credit	OM929	LBSUB	(23,891)	(51,594)	(253,363)	(44,074)	(39,603)	(2,966)
930.1	General Advertising Expense	OM930.1	PTT	-	3,023	49,368	8,588	7,717	578
930.2	Misc. General Expense	OM930.2	LBSUB	4,749	10,255	50,358	8,760	7,872	589
931	Rents	OM931	PTT	-	8,330	136,028	23,663	21,263	1,592
935	Maintenance of General Plant	OM935	PT389	-	63,824	964,753	167,823	150,801	11,292
Total Administrative and General Expense		OMAGT		$ 309,989	$ 761,919	$ 4,720,158	$ 821,090	$ 737,809	$ 55,248
Total Operation & Maintenance Expense		OMT		$ 684,638	$ 2,635,827	$ 14,192,120	$ 2,468,774	$ 2,218,374	$ 166,116

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Operation & Maintenance Expenses (Continued)							
Administrative & General							
920	Admin and General Salaries	OM920	LBSUB	289,095	175,289	635,003	98,268
921	Office Supplies and Expense	OM921	LBSUB	92,224	55,919	202,572	31,348
922	Admin. Expenses Transferred	OM922	LBSUB	(35,721)	(21,659)	(78,462)	(12,142)
923	Outside Services Employed	OM923	LBSUB	105,551	64,000	231,846	35,879
924	Property Insurance	OM924	PTT	34,611	12,275	-	-
925	Injuries and Damages	OM925	LBSUB	40,679	24,665	89,351	13,827
926	Employee Pensions and Benefits	OM926	LBSUB	809,066	490,567	1,777,130	275,013
927	Franchise Requirement	OM927	PTT	123,117	43,662	-	-
928	Regulatory Commission Fee	OM928	PTT	12,981	4,604	-	-
929	Duplicate Charges -Credit	OM929	LBSUB	(94,431)	(57,257)	(207,419)	(32,098)
930 1	General Advertising Expense	OM930.1	PTT	29,818	10,575	-	-
930.2	Misc. General Expense	OM930.2	LBSUB	18,769	11,380	41,227	6,380
931	Rents	OM931	PTT	82,160	29,137	-	-
935	Maintenance of General Plant	OM935	PT389	629,503	223,247	-	-
Total Administrative and General Expense		OMAGT	$	2,137,422 $	1,066,403 $	2,691,248 $	416,474
Total Operation & Maintenance Expense		OMT	$	5,413,189 $	2,383,590 $	11,210,564 $	5,049,385
				$	30,162,627		

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Depreciation Expenses											
Underground Storage											
350-357	Underground Storage Plant	DP350	F003	$	1,086,254	-	-	1,086,254	-	-	-
358	Asset Retire Obligation Gas Plant	DP350	F003	$	13,193	-	-	13,193	-	-	-
Total Underground Storage				$	1,099,446	-	-	1,099,446	-	-	-
Transmission											
365-371	Transmission Plant	DP365	F005	$	91,870	-	-	-	-	91,870	-
Distribution											
374	Land & Land Rights	DP374	F008	$	568	-	-	-	-	-	-
375	Structures & Improvements	DP375	F008		41,312	-	-	-	-	-	-
376	Mains	DP376	F009		5,687,052	-	-	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008		238,761	-	-	-	-	-	-
379	Meas & Reg Station Eq -City Gate	DP379	F008		100,315	-	-	-	-	-	-
380	Services	DP380	F010		5,770,372	-	-	-	-	-	-
381	Meters	DP381	F011		1,202,032	-	-	-	-	-	-
382	Meter Installations	DP382	F011		-	-	-	-	-	-	-
383	House Regulators	DP383	F011		296,890	-	-	-	-	-	-
384	House Regulator Installations	DP384	F011		-	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011		3,086	-	-	-	-	-	-
387	Other Equipment	DP387	F011		1,636	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-City Gate	DP388	F008		5	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	DP388	F009		315	-	-	-	-	-	-
Total Distribution				$	13,342,344	$ -	$ -	$ -	$ -	$ -	$ -
117	Gas Stored Underground	DP117	F003	$	-	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB		-	-	-	-	-	-	-
389-399	General Plant	DP389	PTSUB		352,364	-	-	39,720	-	8,562	-
Common Utility Plant		DPCP	PTSUB		5,194,996	-	-	585,603	-	126,237	-
Total Depreciation Expense		DEPREX		$	20,081,020	$ -	$ -	$ 1,724,770	$ -	$ 226,669	$ -
Regulatory Credits and Accretion											
	Regulatory Credits	REGCR	PTSUB	$	(477,534)	-	-	(53,830)	-	(11,604)	-
	Accretion	ACCRE	PTSUB	$	464,021	-	-	52,307	-	11,276	-
Amortization of Income Tax Credits		ITCAM	PTSUB	$	(153,809)	-	-	(17,338)	-	(3,738)	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Depreciation Expenses									
Underground Storage									
350-357	Underground Storage Plant	DP350	F003	-	-	-	-	-	-
358	Asset Retire Obligation Gas Plant	DP350	F003	-	-	-	-	-	-
Total Underground Storage				-	-	-	-	-	-
Transmission									
365-371	Transmission Plant	DP365	F005	-	-	-	-	-	-
Distribution									
374	Land & Land Rights	DP374	F008	-	568	-	-	-	-
375	Structures & Improvements	DP375	F008	-	41,312	-	-	-	-
376	Mains	DP376	F009	-	-	4,237,842	737,189	662,418	49,603
378	Meas & Reg Station Eq -Gen	DP378	F008	-	238,761	-	-	-	-
379	Meas & Reg Station Eq -City Gate	DP379	F008	-	100,315	-	-	-	-
380	Services	DP380	F010	-	-	-	-	-	-
381	Meters	DP381	F011	-	-	-	-	-	-
382	Meter Installations	DP382	F011	-	-	-	-	-	-
383	House Regulators	DP383	F011	-	-	-	-	-	-
384	House Regulator Installations	DP384	F011	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011	-	-	-	-	-	-
387	Other Equipment	DP387	F011	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-City Gate	DP388	F008	-	5	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	DP388	F009	-	-	235	41	37	3
Total Distribution			$	-	$ 380,960	$ 4,238,077	$ 737,230	$ 662,455	$ 49,606
117	Gas Stored Underground	DP117	F003	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB	-	-	-	-	-	-
389-399	General Plant	DP389	PTSUB	-	8,777	132,669	23,078	20,738	1,553
Common Utility Plant		DPCP	PTSUB	-	129,399	1,955,977	340,250	305,739	22,894
Total Depreciation Expense		DEPREX	$	-	$ 519,136	$ 6,326,723	$ 1,100,558	$ 988,932	$ 74,053
Regulatory Credits and Accretion									
	Regulatory Credits	REGCR	PTSUB	-	(11,895)	(179,797)	(31,276)	(28,104)	(2,104)
	Accretion	ACCRE	PTSUB	-	11,558	174,709	30,391	27,309	2,045
Amortization of Income Tax Credits		ITCAM	PTSUB	-	(3,831)	(57,911)	(10,074)	(9,052)	(678)

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description		Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Depreciation Expenses							
Underground Storage							
350-357	Underground Storage Plant	DP350	F003	-	-	-	-
358	Asset Retire Obligation Gas Plant	DP350	F003	-	-	-	-
Total Underground Storage				-	-	-	-
Transmission							
365-371	Transmission Plant	DP365	F005	-	-	-	-
Distribution							
374	Land & Land Rights	DP374	F008	-	-	-	-
375	Structures & Improvements	DP375	F008	-	-	-	-
376	Mains	DP376	F009	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008	-	-	-	-
379	Meas & Reg Station Eq.-City Gate	DP379	F008	-	-	-	-
380	Services	DP380	F010	5,770,372	-	-	-
381	Meters	DP381	F011	-	1,202,032	-	-
382	Meter Installations	DP382	F011	-	-	-	-
383	House Regulators	DP383	F011	-	296,890	-	-
384	House Regulator Installations	DP384	F011	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011	-	3,086	-	-
387	Other Equipment	DP387	F011	-	1,636	-	-
388	Asset Retire Obligation Gas Plant-City Gate	DP388	F008	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	DP388	F009	-	-	-	-
Total Distribution				$ 5,770,372	$ 1,503,644	$ -	$ -
117	Gas Stored Underground	DP117	F003	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB	-	-	-	-
389-399	General Plant	DP389	PTSUB	86,567	30,700	-	-
Common Utility Plant		DPCP	PTSUB	1,276,278	452,619	-	-
Total Depreciation Expense		DEPREX		$ 7,133,217	$ 1,986,963	$ -	$ -
Regulatory Credits and Accretion							
	Regulatory Credits	REGCR	PTSUB	(117,318)	(41,606)	-	-
	Accretion	ACCRE	PTSUB	113,998	40,428	-	-
Amortization of Income Tax Credits		ITCAM	PTSUB	(37,787)	(13,401)	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Taxes Other Than Income Taxes										
	OTRE	PTT	$	-	-	-	-	-	-	-
Property Taxes	OTPP	PTT		5,819,250	-	-	657,000	-	140,799	-
Unemployment Insurance	OTUN	LBTOT		-	-	-	-	-	-	-
Federal Old Age & Survivor Insurance	OTFICA	LBTOT		-	-	-	-	-	-	-
Public Service Commission Fee	OTCF	PTT		-	-	-	-	-	-	-
Miscellaneous	OTMISC	PTT		-	-	-	-	-	-	-
Total Taxes Other Than Income Taxes	OTT		$	5,819,250 $	- $	- $	657,000 $	- $	140,799 $	-
Interest Expenses	INT	PTT	$	10,397,327	-	-	1,173,869	-	251,567	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Taxes Other Than Income Taxes								
	OTRE	PTT	-	-	-	-		
Property Taxes	OTPP	PTT	-	138,426	2,260,497	393,222	353,339	26,459
Unemployment Insurance	OTUN	LBTOT	-	-	-	-	-	-
Federal Old Age & Survivor Insurance	OTFICA	LBTOT	-	-	-	-	-	-
Public Service Commission Fee	OTCF	PTT	-	-	-	-	-	-
Miscellaneous	OTMISC	PTT	-	-	-	-	-	-
Total Taxes Other Than Income Taxes	OTT		$ -	$ 138,426	$ 2,260,497	$ 393,222	$ 353,339	$ 26,459
Interest Expenses	INT	PTT	-	247,327	4,038,858	702,575	631,315	47,274

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Taxes Other Than Income Taxes						
	OTRE	PTT	-	-	-	-
Property Taxes	OTPP	PTT	1,365,315	484,195	-	-
Unemployment Insurance	OTUN	LBTOT	-	-	-	-
Federal Old Age & Survivor Insurance	OTFICA	LBTOT	-	-	-	-
Public Service Commission Fee	OTCF	PTT	-	-	-	-
Miscellaneous	OTMISC	PTT	-	-	-	-
Total Taxes Other Than Income Taxes	OTT		$ 1,365,315	$ 484,195	$ -	$ -
Interest Expenses	INT	PTT	2,439,425	865,116	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Functional Assignment Vectors									
Gas Supply Demand	F001		1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Gas Supply Commodity	F002		1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
Storage Demand	F003		1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Storage Commodity	F004		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Transmission Demand	F005		1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Transmission Commodity	F006		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Distribution Expense Commodity	F007		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Structures & Equipment	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Mains	F009		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F010		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F011		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Accounts	F012		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F013		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission & Distribution Mains	TDMSUB		$ 297,624,135	$ -	$ -	$ -	$ -	$ 13,658,204	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Functional Assignment Vectors								
Gas Supply Demand	F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Gas Supply Commodity	F002		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Demand	F003		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Storage Commodity	F004		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission Demand	F005		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission Commodity	F006		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Expense Commodity	F007		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Distribution Structures & Equipment	F008		0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
Distribution Mains	F009		0.000000	0.000000	0.745174	0.129626	0.116478	0.008722
Services	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F011		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Accounts	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Customer Service Expense	F013		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission & Distribution Mains	TDMSUB	$	-	$ -	$ 211,603,955	$ 36,809,325	$ 33,075,872	$ 2,476,779

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Functional Assignment Vectors						
Gas Supply Demand	F001		0.000000	0.000000	0.000000	0.000000
Gas Supply Commodity	F002		0.000000	0.000000	0.000000	0.000000
Storage Demand	F003		0.000000	0.000000	0.000000	0.000000
Storage Commodity	F004		0.000000	0.000000	0.000000	0.000000
Transmission Demand	F005		0.000000	0.000000	0.000000	0.000000
Transmission Commodity	F006		0.000000	0.000000	0.000000	0.000000
Distribution Expense Commodity	F007		0.000000	0.000000	0.000000	0.000000
Distribution Structures & Equipment	F008		0.000000	0.000000	0.000000	0.000000
Distribution Mains	F009		0.000000	0.000000	0.000000	0.000000
Services	F010		1.000000	0.000000	0.000000	0.000000
Meters	F011		0.000000	1.000000	0.000000	0.000000
Customer Accounts	F012		0.000000	0.000000	1.000000	0.000000
Customer Service Expense	F013		0.000000	0.000000	0.000000	1.000000
Transmission & Distribution Mains	TDMSUB	$	- $	- $	- $	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Demand	Transmission Commodity
Internally Generated Functional Vectors										
Sub-Total Distribution Plant		PTDSUB		1.000000	-	-	-	-	-	-
Storage-Transmission-Distribution Subtotal		PTSUB		1.000000	-	-	0.112724	-	0.024300	-
Total Storage Plant		PTST		1.000000	-	-	1.000000	-	-	-
Transmission Plant		PT365		1.000000	-	-	-	-	1.000000	-
General Plant		PT389		1.000000	-	-	0.112724	-	0.024300	-
Total Distribution Plant		PTDSUB		1.000000	-	-	-	-	-	-
Sub-Total CWIP		CWIP		1.000000	-	-	0.094157	-	0.024049	-
Total Operation and Maintenance Expenses		OMT		1.000000	0.002139	0.016081	0.048002	0.135444	0.026666	-
Total Depreciation Reserve		DEPR		1.000000	-	-	0.143522	-	0.051620	-
Storage-Transmission -Distribution Plant Subtotal		PTSUB		1.000000	-	-	0.112724	-	0.024300	-
Total Labor Expenses		LBTOT		1.000000	0.003942	0.029633	0.058944	0.124972	0.032959	-
Transmission and Distribution Payroll		LBTD		1.000000	-	-	-	-	0.060287	-
Transmission and Distribution Mains		TDMSUB		1.000000	-	-	-	-	0.045891	-
Storage Operation Expenses Labor Subtotal	OSE			1,099,461	-	-	271,834	827,627	-	-
Storage Maintenance Expenses Labor Subtotal	MSE			856,115	-	-	307,099	549,016	-	-
Mains & Services	CADAL			422,052,652	-	-	-	-	-	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM			1.00000	11.74%	88.26%				
Distribution Operation Expenses Labor Subtotal	DOES			2,923,145	-	-	-	-	-	-
Distribution Maintenance Expenses Labor Subtotal	DMES			4,063,211	-	-	-	-	-	-
Subtotal Labor Expenses	LBSUB		$	13,381,829	$ 56,002	$ 421,015	$ 744,361	$ 1,775,575	$ 448,209	$ -
Subtotal O&M Expenses	OMSUB		$	42,295,604	$ 69,689	$ 523,911	$ 1,678,780	$ 6,277,786	$ 1,040,622	$ -
Depreciation Reserve - Distribution	DEPRDIS		$	163,053,642	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Distribution Commodity	Distribution Structures & Equipment Demand	Distribution Mains - Low & Med. Pressure Demand	Distribution Mains - Low & Med. Pressure Customer	Distribution Mains - High Pressure Demand	Distribution Mains - High Pressure Customer
Internally Generated Functional Vectors								
Sub-Total Distribution Plant		PTDSUB	-	0.028863	0.436295	0.075895	0.068197	0.005107
Storage-Transmission-Distribution Subtotal		PTSUB	-	0.024908	0.376512	0.065496	0	0
Total Storage Plant		PTST	-	-	-	-	-	-
Transmission Plant		PT365	-	-	-	-	-	-
General Plant		PT389	-	0.024908	0.376512	0.065496	0	0
Total Distribution Plant		PTDSUB	-	0.028863	0.436295	0.075895	0	0
Sub-Total CWIP		CWIP	-	0.016924	0.475982	0.082799	0	0
Total Operation and Maintenance Expenses		OMT	0.011381	0.043815	0.235912	0.041038	0	0
Total Depreciation Reserve		DEPR	-	0.019976	0.360449	0.062702	0	0
Storage-Transmission -Distribution Plant Subtotal		PTSUB	-	0.024908	0.376512	0.065496	0	0
Total Labor Expenses		LBTOT	0.020713	0.046179	0.241546	0.042018	0	0
Transmission and Distribution Payroll		LBTD	0.039584	0.085483	0.419777	0.073022	0	0
Transmission and Distribution Mains		TDMSUB	-	-	0.710977	0.123677	0	0
Storage Operation Expenses Labor Subtotal	OSE		-	-	-	-	-	-
Storage Maintenance Expenses Labor Subtotal	MSE		-	-	-	-	-	-
Mains & Services	CADAL		-	-	211,603,955	36,809,325	33,075,872	2,476,779
Demand/Commodity Percent of Purchased Gas Cost	DMCM							
Distribution Operation Expenses Labor Subtotal	DOES		294,287	424,768	834,744	145,207	130,479	9,771
Distribution Maintenance Expenses Labor Subtotal	DMES		-	210,759	2,286,115	397,679	357,343	26,758
Subtotal Labor Expenses	LBSUB		$ 294,287	$ 635,526	$ 3,120,859	$ 542,886	$ 487,822	$ 36,529
Subtotal O&M Expenses	OMSUB		$ 374,650	$ 1,873,908	$ 9,471,962	$ 1,647,684	$ 1,480,565	$ 110,867
Depreciation Reserve - Distribution	DEPRDIS		$ -	$ 3,939,462	$ 73,329,204	$ 12,755,898	$ 11,462,108	$ 858,303

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Functional Assignment and Classification

Description	Name	Vector	Services Customer	Meters Customer	Customer Accounts Customer	Customer Service Expense Customer
Internally Generated Functional Vectors						
Sub-Total Distribution Plant		PTDSUB	0 284683	0.100960	-	-
Storage-Transmission-Distribution Subtotal		PTSUB	0	0	-	-
Total Storage Plant		PTST	-	-	-	-
Transmission Plant		PT365	-	-	-	-
General Plant		PT389	0	0	-	-
Total Distribution Plant		PTDSUB	0	0	-	-
Sub-Total CWIP		CWIP	0	0	-	-
Total Operation and Maintenance Expenses		OMT	0	0	0	0
Total Depreciation Reserve		DEPR	0	0	-	-
Storage-Transmission -Distribution Plant Subtotal		PTSUB	0	0	-	-
Total Labor Expenses		LBTOT	0	0	0	0
Transmission and Distribution Payroll		LBTD	0	0	-	-
Transmission and Distribution Mains		TDMSUB	-	-	-	-
Storage Operation Expenses Labor Subtotal	OSE		-	-	-	-
Storage Maintenance Expenses Labor Subtotal	MSE		-	-	-	-
Mains & Services	CADAL		138,086,721	-	-	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM					
Distribution Operation Expenses Labor Subtotal	DOES		544,691	539,198	-	-
Distribution Maintenance Expenses Labor Subtotal	DMES		618,480	166,077	-	-
Subtotal Labor Expenses	LBSUB	$	1,163,171 $	705,275 $	2,554,931 $	395,379
Subtotal O&M Expenses	OMSUB	$	3,275,767 $	1,317,187 $	8,519,316 $	4,632,911
Depreciation Reserve - Distribution	DEPRDIS	$	54,595,308 $	6,113,360 $	- $	-

Seelye Exhibit 29

Gas Cost of Service Study
Class Allocation

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Plant in Service										
Procurement Expenses										
Demand	PTIS	PTISGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	PTIS	PTISGSC	COM01	-	-	-	-	-	-	-
Total Procurement Expenses				$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	PTIS	PTISSD	DEM02	$ 73,084,009	$ 48,406,101	$ 22,808,308	$ 1,869,600	$ -	$ -	$ -
Commodity	PTIS	PTISSC	COM02	-	-	-	-	-	-	-
Total Storage				$ 73,084,009	$ 48,406,101	$ 22,808,308	$ 1,869,600	$ -	$ -	$ -
Transmission										
Demand	PTIS	PTISTD	DEM03	$ 15,293,236	$ 10,129,246	$ 4,772,765	$ 391,224	$ -	$ -	$ -
Commodity	PTIS	PTISTC	COM03	-	-	-	-	-	-	-
Total Transmission				$ 15,293,236	$ 10,129,246	$ 4,772,765	$ 391,224	$ -	$ -	$ -
Distribution Expenses										
Commodity	PTIS	PTISDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	PTIS	PTISDSD	DEM04	$ 15,676,266	$ 8,978,383	$ 4,188,382	$ 337,282	$ 83,448	$ 1,169,694	$ 919,078
Distribution Mains										
Low/Medium Pressure - Demand	PTIS	PTISDMD	DEM05a	$ 236,960,561	$ 155,882,610	$ 71,613,464	$ 5,812,138	$ 127,015	$ 3,525,335	$ -
Low/Medium Pressure - Customer	PTIS	PTISDMC	CUST01a	41,220,205	37,688,069	3,499,001	29,123	259	3,754	-
High Pressure - Demand	PTIS	PTISDMD	DEM05	37,039,370	21,213,829	9,896,172	796,918	197,167	2,763,716	2,171,568
High Pressure - Customer	PTIS	PTISDMC	CUST01	2,773,573	2,535,398	235,406	2,003	131	610	26
Total Distribution Mains		PTISDIS		$ 317,993,709	$ 217,319,905	$ 85,244,043	$ 6,640,181	$ 324,572	$ 6,293,413	$ 2,171,594
Services										
Customer	PTIS	PTISSC	CUST02	$ 154,617,165	$ 142,301,428	$ 12,067,653	$ 112,407	$ 37,881	$ 91,317	$ 6,478
Meters										
Customer	PTIS	PTISMC	CUST03	$ 54,833,357	$ 41,539,681	$ 10,615,468	$ 622,904	$ 178,290	$ 1,775,357	$ 101,657
Customer Accounts										
Customer	PTIS	PTISCAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service										
Customer	PTIS	PTISCSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 631,497,742	$ 468,674,745	$ 139,696,619	$ 9,973,598	$ 624,191	$ 9,329,781	$ 3,198,807

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Rate Base										
Procurement Expenses										
Demand	NCRB	RBGSD	DEM01	$ 16,916	$ 9,688	$ 4,520	$ 364	$ 90	$ 1,262	$ 992
Commodity	NCRB	RBGSC	COM01	127,172	60,845	31,269	2,985	876	22,758	8,439
Total Procurement Expenses				$ 144,088	$ 70,533	$ 35,789	$ 3,349	$ 966	$ 24,021	$ 9,430
Storage										
Demand	NCRB	RBSD	DEM02	$ 107,165,138	$ 70,979,228	$ 33,444,463	$ 2,741,447	$ -	$ -	$ -
Commodity	NCRB	RBSC	COM02	1,071,140	698,437	344,279	28,424	-	-	-
Total Storage				$ 108,236,278	$ 71,677,665	$ 33,788,742	$ 2,769,871	$ -	$ -	$ -
Transmission										
Demand	NCRB	RBTD	DEM03	$ 3,638,613	$ 2,409,981	$ 1,135,551	$ 93,081	$ -	$ -	$ -
Commodity	NCRB	RBTC	COM03	-	-	-	-	-	-	-
Total Transmission				$ 3,638,613	$ 2,409,981	$ 1,135,551	$ 93,081	$ -	$ -	$ -
Distribution Expenses										
Commodity	NCRB	RBDEC	COM04	$ 90,002	$ 43,061	$ 22,130	$ 2,113	$ 620	$ 16,107	$ 5,972
Distribution Structures & Equipment										
Demand	NCRB	RBDSD	DEM04	$ 11,347,760	$ 6,499,286	$ 3,031,892	$ 244,152	$ 60,406	$ 846,720	$ 665,304
Distribution Mains										
Low/Medium Pressure - Demand	NCRB	RBDMD	DEM05a	$ 170,792,749	$ 112,354,644	$ 51,616,439	$ 4,189,182	$ 91,548	$ 2,540,936	$ -
Low/Medium Pressure - Customer	NCRB	RBDMC	CUST01a	29,710,058	27,164,220	2,521,955	20,991	187	2,705	-
High Pressure - Demand	NCRB	RBDMD	DEM05	26,696,661	15,290,174	7,132,809	574,390	142,111	1,991,988	1,565,189
High Pressure - Customer	NCRB	RBDMC	CUST01	1,999,093	1,827,424	169,673	1,443	94	439	19
Total Distribution Mains				$ 229,198,561	$ 156,636,462	$ 61,440,876	$ 4,786,007	$ 233,940	$ 4,536,069	$ 1,565,208
Services										
Customer	NCRB	RBSC	CUST02	$ 90,087,389	$ 82,911,649	$ 7,031,195	$ 65,494	$ 22,071	$ 53,206	$ 3,775
Meters										
Customer	NCRB	RBMC	CUST03	$ 46,919,438	$ 35,544,395	$ 9,083,372	$ 533,002	$ 152,558	$ 1,519,125	$ 86,985
Customer Accounts										
Customer	NCRB	RBCAC	CUST04	$ 1,473,728	$ 1,327,734	$ 128,693	$ 9,933	$ 687	$ 6,408	$ 275
Customer Service										
Customer	NCRB	RBCSC	CUST05	$ 663,787	$ 598,029	$ 57,965	$ 4,474	$ 309	$ 2,886	$ 124
Total		RBT		$ 491,799,642	$ 357,718,793	$ 115,756,204	$ 8,511,475	$ 471,557	$ 7,004,541	$ 2,337,072

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
<u>Operation and Maintenance Expenses</u>										
Procurement Expenses										
Demand	OMT	OMGSD	DEM01	$ 128,678	$ 73,699	$ 34,380	$ 2,769	$ 685	$ 9,601	$ 7,544
Commodity	OMT	OMGSC	COM01	967,390	462,844	237,865	22,707	6,660	173,122	64,192
Total Procurement Expenses		OMGST		$ 1,096,068	$ 536,543	$ 272,245	$ 25,475	$ 7,345	$ 182,723	$ 71,737
Storage										
Demand	OMT	OMSD	DEM02	$ 2,887,726	$ 1,912,642	$ 901,211	$ 73,872	$ -	$ -	$ -
Commodity	OMT	OMSC	COM02	8,148,096	5,312,968	2,618,911	216,217	-	-	-
Total Storage		OMST		$ 11,035,822	$ 7,225,611	$ 3,520,122	$ 290,089	$ -	$ -	$ -
Transmission										
Demand	OMT	OMTD	DEM03	$ 1,604,161	$ 1,062,492	$ 500,632	$ 41,037	$ -	$ -	$ -
Commodity	OMT	OMTC	COM03	-	-	-	-	-	-	-
Total Transmission		OMTRT		$ 1,604,161	$ 1,062,492	$ 500,632	$ 41,037	$ -	$ -	$ -
Distribution Expenses										
Commodity	OMT	OMDEC	COM04	$ 684,638	$ 327,563	$ 168,341	$ 16,070	$ 4,713	$ 122,521	$ 45,430
Distribution Structures & Equipment										
Demand	OMT	OMDSD	DEM04	$ 2,635,827	$ 1,509,636	$ 704,240	$ 56,711	$ 14,031	$ 196,674	$ 154,535
Distribution Mains										
Low/Medium Pressure - Demand	OMT	OMDMD	DEM05a	$ 14,192,120	$ 9,336,172	$ 4,289,097	$ 348,102	$ 7,607	$ 211,140	$ -
Low/Medium Pressure - Customer	OMT	OMDMC	CUST01a	2,468,774	2,257,226	209,563	1,744	16	225	-
High Pressure - Demand	OMT	OMDMD	DEM05	2,218,374	1,270,546	592,705	47,729	11,809	165,525	130,060
High Pressure - Customer	OMT	OMDMD	CUST01	166,116	151,851	14,099	120	8	37	2
Total Distribution Mains				$ 19,045,384	$ 13,015,795	$ 5,105,464	$ 397,696	$ 19,439	$ 376,927	$ 130,062
Services										
Customer	OMT	OMSC	CUST02	$ 5,413,189	$ 4,982,011	$ 422,492	$ 3,935	$ 1,326	$ 3,197	$ 227
Meters										
Customer	OMT	OMMC	CUST03	$ 2,383,590	$ 1,805,717	$ 461,451	$ 27,077	$ 7,750	$ 77,174	$ 4,419
Customer Accounts										
Customer	OMT	OMCAC	CUST04	$ 11,210,564	$ 10,099,991	$ 978,958	$ 75,556	$ 5,223	$ 48,746	$ 2,089
Customer Service										
Customer	OMT	OMCSC	CUST05	$ 5,049,385	$ 4,549,169	$ 440,936	$ 34,032	$ 2,352	$ 21,956	$ 941
Total		OMTT		$ 60,158,628	$ 45,114,530	$ 12,574,881	$ 967,679	$ 62,180	$ 1,029,919	$ 409,439

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Payroll Expenses										
Procurement Expenses										
Demand	LBTOT	LBGSD	DEM01	$ 65,674	$ 37,614	$ 17,547	$ 1,413	$ 350	$ 4,900	$ 3,850
Commodity	LBTOT	LBGSC	COM01	493,727	236,222	121,399	11,589	3,399	88,356	32,762
Total Procurement Expenses		LBGST		$ 559,400	$ 273,836	$ 138,946	$ 13,002	$ 3,749	$ 93,257	$ 36,612
Storage										
Demand	LBTOT	LBSD	DEM02	$ 982,096	$ 650,477	$ 306,496	$ 25,124	$ -	$ -	$ -
Commodity	LBTOT	LBSC	COM02	2,082,227	1,357,717	669,257	55,254	-	-	-
Total Storage		LBST		$ 3,064,323	$ 2,008,193	$ 975,753	$ 80,377	$ -	$ -	$ -
Transmission										
Demand	LBTOT	LBTD	DEM03	$ 549,153	$ 363,723	$ 171,381	$ 14,048	$ -	$ -	$ -
Commodity	LBTOT	LBTC	COM03	-	-	-	-	-	-	-
Total Transmission		LBTRT		$ 549,153	$ 363,723	$ 171,381	$ 14,048	$ -	$ -	$ -
Distribution Expenses										
Commodity	LBTOT	LBDEC	COM04	$ 345,112	$ 165,118	$ 84,857	$ 8,101	$ 2,376	$ 61,761	$ 22,900
Distribution Structures & Equipment										
Demand	LBTOT	LBDSD	DEM04	$ 769,410	$ 440,670	$ 205,571	$ 16,554	$ 4,096	$ 57,410	$ 45,109
Distribution Mains										
Low/Medium Pressure - Demand	LBTOT	LBDMD	DEM05a	$ 4,024,521	$ 2,647,499	$ 1,216,278	$ 98,713	$ 2,157	$ 59,874	$ -
Low/Medium Pressure - Customer	LBTOT	LBDMC	CUST01a	700,081	640,091	59,427	495	4	64	-
High Pressure - Demand	LBTOT	LBDMC	DEM05	629,074	360,294	168,076	13,535	3,349	46,939	36,882
High Pressure - Customer	LBTOT	LBDMC	CUST01	47,106	43,061	3,998	34	2	10	0
Total Distribution Mains				$ 5,400,783	$ 3,690,946	$ 1,447,779	$ 112,776	$ 5,513	$ 106,887	$ 36,882
Services										
Customer	LBTOT	LBSC	CUST02	$ 1,602,007	$ 1,474,402	$ 125,034	$ 1,165	$ 392	$ 946	$ 67
Meters										
Customer	LBTOT	LBMC	CUST03	$ 911,466	$ 690,492	$ 176,455	$ 10,354	$ 2,964	$ 29,511	$ 1,690
Customer Accounts										
Customer	LBTOT	LBCAC	CUST04	$ 2,996,181	$ 2,699,365	$ 261,640	$ 20,193	$ 1,396	$ 13,028	$ 558
Customer Service										
Customer	LBTOT	LBCSC	CUST05	$ 463,663	$ 417,731	$ 40,489	$ 3,125	$ 216	$ 2,016	$ 86
Total		LBTT		$ 16,661,498	$ 12,224,475	$ 3,627,906	$ 279,696	$ 20,701	$ 364,815	$ 143,906

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Depreciation Expenses										
Procurement Expenses										
Demand	DEPREX	DEGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	DEPREX	DEGSC	COM01	-	-	-	-	-	-	-
Total Procurement Expenses		DEGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	DEPREX	DESD	DEM02	$ 1,724,770	$ 1,142,375	$ 538,272	$ 44,122	$ -	$ -	$ -
Commodity	DEPREX	DESC	COM02	-	-	-	-	-	-	-
Total Storage		DEST		$ 1,724,770	$ 1,142,375	$ 538,272	$ 44,122	$ -	$ -	$ -
Transmission										
Demand	DEPREX	DETD	DEM03	$ 226,669	$ 150,131	$ 70,740	$ 5,799	$ -	$ -	$ -
Commodity	DEPREX	DETC	COM03	-	-	-	-	-	-	-
Total Transmission		DETT		$ 226,669	$ 150,131	$ 70,740	$ 5,799	$ -	$ -	$ -
Distribution Expenses										
Commodity	DEPREX	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	DEPREX	DEDSD	DEM04	$ 519,136	$ 297,329	$ 138,703	$ 11,169	$ 2,763	$ 38,736	$ 30,436
Distribution Mains										
Low/Medium Pressure - Demand	DEPREX	DEDMD	DEM05a	$ 6,326,723	$ 4,161,984	$ 1,912,042	$ 155,181	$ 3,391	$ 94,125	$ -
Low/Medium Pressure - Customer	DEPREX	DEDMC	CUST01a	1,100,558	1,006,252	93,421	778	7	100	-
High Pressure - Demand	DEPREX	DEDMD	DEM05	988,932	566,398	264,223	21,277	5,264	73,790	57,980
High Pressure - Customer	DEPREX	DEDMC	CUST01	74,053	67,694	6,285	53	3	16	1
Total Distribution Mains				$ 8,490,265	$ 5,802,327	$ 2,275,971	$ 177,289	$ 8,666	$ 168,031	$ 57,980
Services										
Customer	DEPREX	DESC	CUST02	$ 7,133,217	$ 6,565,034	$ 556,738	$ 5,186	$ 1,748	$ 4,213	$ 299
Meters										
Customer	DEPREX	DEMC	CUST03	$ 1,986,963	$ 1,505,248	$ 384,666	$ 22,572	$ 6,461	$ 64,333	$ 3,684
Customer Accounts										
Customer	DEPREX	DECAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service										
Customer	DEPREX	DECSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 20,081,020	$ 15,462,445	$ 3,965,089	$ 266,137	$ 19,638	$ 275,312	$ 92,399

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Regulatory Credits										
Procurement Expenses										
Demand	REGCR	DEGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	REGCR	DEGSC	COM01	-	-	-	-	-	-	-
Total Procurement Expenses		DEGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	REGCR	DESD	DEM02	$ (53,830)	$ (35,653)	$ (16,799)	$ (1,377)	$ -	$ -	$ -
Commodity	REGCR	DESC	COM02	-	-	-	-	-	-	-
Total Storage		DEST		$ (53,830)	$ (35,653)	$ (16,799)	$ (1,377)	$ -	$ -	$ -
Transmission										
Demand	REGCR	DETD	DEM03	$ (11,604)	$ (7,686)	$ (3,621)	$ (297)	$ -	$ -	$ -
Commodity	REGCR	DETC	COM03	-	-	-	-	-	-	-
Total Transmission		DETT		$ (11,604)	$ (7,686)	$ (3,621)	$ (297)	$ -	$ -	$ -
Distribution Expenses										
Commodity	REGCR	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	REGCR	DEDSD	DEM04	$ (11,895)	$ (6,812)	$ (3,178)	$ (256)	$ (63)	$ (888)	$ (697)
Distribution Mains										
Low/Medium Pressure - Demand	REGCR	DEDMD	DEM05a	$ (179,797)	$ (118,278)	$ (54,338)	$ (4,410)	$ (96)	$ (2,675)	$ -
Low/Medium Pressure - Customer	REGCR	DEDMC	CUST01a	(31,276)	(28,596)	(2,655)	(22)	(0)	(3)	-
High Pressure - Demand	REGCR	DEDMD	DEM05	(28,104)	(16,096)	(7,509)	(605)	(150)	(2,097)	(1,648)
High Pressure - Customer	REGCR	DEDMC	CUST01	(2,104)	(1,924)	(179)	(2)	(0)	(0)	(0)
Total Distribution Mains				$ (241,282)	$ (164,894)	$ (64,680)	$ (5,038)	$ (246)	$ (4,775)	$ (1,648)
Services										
Customer	REGCR	DESC	CUST02	$ (117,318)	$ (107,973)	$ (9,156)	$ (85)	$ (29)	$ (69)	$ (5)
Meters										
Customer	REGCR	DEMC	CUST03	$ (41,606)	$ (31,519)	$ (8,055)	$ (473)	$ (135)	$ (1,347)	$ (77)
Customer Accounts										
Customer	REGCR	DECAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service										
Customer	REGCR	DECSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		RCR		$ (477,534)	$ (354,538)	$ (105,490)	$ (7,526)	$ (474)	$ (7,079)	$ (2,427)

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Accretion Expense										
Procurement Expenses										
Demand	ACCRE	DEGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	ACCRE	DEGSC	COM01	-	-	-	-	-	-	-
Total Procurement Expenses		DEGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	ACCRE	DESD	DEM02	$ 52,307	$ 34,644	$ 16,324	$ 1,338	$ -	$ -	$ -
Commodity	ACCRE	DESC	COM02	-	-	-	-	-	-	-
Total Storage		DEST		$ 52,307	$ 34,644	$ 16,324	$ 1,338	$ -	$ -	$ -
Transmission										
Demand	ACCRE	DETD	DEM03	$ 11,276	$ 7,468	$ 3,519	$ 288	$ -	$ -	$ -
Commodity	ACCRE	DETC	COM03	-	-	-	-	-	-	-
Total Transmission		DETT		$ 11,276	$ 7,468	$ 3,519	$ 288	$ -	$ -	$ -
Distribution Expenses										
Commodity	ACCRE	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	ACCRE	DEDSD	DEM04	$ 11,558	$ 6,620	$ 3,088	$ 249	$ 62	$ 862	$ 678
Distribution Mains										
Low/Medium Pressure - Demand	ACCRE	DEDMD	DEM05a	$ 174,709	$ 114,931	$ 52,800	$ 4,285	$ 94	$ 2,599	$ -
Low/Medium Pressure - Customer	ACCRE	DEDMC	CUST01a	30,391	27,787	2,580	21	0	3	-
High Pressure - Demand	ACCRE	DEDMD	DEM05	27,309	15,641	7,296	588	145	2,038	1,601
High Pressure - Customer	ACCRE	DEDMC	CUST01	2,045	1,869	174	1	0	0	0
Total Distribution Mains				$ 234,454	$ 160,228	$ 62,850	$ 4,896	$ 239	$ 4,640	$ 1,601
Services										
Customer	ACCRE	DESC	CUST02	$ 113,998	$ 104,918	$ 8,897	$ 83	$ 28	$ 67	$ 5
Meters										
Customer	ACCRE	DEMC	CUST03	$ 40,428	$ 30,627	$ 7,827	$ 459	$ 131	$ 1,309	$ 75
Customer Accounts										
Customer	ACCRE	DECAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service										
Customer	ACCRE	DECSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		ACC		$ 464,021	$ 344,505	$ 102,505	$ 7,313	$ 460	$ 6,879	$ 2,358

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
ITC Amortization										
Procurement Expenses										
Demand	ITCAM	DEGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	ITCAM	DEGSC	COM01	-	-	-	-	-	-	-
Total Procurement Expenses		DEGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	ITCAM	DESD	DEM02	$ (17,338)	$ (11,484)	$ (5,411)	$ (444)	$ -	$ -	$ -
Commodity	ITCAM	DESC	COM02	-	-	-	-	-	-	-
Total Storage		DEST		$ (17,338)	$ (11,484)	$ (5,411)	$ (444)	$ -	$ -	$ -
Transmission										
Demand	ITCAM	DETD	DEM03	$ (3,738)	$ (2,475)	$ (1,166)	$ (96)	$ -	$ -	$ -
Commodity	ITCAM	DETC	COM03	-	-	-	-	-	-	-
Total Transmission		DETT		$ (3,738)	$ (2,475)	$ (1,166)	$ (96)	$ -	$ -	$ -
Distribution Expenses										
Commodity	ITCAM	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	ITCAM	DEDSD	DEM04	$ (3,831)	$ (2,194)	$ (1,024)	$ (82)	$ (20)	$ (286)	$ (225)
Distribution Mains										
Low/Medium Pressure - Demand	ITCAM	DEDMD	DEM05a	$ (57,911)	$ (38,096)	$ (17,502)	$ (1,420)	$ (31)	$ (862)	$ -
Low/Medium Pressure - Customer	ITCAM	DEDMC	CUST01a	(10,074)	(9,211)	(855)	(7)	(0)	(1)	-
High Pressure - Demand	ITCAM	DEDMD	DEM05	(9,052)	(5,184)	(2,419)	(195)	(48)	(675)	(531)
High Pressure - Customer	ITCAM	DEDMC	CUST01	(678)	(620)	(58)	(0)	(0)	(0)	(0)
Total Distribution Mains				$ (77,715)	$ (53,111)	$ (20,833)	$ (1,623)	$ (79)	$ (1,538)	$ (531)
Services										
Customer	ITCAM	DESC	CUST02	$ (37,787)	$ (34,777)	$ (2,949)	$ (27)	$ (9)	$ (22)	$ (2)
Meters										
Customer	ITCAM	DEMC	CUST03	$ (13,401)	$ (10,152)	$ (2,594)	$ (152)	$ (44)	$ (434)	$ (25)
Customer Accounts										
Customer	ITCAM	DECAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service										
Customer	ITCAM	DECSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		ITC		$ (153,809)	$ (114,193)	$ (33,977)	$ (2,424)	$ (153)	$ (2,280)	$ (782)

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Other Taxes										
Procurement Expenses										
Demand	OTT	OTTGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	OTT	OTTGSC	COM01	-	-	-	-	-	-	-
Total Procurement Expenses		OTTGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	OTT	OTTSD	DEM02	$ 657,000	$ 435,154	$ 205,039	$ 16,807	$ -	$ -	$ -
Commodity	OTT	OTTSC	COM02	-	-	-	-	-	-	-
Total Storage		OTTST		$ 657,000	$ 435,154	$ 205,039	$ 16,807	$ -	$ -	$ -
Transmission										
Demand	OTT	OTTTD	DEM03	$ 140,799	$ 93,256	$ 43,941	$ 3,602	$ -	$ -	$ -
Commodity	OTT	OTTTC	COM03	-	-	-	-	-	-	-
Total Transmission		OTTTT		$ 140,799	$ 93,256	$ 43,941	$ 3,602	$ -	$ -	$ -
Distribution Expenses										
Commodity	OTT	OTTDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	OTT	OTTDSD	DEM04	$ 138,426	$ 79,282	$ 36,985	$ 2,978	$ 737	$ 10,329	$ 8,116
Distribution Mains										
Low/Medium Pressure - Demand	OTT	OTTDMD	DEM05a	$ 2,260,497	$ 1,487,050	$ 683,160	$ 55,445	$ 1,212	$ 33,630	$ -
Low/Medium Pressure - Customer	OTT	OTTDMC	CUST01a	393,222	359,527	33,379	278	2	36	-
High Pressure - Demand	OTT	OTTDMD	DEM05	353,339	202,370	94,405	7,602	1,881	26,365	20,716
High Pressure - Customer	OTT	OTTDMC	CUST01	26,459	24,187	2,246	19	1	6	0
Total Distribution Mains				$ 3,033,516	$ 2,073,134	$ 813,190	$ 63,344	$ 3,096	$ 60,036	$ 20,716
Services										
Customer	OTT	OTTSC	CUST02	$ 1,365,315	$ 1,256,563	$ 106,561	$ 993	$ 335	$ 806	$ 57
Meters										
Customer	OTT	OTTMC	CUST03	$ 484,195	$ 366,807	$ 93,738	$ 5,500	$ 1,574	$ 15,677	$ 898
Customer Accounts										
Customer	OTT	OTTCAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service										
Customer	OTT	OTTCSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTTT		$ 5,819,250	$ 4,304,196	$ 1,299,452	$ 93,225	$ 5,742	$ 86,848	$ 29,787

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Interest Expense										
Procurement Expenses										
Demand	INT	INTGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	INT	INTGSC	COM01	-	-	-	-	-	-	-
Total Procurement Expenses		INTGST		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Storage										
Demand	INT	INTSD	DEM02	$ 1,173,869	$ 777,495	$ 366,345	$ 30,029	$ -	$ -	$ -
Commodity	INT	INTSC	COM02	-	-	-	-	-	-	-
Total Storage		INTST		$ 1,173,869	$ 777,495	$ 366,345	$ 30,029	$ -	$ -	$ -
Transmission										
Demand	INT	INTTD	DEM03	$ 251,567	$ 166,622	$ 78,510	$ 6,435	$ -	$ -	$ -
Commodity	INT	INTTC	COM03	-	-	-	-	-	-	-
Total Transmission		INTTT		$ 251,567	$ 166,622	$ 78,510	$ 6,435	$ -	$ -	$ -
Distribution Expenses										
Commodity	INT	INTDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment										
Demand	INT	INTDSD	DEM04	$ 247,327	$ 141,654	$ 66,081	$ 5,321	$ 1,317	$ 18,454	$ 14,500
Distribution Mains										
Low/Medium Pressure - Demand	INT	INTDMD	DEM05a	$ 4,038,858	$ 2,656,930	$ 1,220,611	$ 99,065	$ 2,165	$ 60,087	$ -
Low/Medium Pressure - Customer	INT	INTDMC	CUST01a	702,575	642,372	59,638	496	4	64	-
High Pressure - Demand	INT	INTDMD	DEM05	631,315	361,578	168,675	13,583	3,361	47,106	37,013
High Pressure - Customer	INT	INTDMC	CUST01	47,274	43,214	4,012	34	2	10	0
Total Distribution Mains				$ 5,420,022	$ 3,704,094	$ 1,452,936	$ 113,178	$ 5,532	$ 107,268	$ 37,014
Services										
Customer	INT	INTSC	CUST02	$ 2,439,425	$ 2,245,117	$ 190,394	$ 1,773	$ 598	$ 1,441	$ 102
Meters										
Customer	INT	INTMC	CUST03	$ 865,116	$ 655,380	$ 167,482	$ 9,828	$ 2,813	$ 28,010	$ 1,604
Customer Accounts										
Customer	INT	INTCAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service										
Customer	INT	INTCSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 10,397,327	$ 7,690,361	$ 2,321,748	$ 166,565	$ 10,259	$ 155,173	$ 53,220

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Net Operating Income -- Adjusted Test Period										
Operating Revenues										
Sales and Transportation			REV01	408,703,213	266,835,228	123,545,049	10,222,598	2,791,492	3,961,597	1,347,249
Interdepartmental Sales			REV01	6,531,020	4,263,989	1,974,232	163,356	44,608	63,306	21,529
Forfeited Discounts			REVFD	$ 3,212,301	2,605,350	555,513	38,246	-	13,193	-
Miscellaneous Revenue		REVMSR	REVMISC	443,726	28,485	332,902	-	744	81,595	-
Total Operating Revenues		TOR		$ 418,890,259	$ 273,733,051	$ 126,407,696	$ 10,424,199	$ 2,836,844	$ 4,119,691	$ 1,368,778
Pro-Forma Adjustments to Revenues										
VDT Amortization and Surcredit			REVUC	$ (323)	$ (224)	$ (77)	$ (5)	$ (1)	$ (12)	$ (4)
Adjust Base Rates to reflect full year of FAC Roll-in			REVADJ1	$ 9,941,202	$ 7,856,572	$ 1,939,945	$ 78,152	$ 6,208	$ 54,562	$ 5,762
Elimination of ECR, MSR, DSM, FAC, and GSC accruals			REV01	$ 2,228,479	$ 1,454,935	$ 673,637	$ 55,739	$ 15,221	$ 21,601	$ 7,346
Temperature Normalization				(248,948)	(190,208)	(16,121)	(18,867)	(1,739)	(13,063)	(8,950)
Year-End Customer Adjustment		REVADJ2		1,760,940	259,367	1,404,610	96,963	-	-	
Rate Switching				22,135			(22,236)		44,371	
Adjustment to eliminate gas supply cost recovenes			REVGSC	(322,476,565)	$ (206,301,504)	$ (103,957,947)	$ (8,992,672)	$ (2,711,423)	$ (445,190)	$ (67,829)
Adjustment to eliminate unbilled revenues		REVUB	REV01	11,377,000	$ 7,427,846	$ 3,439,102	$ 284,565	$ 77,706	$ 110,278	$ 37,503
Removal of DSM Revenues			REVADJ4	(2,319,554)	(2,207,347)	(104,277)	-	(899)	(7,031)	-
Total Revenue Adjustments				$ (299,715,634)	$ (191,700,564)	$ (96,621,129)	$ (8,518,360)	$ (2,614,926)	$ (234,483)	$ (26,172)
Total Adjusted Revenue		TREVADJ		$ 119,174,625	$ 82,032,488	$ 29,786,568	$ 1,905,838	$ 221,918	$ 3,885,208	$ 1,342,605
Expenses										
Operation and Maintenance Expenses				$ 60,158,628	$ 45,114,530	$ 12,574,881	$ 967,679	$ 62,180	$ 1,029,919	$ 409,439
Depreciation and Amortization Expenses				20,081,020	15,462,445	3,965,089	266,137	19,638	275,312	92,399
Other Expenses (ITC amortization, Reg Credits, Accretion)				(167,322)	(124,225)	(36,962)	(2,637)	(166)	(2,480)	(850)
Other Taxes				5,819,250	4,304,196	1,299,452	93,225	5,742	86,848	29,787
Total Operating Expenses		TOE		$ 85,891,577	$ 64,756,945	$ 17,802,461	$ 1,324,404	$ 87,394	$ 1,389,598	$ 530,775

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Net Operating Income -- Adjusted Test Period (Cont.)										
Pro-Forma Adjustments to Expenses										
Eliminate DSM Expenses		EXADJ1	REVADJ4	(1,898,813)	(1,806,959)	(85,362)	-	(736)	(5,756)	-
Year-End Customer Adjustment		EXADJ2	REVADJ2	541,722	79,790	432,103	29,829	-	-	-
Depreciation Expenses		EXADJ3	DET	385,987	297,211	76,215	5,116	377	5,292	1,776
Labor Adjustment		EXADJ4	LBTT	209,494	153,705	45,616	3,517	260	4,587	1,809
Pensions/Post Retirement Benefits Adjmt.		EXADJ6	LBTT	78,706	57,746	17,138	1,321	98	1,723	680
Property Insurance Adjmt.			RBT	88,922	64,679	20,930	1,539	85	1,266	423
Liability Insurance Adjmt.			RBT	128,741	93,642	30,302	2,228	123	1,834	612
Eliminate Advertising Expenses		EXADJ7	REVUC	(149,398)	(103,672)	(35,786)	(2,396)	(284)	(5,327)	(1,933)
Rate Case Expenses		EXADJ8	OMTT	107,664	80,740	22,505	1,732	111	1,843	733
Reitred Mainframe Adjmt.			RBT	(352,000)	(256,033)	(82,851)	(6,092)	(338)	(5,013)	(1,673)
2009 Winter Storm Adjmt			PTISDIS	33,538	22,920	8,990	700	34	664	229
Interest Rate Swap Amortization		EXADJ9	RBT	53,039	38,579	12,484	918	51	755	252
Normalize 925 Injuries/Damages Adjmt.		EXADJ10	RBT	38,531	28,026	9,069	667	37	549	183
Adjustment to correct Edison Electric invoice			RBT	(62,735)	(45,631)	(14,766)	(1,086)	(60)	(894)	(298)
Property Tax Adjmt.			RBT	(29,440)	(21,414)	(6,929)	(510)	(28)	(419)	(140)
Federal & State Income Tax Adjmt.			PROFO	3,014,150	1,935,781	964,509	85,055	26,228	2,341	236
Federal & State Income Tax Interest Adjmt.			INTT	(97,159)	(71,863)	(21,696)	(1,556)	(96)	(1,450)	(497)
Prior Income tax true-ups & adjustments			RBT	232,125	168,840	54,636	4,017	223	3,306	1,103
Tax basis depreciation reduction Adjmt.			DET	13,472	10,373	2,660	179	13	185	62
Total Expense Adjustments		ADJTOT		$ 2,336,546	$ 726,460	$ 1,449,766	$ 125,178	$ 26,100	$ 5,485	$ 3,557
Net Income Before Income Taxes				$ 30,946,502	$ 16,549,083	$ 10,534,340	$ 456,256	$ 108,425	$ 2,490,124	$ 808,274
Income Taxes			TXINC	$ 6,084,288	2,622,928	2,431,619	85,773	29,065	691,342	223,560
Net Operating Income (Pro-Forma)		TOM		$ 24,862,214	$ 13,926,155	$ 8,102,721	$ 370,483	$ 79,359	$ 1,798,782	$ 584,714
Unadjusted Net Cost Rate Base				$ 491,799,642	$ 357,718,793	$ 115,756,204	$ 8,511,475	$ 471,557	$ 7,004,541	$ 2,337,072
Depreciation Adjustment			DET	$ (385,987)	(297,211)	(76,215)	(5,116)	(377)	(5,292)	(1,776)
Cash Woking Capital Adjustment			OMTT	$ (94,673)	(70,998)	(19,789)	(1,523)	(98)	(1,621)	(644)
Net Cost Rate Base				$ 491,318,982	$ 357,350,584	$ 115,660,200	$ 8,504,836	$ 471,081	$ 6,997,628	$ 2,334,651
Rate of Return -- Pro-Forma				5.06%	3.90%	7.01%	4.36%	16.85%	25.71%	25.05%

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Net Operating Income -- Proposed Rates										
Test Year Operating Income				$ 24,862,214	$ 13,926,155	$ 8,102,721	$ 370,483	$ 79,359	$ 1,798,782	$ 584,714
Proposed Increase				$ 21,922,879	$ 16,197,217	5,362,513	363,149	-	-	-
Increase in Miscellaneous Charges - Disc/Recon			TREVADJ	665,390	458,014	166,308	10,641	1,239	21,692	7,496
Incremental Income Taxes				8,400,900	6,194,318	2,056,247	139,018	461	8,068	2,788
Net Operating Income Adjusted for Increase				39,049,583	24,387,067	11,575,294	605,256	80,138	1,812,406	589,423
Net Cost Rate Base (Same as Above)				$ 491,318,982	$ 357,350,584	$ 115,660,200	$ 8,504,836	$ 471,081	$ 6,997,628	$ 2,334,651
Rate of Return -- Proposed				7.95%	6.82%	10.01%	7.12%	17.01%	25.90%	25.25%

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Allocation Factors										
Commodity										
Procurement Expenses		COM01		42,412,266	20,292,002	10,428,447	995,514	291,983	7,590,002	2,814,318
					0.478447	0.245883	0.023472			
Storage		COM02		23,642,092	15,415,833	7,598,896	627,363			-
Transmission		COM03		23,642,092	15,415,833	7,598,896	627,363	-	-	-
Distribution		COM04		42,412,266	20,292,002	10,428,447	995,514	291,983	7,590,002	2,814,318
Adjusted Deliveries				42,977,597	20,304,230	11,007,576	1,043,051	288,669	7,559,624	2,774,447
Demand										
Procurement Expenses		DEM01		516,420	295,773	137,977	11,111	2,749	38,533	30,277
Storage		DEM02		12,289,964	8,140,074	3,835,494	314,396	-	-	-
					0.662335	0.312083	0.025582			
Transmission		DEM03		12,289,964	8,140,074	3,835,494	314,396	-	-	-
Distribution Structures		DEM04		516,420	295,773	137,977	11,111	2,749	38,533	30,277
High Pressure Distribution Mains		DEM05		516,420	295,773	137,977	11,111	2,749	38,533	30,277
Low/Medium Pressure Distribution Mains		DEM05a		449,611	295,773	135,880	11,028	241	6,689	-
Customer										
High Pressure Distrib Mains (yr-end cust.)		CUST01		318,528	291,175	27,035	230	15	70	3
Low/Med Pres. Distrib Mains (yr-end cust.)		CUST01a		318,464	291,175	27,033	225	2	29	-
Services		CUST02		154,617,165	142,301,428	12,067,653	112,407	37,881	91,317	6,478
Meters		CUST03		45,693,972	34,616,028	8,846,128	519,081	148,573	1,479,448	84,713
Customer Count (Average)				315,940	290,075	25,560	217	15	70	3
Customer Accounts		CUST04		321,971	290,075	28,116	2,170	150	1,400	60
Customer Service		CUST05		321,971	290,075	28,116	2,170	150	1,400	60
Forfeited Discounts		REVFD		3,212,301	2,605,350	555,513	38,246	-	13,193	-

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
12 Months Ended October 31, 2009

Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)	Special Contracts (SP)
Allocation Factors Continued					119.334752	346.092652	2,392.079493	9,904.875000	21,134.971014	28,237.666667
Taxable Income										
Net Income Before Income Tax		NIBIT		$ 30,946,502	$ 16,549,083	$ 10,534,340	$ 456,256	$ 108,425	$ 2,490,124	$ 808,274
Interest Expense		INT		$ 10,397,327	$ 7,690,361	$ 2,321,748	$ 166,565	$ 10,259	$ 155,173	$ 53,220
Interest Adjustment				$ -	-	-	-	-	-	-
Taxable Income		TXINC		$ 20,549,175	$ 8,858,722	$ 8,212,592	$ 289,691	$ 98,165	$ 2,334,951	$ 755,054
Total Distribution Expense		DISTRT		$ 30,162,627	$ 21,640,723	$ 6,861,988	$ 501,490	$ 47,260	$ 776,494	$ 334,673
Meter Cost				54,833,357	42,377,795	9,878,394	557,271	188,133	1,731,199	100,564
					0.772847	0.180153	0.010163	0.003431	0.031572	0.001834
Number of Customers				318,528	291,175	27,035	230	15	70	3
Services Cost				154,617,165	142,301,428	12,067,653	112,407	37,881	91,317	6,478
					0.920347	0.078049	0.000727	0.000245	0.000591	0.000042
Actual Revenue		REV01		421,091,066	274,923,042	127,289,717	10,532,446	2,876,103	4,081,674	1,388,084
Actual Net Revenue		REVUC		102,114,452	70,860,600	24,460,062	1,637,375	194,108	3,641,316	1,320,991
DSM Allocation		REVADJ4		2,356,128	2,242,152	105,921	-	913	7,142	-
Miscellaneous Revenue Allocation		REVMISC		544,576	34,959	408,564	-	913	100,140	-
GSC Revenue		REVGSC		318,976,614	204,062,442	102,829,655	8,895,071	2,681,995	440,358	67,093
Revenue Adjustment Reflective Base Rates for Full Year		REVADJ1		9,941,202	7,856,572	1,939,945	78,152	6,208	54,562	5,762
Pro-Forma Adjustments		PROFO		(300,541,676)	(193,017,235)	(96,171,472)	(8,480,877)	(2,615,194)	(233,379)	(23,519)
High Pressure System		RBTHP		28,695,754	17,117,598	7,302,482	575,834	142,205	1,992,427	1,565,208

Seelye Exhibit 30

Gas Demand Allocation Factors

LOUISVILLE GAS AND ELECTRIC COMPANY
CALCULATION OF MAXIMUM CLASS DEMANDS FOR
DETERMINATION OF DEMAND ALLOCATION FACTORS
12 MONTHS ENDED OCTOBER 31, 2009

	Residential Rate RGS	Commercial Rate CGS	Industrial Rate IGS	Rate AAGS	IntraCompany	Rate FT (1)	Special Contracts	Total
Actual								
Total Mcf Sales and Transportation	20,292,002	10,428,447	995,514	291,983	437,214	7,603,679	2,814,318	42,863,157
Non-Temp. Sensitive Sales & Transportation - Jul. & Aug.	777,486	551,674	75,004	27,373	71,205	1,073,896	222,509	2,799,148
Annualized Non-Temperature Sensitive Sales & Transport.	4,664,918	3,310,045	450,026	164,236	427,229	6,443,378	1,335,054	16,794,886
Non-Temperature Sensitive Sales & Transportation per Day	12,781	9,069	1,233	450	1,170	17,653	3,658	46,013
Temperature Sensitive Sales & Transportation	15,627,084	7,118,403	545,487	127,747	9,985	1,160,301	1,479,264	26,068,271
Degree Days	4,252	4,252	4,252	4,279	4,279	4,279	4,279	
Temperature Sensitive Sales & Transportation per Degree Day	3,675	1,674	128	30	2	271	346	6,127
Calculated Daily Customer Deliveries (Demands) @ -12 Degrees								
Total Demands	295,773	137,977	11,111	2,749	1,350	38,533	30,277	517,770
Percentage of Total	57.12%	26.65%	2.15%	0.53%	0.26%	7.44%	5.85%	100.00%
Demands - High Pressure Distribution System	295,773	137,977	11,111	2,749	1,350	38,533	30,277	517,770
Demands - Low and Medium Pressure Distribution System	295,773	135,880	11,028	241	-	6,689	-	449,611
Adjustment for Rate Switching:								
Total Mcf Sales and Transportation			(24,358)			1,734,746	(1,710,388)	-
Non-Temp. Sensitive Sales & Transportation - Jul. & Aug.			(2,614)			121,435	(118,821)	-
Annualized Non-Temperature Sensitive Sales & Transport.			(15,686)			728,612	(712,927)	-
Non-Temperature Sensitive Sales & Transportation per Day			(43)			1,996	(1,953)	-
Temperature Sensitive Sales & Transportation			(8,672)			1,006,134	(997,462)	-
Degree Days			4,279			4,279	4,279	
Temperature Sensitive Sales & Transportation per Degree Day			(2)			235	(233)	-
Calculated Daily Customer Deliveries (Demands) @ -12 Degrees			(199)			20,101	(19,902)	-
Calculated Daily Customer Deliveries (Demands) @ -12 Degrees (As Adjusted)								
Total Demands	295,773	137,977	10,912	2,749	1,350	58,634	10,374	517,770
Percentage of Total	57.12%	26.65%	2.11%	0.53%	0.26%	11.32%	2.00%	100.00%
Demands - High Pressure Distribution System	295,773	137,977	10,912	2,749	1,350	58,634	10,374	517,770
Demands - Low and Medium Pressure Distribution System	295,773	135,880	10,513	241	-	26,790	-	469,197

(1) Rate FT includes LG&E Special Contract

Seelye Exhibit 31

Gas Zero Intercept
Distribution Mains

Louisville Gas and Electric Company

Zero Intercept Analysis
Account 376 -- Distribution Mains

Weighted Linear Regression Statistics

	Estimate	Standard Error
Size Coefficient ($ per Foot)	6 6242745	0 3483029
Zero Intercept ($ per Foot)	4 3699078	1 7711843
R-Square	0 9717338	

Plant Classification

Total All Distribution Mains		23,576,054
Zero Intercept		4 3699078
Zero Intercept Cost	$	103,025,182
Total Cost of Sample	$	744,681,659
Percentage of Total		0 13834795

Louisville Gas and Electric Company

Zero Intercept Analysis
Account 376 -- Distribution Mains

Pipe Size	Net Cost of Plant	Quantity	Avg Cost	n	y	x	est y	y*n^.5	n^.5	xn^.5
10	1,868,907.15	46,272	40.38959097	46,272	40.38959	10.00	70.613	8688.2	215.11	2151.093
12	1,773,349.05	34,982	50.69318658	34,982	50.69319	12.00	83.861	9481.4	187.03	2244.417
14	503,514.00	7,950	63.33509471	7,950	63.33509	14.00	97.110	5647.1	89.16	1248.279
16	2,211,303.07	29,398	75.21950715	29,398	75.21951	16.00	110.358	12897	171.46	2743.335
18	824,917.52	8,987	91.79008758	8,987	91.79009	18.00	123.607	8701.7	94.80	1706.396
24	802,493.76	7,681	104.477771	7,681	104.47777	24.00	163.352	9156.6	87.64	2103.392
4	5,953,186.14	308,200	19.31598358	308,200	19.31598	4.00	30.867	10723	555.16	2220.631
6	1,256,014.38	52,254	24.03671266	52,254	24.03671	6.00	44.116	5494.6	228.59	1371.548
8	988,712.89	30,205	32.73341807	30,205	32.73342	8.00	57.364	5688.9	173.80	1390.367
2	78,957,664.31	5,614,602	14.06291386	5,614,602	14.06291	2.00	17.618	33322	2,369.52	4739.03
4	80,510,455.05	2,766,504	29.10187553	2,766,504	29.10188	4.00	30.867	48405	1,663.28	6653.124
6	18,791,491.05	475,773	39.49675801	475,773	39.49676	6.00	44.116	27243	689.76	4138.578
8	6,975,878.42	109,602	63.6473643	109,602	63.64736	8.00	57.364	21071	331.06	2648.495
1	2,440,179.26	36,615	66.64425137	36,615	66.64425	1.00	10.994	12752	191.35	191.3505
1.5	40,628.21	649	62.60125131	649	62.60125	1.50	14.306	1594.8	25.48	38.21322
1.25	12,557.11	382	32.87201147	382	32.87201	1.25	12.650	642.48	19.54	24.43103
10	506,338.40	5,096	99.35996824	5,096	99.35997	10.00	70.613	7092.9	71.39	713.8627
12	43,301,704.30	510,224	84.86802718	510,224	84.86803	12.00	83.861	60621	714.30	8571.596
16	32,607,834.92	256,922	126.9172547	256,922	126.91725	16.00	110.358	64331	506.87	8109.996
2	93,954,810.83	4,730,633	19.86093845	4,730,633	19.86094	2.00	17.618	43198	2,175.00	4350.004
2.5	9,260.74	438	21.14323634	438	21.14324	2.50	20.931	442.5	20.93	52.32112
20	22,255,437.02	154,253	144.2787954	154,253	144.27880	20.00	136.855	56666	392.75	7855.011
22	827,042.28	3,497	236.5005086	3,497	236.50051	22.00	150.104	13986	59.14	1300.98
24	314,983.72	972	324.0573262	972	324.05733	24.00	163.352	10103	31.18	748.2459
4	180,668,868.15	5,014,238	36.03117127	5,014,238	36.03117	4.00	30.867	80683	2,239.25	8956.998
6	48,742,355.89	976,575	49.91153357	976,575	49.91153	6.00	44.116	49323	988.22	5929.309
8	108,600,035.77	2,031,861	53.44855567	2,031,861	53.44856	8.00	57.364	76187	1,425.43	11403.47
1.5	22,710.50	2,591	8.765146934	2,591	8.76515	1.50	14.306	446.16	50.90	76.3528
1.25	57,501.02	9,089	6.326440438	9,089	6.32644	1.25	12.650	603.14	95.34	119.1703
10	1,184,594.30	27,006	43.86411545	27,006	43.86412	10.00	70.613	7208.4	164.34	1643.35
12	365,494.01	6,026	60.65283861	6,026	60.65284	12.00	83.861	4708.3	77.63	931.5278
16	1,194,029.96	15,081	79.17445548	15,081	79.17446	16.00	110.358	9723	122.80	1964.876
2	634,102.15	66,815	9.490416083	66,815	9.49042	2.00	17.618	2453.1	258.49	516.972
3	32,419.81	2,426	13.3634816	2,426	13.36348	3.00	24.243	658.21	49.25	147.7633
4	2,020,550.62	118,777	17.01129527	118,777	17.01130	4.00	30.867	5862.8	344.64	1378.562
6	5,903.45	243	24.29402193	243	24.29402	6.00	44.116	378.71	15.59	93.53074
8	3,464,429.48	113,235	30.5950411	113,235	30.59504	8.00	57.364	10295	336.50	2692.033
1.25	154,211.02	5,258	29.32883687	5,258	29.32884	1.25	12.650	2126.7	72.51	90.64008
0.75	405,461.67	35,635	11.37818645	35,635	11.37819	0.75	9.338	2147.9	188.77	141.5793

Louisville Gas and Electric Company

Zero Intercept Analysis
Account 376 -- Distribution Mains

	Total Distribution Mains			High Pressure Mains			Low and Medium Pressure Mains	
Nominal Size (in inches)	Feet of Pipe	Installed Costs*	Unit Costs		Feet of Pipe	Installed Costs	Feet of Pipe	Installed Costs
				Category II 1"	35			
				Category III 1"	57			
1	36,615	2,440,179	66.6443		92	6,131	36,523	2,434,048
1.25	9,471	70,058	7.3971		0	0	9,471	70,058
1.5	3,240	63,339	19.5490		0	0	3,240	63,339
				Category II 2"	26,763			
				Category III 2"	35,228			
2	10,412,050	173,546,577	16.6679		61,991	1,033,257	10,350,059	172,513,320
2.5	438	9,261	21.1432		0	0	438	9,261
3	2,426	32,420	13.3635	*Category II 3"*	298	3,982	2,128	28,438
				Category II 4"	161,839			
				Category III 4"	183,215			
4	8,207,719	269,153,060	32.7927		345,054	11,315,244	7,862,665	257,837,816
				Category II 6"	77,342			
				Category III 6"	63,559			
6	1,504,845	68,795,765	45.7162		140,901	6,441,455	1,363,944	62,354,310
				Category II 8"	364,971			
				Category III 8"	104,206			
8	2,284,903	120,029,057	52.5314		469,177	24,646,505	1,815,726	95,382,552
10	78,374	3,559,840	45.4212	*Category II 10"*	385	17,487	77,989	3,542,353
				Category II 12"	214,435			
				Category III 12"	3,740			
12	551,232	45,440,547	82.4345		218,175	17,985,152	333,057	27,455,395
14	7,950	503,514	63.3351		0	0	7,950	503,514
16	301,401	36,013,168	119.4859	*Category II 16"*	177,273	21,181,623	124,128	14,831,545
18	8,987	824,918	91.7901		0	0	8,987	824,918
				Category II 20"	71,130			
				Category III 20"	20			
20	154,253	22,255,437	144.2788		71,150	10,265,436	83,103	11,990,001
22	3,497	827,042	236.5005	*Category II 22"*	927	219,236	2,570	607,806
24	8,653	1,117,477	129.1434	*Category II 24"*	921	118,941	7,732	998,536
Total All Mains	**23,576,054**	**$ 744,681,659**			**1,486,344**	**$ 93,234,449**	**22,089,710**	**$ 651,447,210**
Zero Intercept		**$ 4.3699078**				**$ 4.3699078**		**$ 4.3699078**
Customer-Related Costs**		**$ 103,025,182**				**$ 6,495,186**		**$ 96,529,996**
Portion of Total		**0.13834795**				**0.00872210**		**0.12962585**
Demand-Related Costs***		**$ 641,656,476**				**$ 86,739,263**		**$ 554,917,214**
Portion of Total		**0.86165205**				**0.11647831**		**0.74517374**

Notes:

* Mains costs reflect current installed costs determined by applying the applicable Handy-Whitman index to LG&E's actual recorded costs.

** Customer-Related Costs calculated by applying the zero intercept unit cost of $4.1948523 to total feet of pipe

*** Demand-Related Costs equal Total All Distribution Mains less Customer-Related Costs