COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:

APPLICATION OF LOUISVILLE GAS	**)**	
AND ELECTRIC COMPANY FOR AN	**)**	
ADJUSTMENT OF ITS ELECTRIC AND	**)**	**CASE NO. 2016-00371**
GAS RATES AND FOR CERTIFICATES	**)**	
OF PUBLIC CONVENIENCE AND	**)**	
NECESSITY	**)**	

DIRECT TESTIMONY

OF

GLENN A. WATKINS

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL

MARCH 3, 2017

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 1503 Santa Rosa Road, Suite 130, Richmond, Virginia 23229.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am President and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with an office in Richmond, Virginia. Except for a six month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my 36-year career at Technical Associates, I have conducted hundreds of marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving electric, gas, water/wastewater, and telephone utilities throughout the United States and Canada and have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. In addition, I have provided expert testimony before State and Federal courts as well as before State legislatures. A more complete description of my education and experience is provided in Schedule GAW-1.

Q. HAVE YOU PREVIOUSLY PROVIDED EXPERT TESTIMONY BEFORE THIS COMMISSION?

A. Yes. I have provided testimony relating to class cost of service and rate design before this Commission on numerous occasions including previous Kentucky Utilities ("KU") and Louisville Gas & Electric ("LG&E") rate cases.

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

A. Technical Associates has been retained by the Kentucky Office of the Attorney General ("OAG") to assist in its evaluation of the accuracy and reasonableness of LG&E's electric and gas class cost of service studies, proposed distribution of revenues by class and residential rate design for both electric and gas. The purpose of my testimony, therefore, is to comment on LG&E's proposals on these issues and to present my findings and recommendations based on the results of the studies I have undertaken on behalf of the OAG.

II. CLASS COST OF SERVICE – GENERAL CONCEPTS

Q. PLEASE BRIEFLY EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS") AND ITS PURPOSE IN A RATE PROCEEDING.

A. Generally, there are two types of cost of service studies used in public utility ratemaking: marginal cost studies and embedded, or fully allocated, cost studies. Consistent with the practices of the Kentucky Public Service Commission, LG&E has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expense is incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned to that customer or group in the CCOSS. Since most of the utility's costs of providing service are jointly incurred to serve all or most customers, they must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. With regard to those costs in which cost causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor; e.g., peak demand, energy usage, number of customers, etc.

Q. IN YOUR OPINION, HOW SHOULD THE RESULTS OF A CCOSS BE UTILIZED IN THE RATEMAKING PROCESS?

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive individual costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, numerous subjective decisions are required to allocate the myriad of jointly incurred costs.

In these regards, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS only as a guide, with the results being used as one of many tools to assign class revenue responsibility when cost causation factors cannot be realistically ascribed to some costs.

Q. HAVE THE HIGHER COURTS OPINED ON THE USEFULNESS OF COST ALLOCATIONS FOR PURPOSES OF ESTABLISHING REVENUE RESPONSIBILITY AND RATES?

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (predecessor to the FERC), the United States Supreme Court stated:

> But where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[1]

[1] Colorado Interstate Gas Co. v. Federal Power Comm'n, 324 U.S. 581, 589 (1945), 65 S. Ct. 829, 833.

Q. DOES YOUR OPINION, AND THE FINDINGS OF THE U.S. SUPREME COURT, IMPLY THAT COST ALLOCATIONS SHOULD PLAY NO ROLE IN THE RATEMAKING PROCESS?

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible approaches may produce significantly different results. In this regard, when all reasonable cost allocation approaches consistently show that certain classes are over or under contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one set of reasonable cost allocation approaches show dramatically different results than another reasonable approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

III. <u>ELECTRIC CCOSS</u>

Q. PLEASE EXPLAIN HOW YOU PROCEEDED WITH YOUR ANALYSIS OF LG&E'S ELECTRIC CCOSS.

A. In conducting my independent analysis, I reviewed the structure and organization of the Company's CCOSS and reviewed the accuracy and completeness of the primary drivers (allocators) used to assign costs to rate schedules and classes. Next, I reviewed LG&E's selection of allocators to specific rate base, revenue, and expense accounts. I then verified the accuracy of LG&E's CCOSS model by replicating its results using my own computer model. Finally, I adjusted certain aspects of the Company's study to better reflect cost causation and cost incidence by rate schedule and customer class.

Q. NOTWITHSTANDING ANY CONCEPTUAL DISAGREEMENTS ON HOW INDIVIDUAL COSTS SHOULD BE ALLOCATED ACROSS CLASSES, DID YOU FIND THE COMPANY'S STUDY TO BE ACCURATE?

A. As part of my detailed examination of Company witness William Seeyle's CCOSS, I discovered a few minor errors within his model. These minor errors relate to: (1) his assignment of meter reading expenses to the Lighting classes that are not metered;[2] (2) an inconsistency in the allocation of advertising expenses wherein Mr. Seeyle first allocated advertising expenses (Account 913) based on weighted number of customers and then deducted the Company's proforma advertising expense adjustment based on sales revenues; and, (3) the calculation and assignment of income tax expense to individual rate classes.[3]

Q. PLEASE PROVIDE A SUMMARY OF CLASS RATES OF RETURN UNDER MR. SEEYLE'S AS-FILED CCOSS AND THOSE OBTAINED WITH THE MINOR CORRECTIONS YOU DISCUSSED ABOVE.

A. Although Mr. Seeyle conducted CCOSS analyses using two different methodologies, the table below provides a comparison of his as-filed "Modified Base-Intermediate-Peak" method to those obtained with the corrections described above:

Seeyle Modified Base-Intermediate-Peak
Rate of Return ("ROR") At Current Rates
As-Filed and Corrected

Class	As-Filed	Corrected
Residential	2.65%	2.76%
General Service	7.34%	7.32%
Pwr Svc-Primary	6.49%	6.38%
Pwr Svc-Secondary	8.84%	8.59%
TOD-Primary	4.57%	4.55%
TOD-Secondary	11.92%	11.52%
Retail Transmission	3.48%	3.53%
Special Contract #1	1.70%	1.82%
Special Contract #2	2.45%	2.54%
Street Lighting	5.39%	5.43%
Street Lighting Energy	8.01%	7.80%
Traffic Lighting	7.62%	6.89%
TOTAL	4.92%	4.92%

[2] Mr. Seeyle classifies meter reading expenses (Account 902) as "Customer Accounts Expense." He then allocates his classified "Customer Accounts Expense" based on a weighted customer basis (Allocator CUST05), which includes street lighting customers. Street lighting is not metered such that this class should not be assigned any meter reading expenses.

[3] Mr. Seeyle calculates class income tax expense before the Company's proposed proforma adjustments to reduce revenue for Off System ECR revenues and advertising expenses and then effectively allocates the income tax effect of these combined adjustments based on taxable income before the adjustments. The error relates to the fact that some classes (such as the Residential class) are assigned a much larger percentage of the reduced ECR revenues but do not receive the full benefit of the reduced tax expense associated with this reduction in revenues.

As indicated above, these corrections can be characterized as minor in nature.

Q. ARE THERE CERTAIN ASPECTS OF ELECTRIC UTILITY EMBEDDED CCOSS THAT TEND TO BE MORE CONTROVERSIAL THAN OTHERS?

A. Yes. For decades, cost allocation experts and to some degree, utility commissions, have disagreed on how generation and certain distribution plant accounts should be allocated across classes. Beyond a doubt, these two issue areas are the most contentious and often have the largest impact on the results of achieved class RORs.

Q. WHAT METHODS DID MR. SEEYLE UTILIZE TO CONDUCT HIS ELECTRIC CCOSS?

A. With regard to the allocation of generation (production) plant, Mr. Seeyle utilized two separate approaches: Modified Base-Intermediate-Peak ("Modified BIP"); and, Loss of Load Probability ("LOLP"). With regard to distribution plant, Mr. Seeyle classified both the primary and secondary voltage systems as partially customer-related and partially demand-related. As a result, Mr. Seeyle allocates individual distribution plant accounts based partially on number of customers and partially on peak demands. I will explain each of these approaches in more detail later in my testimony.

A. <u>Generation Plant</u>

Q. BEFORE WE DISCUSS SPECIFIC ELECTRIC COST ALLOCATION METHODOLOGIES, PLEASE EXPLAIN HOW GENERATION/PRODUCTION-RELATED COSTS ARE INCURRED; I.E., PLEASE EXPLAIN THE COST CAUSATION CONCEPTS RELATING TO GENERATION/PRODUCTION RESOURCES.

A. Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, production facilities are joint costs; i.e., used by all customers.

Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate (load) throughout the year, there would be no disagreement as to the proper assignment of generation-related costs. All analysts would agree that energy usage in terms of kilowatt-hour ("kWh") would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that LG&E experiences periods (hours) of higher demand during certain times of the year and across various hours of the day. Moreover, all customer classes do not contribute in equal proportions to these varying demands placed on the generation system.

To further complicate matters, the electric utility industry is unique in that there is a distinct energy/capacity trade-off relating to production costs. That is, utilities design their mix of production facilities (generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there is enough available capacity to meet peak demands. The trade-off occurs between the level of fixed investment per unit of capacity kilowatt ("kW") and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investment per kW, whereas smaller units with higher variable production costs generally require significantly less investment per kW. Due to varying levels of demand placed on the system over the course of each day, month, and year there is a unique optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy; i.e., its cost of service.

The investment (capacity) costs of generation facilities are fixed in nature and are considered sunk investment costs. At the same time, the energy cost of running generation plants tends to be almost all variable in nature such that base load units tend to have low variable running costs whereas peaking units tend to have much higher variable running costs per kWh. As a result, generation assets tend to be dispatched based upon the variable running costs of each unit wherein lower variable cost units are dispatched before higher cost units. As such, total system production costs vary each hour of the year. Theoretically, energy and capacity costs should be allocated to customer classes each and every hour of the year. This would result in 8,760 hourly allocations. Although such an analysis is certainly possible with today's technology, hourly supply (generation) and demand (customer load) data is required to conduct such hour-by-hour analyses. While most utilities can and do record hourly production output, they often do not estimate class loads on an hourly basis (at least not for every hour of the year). With these constraints in mind, several allocation methodologies have been developed to allocate electric utility generation plant investment and attendant costs. Each of these methods has strengths and weaknesses regarding the reasonableness in reflecting cost causation.

Q. APPROXIMATELY HOW MANY COST ALLOCATION METHODOLOGIES EXIST RELATING TO THE ALLOCATION OF GENERATION PLANT?

A. The current National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual discusses at least thirteen embedded demand allocation methods, while Dr. James Bonbright notes the existence of at least 29 demand allocation methods in his treatise Principles of Public Utility Rates.[4]

Q. BRIEFLY DISCUSS THE STRENGTHS AND WEAKNESSES OF COMMON GENERATION COST ALLOCATION METHODOLOGIES.

A. A brief description of the most common fully allocated cost methodologies and attendant strengths and weaknesses are as follows:

Single Coincident Peak ("1-CP") -- The basic concept underlying the 1-CP method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. As such, advocates of the 1-CP method reason that customers (or classes) should be responsible for fixed capacity costs based on their respective contributions to this peak system load. The major advantages to the 1-CP method are that the concepts are easy to understand, the analyses required to conduct a CCOSS are relatively simple, and the data requirements are significantly less than some of the more complex methods.

The 1-CP method has several shortcomings, however. First, and foremost, is the fact that the 1-CP method totally ignores the capacity/energy trade-off inherent in the

[4] Principles of Public Utility Rates, Second Edition, page 495.

electric utility industry. That is, under this method, the sole criterion for assigning one hundred percent of fixed generation costs is the classes' relative contributions to load during a single hour of the year. This method does not consider, in any way, the extent to which customers use these facilities during the other 8,759 hours of the year. This may have severe consequences because a utility's planning decisions regarding the amount and type of generation capacity to build and install is predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration. To illustrate, if a utility such as LG&E had a peak load of 6,500 mW and its actual optimal generation mix included an assortment of coal, hydro, combined cycle and combustion turbine units, the total cost of capacity is significantly higher than if the utility only had to consider meeting 6,500 mW for 1 hour of the year. This is because the utility would install the cheapest type of plant (i.e., peaker units) if it only had to consider one hour a year.

There are two other major shortcomings of the 1-CP method. First, the results produced with this method can be unstable from year to year. This is because the hour in which a utility peaks annually is largely a function of weather. Therefore, annual peak load depends on when severe weather occurs. If this occurs on a weekend or holiday, relative class contributions to the peak load will likely be significantly different than if the peak occurred during a weekday. The other major shortcoming of the 1-CP method is often referred to as the "free ride" problem. This problem can easily be seen with a summer peaking utility that peaks about 5:00 p.m. Because street lights are not on at this time of day, this class will not be assigned any capacity costs and will, therefore, enjoy a “free ride” on the assignment of generation costs that this class requires.

4-CP -- The 4-CP method is identical in concept to the 1-CP method except that the peak loads during the highest four months are utilized. This method generally exhibits the same advantages and disadvantages as the 1-CP method.

Summer and Winter Coincident Peak (“S/W Peak”) -- The S/W Peak method was developed because some utilities’ annual peak load occurs in the summer during some years and in the winter during others. Because customers' usage and load characteristics may vary by season, the S/W Peak attempts to recognize this. This method is essentially the same as the 1-CP method except that two hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the 1-CP method, and in my opinion, is no more reasonable than the 1-CP method.

12-CP -- Arithmetically, the 12-CP method is essentially the same as the 1-CP method except that class contributions to each monthly peak are considered. Although the 12-CP method bears little resemblance to how utilities design and build their systems, the results produced by this method better reflect the cost incidence of a utility's generation facilities than does the 1-CP or 4-CP methods.

Most electric utilities have distinct seasonal load patterns such that there are high system peaks during the winter and summer months, and significantly lower system peaks during the spring and autumn months. By assigning class responsibilities based on their respective contributions throughout the year, consideration is given to the fact that utilities will call on all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods. Therefore, the capacity/energy trade-off is implicitly considered to some extent under this method.

The major shortcoming of the 12-CP method is that accurate load data is required by class throughout the year. This generally requires a utility to maintain ongoing load studies. However, once a system to record class load data is in place, the administration and maintenance of such a system is not overly cumbersome for larger utilities.

Peak and Average ("P&A") -- The various P&A methodologies rest on the premise that a utility's generation facilities are designed and placed into service to meet peak load and serve consumers demands throughout the entire year. Hence, the P&A method assigns capacity costs partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year. Although there is not universal agreement on how peak demands should be measured or how the weighting between peak and average demands should be performed, most electric P&A studies use class contributions to coincident-peak demand for the "peak" portion, and weight the peak and average loads based on some arbitrary factor such as system coincident load factor.

The major strengths of the P&A method are that an attempt is made to recognize the capacity/energy trade-off in the assignment of fixed capacity costs, and that data requirements are minimal.

Although the recognition of the capacity/energy trade-off is admittedly arbitrary under the P&A method, most other allocation methods also suffer some degree of arbitrariness. A potential weakness of the P&A method is that a significant amount of fixed capacity investment is allocated based on energy consumption, with no recognition given to lower variable fuel costs during off-peak periods. To illustrate this shortcoming, consider an off-peak or very high load factor class. This class will consume a constant amount of energy during the many cheaper off-peak periods. As such, this class will be assigned a significant amount of fixed capacity costs, while variable fuel costs will be assigned on a system average basis. This can result in an overburdening of costs if fuel costs vary significantly by hour. However, if the consumption patterns of the utility's various classes are such that there is little variation between class time differentiated fuel costs on an overall annual basis, the P&A method can produce fair and reasonable results.

Average and Excess ("A&E") -- The A&E method also considers both peak demands and energy consumption throughout the year. However, the A&E method is much different than the P&A method in both concept and application. The A&E method recognizes class load diversity within a system, such that all classes do not call on the utility's resources to the same degree, at the same times. Mechanically, the A&E method weights average and excess demands based on system coincident load factor. Individual class "excess" demands represent the difference between the class non-coincident peak demand and its average annual demand. The classes' "excess" demands are then summed to determine the system excess demand. Under this method, it is important to distinguish between coincident and non-coincident demands. This is because if coincident, instead of non-coincident, demands are used when calculating class excesses, the end result will be exactly the same as that achieved under the 1-CP method.

Although the A&E method bears virtually no resemblance to how generation systems are designed, this method can produce fair and reasonable results for some utilities. This is because no class will receive a "free-ride" under this method, and because recognition is given to average consumption as well as to the additional costs imposed by not maintaining a perfectly constant load.

A potential shortcoming of this method is that customers that only use power during off-peak periods will be overburdened with costs. Under the A&E method, off-peak customers will be assigned a higher percentage of capacity costs because their non-coincident load factor may be very low even though they call on the utility's resources only during off-peak periods. As such, unless fuel costs are time differentiated, this class will be assigned a large percentage of capacity costs and may not receive the benefits of cheaper off-peak energy costs. Another weakness of the A&E method is that extensive and accurate class load data is required.

Base/Intermediate/Peak ("BIP") -- The BIP method is also known as a production stacking method that explicitly recognizes the capacity and energy tradeoff inherent with generating facilities in general, and specifically, recognizes the mix of a particular utility's resources used to serve the varying demands throughout the year. The BIP method classifies and assigns individual generating resources based on their specific purpose and role within the utility's actual portfolio of production resources and also assigns the dollar amount of investment by type of plant such that a proper weighting of investment costs between expensive base load units relative to inexpensive peaker units is recognized within the cost allocation process.

A major strength of the BIP method is explicit recognition of the fact that individual generating units are placed into service to meet various needs of the system. Expensive base load units, with high capacity factors tend to run constantly throughout the year to meet the energy needs of all customers. These units operate during all periods of demand including low system load as well as during peak use periods. Base load units are, therefore, classified and allocated based on their roles within the utility's portfolio of resource; i.e., energy requirements.

At the other extreme are the utility's peaker units that are designed, built, and operated only to run a few hours of the year during peak system requirements. These peaker units serve only peak loads and are, therefore, classified and allocated on peak demand.

Situated between the high capacity cost/low energy cost base load units and the low capacity cost/high energy cost peaker units are intermediate generating resources. These units may not be dispatched during the lowest periods of system load but, due to their relatively efficient energy costs, are operated during many hours of the year. Intermediate resources are classified and allocated based on their relative usage to peak capability ratios; i.e., their capacity factor.

Hydro units are evaluated on a case-by-case basis. This is because there are several types of hydro generating facilities including run of the river units that run most of the time with no fuel costs, and units powered by stored water in reservoirs that operate under several environmental and hydrological constraints including flood control, downstream flow requirements, management of fisheries, and watershed replenishment. Within the constraints just noted and due to their ability to store potential energy, these units are generally dispatched on a seasonal or diurnal basis to minimize short-term energy costs and also assist with peak load requirements. Pumped storage units are unique in that water is pumped up to a reservoir during off-peak hours (with low energy costs) and released during peak hours of the day. Depending on the characteristics of a unit, hydro facilities may be classified as energy-related (e.g., run of the river), peak-related (e.g., pumped storage) or a combination of energy and demand-related (traditional reservoir storage). The potential weakness of the BIP method is the same as under other methods where no recognition is given to lower variable fuel costs during off-peak periods.

Finally, wind and solar generating facilities may only produce energy when environmental conditions are present; i.e., wind or sunshine. As a result, their reliability factors are such that they may not be relied upon to meet peak loads at all times. For example, many utilities experience peak demands in the early morning and evening hours when there is either no sunlight present or minimal sunlight available for solar generation. As such, wind and solar generating units are classified as energy-related.

<u>Probability of Dispatch</u> -- The Probability of Dispatch method is the most theoretically correct as well as the most equitable method to allocate generation costs when specific data is available. Under this approach, each generation asset (plant or unit) is evaluated on an hourly basis for every hour of the year (8,760 hours). Each generating asset's capital costs are assigned to individual hours based upon how that individual plant is dispatched or utilized. As such, investment or capital costs are distributed based on how a particular plant is actually utilized. For example, the investment costs associated with base load units which operate almost continuously throughout the year, are spread throughout several hours of the year while the investment cost associated with individual peaker units which operate only a few hours during peak periods are assigned to only those few peak hours. The hourly capacity costs for each generating asset are summed to develop hourly investment cost responsibilities. These hourly investments are then assigned to individual rate classes based on class contributions to system load for each hour of the year. As such, the Probability of Dispatch method requires a significant amount of data such that hourly output from each generator is required as well as detailed load studies encompassing each hour of the year (8,760 hours).

Equivalent Peaker ("EP") -- The EP method combines certain aspects of traditional embedded cost methods with those used in forward-looking marginal cost studies. The EP method often relies on planning information in order to classify individual generating units as energy or demand-related and considers the need for a mix of base load intermediate and peaking generation resources.

The EP method has substantial intuitive appeal in that base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units that are seldom used and only called upon during peak load periods are allocated based on peak demands to those classes contributing to the system peak load. However, this method requires a significant level of assumptions regarding the current (or future) costs of various generating alternatives.

Q. MR. WATKINS, YOU HAVE DISCUSSED THE STRENGTHS AND WEAKNESSES OF THE MORE COMMON GENERATION ALLOCATION METHODOLOGIES. ARE ANY OF THESE METHODS CLEARLY INFERIOR IN YOUR VIEW?

A. Yes. In my opinion the 1-CP and seasonal CP (such as 4-CP) methods do not reasonably reflect cost causation for integrated electric utilities because these methods totally ignore the utilization of a utility's facilities. Perhaps the simplest way to explain this is to consider that the methodology selected is used to allocate generation plant investment. Generation investment costs vary from a low of a few hundred dollars per kW of capacity for high operating cost (energy cost) peakers to several thousand dollars per kW for base load nuclear facilities with low operating costs. If a utility were only concerned with being able to meet peak load with no regard to operating costs, it would simply install inexpensive peakers. Under such an unrealistic system design, plant costs would be much lower than in reality but variable operating costs (primarily fuel costs) would be astronomical and would result in a higher overall cost to serve customers. The 1-CP and seasonal CP methods totally ignore this very important fact.

Q. WHAT METHODOLOGIES DID MR. SEEYLE UTILIZE TO ALLOCATE GENERATION PLANT COSTS WITHIN HIS CCOSS?

A. As mentioned earlier, Mr. Seeyle prepared CCOSS utilizing two different methods to allocate generation-related costs: "Modified BIP"; and, LOLP.

Q. PLEASE EXPLAIN MR. SEEYLE'S MODIFIED BIP APPROACH TO ALLOCATE GENERATION-RELATED COSTS.

A. Mr. Seeyle's Modified BIP method does not follow the generally accepted BIP approach. However, I would be reluctant to say his approach is totally unreasonable. Indeed, Mr. Seeyle's so-called Modified BIP is a variant of the Peak & Average method.

Whereas Mr. Seeyle's Modified BIP method does allocate a portion of generation facilities based on energy (34.38%) and a portion on peak demands (36.02% on winter peak and 29.60% on summer peak), his approach does not reflect the actual mix of supply resources utilized by LG&E. As a result, Mr. Seeyle's approach is a version of the P&A method using summer and winter peak demands; i.e., 34.38% is allocated on average demand (energy) and 65.62% is allocated on the average of winter and summer peak demands.

The traditional BIP method is a supply-based approach that classifies generation plant between energy-related and demand-related; i.e., it considers the actual supply characteristics of a utility's generation portfolio. These supply based classifications are then allocated to classes based on demand-side criteria (kWh usage and kW peak demand).

Mr. Seeyle's approach ignores the actual supply-side characteristics of KU's and LG&E's combined generation portfolio because it only considers relative differences in system usages and demands. In fact, given KU's and LG&E's retail customers combined usages and demand profiles, Mr. Seeyle's approach would classify a utility's generation investment exactly the same regardless of its actual portfolio mix of generation resources. Mr. Seeyle's classification would be identical if the Companies' portfolio mix was comprised entirely of base load units or entirely of peaking units. In my opinion, this assumption (or result) is not consistent with the intent of the BIP method - namely, to recognize the capacity/energy tradeoff actually present in KU's and LG&E's generation resources.

Q. PLEASE EXPLAIN MR. SEEYLE'S LOLP APPROACH TO ALLOCATE GENERATION-RELATED COSTS.

A. In simple terms, LG&E personnel calculated a probability of the Company not being able to meet its load requirements with its own generation for each and every hour of the forecasted test year (8,760 hours). As might be imagined, for hours in which the total system load is relatively low, the probability of not meeting the total system load (LOLP) is zero. Likewise, LG&E calculates that there is a probability of not meeting the system load (LOLP) during hours in which system demand is at, or near, the annual peak. With this framework, Mr. Seeyle then multiplies each class' percentage contribution to total jurisdictional load by the calculated system LOLP for each hour of the year. This results in a weighting across classes based on the hourly system LOLPs. These hourly weightings are then added for all hours in which LOLP is greater than zero to develop his class allocation factors for generation plant.

Q. IS THE CONCEPTUAL FRAMEWORK UTILIZED BY MR. SEEYLE REASONABLE?

A. From a conceptual standpoint, Mr. Seeyle's approach to allocate costs is reasonable. However, no credibility can be given to the hourly system LOLPs which serve as the foundation for Mr. Seeyle's calculations.

Q. PLEASE EXPLAIN WHY NO CREDIBILITY CAN BE GIVEN TO THE HOURLY SYSTEM LOLPs THAT WERE CALCULATED BY THE COMPANY.

A. There are a host of reasons. First, the hourly system LOLPs developed by KU/LG&E personnel are black box results from an algorithm in which it is impossible to determine the inputs, assumptions and most importantly, specific methods used to calculate each hourly LOLP. In Confidential response to OAG data request 1-294, the Company indicated that the methodology utilized to calculate hourly LOLPs is embedded within their Power System Production Simulation Software ("PROSYM") such that the hourly LOLP results are simply provided as output. In OAG data request 1-294, the Company was asked to provide all analyses, workpapers, spreadsheets, etc. showing how the hourly system LOLPs were calculated. Although the Company provided numerous input files presumably used to calculate LOLPs, they were unable to show how each hourly LOLP was determined. As a result (and because PROSYM calculated system LOLPs for 8,760 hours), in OAG data request 2-68, the Company was asked to show how the LOLP was developed for a single hour. The Company's response to OAG data request 2-68 was as follows:

> The hourly LOLPs were produced by PROSYM, which is the software provided by ABB that the Companies also use to develop the generation forecast. The attachment to the response to AG 1-293 documents the LOLP calculations performed in PROSYM. However, the LOLP calculations are performed within the software. The Companies do not have access to the underlying proprietary code that performs the LOLP calculations or the calculations' intermediate components.

In short, it is impossible to determine exactly how the Companies' PROSYM model calculates hourly LOLPs such that it is also impossible to verify the results or evaluate the reasonableness of the assumptions that go into the determination of each hourly LOLP. As will be explained later in my testimony, I have serious concerns relating to the inputs, assumptions, and perhaps methodology utilized to develop these black box hourly LOLPs.

The next concern I have is frankly, a matter of common sense. KU and LG&E have more than sufficient installed capacity and indeed, the Companies' acknowledge that they have no plans to build or install additional capacity for the next several years. Therefore, given the significant amount of excess capacity that KU and LG&E already have, there is very little realistic probability that the Companies will not be able to meet its load requirements each and every hour of the year. Indeed, for all intents and purposes, the Companies' hourly loss of load probabilities reflect this reality.

In response to OAG data request 1-294, the Company provided hourly system LOLPs. The largest LOLP during the entire forecasted test year is 0.126%, which means that there is roughly one-tenth of one percent probability that the Companies will not be able to meet it load requirements during this hour. It should be noted that this highest LOLP also coincides with the Companies' forecasted annual peak load demand. All other hours have lower LOLPs than 0.126%. What this means is there is about one-tenth of one percent probability that the Companies will not be able to meet its load requirements during the peak hour of the year (given all other assumptions within the calculation of LOLP). As a result, the Company estimates that in the hour with the highest LOLP (i.e., annual peak load), it would not be able to meet 232 kW of demand. This minimal level of 232 kW equates to the demands of only about 15 to 20 residential households. In other words, even with this exceptionally low LOLP during the annual peak hour and given all other assumptions used to develop this maximum LOLP, the Company will be able to serve all residential, commercial, and industrial customer's load requirements of 6,807,000 kW, but for 232 kW (0.0034%) which must be therefore made up with purchased power or some other resource.

Q. NOTWITHSTANDING THE EXCEPTIONALLY LOW CALCULATED PROBABILITY OF THE COMPANIES NOT BEING ABLE TO MEET ALL OF ITS ANNUAL PEAK LOAD REQUIREMENTS GIVEN ITS PORTFOLIO OF GENERATION AND SUPPLY ASSETS, HAVE YOU INVESTIGATED THE REASONABLENESS OF THESE BLACK BOX LOLP RESULTS?

A. Yes. First and foremost, the Companies' LOLP methodology and calculations do not consider a very valuable capacity resource that being interruptible loads available from the Curtailable Service Rider ("CSR"). In other words, the Companies' LOLP calculations do not consider or reflect the fact that there is more than 130 mW of interruptible load available as a capacity resource.[5] In response to OAG data request 1-291(c), the Company was asked to provide a detailed explanation of how curtailable load or curtailable load credits are reflected within the class hourly loads as used to develop the LOLP study. The Company responded that "the impact of curtailable loads is not reflected in the hourly class load profiles." This is most important and troubling since the Companies have more than 130 mW of load that could be interrupted, yet, for LOLP purposes, they ignore this important resource. Indeed, had the Companies considered curtailable load within their LOLP, there would be virtually no probability of not meeting its load requirements (even with all other assumptions that will be explained below). In other words, the Companies' own calculations show that under a worst case scenario, the Company will be able to meet all but 0.23 mW of load before a single curtailable service customer is interrupted.

Q. IN ADDITION TO THE COMPANIES' FAILURE TO CONSIDER CURTAILABLE SERVICE AS A CAPACITY RESOURCE, HAVE YOU DISCOVERED OTHER UNREASONABLE ASSUMPTIONS WITHIN THE COMPANIES' CALCULATED BLACK BOX HOURLY LOLPs?

A. Yes. As indicated earlier, the maximum LOLP during the forecasted test year is 0.126% during the annual peak hour. The Company forecasts that the six highest hourly LOLPs will occur on the same day during the consecutive afternoon and early evening of August 9th from 2:00 p.m. through 7:59 p.m. (6 hours). During this period, the Companies' calculated LOLPs range from a low of 0.031% to a high of 0.126%. During this six hour period, I evaluated the assumed level of output for every generation and production asset within KU's and LG&E's portfolio of assets. I observed that the following generating units were assumed to be offline (or unavailable) during the entire six hour period:

5 Per Company response to KIUC 1-55 in the KU docket (Case No. 2016-00370).

Unit	Capacity (mW)[6]	Fuel Source
Unavailable for all 6 hours of peak day		
Brown 8	126	Gas/Oil
Brown 9	126	Gas/Oil
Brown 10	126	Gas/Oil
Brown 11	126	Gas/Oil
Cane Run 11	16	Gas
Haefling	42	Gas/Oil
Paddy's Run 11	16	Gas
Paddy's Run 12	33	Gas
Zorn 1	18	Gas
Unavailable 4 of 6 hours including the peak hour		
Trimble 8	199	Gas
Unavailable 3 of 6 hours		
Trimble 10	199	Gas
Total Unavailable Capacity:	1,027	--

Remembering that even during the hour of the highest loss of load probability, the Company expects to meet all but 0.23 mW of its load requirements. However, as we can see above, the Companies' LOLP procedures have modeled more than 1,000 mW of generation capacity that is not dispatched or utilized during this period. Indeed, if only one of these eleven unused generating units are dispatched and utilized, the LOLP becomes zero. The above discussion is limited to the highest LOLPs for six hours of the year. I examined the availability of generating units for other hours in which there is an LOLP and observed that there is a significant amount of unused capacity from the Companies' generating units for each hour in which there is at least some miniscule LOLP. While it is reasonable to model situations in which some units may not be available due to forced outage rates, clearly, the unavailability of eleven gas-fired generating units is unrealistic.

6 Per response to OAG data request 1-301.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING MR. SEEYLE'S PROPOSED CCOSS UTILIZING HIS LOLP APPROACH?

A. No credibility can be given to this method such that it should not be considered in this case.

Q. HAVE YOU CONDUCTED ALTERNATIVE STUDIES THAT MORE ACCURATELY REPRESENT THE CAPACITY AND ENERGY TRADE-OFFS EXHIBITED IN LG&E'S GENERATION PLANT INVESTMENT?

A. Yes. As indicated earlier, there is no single, or absolute, correct method to allocate joint generation costs. While some methods are superior to others, it is my opinion that the results of multiple, yet reasonable, methods should be considered in evaluating class profitability as well as class revenue responsibility.

In my opinion, the Probability of Dispatch and BIP methods better reflect the capacity/energy tradeoffs that exist within an electric utility's generation-related costs. This is particularly true and important for LG&E given the fact that the preponderance of its investment in generation plant is associated with base load generation facilities.[7] As such, I have conducted alternative CCOSS utilizing these two allocation methodologies.

Probability of Dispatch Method

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR CCOSS UTILIZING THE PROBABILITY OF DISPATCH METHOD.

A. As discussed earlier, the Probability of Dispatch method is the most theoretically correct methodology to assign embedded (historical) generation plant investment. However, the data required to utilize this methodology is often not available because this approach requires detailed hourly output data for each generating facility as well as hourly class loads. In this case, LG&E provided both of these critical data sets. As such, I was able to conduct a CCOSS utilizing the Probability of Dispatch method.

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[7] It is recognized that KU and LG&E jointly dispatch their combined generating assets based on the system load of both utilities. As such, my analyses (as well as Mr. Seeyle's) reflects this joint dispatch of generating assets.

The first step in conducting the Probability of Dispatch method is to assign individual generating plant investments to specific hours. In accordance with the procedures set forth in the NARUC: Electric Utility Cost Allocation Manual,[8] each plant's total gross investment and accumulated depreciation was assigned pro-ratably to each hour of the year based on each respective unit's load (output) in that hour. My Schedule GAW-2 provides these hourly assignments. It should be noted that this exercise actually assigns costs to 8,760 hours; however, my Schedule GAW-2 only encompasses several of the first hours in the test year to avoid attachments exceeding 125 pages each. The electronic Excel spreadsheet containing the details of this assignment for each and every hour of the test year are provided to the parties with my filed testimony (Completed 3 Probability of Dispatch LGE – Using Gross Plant). In addition, an hourly analysis was conducted for depreciation reserve due to differences in the net book value of LG&E's various generation facilities. The electronic Excel spreadsheet containing the details of the depreciation reserve for each and every hour of the test year are provided to the parties with my filed testimony (Completed 1 Probability of Dispatch LGE – Using Depreciation Reserve).

Once hourly investment costs are known, these costs were then assigned to individual rate classes on an hour-by-hour basis. As indicated earlier, LG&E provided individual class loads for each hour of the test year. As such, each class' relative contribution to the total system load in a given hour, is multiplied by the hourly generation investment cost. The hourly class investment costs were then summed for all hours of the year to develop class responsibility for LG&E's net generation plant. Schedule GAW-3 provides summaries of the hourly assignment of generation costs to individual rate classes. The class assignment to each and every hour of the test year are provided in an Excel spreadsheet filed with my testimony (Completed 3 Probability of Dispatch LGE – Using Gross Plant.xls).

In addition to assigning fixed investment costs on an hour-by-hour basis, I have also conducted a similar analyses with regard to variable fuel costs. That is, I conducted a time differentiated fuel cost analysis for each hour of the year.

[8] 1992 Edition, page 62.

Q. PLEASE EXPLAIN YOUR TIME DIFFERENTIATED FUEL COST ANALYSIS AND YOUR CONCLUSIONS AS A RESULT OF THIS ANALYSIS.

A. As discussed earlier, LG&E provided each generation plant's hourly output during the forecasted test year. In addition, the Company provided forecasted test year monthly fuel costs (per kWh) for each generating unit. With this data, I was able to calculate hourly fuel costs by individual generating unit. These hourly fuel costs were then assigned to individual rate classes on an hour-by-hour basis based on class hourly loads as discussed previously. The end result of this analysis yielded very similar hourly fuel costs across all classes such that all classes' fuel costs are within 4.4% of the system average annual fuel cost as shown below[9]:

LG&E Class Hourly Fuel Costs
(Annual Weighted Average)

Class	Fuel Cost Per mWh	Deviation From Sys. Average
Residential	$23.036	1.1%
General Service	$23.041	1.1%
Pwr Svc-Primary	$22.372	-1.8%
Pwr Svc-Secondary	$22.984	0.9%
TOD-Primary	$22.356	-1.9%
TOD-Secondary	$23.020	1.0%
Retail Transmission	$21.782	-4.4%
Special Contract #1	$22.307	-2.1%
Special Contract #2	$22.959	0.8%
Street Lighting	$22.771	0.0%
Street Lighting Energy	$22.744	-0.2%
Traffic Lighting	$23.518	3.2%
TOTAL	$22.781	--

Q. PLEASE PROVIDE A SUMMARY OF THE RESULTS OBTAINED UTILIZING THE PROBABILITY OF DISPATCH METHOD.

A. First it should be noted that the following summary and comparison utilizes all other classification and procedures used by Mr. Seeyle in conducting his CCOSS. The

[9] My hourly fuel cost analysis by rate class reflects line losses such that the fuel cost reflect cost per kWh at the meter. The details of this analysis are provided in an Excel spreadsheet filed with my testimony (Hourly Fuel Costs KU and LGE – With Source & Meter-Adjusted.xls).

following table provides a comparison of Mr. Seeyle's Modified BIP results to those obtained utilizing the Probability of Dispatch method (which also incorporates time differentiated fuel costs):

CCOSS Comparison Utilizing LG&E's Procedures
Except for the Allocation of Generation Plant and Fuel Costs
(ROR At Current Rates)

Class	Modified BIP (As Corrected)	Probability Of Dispatch
Residential	2.76%	3.13%
General Service	7.32%	8.27%
Pwr Svc-Primary	6.38%	5.57%
Pwr Svc-Secondary	8.59%	8.41%
TOD-Primary	4.55%	3.75%
TOD-Secondary	11.52%	9.43%
Retail Transmission	3.53%	2.75%
Special Contract #1	1.82%	1.59%
Special Contract #2	2.54%	1.04%
Street Lighting	5.43%	4.65%
Street Lighting Energy	7.80%	2.77%
Traffic Lighting	6.89%	5.18%
TOTAL	4.92%	4.92%

As can be seen in the table above, there are material differences for some classes and minimal differences for other classes. For example, TOD-Secondary decreases from 11.52% to 9.43%, while the Street Lighting Energy class ROR is significantly reduced. A summary of my Probability of Dispatch CCOSS results are provided in my Schedule GAW-4, while the details are provided in Excel format filed with my testimony (TAI Prob Dispatch with Time Fuel & Customer-Demand Split.xls).

<u>**Base-Intermediate-Peak ("BIP") Method**</u>

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR CCOSS UTILIZING THE BASE-INTERMEDIATE-PEAK METHOD.

A. In order to reflect the capacity/energy trade-off inherent in LG&E's mix of generating resources, each plant's owned capacity (mW) and output (mWh) during the test year is required.[10] Schedule GAW-5 provides the classification between energy and demand for LG&E's generation plant under the BIP method. The BIP method evaluates each plant based on its capacity factor and variable fuel costs to determine whether that plant operates to serve primarily energy needs throughout the year, only peak loads, or is of an intermediate type that serves both energy and peak load requirements.

Q. DOES SCHEDULE GAW-5 HELP EXPLAIN THE CAPACITY/ENERGY TRADE-OFF CONSIDERATION USED BY ELECTRIC UTILITIES IN DEVELOPING A PARTICULAR MIX OF GENERATING FACILITIES?

A. Yes. As can be seen in Schedule GAW-5, LG&E's larger, more expensive, generating plants have high capacity factors and lower fuel costs. The large base load units run most hours of the year supplying energy to all customers. In contrast, the smaller, high operating (fuel) cost plants tend to have lower capacity factors meaning they are primarily used to meet peak loads. Because the vast preponderance of LG&E's investment in generation plant is associated with its base load units, a very large percentage (83.6%) of generation plant is classified as energy-related under the BIP method.

Q. PLEASE PROVIDE A SUMMARY OF RESULTS OBTAINED UTILIZING THE BASE-INTERMEDIATE-PEAK METHOD.

A. The following summary and comparison utilizes all other allocations and procedures used by Mr. Seeyle in conducting his CCOSS analysis. The following table provides a comparison of Mr. Seeyle's Modified BIP (as corrected) results to those obtained utilizing the true BIP method:

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[10] KU and LG&E own 75% of Trimble Unit 1 and Trimble Unit 2 wherein a non-affiliate owns the remaining 25% of these units. As such, the available capacity (mW) and energy output (mWh) reflects KU's and LG&E's 75% entitlement.

CCOSS Comparison Utilizing LG&E's Procedures
Except for the Allocation of Generation Plant and Fuel Costs
(ROR At Current Rates)

Class	Modified BIP (As Corrected)	True BIP
Residential	2.76%	3.06%
General Service	7.32%	7.99%
Pwr Svc-Primary	6.38%	5.42%
Pwr Svc-Secondary	8.59%	8.21%
TOD-Primary	4.55%	3.58%
TOD-Secondary	11.52%	12.39%
Retail Transmission	3.53%	2.45%
Special Contract #1	1.82%	1.41%
Special Contract #2	2.54%	1.33%
Street Lighting	5.43%	4.66%
Street Lighting Energy	7.80%	2.66%
Traffic Lighting	6.89%	5.70%
TOTAL	4.92%	4.92%

As can be seen in the table above, the only material difference relates to Street Lighting Energy. A summary of my BIP CCOSS results are provided in my Schedule GAW-6, while the details are provided in Excel format filed with my testimony (TAI BIP with Customer-Demand Split.xls).

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE PROPER ALLOCATION OF LG&E's GENERATION PLANT?

A. KU's and LG&E's combined portfolio of generating assets is comprised predominately of large base load units that serve the energy needs of KU and LG&E throughout the entire year. While the Companies do indeed rely upon intermediate and peaker units to some degree, the dollar investment in these facilities pale in comparison to its base load investments. The Probability of Dispatch and BIP methods are very detailed approaches that are theoretically sound and reasonably reflect the capacity/energy trade-off in generation facilities specific to LG&E's investment. As such, these two methods are the most "accurate" methods from a cost causation perspective. It is my opinion that each of these methods should be considered in evaluating class profitability.

B. Distribution Plant

Q. PLEASE EXPLAIN THE PHRASE "CLASSIFICATION OF DISTRIBUTION PLANT."

A. It is generally recognized that there are no energy-related costs associated with distribution plant. That is, the distribution system is designed to meet localized peak demands. However, largely as a result of differences in customer densities throughout a utility's service area, electric utility distribution plant sometimes is classified as partially demand-related and partially customer-related.

Q. WHY IS DISTRIBUTION PLANT SOMETIMES CLASSIFIED AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED?

A. Even though investment is made in distribution plant and equipment to meet the needs of customers at their required power levels, there may be considerable differences in both customer densities and the mix of customers throughout a utility's service area. Therefore, if one were to allocate distribution plant investment based simply on class contributions to peak demand, an inequitable allocation of these costs may result.

As a hypothetical, suppose a utility serves both an urban area and a rural area. In this situation, many customers' electrical needs are served with relatively few miles of conductors, few poles, etc. in the urban area, while many more miles of conductors, more poles, etc. are required to serve the requirements of relatively few customers in the rural area. If the distribution of classes of customers (class customer mix) is relatively similar in both the rural and urban areas, there is no need to consider customer counts (number of customers) within the allocation process, because all classes use the utility's joint distribution facilities proportionately across the service area. However, if the customer mix is such that commercial and industrial customers are predominately clustered in the more densely populated urban area, while the less dense (rural) portion of the service territory consists almost entirely of residential customers, it may be unreasonable to allocate the total Company's distribution investments based solely on demand; i.e., a large investment in many miles of line is required to serve predominately residential customers in the rural area while the commercial and industrial electrical needs are met with much fewer miles of lines in the urban area. Under this circumstance, an allocation of costs based on a weighting of customers and demand can be considered equitable and appropriate.

Q. PLEASE PROVIDE AN EXAMPLE THAT ILLUSTRATES THE CONCEPTS OF DENSITY AND CLASS CUSTOMER MIX AS THEY RELATE TO COST ALLOCATIONS.

A. As a starting point, it is important to understand absolute and relative class relationships of an electric utility's number of customers, energy requirements, and maximum loads (demands). In terms of simple customer counts, the number of residential accounts make-up the majority of any retail electric utility's number of customers. However, because residential customers tend to be small volume users compared to commercial and industrial customers, the residential class is responsible for a significantly smaller percentage of total kWH energy supplied or peak loads on the system. For example, in LG&E's system, the following characteristics are exhibited:

	Percentage of Total Jurisdictional Distribution System[11]		
Category	Customers	kWh	Peak Demand (NCP)
Residential	88.2%	45.8%	49.0%
Comm./Ind. Distribution Voltage	11.8%	54.2%	51.0%

While the table above shows the relative class differences between number of customers, energy usage, and peak demands, the following table illustrates the absolute size differences between LG&E's different types of customers:

[11] Excludes Lighting and Special Contract classes.

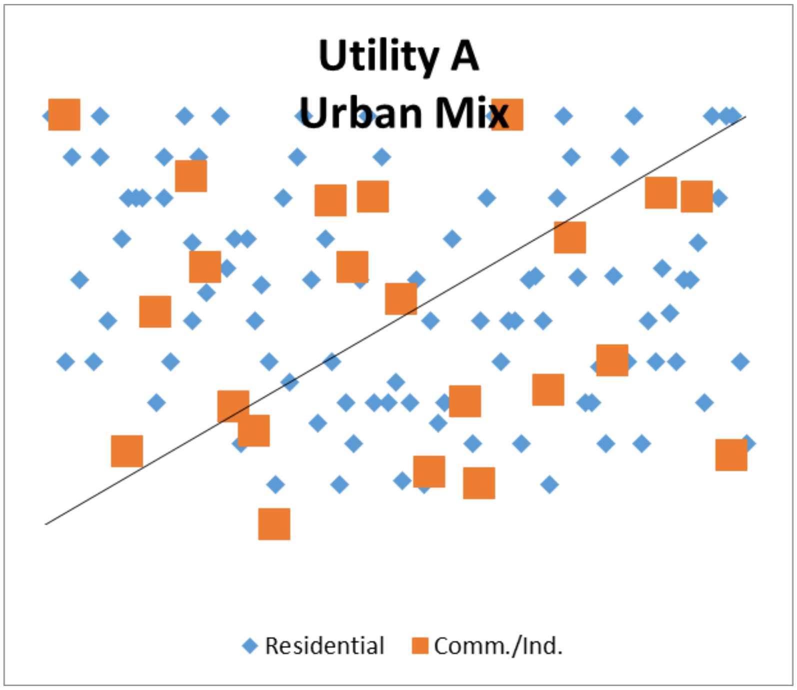
Category	Average Annual kWh Per Customer (kWh)
Residential	11,480
Comm./Ind. Distribution Voltage	101,913

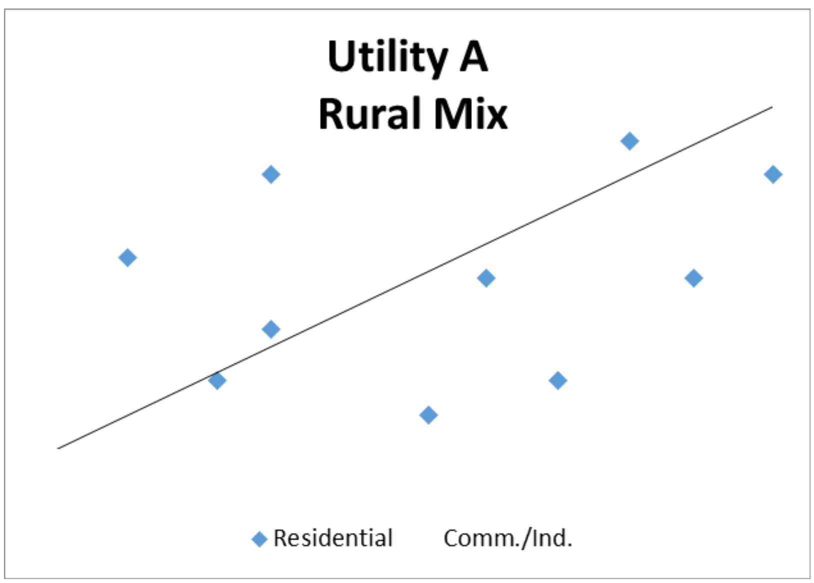
With the above relationships explained, in order to understand the concepts of density and class customer mix, consider examples of two hypothetical electric utilities each of which are comprised of only two distribution lines: one line serving a densely populated area (urban) and another line serving a sparsely populated area (rural). Furthermore, for simplicity and explanatory purposes, assume there are only two classes of customers for each utility: Residential and Commercial/Industrial with the following characteristics:

	Absolute			Relative	
Class	Number of Customers	Peak Load	Peak Load Per Customer	Number of Customers	Peak Load
Residential	110	550	5	83%	33%
Comm./Ind.	22	1,100	50	17%	67%
Total	132	1,650	--	100%	100%

Utility A:

For Utility A, assume all commercial/industrial customers are located on the urban (densely populated) distribution line such that the rural line only serves residential customers as shown graphically below:



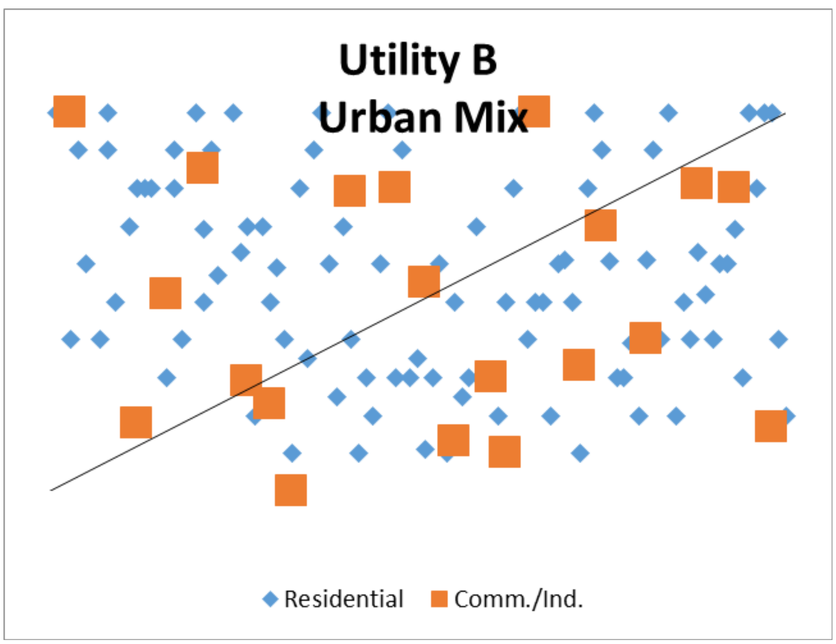


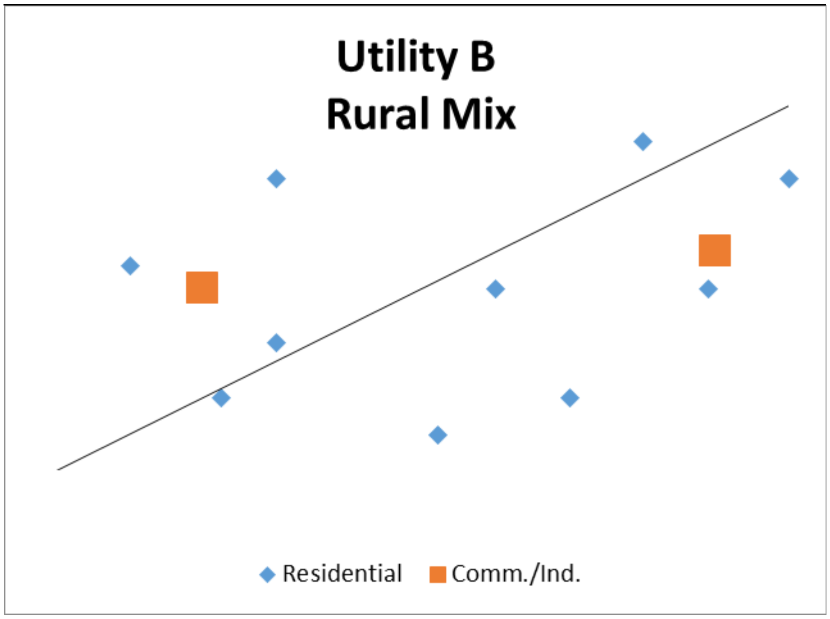
Because the urban line is much shorter in total distance, yet, serves the majority of customers (and loads) <u>and</u> many more miles of line are required to serve relatively few residential only customers in rural areas, it would be unfair, and inconsistent with cost causation to allocate total system line costs only on utilization (kW) because commercial/industrial customers arguably do not cause costs to be incurred for the rural portion of the system. As such, some weighting of relative number of customers and utilization is appropriate to allocate total system line costs.

<u>Utility B</u>:

For Utility B, assume that the relative mix of customers is evenly distributed between the urban and rural lines. In other words, this utility's configuration of customers is as follows:

	Number of Customers			
	Urban Line		Rural Line	
Class	Amount	Percent	Amount	Percent
Residential	100	83%	10	83%
Comm./Ind.	20	17%	2	17%
Total	120	100%	12	100%





As can be seen in the above table and charts, the relative imposition of costs across the two classes for Utility B is the same for the urban and rural lines. That is, while there are more absolute residential customers than commercial/industrial customers on both the urban and rural lines, the proportion (mix) of customers is the same between urban and rural. As such, an allocation of total system lines costs based on utilization (maximum loads) is appropriate such that no consideration of customer counts is needed or desired. Indeed, if distribution costs are classified and allocated partially on number of customers, the Residential class will be over burdened with cost responsibility creating a subsidy for commercial/industrial customers.

Q. DOES THE CLASSIFICATION OF DISTRIBUTION PLANT INVESTMENT AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED REFLECT ANY RELATIVE COST (PER MILE) DIFFERENCES BETWEEN URBAN AND RURAL AREAS?

A. No. It is generally more expensive to install a mile of distribution circuit in an urban area than in a rural area. However, although this cost difference may be substantial, this cost difference is usually ignored due to record keeping limitations, in that all costs are simply assumed to be uniform (averaged) across the rural and urban portions of a service area.

Q. DO YOUR EXAMPLES DISCUSSED ABOVE IMPLY THAT IT COSTS MORE TO SERVE RURAL CUSTOMERS THAN URBAN CUSTOMERS AND THAT PERHAPS A UTILITY'S RURAL CUSTOMERS SHOULD PAY MORE PER UNIT THAN URBAN CUSTOMERS?

A. While it is possible that it technically costs more to serve a rural customer versus an urban customer, regulatory policy in the United States has generally been not to price discriminate based on customer densities, urban versus rural, or other geographic differences. Rather, regulatory policy has been such that classes of customers with similar usage and/or load characteristics are established for pricing purposes. In fact, during my 36-plus years practicing utility costing and pricing across the Country, I have never seen an electric rate structure that discriminates based on customer densities or other geographic characteristics.

Q. IS THERE ACADEMIC SUPPORT FOR YOUR EXPLANATION AND CONCEPTS REGARDING CUSTOMER DENSITIES AND CLASS CUSTOMER MIXES?

A. Yes. In the well-known and often referenced, treatise <u>Principles of Public Utility Rates</u>, Professor James Bonbright states that there:

> is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[12]

Q. BEFORE WE CONTINUE, IS LG&E's DISTRIBUTION SYSTEM COMPRISED OF VARIOUS SUB-SYSTEMS?

A. Yes. As is the case with virtually every electric utility, LG&E's overall distribution system is comprised of a primary voltage system and a secondary voltage

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[12] Bonbright, <u>Principles of Public Utility Rates</u>, Second Edition, page 491.

system. The primary system operates at higher voltage levels than the secondary system and generally consists of plant and equipment between the substations and transformers. The lower voltage secondary system can be thought of as operating downstream from the primary system and delivers electricity to small end-users.

Q. BRIEFLY DESCRIBE THE TYPES OF INVESTMENT (EQUIPMENT) UTILIZED IN LG&E's DISTRIBUTION SYSTEM.

A. For accounting purposes, LG&E's distribution plant is grouped into various accounts. These accounts include: Land and Land Rights (Account 360); Structures and Improvements (Account 361); Station Equipment (Account 362); Poles, Towers and Fixtures (Account 364); Overhead Conductors (Account 365); Underground Conduit (Account 366); Underground Conductors (Account 367); Line Transformers (Account 368); Meters (Account 370); Area Lighting (Account 371) and Street Lighting (Account 373).

Q. DID MR. SEEYLE MAKE AN *A PRIORI* ASSUMPTION THAT DISTRIBUTION PLANT SHOULD BE CLASSIFIED AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED?

A. Yes.

Q. WHAT RELATIVE CUSTOMER/DEMAND PERCENTAGES DID MR. SEEYLE USE IN THIS CASE?

A. The following are Mr. Seeyle's customer/demand percentages used for each distribution plant account:

Classification of Distribution Plant

Account	Percent Customer	Percent Demand
Poles (Primary Voltage)	59.19%	40.81%
Poles (Secondary Voltage)	59.19%	40.81%
Overhead Lines (Primary Voltage)	59.19%	40.81%
Overhead Lines (Secondary Voltage)	59.19%	40.81%
Underground Lines (Primary Voltage)	64.37%	35.63%
Underground Lines (Secondary Voltage)	64.37%	35.63%

Q. HAVE YOU CONDUCTED ANALYSES TO DETERMINE IF A CLASSIFICATION OF DISTRIBUTION PLANT AS PARTIALLY CUSTOMER-RELATED IS APPROPRIATE FOR LG&E?

A. Yes, I have.

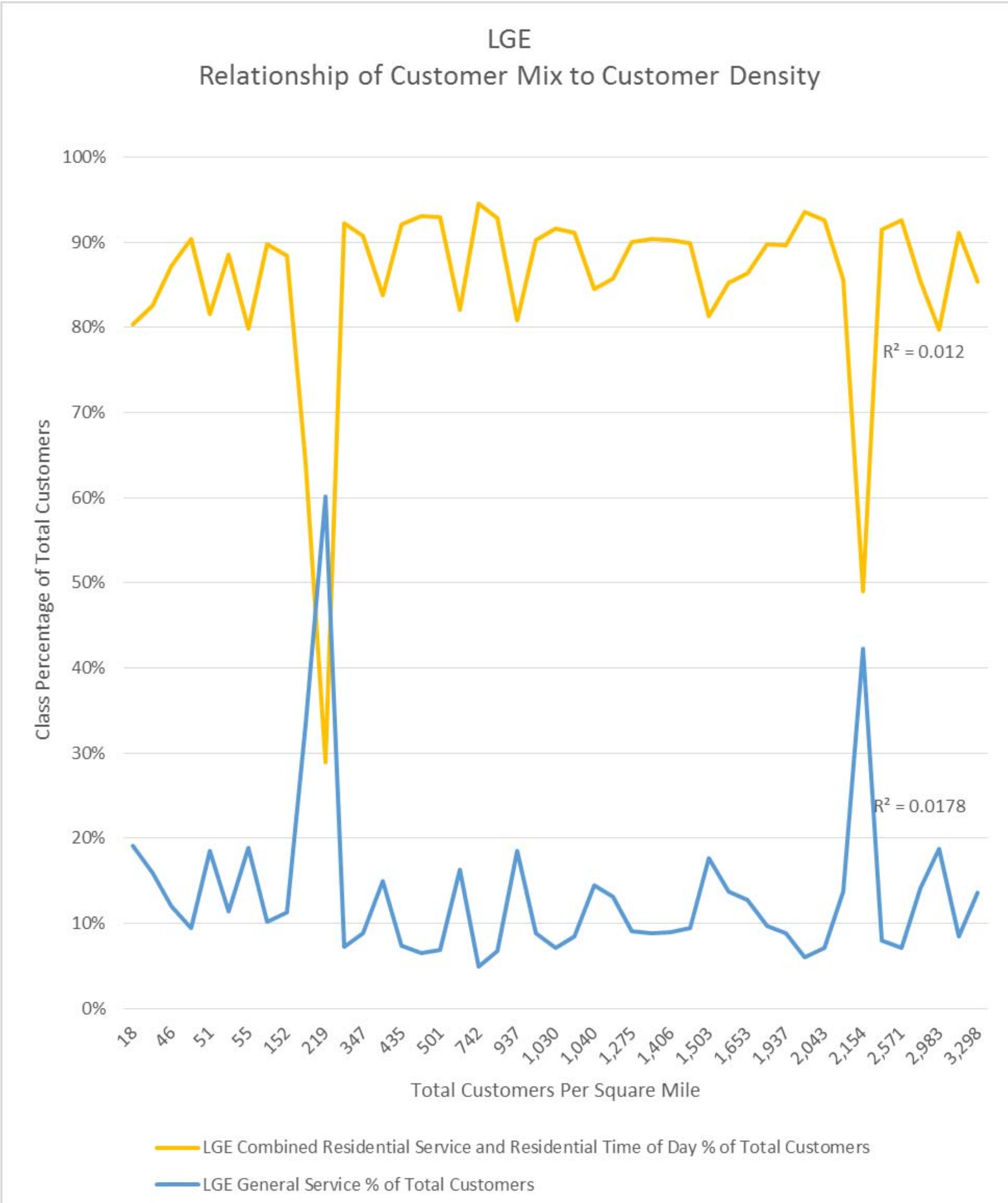
Q. PLEASE EXPLAIN.

A. My. Seeyle has made an *a priori* assumption that it is appropriate to allocate a portion of its distribution plant based on customer counts and a portion based on demand levels. As indicated earlier, the only reason why it may be appropriate to allocate a portion of distribution plant expenses based on number of customers, rather than peak demand, is due to the possibility that the mix of customers varies significantly across the customer density levels within LG&E's service territory. In this regard, I evaluated this assumption by conducting an analysis of the distribution, or mix, of LG&E's customer classes across its service area.

Through discovery, the Company provided a data base of the number of customers by rate schedule for each postal zip-code within its service area. I then evaluated the mix of customers by rate class for each postal zip-code within the LG&E service area. In order to evaluate whether any differences exist in the distribution of customers across various customer density areas, I calculated the number of total LG&E distribution customers (excluding lighting customers) per square mile for each non-Post Office Box zip-code to serve as a measure of density for relatively small geographic areas. I was then able to readily compare LG&E's mix of customers throughout its service area and delineate between sparsely populated and densely populated areas (in terms of number of LG&E customers). As a further refinement, I also evaluated the distribution of customers on a stratified basis. That is, for each customer group (Residential, General Service, Power Service, and Time of Day) I separated small geographical areas (zip codes) into three separate strata (lowest to highest customer densities). I examined each stratum (by customer group) to determine if any significant differences in customer mix occur within each stratum.

This analysis of the distribution of the various customer groups by density provided a basis to determine whether: (a) utilization alone (demand) is an appropriate and fair method to allocate distribution costs; or, (b) whether a weighting of customers and utilization (demand) is appropriate in order to reasonably reflect the imposition or causation of costs.

If there is any basis for a customer classification of distribution plant, this analysis should show a negative correlation between the residential customer mix (residential percentage of total customers) and density across LG&E's service area. In other words, the percentage of residential customers (by zip-code) should decline as customer density per square mile increases from the least dense areas to the most dense areas of LG&E's service territory. Similarly, if Mr. Seeyle's assumption is correct, you should see a distinct positive correlation between non-residential customer mixes and customer densities by zip-code. The graph below shows the percentage of total customers by rate group (Y axis) compared to total customers per square mile (X axis):


LGE
Relationship of Customer Mix to Customer Density
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Class Percentage of Total Customers
R^2 = 0.012
R^2 = 0.0178
18
46
51
55
152
219
347
435
501
742
937
1,030
1,040
1,275
1,406
1,503
1,653
1,937
2,043
2,154
2,571
2,983
3,298
Total Customers Per Square Mile
LGE Combined Residential Service and Residential Time of Day % of Total Customers
LGE General Service % of Total Customers

As can be seen in the graph above, there is absolutely no correlation or trend between the distribution of customers (customer mix) and density levels for any of the three customer groups. Indeed, and as shown in the graph, the correlation coefficients for all three customer groups are essentially zero.

As discussed earlier, I also analyzed this data on a stratified basis. A summary of the approach and data utilized for the stratification analysis is provided below:[13]

Class	Customers Per Sq. Mile (Density)	Count Of Zip Codes	Percent Of Strata	Percent of Total Distribution Customers[14] Number	% of Class
Residential					
Strata 1	18 Min to 435 Max	15	87.09%	63,339	17.52%
Strata 2	435.1 Min to 1,458 Max	15	90.08%	170.330	47.11%
Strata 3	1,458.1 Min to 3,297 Max	15	86.85%	127,855	35.37%
Total		45		361,524	100.00%
General Service					
Strata 1	18 Min to 435 Max	15	12.11%	8,805	19.95%
Strata 2	435.1 Min to 1,458 Max	15	9.17%	17,341	39.29%
Strata 3	1,458.1 Min to 3,297 Max	15	12.22%	17,988	40.76%
Total		45		44,134	100.00%
Power Service					
Strata 1	18 Min to 435 Max	15	0.68%	494	17.03%
Strata 2	435.1 Min to 1,458 Max	15	0.64%	1,217	41.95%
Strata 3	1,458.1 Min to 3,297 Max	15	0.81%	1,190	41.02%
Total		45		2,901	100.00%
Time of Day					
Strata 1	18 Min to 435 Max	15	0.12%	89	18.50%
Strata 2	435.1 Min to 1,458 Max	15	0.11%	207	43.04%
Strata 3	1,458.1 Min to 3,297 Max	15	0.13%	185	38.46%
Total		45		481	100.00%

[13] The data and details of this analysis are provided in Excel format filed with my testimony (LG&E Electric Zip Code Analysis.xls).

[14] Excludes Lighting.

Q. WHAT ARE YOUR FINDINGS AS A RESULT OF THIS ANALYSIS?

A. LG&E's customers are dispersed in a reasonably proportional manner throughout its service area. In fact, the distribution of residential customers is almost identical in the more densely populated zip codes compared to the less densely populated zip codes, which is contrary to the hypothesis and is opposite of what would be expected if one were to accept the notion that distribution investment should be classified as partially customer-related. As important is the fact that with regard to the General Service class, there is also no material difference in the distribution of customers between the least densely and most densely populated areas of LG&E's service territory.

As a result of these analyses, it cannot be said that the less populated portions of LG&E's service area (which require significant investment to serve few customers) are disproportionately required to serve any one class of customers. As such, with respect to LG&E's primary voltage distribution system, plant and expenses should be assigned to classes based only on utilization (peak demand) and any consideration of customer counts is improper for the allocation of distribution plant. Therefore, my studies indicate that LG&E's primary voltage distribution system costs should be classified as 100% demand-related.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE CLASSIFICATION OF LG&E'S SECONDARY VOLTAGE DISTRIBUTION SYSTEM?

A. In conducting the analysis discussed above, I recognize that the Company's primary voltage distribution system serves more customers and provides more power and energy than does its secondary voltage system. In other words, LG&E's secondary voltage system can be thought of as serving customers downstream from the primary voltage system. As such, the secondary voltage system serves smaller individual geographical areas such as individual neighborhoods, etc. The smallest geographical area in which I have data available to evaluate customer densities and customers mixes is on a zip code basis. Because an individual neighborhood (or secondary voltage circuit) may encompass a relatively small geographical area, I cannot reasonably opine as to whether it is inappropriate to classify a portion of the Company's secondary system based partially on customers and based partially on demand. Therefore, I have accepted Mr.

Seeyle's classification of secondary voltage distribution plant as partially customer-related and partially demand-related.

Q. DOES THE NARUC ELECTRIC COST ALLOCATION MANUAL INDICATE IF AN *A PRIORI* ASSUMPTION IS APPROPRIATE REGARDING WHETHER DISTRIBUTION COSTS MUST BE CLASSIFIED AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED?

A. No. In fact, the NARUC Manual (published in 1992) states the following:

> To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.
>
> Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. (page 89)

Q. HAS NARUC PROVIDED MORE RECENT GUIDANCE CONCERNING THE CLASSIFICATION OF DISTRIBUTION PLANT THAN WHAT WAS PUBLISHED IN THE 1992 NARUC ELECTRIC COST ALLOCATION MANUAL?

A. Yes. The 1992 NARUC Manual was written in an era when all retail utility services were bundled (generation, transmission and distribution). Subsequent to the unbundling of retail rates in the mid to late 1990's by several state jurisdictions, NARUC commissioned a study to examine the costing and pricing of electric distribution service in further detail. In December 2000, NARUC published a report entitled: <u>Charging For Distribution Services: Issues in Rate Design</u>. As part of the Executive Summary this report states:

> The usefulness of cost analyses of the distribution system in designing rate structures and setting rate levels depends in large measure upon the manner in which the studies are undertaken. Cost studies (both marginal and embedded) are intended, among other things, to determine the nature and causes of costs, so that they can then be reformulated into rates that cost-causers can pay. Such studies must of necessity rely on a host of simplifying assumptions in order to produce workable results; this is especially true of embedded cost studies. Moreover, it is often the case

> that many of the costs (*e.g.,* administrative and general) that distribution rates recover are not caused by provision of distribution service, but are assigned to it arbitrarily. Too great dependence on cost studies is to be captured by their underlying assumptions and methodological flaws. Utilities and commissions should be cautious before adopting a particular method on the basis of what may be a superficial appeal. More important, however, is the concern that a costing method, once adopted, becomes the predominant and unchallenged determinant of rate design. (page 67)

With specific regard to classification and allocation of certain distribution plant (poles, wires and transformers), Chapter IV of this report is devoted to the costing of distribution services. With respect to embedded cost analyses this updated NARUC report states:

> There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states. A variation is to treat poles, wires, and transformers as energy-related driven by kilowatt-hour sales but, though it has obvious appeal, only a small number of jurisdictions have gone this route.
>
> Two other approaches sometimes used are the minimum size and zero-intercept methods. The minimum size method operates, as its name implies, on the assumption that there is a minimum-size distribution system capable of serving customers minimum requirements. The costs of this hypothetical system are, so the argument goes, driven not by customer demand but rather by numbers of customers, and therefore they are considered customer costs. The demand-related cost portion then is the difference between total distribution investment and the customer-related costs. The zero-intercept approach is a variation on the minimum size. Here the idea is to identify that portion of plant that is necessary to give customers access but which is incapable of serving any level of demand. The logic is that the costs of this system, because it can serve no demand and thus is not demand-related, are necessarily customer-related. However, the distinction between customer and demand costs is not always clear, insofar as the number of customers on a system (or particular area of a system) will have impacts on the total demand on the system, to the extent that their demand is coincident with the relevant peak (system, areal, substation, etc.).
>
> Any approach to classifying costs has virtues and vices. The first potential pitfall lies in the assumptions, explicit and implicit, that a method is built

> upon. In the basic customer method, it is the *a priori* classification of expenditures (which may or may not be reasonable). In the case of the minimum-size and zero-intercept methods, the threshold assumption is that there is some portion of the system whose costs are unrelated to demand (or to energy for that matter). From one perspective, this notion has a certain intuitive appeal these are the lowest costs that must be incurred before any or some minimal amount of power can be delivered but from another viewpoint it seems absurd, since in the absence of any demand no such system would be built at all. Moreover, firms in competitive markets do not indeed, cannot price their products according to such methods: they recover their costs through the sale of goods and services, not merely by charging for the ability to consume, or access. (pages 29 & 30)

In summary, when all of the facts and guidelines are known, it is clear to me that: (a) data and analysis specific to each utility is more appropriate and preferred over an *a priori* assumption that distribution plant must be partially customer-related; and, (b) many (if not most) state regulatory commissions endorse a method in which all distribution plant from substations through line transformers is classified and allocated based solely on demand. A copy of the entire Chapter (IV) from the 2000 NARUC Publication discussing costing studies is provided in my Schedule GAW-7.

Q. WHY IS THE CLASSIFICATION OF DISTRIBUTION PLANT IMPORTANT IN CCOSS ANALYSES?

A. The classification of distribution plant may be the single most important factor affecting class rates of return. To illustrate the importance of this issue, consider the Residential class: whereas this class may account for only 40% to 50% of peak demand, it is responsible for a much higher percentage of the number of customers. Therefore, given the level of investment associated with distribution plant, wide variations in class rates of return can result from different customer/demand classifications.

Q. WHAT ARE YOUR RECOMMENDATIONS CONCERNING THE CLASSIFICATION OF DISTRIBUTION PLANT IN THIS CASE?

A. Based on my customer density/mix analysis of LG&E's distribution system, it is apparent that LG&E's primary voltage distribution system costs should be classified as

100% demand-related. With regard to the Company's secondary voltage distribution system, I have accepted Mr. Seeyle's customer/demand classifications.

Q. WHAT ARE THE CCOSS RESULTS UTILIZING THE GENERATION ALLOCATION METHODS YOU DISCUSSED EARLIER AND THAT ALSO CLASSIFIES PRIMARY VOLTAGE DISTRIBUTION PLANT AS 100% DEMAND-RELATED?

A. The following provides a summary of my CCOSS results at current rates under each allocation method wherein primary voltage distribution costs are classified as 100% demand-related:

100% Primary Voltage Demand Distribution Plant
ROR At Current Rates

Class	Modified BIP (As Corrected)	Probability Of Dispatch	True BIP
Residential	2.76%	4.05%	3.97%
General Service	7.32%	7.88%	7.61%
Pwr Svc-Primary	6.38%	4.23%	4.10%
Pwr Svc-Secondary	8.59%	6.87%	6.72%
TOD-Primary	4.55%	2.62%	2.46%
TOD-Secondary	11.52%	7.78%	10.11%
Retail Transmission	3.53%	2.75%	2.45%
Special Contract #1	1.82%	0.65%	0.50%
Special Contract #2	2.54%	0.18%	0.40%
Street Lighting	5.43%	5.14%	5.16%
Street Lighting Energy	7.80%	1.88%	1.70%
Traffic Lighting	6.89%	5.83%	6.43%
TOTAL	4.92%	4.92%	4.92%

A summary of these CCOSS results are provided in my Schedules GAW-8 and GAW-9. Furthermore, in accordance with the Commission's directive regarding CCOSS, I am providing the functionalization and classification of costs along with the detailed allocation of specific accounts utilizing the Probability of Dispatch method in my Schedules GAW-10 (Class Allocation), GAW-11 (Functionalization/Classification), and

GAW-12 (Demand, Energy, Customer costs). The Excel spreadsheet containing this model is provided with my filed testimony (TAI Prob Dispatch with 100% Demand.xls).

Q. WHAT ARE YOUR CONCLUSIONS REGARDING CLASS COST ALLOCATIONS RELATING TO THIS CASE?

A. As can be seen in the table above, while absolute class RORs vary across allocation methodologies, there are relative consistencies across several classes. The Special Contract customers' RORs at current rates are considerably lower than the system average regardless of allocation approach. The Residential class is somewhat lower than the system average ROR while the General Service, Power Service-Secondary, TOD-Secondary, and Traffic Lighting classes RORs tend to be significantly greater than the system average ROR. These profitability patterns across methodologies can then be used as a tool in evaluating reasonable individual class increases.

IV. <u>ELECTRIC CLASS REVENUE DISTRIBUTION</u>

Q. WHAT ARE THE GENERAL CRITERIA THAT SHOULD BE CONSIDERED IN ESTABLISHING CLASS REVENUE RESPONSIBILITY FOR ELECTRIC UTILITY RATES?

A. There are several criteria that should be considered in evaluating class or rate revenue responsibility. First, class cost allocation results should be considered, but as discussed in detail earlier in my testimony, CCOSS results are not surgically precise. They should only be used as a guide and as one of many tools in evaluating class revenue responsibility. Other criteria that should be considered include: gradualism, wherein rates should not drastically change instantaneously; rate stability, which is similar in concept to gradualism but relates to specific rate elements within a given rate structure; affordability of electricity across various classes as well as a relative comparison of electricity prices across classes; and, public policy concerning current economic conditions as well as economic development.

Because embedded class cost allocations cannot be considered surgically precise and the fact that other criteria to be considered in evaluating class revenue responsibility are clearly subjective in nature, proper class revenue distribution can be deemed more of an art than a science. In this regard, there is no universal mathematical methodology that can be applied across all utilities or across all rate classes. However, most experts and regulatory commissions agree on certain broad parameters regarding class revenue increases. These include: some movement towards allocated cost of service; and, maximum/minimum percentage changes across individual rate classes.

Q. DID LG&E WITNESS SEEYLE CONSIDER AND REFLECT THE VARIOUS SUBJECTIVE CRITERIA AS WELL AS THE BROAD PARAMETERS DISCUSSED ABOVE WITHIN HIS CLASS REVENUE DISTRIBUTION PROPOSAL?

A. Yes. While Mr. Seeyle did consider his CCOSS results, he also recognized other important criteria in developing his proposed class revenue distribution (increases).

Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S PROPOSED CLASS REVENUE INCREASE.

A. The following table provides a summary of current and LG&E proposed revenue by rate class:

LG&E's Proposed Class Revenue Increases
($000)

Class	Revenue At Present Rates	Proposed Increase	% Increase	% of System Average
Residential	$441,518	$42,132	9.54%	112%
General Service	$170,462	$12,181	7.15%	84%
Pwr Svc-Primary	$12,536	$1,035	8.25%	97%
Pwr Svc-Secondary	$164,899	$11,631	7.05%	83%
TOD-Primary	$126,370	$10,385	8.22%	96%
TOD-Secondary	$84,439	$5,698	6.75%	79%
Retail Transmission	$68,896	$5,824	8.45%	99%
Special Contract #1	$6,755	$605	8.95%	105%
Special Contract #2	$3,520	$288	8.20%	96%
Street Lighting	$23,389	$1,920	8.21%	96%
Street Lighting Energy	$245	$0	0.00%	0%
Traffic Lighting	$304	$21	6.76%	79%
Curtailable Service Rider	-$4,335	$1,920	44.30%	520%
TOTAL	$1,098,995	$93,640	8.52%	100%

Q. HAVE YOU CONDUCTED ANALYSES TO EVALUATE THE REASONABLENESS OF MR. SEEYLE'S PROPOSED CLASS REVENUE INCREASES?

A. Yes. I have evaluated Mr. Seeyle's proposed class revenue increases both in terms of relative class magnitudes as well as in terms of whether his proposed changes reflect a reasonable movement towards allocated cost of providing service.

Q. PLEASE EXPLAIN YOUR EVALUATION OF MR. SEEYLE'S PROPOSED CLASS REVENUE DISTRIBUTION IN TERMS OF RELATIVE MAGNITUDES.

A. A common technique utilized in the industry is to evaluate class percentage increases relative to the overall system increases. While there are no hard and fast rules, a common practice is that no class should receive an increase greater than approximately 150% of the system average percentage increase. Furthermore, I am of the opinion that no class should receive a rate decrease when there is a significant overall increase to the total Company's revenue requirement. In this regard, Mr. Seeyle's proposed revenue distribution fulfills this criteria. However, as will be shown below, he has limited individual class increases somewhat too narrowly.

Q. PLEASE EXPLAIN WHY IT IS YOUR OPINION THAT MR. SEEYLE'S PROPOSED CLASS REVENUE INCREASES ARE LIMITED TOO NARROWLY.

A. As indicated several times earlier in my testimony, class cost of service studies cannot be considered surgically precise such that the results obtained from other reasonable methods and approaches may yield somewhat different results. In this regard, it is beneficial to consider the results of multiple CCOSS in conjunction with the concept of gradualism and the other subjective criteria discussed earlier.

My Schedule GAW-13 provides a summary comparison of class rates of return at current rates under each of the CCOSS that should be considered in this case. The following table provides the average indexed ROR at current rates of all methods as well as the average indexed ROR of the methods in which primary voltage distribution plant is classified as 100% demand-related:

Average Indexed ROR Under Multiple Methods and LG&E Proposed
Percent Increases as a Percent of System Average Percent Increase

Class	Average (All Methods)	Average Primary Distribution 100% Demand	Seeyle Proposed Pct. Of Sys. Average Increase
Residential	70%	79%	112%
General Service	156%	152%	84%
Pwr Svc-Primary	103%	89%	97%
Pwr Svc-Secondary	155%	140%	83%
TOD-Primary	68%	56%	96%
TOD-Secondary	205%	185%	79%
Retail Transmission	59%	59%	99%
Special Contract #1	23%	13%	105%
Special Contract #2	23%	13%	96%
Street Lighting	105%	111%	96%
Street Lighting Energy	76%	62%	0%
Traffic Lighting	128%	136%	79%
TOTAL	100%	100%	100%

As indicated in the table above, the cost studies indicate that the TOD-Primary, Retail Transmission, and both Special Contract classes are contributing significantly less to profits than the system as a whole which indicates that larger percentage increases are warranted for these classes. However, Mr. Seeyle proposes very modest increases (above the system average percentage increase) to these classes of 96%, 99%, 105%, and 96%, respectively. At the same time, the General Service, Power Service-Secondary, and TOD-Secondary classes are contributing significantly more to profits than the system average. Although Mr. Seeyle proposes to increase these classes by a lower percentage rate than the system average percentage, there will be little movement towards allocated cost of service with his recommended narrow bands. Finally, although the Lighting Energy class is somewhat below the system average ROR (indexed ROR less than 100%), Mr. Seeyle proposes no increase to this class. Under Mr. Seeyle's proposal of no increase to Lighting Energy, this class will move further away from the allocated cost of providing service.

As a result, I recommend that Mr. Seeyle's narrow band of class increases be expanded somewhat in order to move these classes closer to allocated cost of service.

Q. PLEASE EXPLAIN AND PROVIDE YOUR RECOMMENDED MODIFICATIONS TO MR. SEEYLE'S CLASS REVENUE DISTRIBUTION PROPOSAL.

A. I recommend somewhat larger percentage increases to the TOD-Primary, Retail Transmission, and both Special Contract classes and somewhat smaller percentage increases to the General Service, TOD-Secondary, and Traffic Energy classes. I also recommend that the Lighting Energy class be increased at the system average percentage increase. The table below provides my recommended class revenue increases at the Company's proposed overall increase of $94 million:

OAG Proposed Class Revenue Distribution
At the Company's Proposed Overall Increase
($000)

Class	Proposed Increase	Percent Increase	Percent Of Sys. Average Percent Increase
Residential	$42,132	9.54%	112%
General Service	$10,167	5.96%	70%
Pwr Svc-Primary	$1,035	8.25%	97%
Pwr Svc-Secondary	$11,240	6.82%	80%
TOD-Primary	$12,383	9.80%	115%
TOD-Secondary	$4,677	5.54%	65%
Retail Transmission	$7,044	10.22%	120%
Special Contract #1	$713	10.55%	124%
Special Contract #2	$371	10.55%	124%
Street Lighting	$1,920	8.21%	96%
Street Lighting Energy	$21	8.52%	100%
Traffic Lighting	$18	5.96%	70%
Curtailable Service Rider	$1,920	44.30	--
TOTAL	$93,640	8.52%	100%

Q. PLEASE PROVIDE A COMPARISON OF MR. SEEYLE'S PROPOSED CLASS REVENUE INCREASES TO THOSE YOU RECOMMEND.

A. The following table provides a comparison of the Company's and my recommended class revenue increases at the Company's overall requested $94 million increase:

Comparison of LG&E and OAG
Class Revenue Distribution

Class	LG&E Proposed Increase	OAG Recommended Increase
Residential	$42,132	$42,132
General Service	$12,181	$10,167
Pwr Svc-Primary	$1,035	$1,035
Pwr Svc-Secondary	$11,631	$11,240
TOD-Primary	$10,385	$12,383
TOD-Secondary	$5,698	$4,677
Retail Transmission	$5,824	$7,044
Special Contract #1	$605	$713
Special Contract #2	$288	$371
Street Lighting	$1,920	$1,920
Street Lighting Energy	$0	$21
Traffic Lighting	$21	$18
Curtailable Service Rider	$1,920	$1,920
TOTAL	$93,640	$93,640

Q. IN THE EVENT THE COMMISSION AUTHORIZES AN OVERALL REVENUE INCREASE LESS THAN THE $94 MILLION REQUESTED BY LG&E, HOW SHOULD THE ULTIMATE INCREASE BE DISTRIBUTED ACROSS RATE SCHEDULES?

A. I recommend that any overall increase be distributed to rate classes in proportion to the class increases I recommend above.

V. ELECTRIC RESIDENTIAL RATE DESIGN

Q. PLEASE EXPLAIN LG&E'S CURRENT RESIDENTIAL RATE STRUCTURE.

A. LG&E offers three different rate schedules for Residential service. Rate RS is the standard Residential rate that serves all but 35 customers.[15] This rate structure is comprised of a fixed monthly customer charge and a flat energy charge per kWh. The Company also offers two Residential Time of Day rates. These Time of Day rates include a fixed monthly charge plus time differentiated rates for demand charges (RTOD-

15 Per Filing Schedule M-1.3-E.

Demand) and another that incorporates time differentiated energy charges (RTOD-Energy).

Q. DOES LG&E PROPOSE SIGNIFICANT INCREASES TO FIXED MONTHLY CUSTOMER CHARGES?

A. Yes. LG&E witnesses Robert Conroy and William Seeyle propose to increase all residential customer charges from $10.75 to $22.00 per month, or by more than 100%.

Q. MR. WATKINS, HAVE YOU IDENTIFIED A COMMON OBJECTIVE IN LG&E'S RESIDENTIAL RATE DESIGN PROPOSAL?

A. Yes. It is clear from the testimonies of Messrs. Conroy and Seeyle that the primary objective of LG&E's residential rate design is to guarantee revenue collection and profitability associated with fixed monthly customer charges. Moreover, and as will be discussed later in my testimony, the witnesses are clearly opening the door for even more revenue stability by proposing to differentiate energy charges between "fixed" and "variable" components as well as advocate the possibility of demand-based rates for all residential customers and the possibility of revenue decoupling in the future.

Q. WHY DOES LG&E DESIRE MORE RESIDENTIAL REVENUE COLLECTED FROM FIXED CHARGES?

A. Fixed monthly customer charges represent guaranteed revenue to LG&E. This guarantee of revenue obviously reduces the risks of LG&E's operations and provides much more assurances of net income available to shareholders.

Q. HOW DOES LG&E SUPPORT THIS EXCEPTIONALLY LARGE INCREASE TO THE FIXED MONTHLY CUSTOMER CHARGES?

A. Messrs. Conroy and Seeyle offer three rationale for high customer charges. First, Mr. Conroy observes that a residential rate design that recovers a larger portion of revenue from fixed charges will stabilize customers' monthly bills. Second, Mr. Seeyle is of the opinion that because the majority of LG&E's total costs of providing service are "fixed" in nature, a large portion of its revenues should be collected from fixed charges.

Third, Mr. Seeyle claims that higher fixed charges will help eliminate intra-class subsidies within the Residential class.

Q. IS MR. CONROY CORRECT IN HIS ASSERTION THAT THE COLLECTION OF A HIGHER PROPORTION OF TOTAL REVENUES FROM FIXED CHARGES WILL TEND TO STABILIZE CUSTOMERS' MONTHLY BILLS?

A. Mathematically, Mr. Conroy is absolutely correct. However, this certainly is not an objective of proper economic rate design or accepted public policy. If a rate structure is reconfigured such that a larger proportion of customers' bills are comprised of non-avoidable fixed charges and a smaller proportion of customers' bills are comprised of volumetrically-based (energy) charges, customers' abilities to make rational economic decisions are reduced. In other words, the ability of individuals to control their total electric bill is diminished with rate structures that are comprised largely of fixed charges. This reduced ability to control bills leads to uneconomic decisions relating to the consumption of electricity and clearly hampers incentives to conserve energy.

Q. IS MR. SEEYLE'S ASSERTION THAT FIXED COSTS SHOULD BE COLLECTED FROM FIXED CHARGES IN ACCORDANCE WITH SOUND ECONOMIC PRINCIPLES OR ACCEPTED PRICING PRACTICES?

A. No. Mr. Seeyle has a profound misunderstanding of sound economic principles that are contrary to accepted pricing practices. First, I will discuss the theoretical aspects of sound economic pricing principles and then I will discuss accepted pricing practices in our economy.

The most basic tenet of competition is that prices determined through a competitive market ensure the most efficient allocation of society's resources. Because public utilities are generally afforded monopoly status under the belief that resources are better utilized without duplicating the fixed facilities required to serve consumers, a fundamental goal of regulatory policy is that regulation should serve as a surrogate for competition to the greatest extent practical.[16] As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

[16] James C. Bonbright, et al., *Principles of Public Utility Rates*, p. 141 (Second Edition, 1988).

Q. PLEASE BRIEFLY DISCUSS HOW PRICES ARE GENERALLY STRUCTURED IN COMPETITIVE MARKETS.

A. Under economic theory, efficient price signals result when prices are equal to marginal costs.[17] It is well known that costs are variable in the long-run. Therefore, efficient pricing results from the incremental variability of costs even though a firm's short-run cost structure may include a high level of sunk or "fixed" costs or be reflective of excess capacity. Indeed, competitive market-based prices are generally structured based on usage; i.e. volume-based pricing.

Q. PLEASE BRIEFLY EXPLAIN THE ECONOMIC PRINCIPLES OF EFFICIENT PRICE THEORY AND HOW SHORT-RUN FIXED COSTS ARE RECOVERED UNDER SUCH EFFICIENT PRICING.

A. Perhaps the best known micro-economic principle is that in competitive markets (i.e., markets in which no monopoly power or excessive profits exist) prices are equal to marginal cost. Marginal cost is equal to the incremental change in cost resulting from an incremental change in output. A full discussion of the calculus involved in determining marginal costs is not appropriate here. However, it is readily apparent that because marginal costs measure the changes in costs with output, short-run "fixed" costs are irrelevant in efficient pricing. This is not to say that efficient pricing does not allow for the recovery of short-run fixed costs. Rather, they are reflected within a firm's production function such that no excess capacity exists and that an increase in output will require an increase in costs -- including those considered "fixed" from an accounting perspective. As such, under efficient pricing principles, marginal costs capture the variability of costs, and prices are variable because prices equal these costs.

Q. PLEASE EXPLAIN HOW THIS THEORY OF COMPETITIVE PRICING SHOULD BE APPLIED TO REGULATED PUBLIC UTILITIES, SUCH AS LG&E.

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[17] Strictly speaking, efficiency is achieved only when there is no excess capacity such that short-run marginal costs equal long-run marginal costs. In practice, there is usually at least some excess capacity present such that pricing based on long-run marginal costs represents the most efficient utilization of resources.

A. Due to LG&E's investment in system infrastructure, there is no debate that many of its short-run costs are fixed in nature. However, as discussed above, efficient competitive prices are established based on long-run costs, which are entirely variable in nature.

Marginal cost pricing only relates to efficiency. This pricing does not attempt to address fairness or equity. Fair and equitable pricing of a regulated monopoly's products and services should reflect the benefits received for the goods or services. In this regard, those that receive more benefits should pay more in total than those who receive fewer benefits. Regarding electricity usage, i.e., the level of kWh consumption is the best and most direct indicator of benefits received. Thus, volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy has consistently been the belief of economists, regulators, and policy makers for many years. For example, consider utility industry pricing in the 1800s, when the industry was in its infancy. Customers paid a fixed monthly fee and consumed as much of the utility commodity/service as they desired (usually water). It soon became apparent that this fixed monthly fee rate schedule was inefficient and unfair. Utilities soon began metering their commodity/service and charging only for the amount actually consumed. In this way, consumers receiving more benefits from the utility paid more, in total, for the utility service because they used more of the commodity.

Q. IS THE ELECTRIC UTILITY INDUSTRY UNIQUE IN ITS COST STRUCTURES, WHICH ARE COMPRISED LARGELY OF FIXED COSTS IN THE SHORT-RUN?

A. No. Most manufacturing, agricultural, and transportation industries are comprised of cost structures predominated with "fixed" costs. Obvious examples of these industries include: automobile and truck manufacturing; petroleum production; farming; airline; rail transportation; and shipping transportation. Indeed, virtually every capital intensive industry is faced with a high percentage of fixed costs in the short-run. Prices for competitive products and services in these capital-intensive industries are invariably established on a volumetric basis, including those that were once regulated.

Accordingly, LG&E's position that its fixed costs should be recovered through fixed monthly charges is incorrect. Pricing should reflect the Company's long-run costs, wherein all costs are variable or volumetric in nature, and users requiring more of the Company's products and services should pay more than customers who use less of these products and services. Stated more simply, those customers who conserve or are otherwise more energy efficient, or those who use less of the commodity for any reason, pay less than those who use more electricity.

Q. CAN YOU PROVIDE AN EXAMPLE OF WHAT EFFICIENT PRICING STRUCTURES AND PRACTICES PREVAIL IN COMPETITIVE ELECTRICITY MARKETS?

A. Yes. In several States, the provision of electricity to retail customers has been unbundled wherein distribution service remains regulated, but customers have the ability to shop for transmission and generation service in a competitive marketplace. In every instance in which I am aware, residential customers pay for competitively-based transmission and generation service entirely on a volumetric basis; i.e., no fixed charges are imposed. In this regard, there is no question that the total cost of transmission and generation service is largely "fixed" in nature due to the large capital investments required to provide service.

Q. ARE HIGH FIXED CUSTOMER CHARGE RATE STRUCTURES CONTRARY TO EFFECTIVE CONSERVATION EFFORTS?

A. Yes. High fixed charge rate structures actually promote additional consumption because a consumer's price of incremental consumption is less than what an efficient price structure would otherwise be. A clear example of this principle is exhibited in the natural gas transmission pipeline industry. As discussed in its well-known Order 636, the FERC's adoption of a "Straight Fixed Variable" ("SFV") pricing method[18] was a result of national policy (primarily that of Congress) to encourage increased use of domestic natural gas by promoting additional interruptible (and incremental firm) gas usage. The

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[18] Under Straight Fixed Variable pricing, customers pay a fixed charge that is designed to recover all of the utility's fixed costs.

FERC's SFV pricing mechanism greatly reduced the price of incremental (additional) natural gas consumption. This resulted in significantly increasing the demand for, and use of, natural gas in the United States after Order 636 was issued in 1992.

FERC Order 636 had two primary goals. The first goal was to enhance gas competition at the wellhead by completely unbundling the merchant and transportation functions of pipelines.[19] The second goal was to encourage the increased consumption of natural gas in the United States. In the introductory statement of the Order, FERC stated:

> The Commission's intent is to further facilitate the unimpeded operation of market forces to stimulate the production of natural gas... [and thereby] contribute to reducing our Nation's dependence upon imported oil… .[20]

With specific regard to the SFV rate design adopted in Order 636, FERC stated:

> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant gas over alternate fuels such as foreign oil. SFV is the best method for doing that.[21]

Recently, some public utilities have begun to advocate SFV residential pricing. The companies claim a need for enhanced fixed charge revenues. To support their claim, the companies argue that because retail rates have been historically volumetric based, there has been a disincentive for utilities to promote conservation, or encourage reduced consumption. However, the FERC's objective in adopting SFV pricing suggests the exact opposite. The price signal that results from SFV pricing is meant to promote additional consumption, not reduce consumption. Thus, a rate structure that is heavily based on a fixed monthly customer charge sends an even stronger price signal to consumers to use more energy.

Q. ARE CONSERVATION AND EFFICIENCY GAINS A NEW RISK TO PUBLIC UTILITIES?

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[19] Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636 (Apr. 9, 1992), p. 7.

[20] *Id.* p. 8 (alteration in original).

[21] *Id.* pp. 128-129.

A. No. Conservation through efficiency gains has been ongoing for many years and is not a new risk. As a result, even though average residential electric usage per appliance has been declining, utilities have remained financially healthy and have continued their investments under volumetric pricing structures. Also, FERC's movement to straight fixed variable pricing for pipelines was unquestionably initiated to promote additional demand for natural gas, not less, and did in fact do so.

Q. DOES LG&E HAVE ANY APPROVED PLANS TO COMPENSATE THE COMPANY FOR CONSERVATION EFFORTS?

A. Yes. LG&E has an approved Demand Side Management Cost Recovery Mechanism wherein the Company is compensated for not only the cost of implementing its conservation programs but also provides compensation for diminished revenues resulting from its conservation programs. In addition, the Company is provided an incentive bonus (up to 5% of program expenditures) of 15% on the expected net resource savings for each approved DSM program.

Q. AS A PUBLIC POLICY MATTER, WHAT IS THE MOST EFFECTIVE TOOL THAT REGULATORS HAVE TO PROMOTE COST EFFECTIVE CONSERVATION AND THE EFFICIENT UTILIZATION OF RESOURCES?

A. Unquestionably, one of the most important and effective tools that this, or any, regulatory Commission has to promote conservation is by developing rates that send proper pricing signals to conserve and utilize resources efficiently. A pricing structure that is largely fixed, such that customers' effective prices do not properly vary with consumption, promotes the inefficient utilization of resources. Pricing structures that are weighted heavily on fixed charges are much more inferior from a conservation and efficiency standpoint than pricing structures that require consumers to incur more cost with additional consumption.

Q. A CUSTOMER'S TOTAL ELECTRIC BILL IS COMPRISED OF A BASE RATE COMPONENT, A FUEL ADJUSTMENT CLAUSE ("FAC") RIDER; AND VARIOUS OTHER RIDERS. THESE FUEL AND OTHER RIDERS ARE VOLUMETRICALLY PRICED AND REPRESENT A SIGNIFICANT PORTION OF A CUSTOMER'S BILL. DOES THE VOLUMETRIC PRICING OF THESE COMPONENTS ELIMINATE THE NEED FOR A PROPER PRICING SIGNAL FROM BASE RATES?

A. No, certainly not. The fact that significant revenue may be collected volumetrically through riders does not lessen the need for reasonable design of the underlying base rates.

Q. NOTWITHSTANDING THE EFFICIENCY REASONS AS TO WHY REGULATION SHOULD SERVE AS A SURROGATE FOR COMPETITION, ARE THERE OTHER RELEVANT ASPECTS TO THE PRICING STRUCTURES IN COMPETITIVE MARKETS *VIS A VIS* THOSE OF REGULATED UTILITIES?

A. Yes. In competitive markets, consumers, by definition, have the ability to choose various suppliers of goods and services. Consumers and the market have a clear preference for volumetric pricing. Utility customers are not so fortunate in that the local utility is a monopoly. The only reason utilities are able to achieve pricing structures with high fixed monthly charges is due to their monopoly status. In my opinion, this is a critical consideration in establishing utility pricing structures. Competitive markets and consumers in the United States have demanded volumetric based prices for generations. Hence, a regulated utility's pricing structure should not be allowed to counter the collective wisdom of markets and consumers simply because of its market power.

Q. PLEASE RESPOND TO MR. SEEYLE'S ASSERTION THAT HIGHER FIXED CUSTOMER CHARGES HELP REDUCE INTRA-CLASS SUBSIDIES.

A. Although I have already explained why the notion that fixed costs should be recovered from fixed charges does not comport with accepted economic theory and practice, the genesis of Mr. Seeyle's rationale relating to intra-class subsidies rests on the premise that the revenue derived from small volume customers does not sufficiently recover the total costs to provide service, such that the revenue generated from large volume customers subsidize the small volume customers. Mr. Seeyle's rationale and opinion is incorrect and fails to consider two important aspects of cost causation and ratemaking principles and practices.

First, one must compare the "cost causation" of "small volume and large volume" customers within a particular rate class particularly as it relates to residential customers. Based on the seasonal nature of the demand for electricity, residential customers use much more electricity in the winter and summer months than during the spring and fall months due to the use of electricity for heating and air conditioning. Some residential customers do not use electricity for space heating purposes and may not have air conditioning (or use in a limited fashion). As such, these annual small volume customers use electricity at a much more constant rate throughout the year than do residential large volume customers; i.e., small volume customer's usage is more constant throughout the year.

To illustrate, LG&E's average residential customer used about 950 kWh during the winter months of January and February and about 1,386 kWh during the summer months of July and August. However, during the spring and fall months of April, May, October, and November, the average residential customer used only about 715 kWh.[22] As a result, the load factor of small volume (non-heating/air conditioning customers) tends to be much higher than that for large volume (heating/air conditioning customers). As a matter of cost causation, LG&E must plan and install relatively more capacity for heating/air conditioning customers than for small volume customers. This additional capacity obviously comes at a cost such that the cost to serve a high load factor (low annual volume) customer is significantly less than that for a low load factor (high annual volume) customer.

The second aspect concerns the pricing structure of goods and services generally, and public utility rates specifically. That is, taken to the extreme, it could be argued that every consumer of a good or service (whether competitive or regulated) imposes a different cost upon the good or service provided such that a different price could

[22] Per LG&E response to Association of Community Ministries data request 1-6.

theoretically be calculated for every individual customer. This of course is not done in practice as it is not practical or reasonable. For example, if two customers purchase gasoline from a gas station at the same time, one driving a very large vehicle with a large fuel tank and the other driving a very small car with a small fuel tank, the customer purchasing a small amount of gasoline does not pay more per gallon than the customer purchasing significantly more gasoline. This is true even though the ultimate delivered price of gasoline includes a significant level of "fixed" costs such as the cost of the store, gas pumps, labor, etc.

Q. HAVE YOU CONDUCTED ANY STUDIES OR ANALYSES TO INDICATE THE LEVELS AT WHICH LG&E'S RESIDENTIAL CUSTOMER CHARGES SHOULD BE ESTABLISHED?

A. Yes. In designing public utility rates, there is a method that produces maximum fixed monthly customer charges and is consistent with efficient pricing theory and practice. This technique considers only those costs that vary as a result of connecting a new customer and which are required in order to maintain a customer's account. This technique is a direct customer cost analysis and uses a traditional revenue requirement approach. Under this method, capital cost provisions include an equity return, interest, income taxes, and depreciation expense associated with the investment in service lines and meters. In addition, operating and maintenance provisions are included for customer metering, records, and billing.

Under this direct customer cost approach, there is no provision for corporate overhead expenses or any other indirect costs as these costs are more appropriately recovered through energy (kWh) charges.

Q. HAVE YOU CONDUCTED DIRECT CUSTOMER COST ANALYSES APPLICABLE TO LG&E'S RESIDENTIAL CLASS?

A. Yes. I conducted a direct customer cost analysis for LG&E's Residential class. The details of this analysis are provided in my Schedule GAW-14. As indicated in this Attachment, the Residential direct customer cost is $4.15 per month. It should be noted that my customer cost analyses is based on the Company's proposed return on equity of

10.23%. If a lower cost of equity is used, the resulting customer costs are somewhat reduced.

Q. WHY IS IT APPROPRIATE TO EXCLUDE CORPORATE OVERHEAD AND OTHER INDIRECT COSTS IN DEVELOPING RESIDENTIAL CUSTOMER CHARGES?

A. Like all electric utilities, LG&E is in the business of providing electricity to meet the energy needs of its customers. Because of this and the fact that customers do not subscribe to LG&E's services simply to be "connected," overhead and indirect costs are most appropriately recovered through volumetric energy charges.

Q. MR. SEEYLE CLAIMS THAT HIS "COST-BASED" RESIDENTIAL CUSTOMER CHARGE IS $22.04 PER MONTH. PLEASE EXPLAIN HOW MR. SEEYLE ARRIVED AT THIS LEVEL.

A. Mr. Seeyle's figure of $22.04 per residential customer per month includes the majority of distribution plant investment costs associated with poles and overhead lines (59%), underground conductors and conduit (64%), and transformers (41%). In addition, Mr. Seeyle's calculated residential customer cost of $22.04 per month includes about $16.3 million in administrative and general expenses plus additional other overhead expenses. Finally, Mr. Seeyle's customer cost analysis includes the entire amount of uncollectible expense assigned to the Residential class ($1.8 million). These costs should not be reflected within the determination of an appropriate fixed monthly customer charge.

Q. SHOULD ANY DISTRIBUTION OVERHEAD LINES, UNDERGROUND LINES, OR TRANSFORMER COSTS BE CONSIDERED IN DETERMINING THE LEVEL, OR REASONABLENESS, OF FIXED MONTHLY CHARGES?

A. No. Every electric utility's investment in distribution lines and transformers reflects the back bone of the company's distribution system and indeed, serves as the infrastructure supporting the company's entire existence. In other words, distribution lines and transformers are the conduit to move electricity from the transmission system to individual customers. Residential electric customers do not subscribe to LG&E's service simply to be "connected," rather, they rely upon LG&E to distribute their energy requirements throughout the year.

Q. WHY THEN ARE DISTRIBUTION COSTS SOMETIMES CLASSIFIED AND ALLOCATED BASED PARTIALLY ON PEAK DEMANDS AND PARTIALLY ON NUMBER OF CUSTOMERS?

A. I provided a detailed discussion of this topic earlier in my testimony. In short, the reason that some analysts classify distribution plant as partially customer-related and partially demand-related has nothing to do with cost causation but rather, is a means to equitably allocate costs due to differences in customer densities and the mix of customers across classes.

Q. IS THERE ACADEMIC SUPPORT FOR YOUR OPINION THAT DISTRIBUTION POLES, LINES, AND TRANSFORMERS SHOULD NOT BE CONSIDERED AS "CUSTOMER-RELATED" COSTS FOR PURPOSES OF DETERMINING THE REASONABLENESS OF FIXED MONTHLY CUSTOMER CHARGES?

A. Yes. In his well-known treatise <u>Principles of Public Utility Rates</u>, Professor James C. Bonbright states:

> . . . if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customers costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories. (Second Edition, page 492)

Q. BASED ON YOUR OVERALL EXPERIENCE AS WELL AS THE STUDIES AND ANALYSES YOU HAVE CONDUCTED FOR THIS CASE, WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE CUSTOMER CHARGES FOR LG&E'S RESIDENTIAL CUSTOMERS?

A. Although my residential customer cost analysis indicates a maximum monthly customer charge of $4.15 per month, I recommend maintaining the current customer charge of $10.75 per month. In this regard, I recognize that the current rate of $10.75 more than double that of the direct customer cost, however, in the interest of rate continuity and rate stability, my recommendation of maintaining the current monthly customer charge is in the best public interest.

Q. PLEASE BRIEFLY SUMMARIZE WHY YOUR RECOMMENDATION TO MAINTAIN THE CURRENT LEVEL OF CUSTOMER CHARGES IS APPROPRIATE.

A. It must be remembered that my proposed rate design will allow the Company a reasonable opportunity to recover all of its costs and earn a fair rate of return. Utilities advocate higher fixed customer charges in order to minimize their risks by guaranteeing revenue recovery through fixed charges. Whether electricity rates are largely volumetric priced or largely based on fixed charges, the reality is the utility will collect its required revenues. This is particularly relevant in this case since the Company is using a forecasted test year that reflects energy usages (kWh) under normal weather conditions. Rate designs structured largely based on volumetric charges promote conservation, are efficient, and are in accordance with pricing practices in competitive markets.

Finally, no cross-subsidization issues are created across customers within the same class as long as the fixed customer charge recovers the incremental cost of connecting and maintaining each customer's account. Indeed, the incremental cost of connecting and maintaining a residential customer's account is slightly above $4.00 per month. My recommendation to maintain the current residential customer charge of $10.75 is considerably higher than this incremental cost. At the same time, my recommendation to maintain the current rate level adheres to the accepted ratemaking principles of rate continuity and rate stability.

Q. DOES THE COMPANY PROPOSE ANY STRUCTURAL CHANGES TO THE MANNER IN WHICH ENERGY CHARGES ARE PRESENTED ON CUSTOMER'S BILLS?

A. Yes. Messrs. Conroy and Seeyle propose a change in the way residential customers' bills are presented. Currently, a customer's bill simply shows that month's kWh energy charges. The Company is proposing to bifurcate this energy charge into a "variable cost" component and a "fixed cost" component. Mr. Seeyle testifies that this proposal is solely for educational and informational purposes at this point in time.

Q. WHAT IS THE COMPANY'S RATIONALE FOR PROPOSING THIS "EDUCATIONAL AND INFORMATIONAL" BIFURCATION OF ENERGY CHARGES?

A. Mr. Seeyle indicates that the Company wants customers, stakeholders, and employees to be aware that two types of costs are included in the energy charge. Mr. Seeyle opines that "it is important for customers, stakeholders, and employees to understand that not all costs are automatically reduced when customers use less energy."

Similarly, Mr. Conroy testifies that:

> splitting the energy charge solely on the tariff sheets as proposed will allow the Commission and interested customers to see how much fixed-cost recovery versus truly variable-cost recovery is embedded in the Company's volumetric energy rate for those rate schedules. The Company plans to provide additional educational material on this issue to customers periodically by discussing it in bill inserts or customer newsletters enclosed in customers' bills.

Q. DO YOU SUPPORT THIS PROPOSED BIFURCATION OF ENERGY CHARGES WITHIN CUSTOMERS' BILLS?

A. No. First, even for those customers that understand the concepts of fixed versus variable costs, they could care less about the cost structure for ratemaking purposes within their energy charges. What the customer is interested in is what those variable charges are in total. As an analogy, when consumers purchase gasoline, they could care less how much of the total cost per gallon is associated with the fixed cost of producing, transporting, and delivering that gallon of gasoline versus the variable cost of gasoline at the wellhead. Second, in my practice throughout the United States, I have not seen such a proposal, let alone such a bifurcation of rates between "fixed" and "variable" costs. This could lead to additional customer confusion as they may not understand the distinction between "fixed" and "variable" costs, and perhaps more importantly, may disagree with the Company's determination of what is and what is not a fixed cost. The point of this is that such a distinction is unnecessary, will not assist consumers in their efficient utilization of electricity, nor assist in making decisions on how to control their electricity bills. Indeed, it is clear that this proposal is nothing more than a campaign by LG&E to advocate the collection of so-called "fixed" costs from non-avoidable charges.

Q. MR. SEEYLE DISCUSSES THE POTENTIAL RATE DESIGN PROBLEMS CREATED BY DISTRIBUTED GENERATION. PLEASE RESPOND TO THESE POTENTIAL RATE DESIGN PROBLEMS ESPOUSED BY MR. SEEYLE.

A. While Mr. Seeyle acknowledges that distributed generation has not created any significant problems for LG&E, it is creating problems with the erosion of fixed cost recovery for utilities in western States. As a result, Mr. Seeyle believes it is important for LG&E to be aware of what is going on in other jurisdictions in order to begin educating its customers, stakeholders, and employees about the kinds of costs that are fixed and those that are variable and thus, avoidable.

In this regard, it is clear that Mr. Seeyle is attempting to again make a case for collecting more (or virtually all) fixed costs through either unavoidable customer charges or inelastic demand charges. I am well aware of the situation involving distributed generation in the desert States of Arizona, New Mexico, and Nevada. Given the climate and typography of these western States, distributed generation (solar) has become increasingly prevalent and has indeed created issues for the utilities in these States. There are a myriad of reasons for this including the fact that these desert States experience intense sunshine for on most days thereby making solar generation more practical and affordable. Similarly, there are few trees to block sunlight in the desert or open plains. Finally, many western residential customers are extremely rural in nature, wherein sustained outages present numerous concerns and problems to these very rural customers. None of these situations exist in Kentucky, nor are they likely to prevail in the foreseeable future. Indeed, Mr. Seeyle's distributed generation argument is nothing more than the gnat on the mule's back driving the plow.

Q. MR. SEEYLE ALSO ASSERTS THAT SOME UTILITIES ARE CONSIDERING THE IMPLEMENTATION OF THREE- AND MULTI-PART RATES FOR RESIDENTIAL, SMALL COMMERCIAL AND INDUSTRIAL CUSTOMERS. PLEASE COMMENT ON THIS ASSERTION.

A. Mr. Seeyle claims that some of these approaches are being <u>adopted</u> by utilities. In this regard, Mr. Seeyle is referring to mandatory demand charges. While Mr. Seeyle is correct that mandatory demand charges have been proposed by a handful of utilities throughout the United States, not a single one has been approved. Typical residential customers do not understand the concept of power versus energy usage and therefore, do not understand the concept of demand charges. As a result and universally, residential customers have expressed nothing short of outrage over utilities' proposals to implement mandatory demand charges. Indeed, this Commission needs to look no further than Glasgow, Kentucky as it relates to the mandatory residential demand charge initially implemented by the Glasgow Electric Plant Board. This utility initially implemented mandatory residential demand charges (which is not subject to this Commission's jurisdiction). Almost immediately, there was public outcry relating to these mandatory demand charges. As a result, the utility was forced to continue offering energy only-based rates. Other examples include mandatory demand charge proposals in Arizona that were supported by the Commission Staff. Once again, there was much public outcry against this change as has ever been seen. Ultimately, the Arizona Corporation Commission denied the utilities request for mandatory residential demand charges.

Q. WHY ARE SOME UTILITIES ADVOCATING MANDATORY RESIDENTIAL DEMAND CHARGES?

A. Maximum peak load (demand) is considerably more inelastic than energy consumption; i.e., a customer's total demand will not vary as much as its energy consumption regardless of a consumer's attempts to reduce consumption or engage in conservation practices. As a result, this creates more guarantee of revenue recovery to the utility, which in turn, reduces the utility's risks.

Q. DOES LG&E CURRENTLY HAVE ALTERNATIVE RESIDENTIAL RATE DESIGN OPTIONS AVAILABLE TO ITS CUSTOMERS?

A. Yes. As discussed earlier, the Company offers an optional Time of Day energy-based rate schedule as well as an optional demand-based rate schedule. Currently, there are only about 35 customers subscribed to the Time of Day demand-based rate schedule or Time of Day energy-based rate schedule. This lack of participation is evidence of the fact that residential customers do not like or do not want demand-based rates. In this regard, this is a very important public policy issue. That is, in competitive markets, consumers (the market) dictate how pricing structures are developed. However, with respect to public utilities, they are monopolists and consumers have no other option for these public goods and services. Under the tried and true energy only-based rates, utilities have, and will continue to have, the realistic opportunity to recover their costs and provide a reasonable profit to their shareholders. As such, these proposals advocated by LG&E and other utilities are nothing more than a red herring in that the utilities are using these rate design approaches to reduce their risk and increase shareholder value at the expense of the consuming public.

VI. NATURAL GAS CCOSS

Q. WITH REGARD TO NATURAL GAS LDCs, ARE THERE ANY ASPECTS OF CLASS COST ALLOCATIONS THAT TEND TO OVERSHADOW OTHER ISSUES OR IS OFTEN CONTROVERSIAL?

A. Yes. The area of cost allocation that tends to overshadow all other issues relates to the classification and allocation of distribution mains such that the methodology employed and selection of external allocators for this account (Account 376) has a profound impact on the ultimate calculated class rates of return ("ROR"). Furthermore, several other rate base and operating income accounts are typically allocated to classes based on the previous assignment of distribution mains.

Q. WHAT METHODS ARE COMMONLY USED TO ALLOCATE NATURAL GAS DISTRIBUTION MAINS?

A. While a myriad of cost allocation methods and approaches have been developed, three (3) methods predominate in the natural gas LDC industry: "peak responsibility," "Peak and Average" or "Demand/Commodity," and "Customer/Demand," which I will address shortly in more detail. These methods differ in the criteria used to allocate mains, as cost allocation analysts do not universally agree on the cost causative factors or drivers influencing mains investments. There are three (3) criteria generally considered when selecting a mains cost allocation method: peak demand (whether coincident, non-coincident, actual, or design day); annual (average day) usage; and, number of customers. Because a LDC system must be capable of supplying gas to its firm customers during peak demand periods (i.e., on very cold days), relative class peak day demands are often considered a good proxy for measuring the cost causation of mains investment.[23] Annual (or average day) throughput is also often used to allocate mains as this factor reflects the utilization of a utility's mains investment. Number of customers is also sometimes considered when allocating mains. That is, customer counts by class serve as a basis for allocation mains. Even though annual levels of usage and peak load requirements vary greatly between customer classes (residential versus large industrial), some analysts are of the opinion that customer counts should be considered because at least some infrastructure investment in mains is required simply to "connect" every customer to the system. With these three criteria identified, various methods weight and utilize these criteria differently within the cost allocation process. In other words, some methods rely on only one criterion while others consider two or more criteria with varying weights given to each factor utilized.

The three most common natural gas LDC cost allocation methods are: the "peak responsibility" method (whether coincident or class non-coincident) in which peak day demands are the only factor utilized to allocate mains; the "Peak and Average" or "Demand/Commodity" approach in which both peak day and annual (average day)

[23] Embedded cost allocations are directly only concerned with relative, not absolute, criteria. That is, because embedded cost allocations reflect nothing more than dividing total system costs between classes, it is the relative (percentage) contributors to total system amounts that are relevant.

throughput is reflected within the allocation of mains;[24] and the Customer/Demand method that utilizes a combination of peak day demands and customer counts to assign mains cost responsibility.

Under the Customer/Demand method, the weights given to class customer counts and peak day demands are determined from a separate analysis using one of two approaches: minimum-size and zero-intercept. The "minimum-size" approach prices the entire system footage of mains at the cost per foot of the smallest diameter pipe installed. This "minimum-size" cost is then divided by the actual total investment in mains to determine the weight given to customer counts. One (1) minus the customer percentage is then given to the peak day demand within the allocation process. The second approach used to classify and allocate mains based partially on customers and partially on peak demand is known as the "zero-intercept" method. Under this approach, statistical linear regression techniques are used to estimate the cost of a theoretical "zero size" main. Similar to the minimum size approach, the cost of this estimated zero size pipe per foot is multiplied by the total system footage and is then divided by total mains investment to arrive at a customer weighting.

Q. WHICH METHOD DID THE COMPANY USE TO ALLOCATE COSTS TO CUSTOMER CLASSES FOR THIS CASE?

A. Company witness Seeyle conducted his cost study utilizing the Customer/Demand method to allocate mains.

Q. IS THERE A PREFERRED METHOD TO ALLOCATE NATURAL GAS DISTRIBUTION MAINS COSTS?

A. Yes. The Peak and Average approach is the most fair and equitable method to assign natural gas distribution mains costs to the various customer classes. This method recognizes each class's utilization of the Company's facilities throughout the year yet

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24 Under the Peak and Average or Demand/Commodity approach, peak use and annual throughput are either weighted equally or based on system load factor, where load factor is the ratio of average daily usage to peak day usage. When using a load factor approach to weight Peak and Average usage, the weighting of average day usage is that of the system load factor while the peak day weight is one minus the system load factor.

also recognizes that some classes rely upon the Company's facilities (mains) more than others during peak periods.

Q. HOW APPROPRIATE IS A CUSTOMER/DEMAND SEPARATION FROM A DESIGN OR OPERATIONAL PERSPECTIVE?

A. First and foremost, the classification of distribution plant as partially customer, and partially demand-related results from the view that the assignment of these plant items to classes based solely on a demand allocator would not be equitable to some classes. I emphasize this point, because many analysts "lose sight of the forest for the trees." When classifying individual accounts within distribution plant, analysts sometimes do not consider how a distribution system is designed and connected.

There are several major factors the analyst should keep in mind when classifying natural gas distribution plant. First is the fact that purchasing economies are usually present. For example, there are many types and sizes of pipe manufactured. However, due to purchasing economies, a utility may purchase only a few different sizes of pipe. This will result in some "over capacity," however, the total installed cost will be less than if every segment of the system is optimally sized. Second, most components of the distribution system are somewhat oversized for other reasons, such as pressure equalization, safety, reliability, and growth uncertainty. Third, historical asset records reflecting capitalized labor and material costs by size and type of investment are far from perfect.[25] These asset records are the underlying source for conducting minimum size and zero-intercept studies. Fourth, and particularly relevant to most natural gas LDC's including LG&E is that it generally costs significantly more to install and maintain mains pipes in more urban (densely populated) areas of the Company's service area than in its more suburban (less densely populated) areas. This is because of the infrastructure within, and adjacent to, mains rights-of-way as well as the predominant types of pipe used in various areas. In the more urban parts of a service area, mains are generally buried under roads and sidewalks creating significantly higher costs than suburban areas in which a single trench along a road-side is often the only thing necessary. Moreover,

[25] Reasons for less than perfect record keeping include: the loss of data over time, the changing needs of recordkeeping by a Company, data processing limitation, different record keeping practices and detail by companies prior to mergers/acquisition by other companies.

due to the size of pipes required as well as safety needs, larger pipes in the suburban areas tend to be steel as opposed to much cheaper plastic pipe.

Although these factors are reflective of how distribution systems are actually installed and operated, classification studies do not account for these factors. In fact, the presence of these factors can seriously skew the results of such studies.

Q. SHOULD PEAK DAY DEMANDS BE THE ONLY CONSIDERATION WHEN ALLOCATING NATURAL GAS DISTRIBUTION MAINS?

A. No. Perhaps the most fundamental aspect of cost allocation is the desire to reasonably assign costs (plant and expenses) based on cost causation. As indicated earlier, while it is appropriate to consider and reflect class peak demands when allocating distribution mains, it should not be the only criteria. An LDC system is constructed and is in existence in order to serve the natural gas energy needs of its customers throughout the year. If LG&E's (or any natural gas LDCs) customers only demanded gas for one day of the year (the so-called peak day), the costs to deliver gas throughout the system would be prohibitively high such that a system would never exist. In other words, LG&E's customers demand and utilize natural gas every day of the year, not just one day out of 365 days. If by chance, a customer did require gas for only one day a year, it would be prohibitively expensive to the Company (and ultimately the customer) to provide service as the investment in mains would therefore be required to be recovered from a very small amount of natural gas energy (usage) and would be economically unfeasible.

Q. IS LG&E'S "MAINS EXTENSION" POLICY CONSISTENT WITH THE REALITY THAT CUSTOMERS UTILIZE NATURAL GAS THROUGHOUT THE YEAR AND NOT ON JUST A SINGLE DAY?

A. Yes. When LG&E evaluates a main extension proposal or project, it considers the maximum load that will be placed on the extension as well as the annual usage of the main extension in determining customer (developer) contribution requirements.

Q. EVEN THOUGH MAINS ARE INSTALLED TO MEET THE NATURAL GAS ENERGY NEEDS OF CUSTOMERS THROUGHOUT THE YEAR AND IT WOULD BE PROHIBITIVELY EXPENSIVE TO SERVE A CUSTOMER FOR ONLY ONE DAY PER YEAR, DOES IT COST MORE TO INSTALL A MAIN WITH HIGHER PEAK DEMANDS PLACED UPON IT THAN ANOTHER SEGMENT WITH LOWER PEAK DAY DEMAND REQUIREMENTS?

A. While this is correct as a broadly general statement, there is not a direct and linear relationship between peak demands (capacity requirements) and costs. This is the most important concept. That is, if one were to consider allocating the cost of mains based on the physical relationships of peak day demand (load) one must evaluate whether <u>costs</u> increase proportionally and in a linear manner with <u>peak load</u>. In reality, if the peak load on one line segment of mains is double that of another line segment, the cost of mains for a higher capacity pipe (to meet these additional costs) may be higher but is not double that of the lower capacity main. This reality reflects the major shortcoming of the Peak Responsibility method (which allocates mains entirely on peak day demand) because it is premised on the incorrect assumption that there is a direct and perfectly linear relationship between peak loads (demand), system capacity, and costs. With regard to system capacity, the amount of gas that can be delivered throughout a LDC system is not only a function of the size of pipe(s) but also pressurization of gas within these pipes, and, as well, the presence or absence of looping various segments of the distribution system. In very simple terms, and all else constant, the *capacity* of pipes increases by a factor of exactly 4 to 1 as the diameter of pipe increases.[26] Therefore, if the size of pipe is doubled, the capacity of the pipe increases by a factor of four. At the same time, the cost of this additional capacity is far less than four times as much.[27]

Additionally, and as important as the geometric capacity of pipe at a given pressure, the amount of gas required to be pushed through a distribution system can be met with larger pipes at lower pressures or smaller pipes at higher pressures. This fact is

[26] The volume of a cylinder (pipe) is equal to pi (3.14159) x Radius^2 x length. Therefore, it can be seen that as the diameter doubles, the area (volume) of the pipe increases by four times that of the smaller pipe.

[27] The cost of mains investment reflects the cost of capitalized labor to install the main plus the cost of materials (the piping). Although the labor cost of installing pipe increases somewhat with larger size pipe, these additional labor costs tend to be much smaller than the capacity added. Similarly, the materials cost of the pipe also increases but by a much smaller percentage than the capacity added.

most relevant for cost allocation purposes for older LDC's with large mains replacement programs. With increases in materials, technology, and pipe coupling improvements, we are seeing that LDC's are replacing their systems with smaller plastic pipes operated at higher pressures. For example, based on current pipe manufacturing specifications, a 2-inch plastic pipe operating at 60 pounds per square inch gauge ("psig") has approximately 3.6 times the capacity of a 4-inch plastic line operating at low pressures (less than 1psig). Because the allocation of mains only concerns the assignment of the pipes costs, there is not a clear relationship between a main segment's capacity (peak load ability) and the cost of that pipe. The relevance of this is that an allocation method that only considers peak load by definition assumes there is a direct and perfectly linear relationship between load (capacity) and the cost of mains. This assumption is clearly not accurate.

Q. SINCE THERE IS NOT A DIRECT AND LINEAR RELATIONSHIP BETWEEN PEAK LOAD REQUIREMENTS AND THE COST OF MAINS, IS THERE A COST ALLOCATION METHOD THAT REASONABLY REFLECTS THE COST CAUSATION OF MAINS?

A. Yes. When properly applied, the Peak and Average (Demand/Commodity) method reasonably and fairly models the economies of scale reflected in mains investment. If all customers (and classes) demanded and utilized natural gas at a consistent rate throughout the year, LG&E's LDC system would be comprised of smaller size mains. Obviously, such is not the case in that LG&E's peak (design day) demands are about 4.7 times that of its average day firm service demands.[28] Even though the increased capacity required to serve design day peak loads is about four and a half times that required for average day loads, the actual cost of mains is smaller than this relationship. As such, a cost allocation method which allocates about half of LG&E's mains costs based on average demand and the remaining half on peak demand serves as a reasonable proxy for cost causation and fairly assigns class cost responsibility. To summarize, the allocation of mains solely on peak demands does not reflect cost

[28] Per Company CCOSS. Total design day demand is 567,935 MCF, whereas average day demand is 121,373 MCF.

causation due to the economies of scale present in meeting the capacity (design day) needs of the company's distribution system; i.e., as peak demand increases, costs increase at a decreasing rate.

Q. DID YOU FIND MR. SEEYLE'S NATURAL GAS CCOSS MODEL TO BE MATHEMATICALLY ACCURATE?

A. Yes. As a result, I was able to utilize Mr. Seeyle's natural gas Excel model for purposes of my analysis in this case.

Q. WHAT ARE THE END-RESULTS OF MR. SEEYLE'S CLASSIFICATION OF MAINS AS IT APPLIES TO HIS CCOSS?

A. Mr. Seeyle bifurcates mains between low/medium pressure and high pressure. With regard to low/medium pressure mains, Mr. Seeyle has classified this investment based on a weighting of 61.94% on number of customers and 38.06% on design day demands. With regard to high pressure mains, Mr. Seeyle has classified this investment based on a weighting of 41.58% on number of customers and 58.42% on design day demands. On a combined basis, Mr. Seeyle's distribution mains classification results in 59.92% customer-related and 40.08% demand-related.[29]

What this means is that for about 60% of the Company's cost of mains, the same dollar amount is allocated to a small non-heating apartment customer as is assigned to a huge industrial factory that uses millions of MCF per year and that only about 40% of the Company's largest single investment (distribution mains) is utilized to serve customers with varying load and usage requirements. By any standard, this is grossly unreasonable and simply does not pass any informed or even common sense "smell test."

Q. DOES MR. SEEYLE'S CLASSIFICATION OF DISTRIBUTION MAINS RESULT IN A BIAS TO ANY PARTICULAR CLASSES IN HIS CUSTOMER/DEMAND CCOSS?

[29] There is much more investment associated with low/medium pressure mains ($384.8 million) than high pressure mains ($42.2 million).

A. Yes. Mr. Seeyle's Customer/Demand split of mains severely over-allocates cost to the Residential class since this class represents more than 92% of the number of customers but only about 54% of design day demand relating to high pressure mains and 64% of design day demand relating to low/medium pressure mains. At the same time, the Residential class accounts for only about 44% of system annual throughput (usage). As such, Mr. Seeyle's classification of mains significantly over-assigns mains and mains-related costs to the Residential class. Furthermore, because many other rate base and expense items are allocated to classes based on the previous allocation of mains investment, Mr. Seeyle's bias has a compounding effect on the total costs allocated to each class.

Q. HAVE YOU CONDUCTED A CCOSS THAT UTILIZES A MORE REASONABLE ALLOCATION OF COSTS AND MORE REASONABLY REFLECTS COST CAUSATION?

A. Yes. I have conducted my preferred CCOSS utilizing the P&A method to allocate mains-related costs. Under my recommended approach, mains are classified as 100% demand-related and are allocated based 50% on design day demands and 50% on annual throughput (average day demands). My recommended CCOSS produces the following class RORs at current rates:

ROR At Current Rates

Class	Seeyle Customer/ Demand	OAG P&A
Residential (RGS)	5.08%	6.24%
Commercial (CGS)	7.32%	4.86%
Industrial (IGS)	21.31%	13.45%
As Available Gas (AAGS)	30.69%	10.87%
Firm Transportation (FT)	11.00%	5.83%
Total	6.00%	6.00%

The details of my Peak and Average CCOSS are provided in my Schedule GAW-15.

Q. HAS THIS COMMISSION PROVIDED GUIDANCE REGARDING THE METHODOLOGIES TO BE EMPLOYED FOR NATURAL GAS CLASS COST OF SERVICE STUDIES?

A. Yes. In a recent litigated rate case involving Atmos Energy Corporation (Case No. 2013-00148) wherein the Company utilized the Customer/Demand approach and I utilized the same P&A approach recommended in this case, the Commission found: "that a Peak and Average COSS such as the AG proposed reflects a reasonable methodology. However, we also find the methodology used by Atmos-Ky to be reasonable . . . ."

VII. NATURAL GAS CLASS REVENUE DISTRIBUTION

Q. HOW DOES THE COMPANY PRESENT ITS PROPOSED CLASS REVENUE INCREASES?

A. Mr. Seeyle presents his proposed class revenue increases based on total revenues which includes gas costs and DSM riders. Because gas and DSM costs are not subject to this rate case and because transportation customers do not purchase gas from LG&E, Mr. Seeyle's presentation of class percentage increases are deceiving. To illustrate, consider the following table as it relates to the Residential and Firm Transportation classes:

	Residential ($000)	Firm Transportation ($000)
Base + GLT Revenue	$127,233	$5,841
Gas Cost Revenue	$84,917	$0
DSM Revenue	$2,013	$1,930
Total Revenue	$214,164	$7,771
LG&E Proposed Increase	$10,631	$155
Pct. Increase in Total Revenues	4.96%	2.01%
Pct. Increase in Base + GLT Revenues	8.36%	2.66%

As can be seen above, Mr. Seeyle portrays the Residential class increase to be only 4.96% whereas his proposal actually results in an 8.36% increase to the rates in question in this proceeding. At the same time, the Firm Transportation class' increase is

2.01% on a "total" revenue basis and 2.66% increase relating to the rates in question in this proceeding.

Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S PROPOSED CLASS REVENUE INCREASES.

A. The following table provides a summary of the Company's proposed class revenue increases as well as the percentage increases in base plus GLT revenues:[30]

	Base + GLT Revenue At Present Rates	Proposed Increase	% Increase	% Of System Average
Residential (RGS)	$127,233.1	$10,631.0	8.36%	113%
Commercial (CGS)	$45,350.4	$3,141.8	6.93%	94%
Industrial (IGS)	$5,573.8	$0.4	0.01%	0%
As Available Gas (AAGS)	$561.6	-$71.6	-12.75%	-172%
Firm Transportation (FT)	$5,841.3	$155.2	2.66%	36%
Intra-Company Sales	$2,291.8	-$70.9	-3.09%	-42%
Distributed Generation Gas (DGGS)	$7.0	$1.3	18.37%	--
Substitute Gas Sales (SGSS)	$9.1	$41.3	454.26%	--
Total	$186,868.2	$13,828.5	7.40%	100%

Q. IS MR. SEEYLE'S PROPOSED REVENUE ALLOCATION REASONABLE?

A. No. Although the Company indicates that the primary drivers for its overall requested 7.40% increase in base rates relate to increased investments and increased expenses utilized to serve all customers, the Company is proposing a 12.75% rate reduction to As Available Gas Service and a 3.09% rate reduction to its affiliated companies (Intra-Company Sales). In my opinion, there should not be any rate reductions when overall revenues are increased in rate cases. As a result and considering both Mr. Seeyle's Customer/Demand study as well as my P&A CCOSS, I recommend no change in rates to Industrial Gas Service, As Available Gas Service, and Intra-Company Sales. Furthermore, because of the wide disparity in CCOSS results associated with the

[30] GLT revenues are included within base rates because under the Company's proposal the revenues currently collected within the GLT rider will be rolled into base rates at the conclusion of this case.

Firm Transportation class, and the fact that the Residential and Commercial classes are contributing to profits at about the system average ROR, I recommend that these three classes be increased at equal percentage rates in order to achieve the Company's requested $13.829 million overall increase. The following table provides my recommended class revenue distribution:

OAG Proposed Natural Gas Class Revenue Distribution
At The Company's Proposed Overall Increase
($000)

	Proposed Increase	Percent Increase	Percent Of Sys. Average Percent Increase
Residential (RGS)	$9,830.6	7.73%	104%
Commercial (CGS)	$3,504.0	7.73%	104%
Industrial (IGS)	$0	0.00%	0%
As Available Gas (AAGS)	$0	0.00%	0%
Firm Transportation (FT)	$451.3	7.73%	104%
Intra-Company Sales	$0	0.00%	0%
Distributed Generation Gas (DGGS)	$1.3	18.37%	--
Substitute Gas Sales (SGSS)	$41.3	454.26%	--
Total	$13,828.5	7.40%	100%

Q. PLEASE PROVIDE A COMPARISON OF MR. SEEYLE'S PROPOSED CLASS REVENUE INCREASES TO THOSE YOU RECOMMEND.

A. The following table provides a comparison of the Company's and my recommended class revenue increases at the Company's overall requested $13.8 million increase:

Comparison of LG&E and OAG
Natural Gas Class Revenue Distribution
($000)

	LG&E Proposed Increase	OAG Recommended Increase
Residential (RGS)	$10,631.0	$9,830.6
Commercial (CGS)	$3,141.8	$3,504.0
Industrial (IGS)	$0.4	$0
As Available Gas (AAGS)	-$71.6	$0
Firm Transportation (FT)	$155.2	$451.3
Intra-Company Sales	-$70.9	$0
Distributed Generation Gas (DGGS)	$1.3	$1.3
Substitute Gas Sales (SGSS)	$41.3	$41.3
Total	$13,828.5	$13,828.5

Q. IN THE EVENT THE COMMISSION AUTHORIZES AN OVERALL REVENUE INCREASE LESS THAN THE $13.8 MILLION REQUESTED BY LG&E, HOW SHOULD THE ULTIMATE NATURAL GAS INCREASE BE DISTRIBUTED ACROSS RATE SCHEDULES?

A. I recommend that any overall increase be distributed to rate classes in proportion to the class increases I recommend above.

VIII. NATURAL GAS RESIDENTIAL RATE DESIGN

Q. DOES LG&E ALSO PROPOSE SIGNIFICANT INCREASES TO FIXED MONTHLY CUSTOMER CHARGES FOR NATURAL GAS?

A. Yes. LG&E witnesses Conroy and Seeyle propose to increase the residential customer charge from $13.50 to $24.00 per month, or by 78%.

Q. DOES THE COMPANY MAKE THE SAME ARGUMENTS FOR EXCESSIVELY LARGE INCREASES TO NATURAL GAS CUSTOMER CHARGES AS IT DOES FOR ITS PROPOSED INCREASES TO ELECTRIC CUSTOMER CHARGES?

A. Yes.

Q. HAVE YOU CONDUCTED A DIRECT CUSTOMER COST ANALYSIS APPLICABLE TO LG&E'S RESIDENTIAL NATURAL GAS CLASS?

A. Yes. I conducted the same direct customer cost analysis for LG&E's natural gas customers as I did for the Company's electric operations which was discussed earlier in my testimony. The details of this analysis for natural gas are provided in my Schedule GAW-16. As indicated in this schedule, the natural gas residential direct customer cost is at most $13.04 per month. It should be noted that my customer cost analyses is based on the Company's proposed return on equity of 10.23%. If a lower cost of equity is used, the resulting customer costs are somewhat reduced.

Q. MR. SEEYLE CLAIMS THAT HIS COST-BASED RESIDENTIAL CUSTOMER CHARGE IS $24.05 PER MONTH. PLEASE EXPLAIN HOW MR. SEEYLE ARRIVED AT THIS LEVEL.

A. As was the case surrounding his electric customer cost analysis, Mr. Seeyle included the majority of distribution mains investment costs in his analysis. In addition, he also included a significant portion of administrative and general expenses as well as all uncollectible expenses assigned to the Residential class within his customer cost analysis. For the reasons discussed for electric operations, these costs should not be reflected in the determination of a fixed monthly charge.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING THE LEVEL OF RESIDENTIAL NATURAL GAS CUSTOMER COSTS CALCULATED BY MR. SEEYLE?

A. Yes. Mr. Seeyle calculates that the Residential class' total customer cost are $87.165 million. He also calculates a total "revenue requirement" of the Residential class to be $137.452 million. Therefore, Mr. Seeyle concludes that more than 63% of the costs to serve residential natural gas customers have nothing to do with utilization or the demands placed upon the Company's distribution system.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE CUSTOMER CHARGE FOR LG&E NATURAL GAS RESIDENTIAL CUSTOMERS?

A. Considering that the direct customer cost to residential customers is $13.04 coupled with the fact that the Company already collects more than half of its base rate revenues from fixed monthly charges, I recommend maintaining the current customer charge of $13.50 per month.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS & ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	)))))	CASE NO. 2016-00371

AFFIDAVIT OF Glenn Watkins

Commonwealth of Virginia)

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

Glenn Watkins

SUBSCRIBED AND SWORN to before me this 17th day of February, 2017.

Jennifer R Dolen

NOTARY PUBLIC

My Commission Expires: 10/31/2018

JENNIFER R. DOLEN
NOTARY PUBLIC
REG # 7315146
MY COMMISSION EXPIRES 10/31/2018
COMMONWEALTH OF VIRGINIA

BACKGROUND & EXPERIENCE PROFILE
GLENN A. WATKINS
VICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Mar. 1993-Present	Vice President/Senior Economist, Technical Associates, Inc. (Mar. 1993-June 1995 Traded as C. W. Amos of Virginia)
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. <u>Public Utility Regulation</u>

A. <u>Costing Studies</u> -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. <u>Rate Design Studies</u> -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI=s administrative assigned risk plan and pool expenses.

GLENN A. WATKINS

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

KENTUCKY UTILITIES AND LOUISVILLE GAS & ELECTRIC
Assignment of Gross Plant to Hours Based on Dispatch

Month	Day	Year	Hour	Adjusted Hour	Brown 1	Brown 1 Plant Investment Allocation	Brown 2	Brown 2 Plant Investment Allocation	Brown 3	Brown 3 Plant Investment Allocation	Brown 5	Brown 5 Plant Investment Allocation	Cane Run 7	Cane Run 7 Hour %	Cane Run 7 Plant Investment Allocation	Ghent 1	Ghent 1 Hour %	Ghent 1 Plant Investment Allocation	Total Investment by Hour
Total Output By Plant All Periods					76,552		270,295		585,272		14,495		5,361,923			3,029,956			33,262,127
Plant Investment					$ -		$ -		$ -		$ 26,261,285		$ 118,444,416.86			$ -			3,445,979,890
						$ Investment Allocation Test Factor		$ Investment Allocation Test Factor		$ Investment Allocation Test Factor		$ Investment Allocation Test Factor		% Test Factor	$ Investment Allocation Test Factor		% Test Factor	$ Investment Allocation Test Factor	
						$ -		$ -		$ -		$ 26,261,284.66		100%	$ 118,444,416.86		100%	$ -	
7	1	2017	1	0	36	$ -	64	$ -	155	$ -	0	$ -	497	0.00927%	$ 10,979.79	334	0.01102%	$ -	$ 289,874.08
7	1	2017	2	1	36	$ -	64	$ -	155	$ -	0	$ -	571	0.01064%	$ 12,606.71	334	0.01102%	$ -	$ 291,501.01
7	1	2017	3	2	36	$ -	64	$ -	155	$ -	0	$ -	465	0.00867%	$ 10,265.18	334	0.01102%	$ -	$ 289,159.48
7	1	2017	4	3	36	$ -	64	$ -	155	$ -	0	$ -	397	0.00740%	$ 8,763.07	334	0.01102%	$ -	$ 287,657.36
7	1	2017	5	4	36	$ -	64	$ -	155	$ -	0	$ -	394	0.00734%	$ 8,696.80	334	0.01102%	$ -	$ 287,591.09
7	1	2017	6	5	36	$ -	64	$ -	155	$ -	0	$ -	368	0.00686%	$ 8,122.46	334	0.01102%	$ -	$ 287,016.75
7	1	2017	7	6	36	$ -	64	$ -	155	$ -	0	$ -	438	0.00818%	$ 9,683.78	334	0.01102%	$ -	$ 288,741.02
7	1	2017	8	7	36	$ -	64	$ -	155	$ -	0	$ -	622	0.01160%	$ 13,739.93	334	0.01102%	$ -	$ 296,829.54
7	1	2017	9	8	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	334	0.01102%	$ -	$ 321,385.79
7	1	2017	10	9	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	384	0.01267%	$ -	$ 381,571.95
7	1	2017	11	10	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	424	0.01399%	$ -	$ 423,567.40
7	1	2017	12	11	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	434	0.01432%	$ -	$ 440,647.40
7	1	2017	13	12	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	474	0.01564%	$ -	$ 465,297.03
7	1	2017	14	13	36	$ -	86	$ -	176	$ -	0	$ -	662	0.01235%	$ 14,623.52	474	0.01564%	$ -	$ 471,742.08
7	1	2017	15	14	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	474	0.01564%	$ -	$ 500,421.51
7	1	2017	16	15	36	$ -	85	$ -	173	$ -	0	$ -	662	0.01235%	$ 14,623.52	474	0.01564%	$ -	$ 502,829.15
7	1	2017	17	16	36	$ -	86	$ -	162	$ -	0	$ -	662	0.01235%	$ 14,623.52	474	0.01564%	$ -	$ 501,917.65
7	1	2017	18	17	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	474	0.01564%	$ -	$ 496,709.31
7	1	2017	19	18	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	474	0.01564%	$ -	$ 452,728.43
7	1	2017	20	19	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	474	0.01564%	$ -	$ 414,234.18
7	1	2017	21	20	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	474	0.01564%	$ -	$ 401,597.48
7	1	2017	22	21	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	424	0.01399%	$ -	$ 394,114.70
7	1	2017	23	22	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	384	0.01267%	$ -	$ 337,197.26
7	1	2017	24	23	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	334	0.01102%	$ -	$ 314,450.13
7	2	2017	1	0	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	334	0.01102%	$ -	$ 283,042.49
7	2	2017	2	1	36	$ -	64	$ -	155	$ -	0	$ -	622	0.01160%	$ 13,739.93	334	0.01102%	$ -	$ 271,903.43
7	2	2017	3	2	36	$ -	64	$ -	155	$ -	0	$ -	622	0.01160%	$ 13,739.93	334	0.01102%	$ -	$ 270,353.29
7	2	2017	4	3	36	$ -	64	$ -	155	$ -	0	$ -	473	0.00882%	$ 10,443.45	334	0.01102%	$ -	$ 263,029.17
7	2	2017	5	4	36	$ -	64	$ -	155	$ -	0	$ -	622	0.01160%	$ 13,739.93	337	0.01111%	$ -	$ 194,294.10
7	2	2017	6	5	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	0	0.00000%	$ -	$ 209,945.02
7	2	2017	7	6	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	0	0.00000%	$ -	$ 220,509.29
7	2	2017	8	7	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	0	0.00000%	$ -	$ 241,821.51
7	2	2017	9	8	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	0	0.00000%	$ -	$ 268,765.97
7	2	2017	10	9	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	0	0.00000%	$ -	$ 307,643.81
7	2	2017	11	10	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	0	0.00000%	$ -	$ 365,680.82
7	2	2017	12	11	36	$ -	86	$ -	188	$ -	0	$ -	662	0.01235%	$ 14,623.52	0	0.00000%	$ -	$ 400,591.04
7	2	2017	13	12	46	$ -	86	$ -	204	$ -	0	$ -	662	0.01235%	$ 14,623.52	0	0.00000%	$ -	$ 703,291.15
7	2	2017	14	13	42	$ -	86	$ -	211	$ -	0	$ -	662	0.01235%	$ 14,623.52	42	0.00139%	$ -	$ 722,796.04
7	2	2017	15	14	54	$ -	87	$ -	205	$ -	0	$ -	662	0.01235%	$ 14,623.52	84	0.00277%	$ -	$ 742,143.07
7	2	2017	16	15	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	126	0.00416%	$ -	$ 779,302.50
7	2	2017	17	16	36	$ -	74	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	168	0.00554%	$ -	$ 602,615.08
7	2	2017	18	17	36	$ -	86	$ -	158	$ -	0	$ -	662	0.01235%	$ 14,623.52	210	0.00693%	$ -	$ 508,141.54
7	2	2017	19	18	36	$ -	86	$ -	180	$ -	0	$ -	662	0.01235%	$ 14,623.52	252	0.00832%	$ -	$ 442,904.94
7	2	2017	20	19	48	$ -	86	$ -	206	$ -	0	$ -	662	0.01235%	$ 14,623.52	294	0.00970%	$ -	$ 420,236.44
7	2	2017	21	20	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	336	0.01109%	$ -	$ 429,931.37
7	2	2017	22	21	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	378	0.01248%	$ -	$ 418,435.35
7	2	2017	23	22	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	380	0.01254%	$ -	$ 378,365.19
7	2	2017	24	23	36	$ -	64	$ -	155	$ -	0	$ -	662	0.01235%	$ 14,623.52	332	0.01096%	$ -	$ 346,098.64

Note: Due to the number of generating units, all units are not provided in this Schedule. Please see Excel file for all generating units.

Schedule GAW-3

LOUISVILLE GAS & ELECTRIC COMPANY
Assignment of Hourly Generation Investment Costs to Rate Classes

					LGE Demand % of Total System Demand															
LG&E Rate Schedule ---->					1	100	210	220	230	240	300	320	400	420	600	801	802	60	61	62
Month	Day	Year	Hour	Total Investment by Hour																
7	1	2017	1	$ 289,874.08	$ 122,385.14	$ 27,919.66	$ 2,988.60	$ 34,286.58	$ 11,154.82	$ 15,718.79	$ 5,800.29	$ 211.14	$ 6,574.52	$ 29,432.04	$ 24,102.47	$ 1,279.98	$ 2,354.49	$ 5,411.30	$ 82.56	$ 171.70
7	1	2017	2	$ 291,501.01	$ 110,008.58	$ 30,202.85	$ 3,231.43	$ 37,011.61	$ 12,076.08	$ 16,805.24	$ 6,175.43	$ 189.17	$ 6,989.08	$ 32,413.26	$ 26,200.14	$ 1,381.43	$ 2,769.57	$ 5,775.87	$ 88.01	$ 183.26
7	1	2017	3	$ 289,159.48	$ 104,083.79	$ 31,766.77	$ 3,236.90	$ 37,873.03	$ 11,680.81	$ 17,020.66	$ 6,310.23	$ 181.95	$ 7,033.94	$ 32,931.63	$ 26,481.07	$ 1,465.42	$ 2,890.73	$ 5,924.32	$ 90.24	$ 187.98
7	1	2017	4	$ 287,657.36	$ 101,940.18	$ 36,058.50	$ 3,230.75	$ 38,074.26	$ 9,960.86	$ 17,534.29	$ 6,299.44	$ 182.11	$ 7,067.31	$ 32,434.43	$ 24,197.18	$ 1,397.93	$ 3,004.09	$ 5,994.43	$ 91.40	$ 190.20
7	1	2017	5	$ 287,591.09	$ 93,577.20	$ 44,960.08	$ 3,479.02	$ 40,703.12	$ 8,949.06	$ 18,503.64	$ 6,855.15	$ 242.99	$ 7,372.49	$ 31,638.50	$ 20,579.38	$ 1,377.96	$ 2,963.10	$ 6,102.61	$ 93.18	$ 193.63
7	1	2017	6	$ 287,016.75	$ 89,907.94	$ 45,758.45	$ 3,450.42	$ 41,520.43	$ 8,369.36	$ 18,407.96	$ 7,171.33	$ 348.88	$ 7,104.19	$ 30,910.20	$ 23,693.15	$ 1,237.39	$ 2,712.29	$ 6,136.41	$ 93.62	$ 194.70
7	1	2017	7	$ 288,741.02	$ 94,950.71	$ 47,673.30	$ 3,433.62	$ 42,434.55	$ 8,238.72	$ 18,820.83	$ 7,879.60	$ 509.18	$ 7,197.00	$ 31,099.24	$ 22,592.21	$ 1,205.48	$ 2,613.97	$ -	$ 92.62	$ -
7	1	2017	8	$ 296,829.54	$ 90,622.11	$ 53,767.15	$ 3,686.51	$ 46,775.07	$ 8,733.72	$ 20,440.30	$ 8,295.49	$ 646.74	$ 7,705.05	$ 33,018.54	$ 19,188.73	$ 1,236.43	$ 2,625.13	$ -	$ 88.55	$ -
7	1	2017	9	$ 321,385.79	$ 107,311.57	$ 55,025.17	$ 3,723.98	$ 49,159.46	$ 9,807.75	$ 21,000.28	$ 8,158.50	$ 704.91	$ 7,732.89	$ 33,104.50	$ 22,168.68	$ 1,078.39	$ 2,324.13	$ -	$ 85.58	$ -
7	1	2017	10	$ 381,571.95	$ 135,715.53	$ 63,899.09	$ 4,304.67	$ 57,071.76	$ 11,961.19	$ 24,343.09	$ 9,118.27	$ 718.48	$ 8,751.07	$ 36,853.89	$ 24,605.37	$ 1,202.86	$ 2,933.35	$ -	$ 93.34	$ -
7	1	2017	11	$ 423,567.40	$ 164,785.95	$ 68,115.87	$ 4,523.01	$ 59,817.14	$ 13,887.12	$ 25,591.25	$ 9,581.02	$ 852.21	$ 9,061.51	$ 37,671.53	$ 25,289.58	$ 1,187.62	$ 3,109.44	$ -	$ 94.17	$ -
7	1	2017	12	$ 440,647.40	$ 178,562.61	$ 70,411.03	$ 4,664.35	$ 60,961.18	$ 14,055.69	$ 25,819.53	$ 9,562.78	$ 675.26	$ 9,267.36	$ 37,108.57	$ 25,102.96	$ 1,172.31	$ 3,192.53	$ -	$ 91.23	$ -
7	1	2017	13	$ 465,297.03	$ 202,360.71	$ 70,446.92	$ 4,676.01	$ 60,770.57	$ 14,145.41	$ 25,974.03	$ 9,535.22	$ 818.19	$ 9,227.77	$ 37,807.10	$ 25,232.41	$ 1,165.36	$ 3,046.04	$ -	$ 91.31	$ -
7	1	2017	14	$ 471,742.08	$ 204,097.41	$ 72,455.44	$ 4,793.26	$ 62,454.10	$ 14,258.59	$ 26,305.49	$ 9,483.66	$ 779.02	$ 9,281.19	$ 38,477.67	$ 25,197.46	$ 1,201.15	$ 2,868.01	$ -	$ 89.64	$ -
7	1	2017	15	$ 500,421.51	$ 221,340.00	$ 73,672.48	$ 5,148.10	$ 66,026.36	$ 14,215.05	$ 27,807.96	$ 9,989.75	$ 760.47	$ 9,611.65	$ 40,197.36	$ 26,926.92	$ 1,272.87	$ 3,360.39	$ -	$ 92.15	$ -
7	1	2017	16	$ 502,829.15	$ 235,830.27	$ 66,424.06	$ 5,036.92	$ 65,691.60	$ 12,278.53	$ 27,678.39	$ 9,407.06	$ 424.18	$ 9,475.45	$ 39,028.90	$ 26,967.62	$ 1,279.99	$ 3,215.50	$ -	$ 90.66	$ -
7	1	2017	17	$ 501,917.65	$ 250,296.30	$ 58,559.39	$ 4,770.55	$ 62,196.25	$ 11,793.50	$ 26,845.73	$ 8,606.71	$ 351.82	$ 9,069.55	$ 38,202.50	$ 26,408.49	$ 1,275.57	$ 3,451.43	$ -	$ 89.87	$ -
7	1	2017	18	$ 496,709.31	$ 260,063.20	$ 48,487.66	$ 4,606.09	$ 58,986.54	$ 11,338.19	$ 25,815.09	$ 8,151.26	$ 261.19	$ 8,915.32	$ 38,476.20	$ 26,960.67	$ 1,286.62	$ 3,270.64	$ -	$ 90.65	$ -
7	1	2017	19	$ 452,728.43	$ 241,274.10	$ 41,298.83	$ 4,122.22	$ 52,397.87	$ 10,085.63	$ 22,963.43	$ 7,404.56	$ 243.40	$ 8,321.64	$ 35,192.83	$ 25,237.90	$ 1,194.21	$ 2,908.37	$ -	$ 83.46	$ -
7	1	2017	20	$ 414,234.18	$ 220,450.54	$ 38,142.02	$ 3,813.62	$ 46,883.66	$ 9,248.16	$ 20,575.96	$ 6,895.98	$ 230.49	$ 7,654.19	$ 32,649.10	$ 23,846.57	$ 1,112.99	$ 2,651.77	$ -	$ 79.11	$ -
7	1	2017	21	$ 401,597.48	$ 207,889.44	$ 36,953.17	$ 3,716.21	$ 44,363.37	$ 8,985.01	$ 19,401.38	$ 6,745.83	$ 213.55	$ 7,537.70	$ 32,548.15	$ 24,027.32	$ 1,234.74	$ 2,647.23	$ 5,094.72	$ 78.02	$ 161.65
7	1	2017	22	$ 394,114.70	$ 196,353.57	$ 35,825.90	$ 3,673.53	$ 44,384.81	$ 10,312.03	$ 19,283.09	$ 7,042.22	$ 254.71	$ 7,807.19	$ 34,112.75	$ 25,267.67	$ 1,584.06	$ 2,711.56	$ 5,254.49	$ 80.41	$ 166.72
7	1	2017	23	$ 337,197.26	$ 158,590.00	$ 30,913.90	$ 3,227.38	$ 39,073.65	$ 10,139.51	$ 17,041.73	$ 6,349.06	$ 217.46	$ 7,187.23	$ 31,748.96	$ 23,718.26	$ 1,585.66	$ 2,343.26	$ 4,833.94	$ 73.89	$ 153.38
7	1	2017	24	$ 314,450.13	$ 133,814.39	$ 30,890.43	$ 3,038.59	$ 38,614.82	$ 11,637.62	$ 16,800.33	$ 6,282.92	$ 226.28	$ 7,235.38	$ 32,241.30	$ 24,136.88	$ 1,544.88	$ 2,692.38	$ 5,056.29	$ 77.19	$ 160.43
7	2	2017	1	$ 283,042.49	$ 115,731.13	$ 28,585.74	$ 2,818.85	$ 35,192.99	$ 11,062.64	$ 15,574.80	$ 5,835.63	$ 207.06	$ 6,597.92	$ 30,154.57	$ 22,441.56	$ 1,444.68	$ 2,340.08	$ 4,827.99	$ 73.67	$ 153.19
7	2	2017	2	$ 271,903.43	$ 101,981.57	$ 28,402.09	$ 2,985.71	$ 35,687.08	$ 11,406.01	$ 15,725.02	$ 5,812.64	$ 188.36	$ 6,665.70	$ 30,741.76	$ 23,459.82	$ 1,482.03	$ 2,284.20	$ 4,853.47	$ 73.97	$ 154.00
7	2	2017	3	$ 270,353.29	$ 95,607.77	$ 29,859.49	$ 3,124.07	$ 36,681.50	$ 10,947.52	$ 16,128.97	$ 5,984.68	$ 168.88	$ 6,785.51	$ 32,163.58	$ 23,733.13	$ 1,529.17	$ 2,434.81	$ 4,970.75	$ 75.73	$ 157.72
7	2	2017	4	$ 263,029.17	$ 90,708.84	$ 29,820.47	$ 3,261.34	$ 36,689.84	$ 8,955.91	$ 16,557.21	$ 5,934.04	$ 180.60	$ 6,862.32	$ 31,529.67	$ 23,252.79	$ 1,504.62	$ 2,511.32	$ 5,024.23	$ 76.55	$ 159.42
7	2	2017	5	$ 194,294.10	$ 63,499.14	$ 26,453.48	$ 2,470.56	$ 27,840.58	$ 6,081.83	$ 12,626.32	$ 4,659.74	$ 158.96	$ 5,123.84	$ 22,461.19	$ 15,954.74	$ 1,081.90	$ 1,935.98	$ 3,768.81	$ 57.47	$ 119.58
7	2	2017	6	$ 209,945.02	$ 68,559.64	$ 30,922.19	$ 2,585.17	$ 30,355.87	$ 6,057.10	$ 13,314.96	$ 5,322.41	$ 251.73	$ 5,355.27	$ 22,988.13	$ 16,799.06	$ 1,075.04	$ 1,994.45	$ 4,168.14	$ 63.60	$ 132.25
7	2	2017	7	$ 220,509.29	$ 65,152.15	$ 37,618.48	$ 2,772.17	$ 34,157.63	$ 6,540.23	$ 15,053.02	$ 6,097.81	$ 342.64	$ 5,863.48	$ 25,080.00	$ 18,520.60	$ 1,137.06	$ 2,107.82	$ -	$ 66.19	$ -
7	2	2017	8	$ 241,821.51	$ 79,018.79	$ 42,000.53	$ 2,885.62	$ 36,031.67	$ 6,660.59	$ 15,839.81	$ 6,356.32	$ 457.10	$ 5,994.55	$ 24,568.77	$ 18,710.17	$ 1,125.52	$ 2,105.05	$ -	$ 67.02	$ -
7	2	2017	9	$ 268,765.97	$ 91,932.47	$ 45,680.35	$ 3,135.95	$ 40,501.25	$ 7,572.05	$ 17,370.72	$ 6,849.31	$ 506.76	$ 6,456.92	$ 26,299.33	$ 19,052.70	$ 1,187.77	$ 2,152.42	$ -	$ 67.98	$ -
7	2	2017	10	$ 307,643.81	$ 112,360.10	$ 49,967.62	$ 3,467.38	$ 45,444.15	$ 9,174.15	$ 19,311.02	$ 7,380.83	$ 483.19	$ 7,021.78	$ 28,275.55	$ 21,023.86	$ 1,264.23	$ 2,399.34	$ -	$ 70.62	$ -
7	2	2017	11	$ 365,680.82	$ 146,741.36	$ 57,549.69	$ 3,811.56	$ 50,756.36	$ 11,607.82	$ 21,765.70	$ 7,932.39	$ 573.34	$ 7,605.49	$ 30,868.72	$ 22,467.37	$ 1,240.36	$ 2,684.02	$ -	$ 76.64	$ -
7	2	2017	12	$ 400,591.04	$ 163,746.83	$ 63,069.63	$ 4,153.70	$ 55,052.97	$ 12,775.58	$ 23,547.63	$ 8,381.87	$ 490.25	$ 8,345.13	$ 33,024.58	$ 23,747.67	$ 1,338.03	$ 2,839.09	$ -	$ 78.07	$ -
7	2	2017	13	$ 703,291.15	$ 299,305.80	$107,609.19	$ 7,114.44	$ 93,965.82	$ 21,826.11	$ 40,162.40	$ 14,596.30	$ 1,130.66	$ 14,189.79	$ 55,793.05	$ 40,367.34	$ 2,259.68	$ 4,839.39	$ -	$ 131.18	$ -
7	2	2017	14	$ 722,796.04	$ 311,858.97	$110,252.49	$ 7,258.22	$ 95,781.84	$ 22,076.34	$ 40,203.99	$ 14,610.52	$ 948.35	$ 14,053.04	$ 58,186.13	$ 40,816.42	$ 2,029.58	$ 4,588.99	$ -	$ 131.16	$ -
7	2	2017	15	$ 742,143.07	$ 330,863.63	$108,396.51	$ 7,366.68	$ 97,330.82	$ 20,765.67	$ 41,149.81	$ 14,492.44	$ 810.55	$ 13,995.29	$ 58,621.48	$ 41,425.30	$ 2,016.40	$ 4,777.32	$ -	$ 131.16	$ -
7	2	2017	16	$ 779,302.50	$ 376,373.52	$100,450.87	$ 7,539.37	$ 98,619.24	$ 18,194.55	$ 42,083.85	$ 13,796.09	$ 647.05	$ 14,160.07	$ 58,376.43	$ 42,097.79	$ 2,073.34	$ 4,754.84	$ -	$ 135.48	$ -
7	2	2017	17	$ 602,615.08	$ 306,070.51	$ 69,138.81	$ 5,659.01	$ 73,212.86	$ 13,704.03	$ 31,977.75	$ 9,948.82	$ 384.09	$ 10,826.55	$ 44,408.31	$ 32,050.04	$ 1,607.13	$ 3,523.89	$ -	$ 103.29	$ -
7	2	2017	18	$ 508,141.54	$ 261,644.10	$ 48,277.49	$ 4,883.03	$ 60,687.85	$ 11,804.70	$ 26,904.85	$ 8,529.60	$ 311.38	$ 9,495.90	$ 41,288.25	$ 29,281.09	$ 1,500.52	$ 3,444.58	$ -	$ 88.23	$ -
7	2	2017	19	$ 442,904.94	$ 231,544.39	$ 39,116.44	$ 4,179.93	$ 51,305.58	$ 10,207.39	$ 22,889.55	$ 7,510.16	$ 233.80	$ 8,520.26	$ 36,116.78	$ 26,496.43	$ 1,532.49	$ 3,172.83	$ -	$ 78.89	$ -
7	2	2017	20	$ 420,236.44	$ 216,624.84	$ 37,808.71	$ 4,040.08	$ 47,997.08	$ 9,811.41	$ 21,879.18	$ 7,362.04	$ 238.58	$ 8,459.83	$ 35,718.76	$ 25,494.52	$ 1,504.10	$ 3,219.73	$ -	$ 77.59	$ -
7	2	2017	21	$ 429,931.37	$ 210,230.23	$ 39,461.04	$ 4,155.41	$ 49,045.54	$ 10,426.26	$ 22,484.54	$ 7,863.25	$ 266.76	$ 9,093.23	$ 38,561.91	$ 27,891.55	$ 1,608.44	$ 3,346.66	$ 5,249.66	$ 80.32	$ 166.57
7	2	2017	22	$ 418,435.35	$ 194,444.98	$ 38,103.66	$ 4,181.55	$ 48,373.39	$ 11,903.16	$ 22,621.71	$ 8,122.30	$ 269.17	$ 9,437.09	$ 40,625.23	$ 29,575.07	$ 1,706.63	$ 3,515.53	$ 5,306.40	$ 81.10	$ 168.37
7	2	2017	23	$ 378,365.19	$ 166,648.57	$ 36,686.44	$ 3,885.76	$ 44,136.18	$ 11,962.30	$ 20,505.32	$ 7,730.42	$ 257.34	$ 8,986.10	$ 38,829.32	$ 28,405.13	$ 1,678.02	$ 3,271.97	$ 5,140.70	$ 78.51	$ 163.11
7	2	2017	24	$ 346,098.64	$ 140,862.64	$ 35,023.93	$ 3,722.87	$ 42,480.51	$ 13,301.98	$ 19,358.30	$ 7,324.24	$ 255.75	$ 8,665.77	$ 37,144.51	$ 27,941.30	$ 1,588.49	$ 3,057.73	$ 5,129.61	$ 78.25	$ 162.76

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch with Time, Fuel Customer-Demand Split

Rate of Return Summary

	Allocation Factor Name	No.	Total Kentucky	Residential (RS) (RS	General Service (GS)	Pwr Svc Primary PS-Pri	Pwr Svc Secondary PS-Sec	Time of Day Primary TOD-Pri	Time of Day Secondary TOD-Sec	Retail Transmission RTS	Special Contract #1	Special Contract #2	Street Lighting RLS,LS,DSK	Street Lighting LE	Traffic Lighting TLE
Revenues At Current Rates															
Operating Revenues															
Sales	DIR		$965,204,065	$379,200,073	$135,825,835	$11,517,853	$151,571,212	$116,918,595	$77,629,237	$64,284,636	$6,341,748	$3,292,762	$18,141,167	$210,819	$270,128
Sales for Resale	E01	2	$42,971,045	$15,545,980	$5,051,887	$601,688	$6,971,340	$6,729,278	$2,959,628	$4,097,615	$399,948	$211,291	$378,490	$12,337	$11,561
Curtailable Service Rider		W/S Peak	-$4,334,522	-$1,773,618	-$609,313	-$48,825	-$673,637	-$522,179	-$351,477	-$306,999	-$34,278	-$13,445	$0	$0	-$753
Forfeited Discounts	LPAY		$2,623,527	$2,068,557	$375,660	$4,867	$83,927	$29,247	$50,540	$10,395	$0	$0	$334	$0	$0
Misc Service Revenues	MISCSERV		$3,775,989	$3,513,478	$227,290	$848	$33,247	$100	$262	$12	$0	$0	$751	$0	$0
Rent From Electric Property	RBT	Rate Base	$3,785,840	$1,745,710	$443,148	$39,023	$465,785	$426,273	$259,033	$230,122	$25,662	$13,811	$135,530	$858	$885
Other Electric Revenue	RBT	Rate Base	$11,598,968	$5,348,465	$1,357,706	$119,559	$1,427,060	$1,306,006	$793,619	$705,043	$78,623	$42,313	$415,234	$2,629	$2,712
Total Unadjusted Revenues			$1,025,624,912	$405,648,646	$142,672,213	$12,235,013	$159,878,934	$124,887,321	$81,340,843	$69,020,824	$6,811,702	$3,546,732	$19,071,507	$226,644	$284,533
Adj to eliminate Off System ECR revenues	ECRREV		(8,423,260)	-$3,297,837	-$1,848,542	-$80,619	-$1,002,890	-$833,194	-$537,754	-$461,699	-$42,712	-$23,117	-$290,133	-$2,399	-$2,365
Total Adjusted Revenues At Current Rates			$1,017,201,653	$402,350,809	$140,823,671	$12,154,395	$158,876,044	$124,054,127	$80,803,090	$68,559,125	$6,768,990	$3,523,615	$18,781,374	$224,245	$282,168
Total O&M Expense			$685,621,902	$285,986,036	$85,136,374	$8,427,295	$99,233,467	$92,199,494	$44,523,506	$53,972,741	$5,485,662	$2,919,685	$7,365,725	$170,089	$201,828
Depreciation Expense			$138,842,527	$63,669,206	$16,180,660	$1,440,010	$17,193,872	$15,752,016	$9,646,484	$8,505,588	$948,424	$510,312	$4,932,073	$31,296	$32,587
Taxes Other Than Income Taxes			$32,529,209	$15,094,054	$3,801,134	$332,159	$3,970,703	$3,625,774	$2,222,286	$1,945,320	$218,537	$117,460	$1,187,021	$7,262	$7,499
Amortization of ITCs			-$1,002,535	-$465,192	-$117,149	-$10,237	-$122,375	-$111,745	-$68,490	-$59,954	-$6,735	-$3,620	-$36,583	-$224	-$231
Eliminate Advertising Expense			-$984,863	-$733,845	-$182,346	-$726	-$28,460	-$5,317	-$13,907	-$655	-$10	-$10	-$19,348	-$36	-$204
Total Expenses Before Interest and Taxes			$855,006,240	$363,550,260	$104,818,673	$10,188,501	$120,247,207	$111,460,222	$56,309,879	$64,363,039	$6,645,878	$3,543,828	$13,428,888	$208,386	$241,479
Earnings Before Interest and Taxes			$162,195,413	$38,800,549	$36,004,998	$1,965,894	$38,628,837	$12,593,905	$24,493,211	$4,196,085	$123,112	-$20,212	$5,352,487	$15,858	$40,690
Interest			$62,185,554	$28,855,055	$7,266,566	$634,982	$7,590,728	$6,931,332	$4,248,307	$3,718,836	$417,774	$224,547	$2,269,209	$13,882	$14,335
Taxable Income			$100,009,859	$9,945,494	$28,738,432	$1,330,912	$31,038,108	$5,662,573	$20,244,904	$477,249	-$294,662	-$244,759	$3,083,277	$1,977	$26,354
Income Taxes		TAXINC	$45,082,535	$4,483,239	$12,954,736	$599,950	$13,991,387	$2,552,580	$9,126,016	$215,135	-$132,828	-$110,333	$1,389,883	$891	$11,880
Net Operating Income			$117,112,878	$34,317,310	$23,050,261	$1,365,945	$24,637,450	$10,041,325	$15,367,195	$3,980,951	$255,940	$90,121	$3,962,604	$14,967	$28,810
Rate Base															
Total Gross Plant (including Plant Held for Future Use)			$4,331,626,534	$2,011,472,375	$506,228,612	$44,184,432	$528,238,706	$482,249,899	$295,597,904	$258,614,493	$29,068,344	$15,622,911	$158,384,907	$966,314	$997,635
CWIP			$123,541,730	$55,794,298	$14,370,991	$1,307,696	$15,584,876	$14,332,487	$8,764,168	$7,814,618	$862,275	$464,347	$4,188,354	$28,218	$29,403
Accumulated Depreciation			$1,684,052,746	$779,031,693	$196,749,255	$17,289,979	$206,766,514	$188,691,565	$115,658,408	$101,368,896	$11,380,965	$6,106,494	$60,249,085	$372,417	$387,474
Net Plant			$2,771,115,518	$1,288,234,979	$323,850,348	$28,202,149	$337,057,069	$307,890,821	$188,703,664	$165,060,215	$18,549,654	$9,980,764	$102,324,176	$622,115	$639,564
Working Capital															
Cash Working Capital			$75,842,724	$31,936,848	$9,414,246	$925,710	$10,859,348	$10,118,381	$4,870,130	$5,908,223	$601,351	$322,157	$844,470	$19,121	$22,740
Materials & Supplies			$36,896,266	$17,133,476	$4,311,994	$376,358	$4,499,473	$4,107,746	$2,517,867	$2,202,847	$247,601	$133,074	$1,349,103	$8,231	$8,498
Fuel Stock			$36,289,311	$12,857,339	$4,162,348	$495,022	$5,768,077	$5,517,354	$3,312,924	$3,345,040	$330,160	$178,870	$302,544	$9,871	$9,762
Prepayments			$13,972,166	$6,488,238	$1,632,899	$142,522	$1,703,895	$1,555,553	$953,485	$834,191	$93,763	$50,394	$510,889	$3,117	$3,218
Total Working Capital			$163,000,467	$68,415,901	$19,521,486	$1,939,613	$22,830,794	$21,299,034	$11,654,406	$12,290,300	$1,272,875	$684,495	$3,007,006	$40,340	$44,217
Less:															
ADIT			$546,457,652	$253,757,904	$63,863,423	$5,574,100	$66,640,113	$60,838,381	$37,291,243	$32,625,589	$3,667,126	$1,970,913	$19,981,096	$121,906	$125,857
Accumulated ITCs			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Advances			$6,724,404	$5,007,244	$810,590	$25,682	$313,419	$266,113	$159,648	$0	$16,455	$8,616	$114,504	$842	$1,289
Net Rate Base			$2,380,933,929	$1,097,885,732	$278,697,821	$24,541,979	$292,934,329	$268,085,361	$162,907,179	$144,724,926	$16,138,948	$8,685,730	$85,235,581	$539,707	$556,635
Rate of Return At Current Rates			4.92%	3.13%	8.27%	5.57%	8.41%	3.75%	9.43%	2.75%	1.59%	1.04%	4.65%	2.77%	5.18%
Indexed Rate of Return At Current Rates			100%	64%	168%	113%	171%	76%	192%	56%	32%	21%	95%	56%	105%

Kentucky Utilities & LG&E
Forecasted Test Year Generation Statistics

(1) Generating Unit	(2) Fuel	(3) KU + LG&E Ownership Capacity 1/	(3A) Forecasted Average Fuel Cost 2/	(4) Forecasted Net MWH Produced 3/	(5) Generation Order 4/	(6) Total Gross Investment 1/	(7) Total Net Investment 1/	(8) Capacity Factor	Designation	(9) Net Investment Energy	(10) Net Investment Demand
Brown Solar	Solar	10	$0.0000	19,522	1	$25,475,574	$24,869,280	22.29%	Solar	$24,869,280	$0
Dix Dam 1	Hydro	11	$0.0000	25,269	2	$14,123,640	$3,949,856	26.22%	Hydro	$3,949,856	$0
Dix Dam 2	Hydro	11	$0.0000	25,269	2	$14,123,640	$3,949,855	26.22%	Hydro	$3,949,855	$0
Dix Dam 3	Hydro	11	$0.0000	25,268	2	$14,123,639	$3,949,855	26.22%	Hydro	$3,949,855	$0
Ohio Falls 1	Hydro	13	$0.0000	35,468	2	$15,936,615	$2,069,225	31.15%	Hydro	$2,069,225	$0
Ohio Falls 2	Hydro	13	$0.0000	35,468	2	$15,936,615	$2,069,226	31.15%	Hydro	$2,069,226	$0
Ohio Falls 3	Hydro	13	$0.0000	35,468	2	$15,936,614	$2,069,226	31.15%	Hydro	$2,069,226	$0
Ohio Falls 4	Hydro	10	$0.0000	35,468	2	$15,936,614	$2,069,226	40.49%	Hydro	$2,069,226	$0
Ohio Falls 5	Hydro	13	$0.0000	35,468	2	$15,936,614	$2,069,226	31.15%	Hydro	$2,069,226	$0
Ohio Falls 6	Hydro	13	$0.0000	35,469	2	$15,936,614	$2,069,226	31.15%	Hydro	$2,069,226	$0
Ohio Falls 7	Hydro	13	$0.0000	35,469	2	$15,936,614	$2,069,226	31.15%	Hydro	$2,069,226	$0
Ohio Falls 8	Hydro	10	$0.0000	35,469	2	$15,936,614	$2,069,226	40.49%	Hydro	$2,069,226	$0
Trimble County 2	Coal	628.5 (a)	$0.0193	3,367,360	3	$1,111,229,983	$880,695,676	61.16%	Base	$880,695,676	$0
Mill Creek 4	Coal	544	$0.0211	3,205,409	4	$837,207,205	$602,354,116	67.26%	Base	$602,354,116	$0
Mill Creek 3	Coal	463	$0.0216	2,296,304	5	$534,353,330	$412,814,072	56.62%	Base	$412,814,072	$0
Ghent 2	Coal	556	$0.0211	2,926,599	6	$426,925,817	$230,306,975	60.09%	Base	$230,306,975	$0
Mill Creek 2	Coal	356	$0.0215	1,578,371	7	$376,161,674	$324,010,100	50.61%	Base	$324,010,100	$0
Ghent 1	Coal	557	$0.0214	2,984,003	8	$732,470,922	$472,757,776	61.16%	Base	$472,757,776	$0
Mill Creek 1	Coal	356	$0.0210	1,892,628	9	$328,252,201	$224,580,500	60.69%	Base	$224,580,500	$0
Trimble County 1	Coal	425 (a)	$0.0217	2,063,666	10	$641,927,268	$368,792,796	55.43%	Base	$368,792,796	$0
Ghent 4	Coal	556	$0.0224	2,928,773	11	$1,197,830,397	$869,222,907	60.13%	Base	$869,222,907	$0
Cane Run 7	Gas	808	$0.0218	4,881,876	12	$530,421,264	$503,531,414	68.97%	Base	$503,531,414	$0
Ghent 3	Coal	557	$0.0227	2,892,762	13	$694,725,329	$389,380,015	59.29%	Base	$389,380,015	$0
Brown 2	Coal	180	$0.0316	337,136	15	$65,243,804	$32,365,017	21.38%	Intermediate	$6,919,972	$25,445,045
Brown 1	Coal	114	$0.0353	133,696	16	$84,714,615	$34,940,306	13.39%	Intermediate	$4,677,741	$30,262,565
Brown 3	Coal	464	$0.0352	836,934	17	$959,593,511	$717,432,540	20.59%	Intermediate	$147,723,706	$569,708,834
Trimble County 5	Gas	199	$0.0353	412,064	18	$67,773,389	$37,167,908	23.64%	Peak	$0	$37,167,908
Trimble County 6	Gas	199	$0.0352	340,822	19	$68,123,095	$39,147,099	19.55%	Peak	$0	$39,147,099
Trimble County 7	Gas	199	$0.0355	216,530	20	$58,859,184	$36,397,367	12.42%	Peak	$0	$36,397,367
Trimble County 8	Gas	199	$0.0350	73,170	21	$56,427,769	$34,926,680	4.20%	Peak	$0	$34,926,680
Trimble County 9	Gas	199	$0.0351	206,922	22	$57,017,600	$35,401,129	11.87%	Peak	$0	$35,401,129
Trimble County 10	Gas	199	$0.0345	47,408	23	$63,011,288	$38,702,047	2.72%	Peak	$0	$38,702,047
Paddy's Run 13	Gas	178	$0.0352	192,857	24	$84,247,706	$56,428,259	12.37%	Peak	$0	$56,428,259
Brown 9	Gas/Oil	126	$0.0488	11,645	26	$56,321,311	$26,219,865	1.06%	Peak	$0	$26,219,865
Brown 10	Gas/Oil	126	$0.0480	9,683	27	$36,511,347	$19,321,109	0.88%	Peak	$0	$19,321,109
Brown 5	Gas	123	$0.0449	38,599	28	$50,149,164	$25,142,199	3.58%	Peak	$0	$25,142,199
Brown 8	Gas/Oil	126	$0.0485	17,630	29	$37,676,408	$14,114,510	1.60%	Peak	$0	$14,114,510
Brown 11	Gas/Oil	126	$0.0482	13,080	30	$45,748,645	$16,936,492	1.19%	Peak	$0	$16,936,492
Brown 6	Gas/Oil	177	$0.0361	71,392	31	$66,107,337	$36,727,111	4.60%	Peak	$0	$36,727,111

Kentucky Utilities & LG&E
Forecasted Test Year Generation Statistics

(1) Generating Unit	(2) Fuel	(3) KU + LG&E Ownership Capacity 1/	(3A) Forecasted Average Fuel Cost 2/	(4) Forecasted Net MWH Produced 3/	(5) Generation Order 4/	(6) Total Gross Investment 1/	(7) Total Net Investment 1/	(8) Capacity Factor	Designation	(9) Net Investment Energy	(10) Net Investment Demand
Brown 7	Gas/Oil	177	$0.0360	92,767	32	$61,613,444	$31,606,825	5.98%	Peak	$0	$31,606,825

Kentucky Utilities & LG&E
Forecasted Test Year Generation Statistics

(1) Generating Unit	(2) Fuel	(3) KU + LG&E Ownership Capacity 1/	(3A) Forecasted Average Fuel Cost 2/	(4) Forecasted Net MWH Produced 3/	(5) Generation Order 4/	(6) Total Gross Investment 1/	(7) Total Net Investment 1/	(8) Capacity Factor	Designation	(9) Net Investment Energy	(10) Net Investment Demand
Cane Run 11	Gas/Oil	16	$0.0502	56	33	$3,698,729	$448,806	0.04%	Peak	$0	$448,806
Paddy's Run 11	Gas	16	$0.0496	209	34	$2,151,053	$391,303	0.15%	Peak	$0	$391,303
Paddy's Run 12	Gas	33	$0.0574	182	35	$4,318,568	$204,485	0.06%	Peak	$0	$204,485
Zorn 1	Gas	18	$0.0688	126	36	$1,974,690	-$111,858	0.08%	Peak	$0	-$111,858
Haefling 1	Gas/Oil	21	$0.1959	72	37	$2,183,480	$714,218	0.04%	Peak	$0	$714,218
Haefling 2	Gas/Oil	21	$0.1959	72	37	$2,183,479	$714,217	0.04%	Peak	$0	$714,217

	Energy	Demand
TOTAL BASE	$5,278,446,347	$0
TOTAL INTERMEDIATE	$159,321,419	$625,416,444
TOTAL PEAK	$0	$450,599,771
TOTAL HYDRO	$28,403,373	$0
TOTAL SOLAR	$24,869,280	$0
TOTAL ALL UNITS	$5,491,040,419	$1,076,016,215
PERCENT OF TOTAL	83.61%	16.39%

1/ Per LG&E response to AG 1-301.
2/ Per LG&E response to AG 1-305.
3/ Per LG&E response to AG 1-302. Kwh reflects only KU + LG&E ownership share of output.
4/ Per LG&E response to AG 1-303.

(a) Reflects KU and LG&E combined 75% ownership

LOUISVILLE GAS AND ELECTRIC COMPANY

Schedule GAW-6

Base Intermediate Peak with Customer-Demand Split Rate of Return Summary

	Allocation Factor Name	Allocation Factor No.	Total Kentucky	Residential (RS) (RS	General Service (GS)	Pwr Svc Primary PS-Pri	Pwr Svc Secondary PS-Sec	Time of Day Primary TOD-Pri	Time of Day Secondary TOD-Sec	Retail Transmission RTS	Special Contract #1	Special Contract #2	Street Lighting RLS,LS,DSK	Street Lighting LE	Traffic Lighting TLE
Revenues At Current Rates															
Operating Revenues															
Sales	DIR		$965,204,065	$379,200,073	$135,825,835	$11,517,853	$151,571,212	$116,918,595	$77,629,237	$64,284,636	$6,341,748	$3,292,762	$18,141,167	$210,819	$270,128
Sales for Resale	E01	2	$42,971,045	$15,545,980	$5,051,887	$601,688	$6,971,340	$6,729,278	$2,959,628	$4,097,615	$399,948	$211,291	$378,490	$12,337	$11,561
Curtailable Service Rider	INTCRE	Intermed + Peak	-$4,334,522	-$1,568,135	-$509,588	-$60,693	-$703,204	-$678,787	-$298,540	-$413,330	-$40,343	-$21,313	-$38,179	-$1,244	-$1,166
Forfeited Discounts	LPAY		$2,623,527	$2,068,557	$375,660	$4,867	$83,927	$29,247	$50,540	$10,395	$0	$0	$334	$0	$0
Misc Service Revenues	MISCSERV		$3,775,989	$3,513,478	$227,290	$848	$33,247	$100	$262	$12	$0	$0	$751	$0	$0
Rent From Electric Property	RBT	Rate Base	$3,785,840	$1,774,166	$457,196	$38,920	$472,933	$423,946	$217,128	$227,950	$25,540	$13,139	$133,299	$784	$837
Other Electric Revenue	RBT	Rate Base	$11,598,968	$5,435,650	$1,400,748	$119,243	$1,448,961	$1,298,876	$665,231	$698,387	$78,250	$40,256	$408,398	$2,403	$2,565
Total Unadjusted Revenues			$1,025,624,912	$405,969,770	$142,829,029	$12,222,727	$159,878,414	$124,721,256	$81,223,486	$68,905,666	$6,805,143	$3,536,135	$19,024,261	$225,100	$283,926
Adj to eliminate Off System ECR revenues	ECRREV		-$8,423,260	-$3,297,837	-$1,848,542	-$80,619	-$1,002,890	-$833,194	-$537,754	-$461,699	-$42,712	-$23,117	-$290,133	-$2,399	-$2,365
Total Adjusted Revenues At Current Rates			$1,017,201,653	$402,671,933	$140,980,487	$12,142,108	$158,875,524	$123,888,062	$80,685,733	$68,443,967	$6,762,431	$3,513,018	$18,734,128	$222,701	$281,561
Total O&M Expense			$685,621,902	$285,760,589	$84,966,470	$8,489,265	$99,345,694	$93,010,429	$43,008,170	$54,747,699	$5,534,438	$2,895,026	$7,489,380	$174,225	$200,517
Depreciation Expense			$138,842,527	$64,684,393	$16,739,639	$1,438,056	$17,496,495	$15,693,138	$7,997,995	$8,451,463	$944,901	$485,306	$4,851,634	$28,654	$30,853
Taxes Other Than Income Taxes			$32,529,209	$15,318,618	$3,924,783	$331,727	$4,037,645	$3,612,750	$1,857,633	$1,933,347	$217,758	$111,929	$1,169,228	$6,677	$7,115
Amortization of ITCs			-$1,002,535	-$472,113	-$120,960	-$10,224	-$124,438	-$111,343	-$57,251	-$59,585	-$6,711	-$3,450	-$36,035	-$206	-$219
Eliminate Advertising Expense			-$984,863	-$733,845	-$182,346	-$726	-$28,460	-$5,317	-$13,907	-$655	-$10	-$10	-$19,348	-$36	-$204
Total Expenses Before Interest and Taxes			$855,006,240	$364,557,643	$105,327,586	$10,248,099	$120,726,935	$112,199,656	$52,792,640	$65,072,270	$6,690,375	$3,488,801	$13,454,858	$209,315	$238,062
Earnings Before Interest and Taxes			$162,195,413	$38,114,290	$35,652,901	$1,894,009	$38,148,589	$11,688,406	$27,893,093	$3,371,697	$72,055	$24,218	$5,279,270	$13,386	$43,499
Interest			$62,185,554	$29,284,350	$7,502,943	$634,156	$7,718,699	$6,906,434	$3,551,206	$3,695,949	$416,284	$213,973	$2,235,193	$12,764	$13,602
Taxable Income			$100,009,859	$8,829,941	$28,149,958	$1,259,853	$30,429,890	$4,781,972	$24,341,887	-$324,252	-$344,229	-$189,755	$3,044,076	$622	$29,896
Income Taxes		TAXINC	$45,082,535	$3,980,369	$12,689,463	$567,917	$13,717,213	$2,155,622	$10,972,858	-$146,167	-$155,172	-$85,538	$1,372,212	$280	$13,477
Net Operating Income			$117,112,878	$34,133,922	$22,963,437	$1,326,092	$24,431,376	$9,532,784	$16,920,235	$3,517,863	$227,227	$109,756	$3,907,058	$13,106	$30,022
Rate Base															
Total Gross Plant (including Plant Held for Future Use)			$4,331,626,534	$2,041,276,442	$522,639,241	$44,127,093	$537,123,188	$480,521,340	$247,201,212	$257,025,493	$28,964,925	$14,888,766	$156,023,350	$888,747	$946,737
CWIP			$123,541,730	$56,746,274	$14,895,165	$1,305,864	$15,868,657	$14,277,275	$7,218,323	$7,763,863	$858,972	$440,898	$4,112,923	$25,740	$27,777
Accumulated Depreciation			$1,684,052,746	$788,899,671	$203,196,020	$17,308,728	$210,569,026	$188,640,560	$96,702,200	$101,346,343	$11,366,903	$5,841,287	$59,465,133	$346,955	$369,919
Net Plant			$2,771,115,518	$1,309,123,045	$334,338,387	$28,124,229	$342,422,819	$306,158,054	$157,717,335	$163,443,014	$18,456,993	$9,488,376	$100,671,139	$567,533	$604,595
Working Capital															
Cash Working Capital			$75,842,724	$31,909,780	$9,393,846	$933,151	$10,872,822	$10,215,745	$4,688,192	$6,001,268	$607,207	$319,196	$859,316	$19,618	$22,582
Materials & Supplies			$36,896,266	$17,387,344	$4,451,777	$375,869	$4,575,150	$4,093,022	$2,105,630	$2,189,312	$246,720	$126,821	$1,328,988	$7,570	$8,064
Fuel Stock			$36,289,311	$13,302,782	$4,407,616	$494,166	$5,900,862	$5,491,520	$2,589,602	$3,321,291	$328,614	$167,898	$267,249	$8,711	$9,001
Prepayments			$13,972,166	$6,584,375	$1,685,834	$142,337	$1,732,553	$1,549,978	$797,376	$829,066	$93,430	$48,025	$503,271	$2,867	$3,054
Total Working Capital			$163,000,467	$69,184,280	$19,939,073	$1,945,523	$23,081,387	$21,350,265	$10,180,800	$12,340,936	$1,275,971	$661,940	$2,958,824	$38,766	$42,701
Less:															
ADIT			$546,457,652	$257,517,845	$65,933,711	$5,566,867	$67,760,938	$60,620,315	$31,185,743	$32,425,129	$3,654,079	$1,878,297	$19,683,173	$112,120	$119,436
Accumulated ITCs			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Advances			$6,724,404	$5,007,244	$810,590	$25,682	$313,419	$266,113	$159,648	$0	$16,455	$8,616	$114,504	$842	$1,289
Net Rate Base			$2,380,933,929	$1,115,782,235	$287,533,159	$24,477,202	$297,429,849	$266,621,892	$136,552,743	$143,358,821	$16,062,430	$8,263,403	$83,832,287	$493,336	$526,571
Rate of Return At Current Rates			4.92%	3.06%	7.99%	5.42%	8.21%	3.58%	12.39%	2.45%	1.41%	1.33%	4.66%	2.66%	5.70%
Indexed Rate of Return At Current Rates			100%	62%	162%	110%	167%	73%	252%	50%	29%	27%	95%	54%	116%

CHARGING FOR DISTRIBUTION UTILITY SERVICES: ISSUES IN RATE DESIGN

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IV. THE COSTS OF DISTRIBUTION SERVICES

A first question to be answered when designing rates is what does it cost to provide the service? What are the causes and magnitudes of the relevant costs? It s helpful to observe that the costs recovered by distribution-level rates have historically extended far beyond the distribution system. Are there other costs, not directly related to distribution services, that distribution rates are expected to recover? What follow here are an overview of utility costing methodologies and a discussion of some practical considerations to keep in mind when determining rate structures.

A. Utility Plant Costing Methods

Utilities and regulatory commissions use a variety of methods for determining and allocating cost responsibility among customers and customer classes. There are two general types of cost study, embedded and marginal. Embedded, or fully distributed, seeks to identify and assign the historical, or accounting, costs that make up a utility s revenue requirement. Marginal, as the name connotes, aims at determining the change in total costs imposed on the system by a change in output (whether measured by kilowatt-hour, kilowatt, customer, customer group, or other relevant cost driver). Each commission around the country uses these studies in its own way to inform the rate design process; in the end, most commissions rely on embedded cost studies for ultimate allocations and price levels, constrained as they are by a legal requirement to set rates that offer the prudent utility a reasonable opportunity to earn a fair rate of return on its assets used in service to public.[33] The allocations, however, are often structured to reflect at least relative differences in the marginal costs of providing a company s various services.

1. Cost Causation

There is broad agreement in the literature that distribution investment is causally related to peak demand. Numbers of customers on the system and energy needs are also seen to drive costs, but there is less of a consensus on these points or on their implications for rate design. In addition, not all jurisdictions employ the same methods for analyzing the various cost components, and there is of course a wide range of views on their nature marginal, embedded, fixed, variable, joint, common,[34] etc. and thus on how they should be recovered in rates.

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33. NARUC, p. 32.

34. The costs of multiple products or services supplied by the same plant or process are either common or joint. Common are those that generally do not vary with changes in output. The classic example is the president s desk, which is needed to run the firm as a whole but is incremental to the provision of no particular good or service. Another example is that of an airline flight, the majority of whose costs are incurred in a single lump and do not vary with the number of passengers carried. Put another way, common costs are those for which the unit of production (the single flight), which is the basis of cost incurrence, is larger than the unit of sale (a

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Numbers of customers, usage, and demand, however, are only part of the story. Other factors also play an important role: geography (particularly population density), system design (*e.g.*, aerial versus underground lines), and the utility s business practices (for example, the extent of expenditures on billing, answering customers questions/complaints, etc.). The implications of such factors on rate design is unclear, however: one can charge for services on the basis of numbers of customers, usage, and demand, but not on the basis of other such factors.[35]

2. Embedded Costs

a. Cost Classification: Customers, Demand, and Energy

Traditionally, customer costs are those that are seen to vary with the number of customers on the system service drops (the line from the distribution radial to the home or business), meters, and billing and collection. Some utilities and jurisdictions also include some portion of the primary and secondary distribution plant (poles, wires, and transformers) in these costs, on the ground that they also are driven more by numbers of customers than by demand or energy. Similar reasoning leads to the designation of the costs of customer service and customer premises equipment as customer-related. But, since the system and its components are sized to serve a maximum level of anticipated demand, the notion that there are any customer costs (aside from perhaps metering and billing) that are not more properly categorized as demand can be challenged (see Subsections 3 and 4, below).

Utilities classify significant portions of their embedded distribution investment as demand-related, reasoning that it is designed and installed to serve a customer or group of customers according to their contribution to some peak load (system, substation, etc.). Substations are a typical example of such costs, but so too may be a significant portion of the wires and related facilities, since they are sized, at least in part, to serve a peak demand.

There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states. A

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34. (...continued)
single ticket to a single passenger). Kahn, Vol. I, p. 77. If services produced in common can be produced in varying proportions, it may then be possible to identify separate marginal production costs for each.

Products that are produced in fixed proportions (*e.g.*, cotton fiber and cottonseed oil, beef and hides, mutton and wool) are characterized by joint costs. For that aspect of their production process that is joint, the products have no separately identifiable marginal costs. *Id.*, p. 79. See also Bonbright, pp. 355-360.

35. These other cost factors can have huge effects on prices. Three distribution utilities in the American south, owned by the same holding company and using the same costing methodology, recently proposed new metering, customer service rates, and delivery rates. The rates, designed as a combination of monthly per-customer and per-kW of peak demand charges, vary from company to company by ratios ranging from 1.25 to 1.9.

variation is to treat poles, wires, and transformers as energy-related driven by kilowatt-hour sales but, though it has obvious appeal, only a small number of jurisdictions have gone this route.

Two other approaches sometimes used are the minimum size and zero-intercept methods. The minimum size method operates, as its name implies, on the assumption that there is a minimum-size distribution system capable of serving customers minimum requirements. The costs of this hypothetical system are, so the argument goes, driven not by customer demand but rather by numbers of customers, and therefore they are considered customer costs. The demand-related cost portion then is the difference between total distribution investment and the customer-related costs. The zero-intercept approach is a variation on the minimum size. Here the idea is to identify that portion of plant that is necessary to give customers access but which is incapable of serving any level of demand. The logic is that the costs of this system, because it can serve no demand and thus is not demand-related, are necessarily customer-related.[36] However, the distinction between customer and demand costs is not always clear, insofar as the number of customers on a system (or particular area of a system) will have impacts on the total demand on the system, to the extent that their demand is coincident with the relevant peak (system, areal, substation, etc.).

Any approach to classifying costs has virtues and vices. The first potential pitfall lies in the assumptions, explicit and implicit, that a method is built upon. In the basic customer method, it is the *a priori* classification of expenditures (which may or may not be reasonable). In the case of the minimum-size and zero-intercept methods, the threshold assumption is that there is some portion of the system whose costs are unrelated to demand (or to energy for that matter). From one perspective, this notion has a certain intuitive appeal these are the lowest costs that must be incurred before any or some minimal amount of power can be delivered but from another viewpoint it seems absurd, since in the absence of any demand no such system would be built at all. Moreover, firms in competitive markets do not indeed, cannot price their products according to such methods: they recover their costs through the sale of goods and services, not merely by charging for the ability to consume, or access.

Other assumptions are of a more technical nature. What constitutes the minimum system? What are the proper types of equipment to be modeled? What cost data are applicable (historical, current installations, etc.)? Doesn t the minimum system in fact include demand costs, since such a system can serve some amount of demand? The zero-intercept method attempts to model a system that has no demand-serving capability whatsoever, but what remains is not necessarily a system whose costs are driven any more by the number of customers than it is by geographical considerations, whose causative properties are neither squarely demand- nor customer-related. Does use of an abstract minimum system place a disproportionate share of the cost burden on

36. It is called zero-intercept because it relates installed cost to current carrying capacity or demand rating, creat[ing] a curve for various sizes of the equipment involved, using regression techniques, and extend[ing] the curve to a no-load intercept. NARUC, p. 92.

certain customers or classes, in certain cases even resulting in double-counting? The answers chosen to these and other questions will have impacts upon the respective assignments (by type and customer class) of costs.[37]

Historically, the investment decisions of system planners in vertically-integrated utilities were constrained by the least total cost objective: simply, that they would make that combination of investments that were expected, given their assessments of risk, to meet expected demand for service over some reasonable planning horizon. Given the inability to store electricity and the typical obligation to serve all customers *on demand,* a utility was required to have sufficient capacity available to meet peak demand. And, if its only obligation were to meet peak demand, then it would install only the most inexpensive capacity. However, it had also to serve energy needs at other times, and it is a general characteristic of electric generation technology that as capacity costs decrease variable operating costs increase. There is, therefore, a trade-off between capacity and energy costs that system planners considered when building (or purchasing) new capacity, if they hoped to minimize total costs. Put another way, significant portions of generating capacity were purchased not to meet demand, but to serve energy, when the fuel cost savings that the more expensive generation would produce were greater than the additional costs of that capacity. These incremental capacity costs were therefore correctly viewed as energy costs.

A similar kind of analysis can inform the design of distribution systems, as it also does transmission. The question is whether there is some amount of capacity in excess of the minimum needed to meet peak demand that can cost-effectively be installed. The additional capacity larger substations, conductors, transformers will reduce energy losses; if the cost of energy saved is greater than that of the additional capacity, then the investment will be cost-effective and should be made.[38] For the purposes of cost analysis and rate design, these kinds of distribution investments are rightly treated as energy-related.[39]

b. Cost Allocation

As a general matter, distribution facilities are designed and operated to serve localized area loads. Substations are designed to meet the maximum expected load of the distribution feeders radiating from them. The feeders are designed to meet at least the maximum expected loads at the primary

37. Sterzinger, George, The Customer Charge and Problems of Double Allocation of Costs, *Public Utilities Fortnightly*, July 2, 1981, p. 31; see also Bonbright, p. 347-348.

38. Losses vary with the square of the load. We note also that there is some minimum amount of losses that cannot be avoided, and that conductors must be sized such that the losses can be absorbed while still meeting peak load. To this degree, losses impose a capacity, rather than energy, cost.

39. An unhappy consequence of separating distribution and transmission planning from that of generation in restructured markets is the potential loss of this capacity-versus-energy consideration when making new investment. Certainly, without some sort of regulatory or legislative requirement, wires-only companies have no generation cost-savings motive to guide their planning decisions.

and secondary service levels. (As noted above, some investment in distribution capacity may be seen as reducing energy losses rather than serving peak demand.) For costing purposes it is the relevant subsystem s (substation, feeder, etc.?) peak that matters, but these peaks may or may not be coincident with each other or with the overall system s peak. There can be significant variation among them. Consequently, one practice is to allocate the costs of substations and primary feeders (which usually enjoy relatively high load factors) to customer class non-coincident peaks and to allocate secondary feeders and line transformers (with lower load factors) to the individual customer s maximum demand.[40] In addition, costs are allocated according to voltage level; customers taking service at higher levels are typically not assigned any of the costs of the lower-voltage systems that do not serve them. Costs are then allocated among customer rate groups (or classes) which requires, among other things, information and judgments about coincidence of demand when customers of different classes share facilities, as is often the case.

3. Marginal Costs

For the reasons stated earlier, it is the long-run marginal cost that is most relevant to designing rates. It can be described as the cost of that lumpy, geographically dispersed set of investments that a utility must make if demand continues to grow after the distribution system has initially been built out.

a. Demand and Energy

As already noted, the drivers of distribution costs are typically seen to be peak demand (itself driven by both customer demand and numbers of customers) and energy needs.[41] For the purposes of marginal cost analysis, it is also necessary to identify investments that are not made to serve incremental demands, but are made for some other purpose reliability, replacement of existing systems, etc. The costs of these investments are generally not included in marginal cost calculations, although, in certain cases, there may be legitimate arguments to the contrary.[42]

40. Class non-coincident peak may not be the best measure of cost causation, since much of the system serves a variety of customer classes. Chernick, Paul, *From Here to Efficiency: Securing Demand-Management Resources*, Vol. 5, 1993, p. 81. Ideally, the object is to design rates that reflect the costs of customers contributions to the relevant peak.

41. It is worth noting that, in the short run, distribution costs vary more closely with numbers of customers than with load (except in capacity-constrained areas). For rate design, with its focus on the long run, this fact need not be a distraction. It does, however, have implications for setting revenue requirements. We address this question in Chapter V, below.

42. For instance, at the time that an investment to replace existing facilities (whose loads, let us say, are not expected to change over some extended period) is being contemplated, there are costs that can potentially be avoided. In the extreme, replacement would be unnecessary if all customers served by the facility were to decide to go offgrid. Other, more likely alternatives involve combinations of end-use efficiency, distributed generation, and smaller, more efficient distribution technologies. On these bases, the marginal or, more reasonably, the larger

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Many of the same cost classification and assignment questions that pervade embedded cost analyses also recur in marginal cost studies, although their answers have different analytical effects. Whereas an embedded cost study strives to identify and assign total historical costs to classes of service (on the basis of any of a number of principles, including cost causation and fairness), a marginal cost analysis aims to determine the cost consequences of changes in output and thus the value of resources that must be used to serve incremental demand. Therefore, costs that are unaffected by changes in output (which describes all common and many joint costs) are excluded from the costs under examination.[43]

The study period for a marginal cost analysis is forward-looking and should be of sufficient duration to assure that all incremental demand is related to the investments forecast to serve that demand: a mismatch of timing and investment could result in significantly over- or understated costs. Those incremental costs are then discounted to their present value and annualized over the planning horizon. This has the effect of smoothing out the lumpiness of investment in relation to changes in demand.[44] This analysis relates changes in total costs to changes in demand (aggregating demand increases caused by the addition of customers with those caused by increases in demand per customer).[45] Since new customers create additional demand, this approach is not unreasonable.

Even so, some jurisdictions consider certain costs customer-related and treat them separately for the purpose of marginal cost analysis. Customer premises equipment that which is dedicated specifically to individual customers and unrelated to variations in demand (meters and perhaps service drops) are probably the only distribution costs that can be directly assigned to customers (except in the cases of customers who have additional facilities transformers, wires, even

42. (...continued)
incremental costs of distribution can be calculated. If replacement of the particular component of the system is forecast for some time in the future, then its expected future costs would need to be discounted appropriately to yield a present-value incremental cost.

43. Because marginal cost is defined as the change in total cost arising from a change in output, all costs are, strictly speaking, included in the analysis. It just happens that most are netted out, to reveal those that are caused by the change in output. As a practical matter, however, an analyst may simply identify the costs that vary with output and exclude the rest. It is this second approach, however, that raises debates about the nature of costs and whether they should be included in the analysis. Are they joint or common? Do they vary with demand, energy, customers, or not at all? Resolving the issues usually requires large doses of judgment.

44. An alternative approach is to calculate the cost (savings) of advancing (deferring) by one year the planned stream of investments to meet the increment (decrement) in demand. This approach yields a cost that is equal to the value of the marginal investments for one year (which is the same as the economic carrying charge on those investments). This method is often used, for example, to determine an annual cost per kW of generating capacity.

45. For sizing much of the distribution system, demand is the critical factor. One customer contributing six kilowatts to peak demand has the same impact as two each contributing three kilowatts.

substations, dedicated solely to their needs).[46] Some jurisdictions also consider other facilities (line transformers, secondary level conductors) in some measure customer-related, but, to the extent that they are jointly-used to serve more than one customer, it may be difficult to establish that the addition or loss of any one customer will affect the costs of those facilities.[47] In any event, if some costs are deemed marginal customer costs (which means that they are avoidable only at the time of hook-up), it by no means follows that they should be recovered in recurring monthly fixed fees (see Section V.A.5., below).

Other approaches sometimes used to resolve the cost-causation question are the minimum system and zero intercept methods. Here, instead of using embedded cost data, the distribution system is modeled to determine the cost (in current dollars) of a hypothetical system that could serve all customers minimum demand or (in the case of zero-intercept) that could provide voltage but not power.[48] This cost would be deemed customer-related and separated from the total incremental cost previously determined, to identify the demand (or, more properly, the demand- and energy-related) portion. For the reasons stated earlier, we challenge the wisdom of these approaches.[49]

Other methodological difficulties may also arise. By definition, joint and common costs are not marginal, but occasionally they creep into the analysis, when, for example, they make use of what are in effect *average*, not *marginal*, investments and expenditures.[50] And, as with embedded costs, marginal costs are typically broken out by customer class. Here, again, the analysis requires

46. After the meter, the customer service drop is typically seen as the least demand-related component of the system: it is sized to exceed any realistic maximum demand that the consumer might impose and it will last a very long time. However, although it is true that no investment would be made unless a customer were present, it is also true that the amount of the initial investment increases as the customer s forecasted load increases. Thus, customer investments can be seen as demand-related, as can investments farther up the system transformers, wires, and substations whose sizing depends on expected peak demand. Bouford, James D., Standardized Component Method for the Determination of Marginal and Avoided Demand Cost at the Distribution Level, Central Maine Power Company, (unpublished and undated), pp. 3-4.

47. NARUC, p. 136.

48. A handbook published by the National Economic Research Associates (NERA), which is often cited in support of the minimum system distribution cost classification, states that only the labor costs necessary to put together a minimum system and no conductor and transformer costs are customer-related. NERA, How To Quantify Marginal Costs: Topic 4, (prepared for the Electric Utility Rate Design Study, March 10, 1977), pp. 76.

49. California, for instance, has rejected the minimum system approach to marginal costs, favoring instead a method which uses the weighted average of the costs of continuing to serve existing customers and the costs of initiating service to new customers.

50. See, *e.g.*, NARUC, p. 127, which notes that, because calculating marginal distribution and customer costs can be difficult, it is still common for analysts to use some variation of a projected embedded methodology for these elements, rather than a strictly marginal approach. This tack is justified by the sweeping assumption that projected embedded distribution costs are a reasonable approximation of marginal costs. The assumption is, however, contestable. FERC accounting requirements, which form the basis of most embedded cost analyses, include in distribution certain, and often substantial, administrative and general (A&G) costs (Accounts 920 to 935). A&G is not caused by the provision of distribution service.

reasonable assessments of the coincidence of demand, when customers of different classes share facilities.

Another dimension of cost, and perhaps most revealing, is the geographic. There are several aspects to it. First are the topographical and meteorological characteristics of the area over which the distribution system is laid. Elevations, plant life, weather, soil conditions, and so on all have effects on costs. So too demography, which is captured partly by demand and numbers of customers, but also affecting costs is the density of customers in an area (sometimes expressed as customers per mile). These influences combine in assorted ways, with themselves but also with changes in load and rates of investment, to produce variations in costs from one area of the distribution system to another. It is not unusual to see marginal distribution costs varying greatly from one place to another, even when the distances between the different areas is comparatively short. Table 1 describes the significant variations in costs for incremental distribution investments in a large mid-western utility.

	Average System Marginal Costs per kW	Area Specific High-Low Marginal Costs per kW	Annual Cost @ 15% Capital Cost Recovery Factor	Average Marginal Costs per kWh @ 20% Load Factor[51]	High Marginal Costs per kWh @ 20% Load Factor
Transmission	$230	NA	$34	$0.02	$0.04
Distribution Lines	$960	$1,575 - 0	$140	$0.08	$0.135
Distribution Transformers	$60	$300 - 0	$9	$0.0015	$0.025
Total	$1,250	$1,875 - 0	$183	$.1015	$0.20

Table 1

Differentiating marginal costs along these lines will tell a utility where investment (whether in new facilities, end-use efficiency, or distributed generation) is needed and what the minimum value of that investment is. Whether for rate-making purposes this information is useful should distribution rates be geographically deaveraged ? is a tougher question. We take it up in Chapter V, below.

51. This is estimated load factor for the incremental distribution investment alone, not for the entire distribution system altogether. Incremental investment to meet peak needs typically manifests low load factors; 20% is a conservatively high estimate.

4. Key Concern in Determining Costs: Follow the Money

The occasionally technical and arcane matters taken up in embedded and marginal cost studies are, of course, important, but it is perhaps more important to bear in mind that, in rate design cases, what is fundamentally at issue is who should bear what revenue responsibilities. In the interplay between cost allocation and rate structures, the debate over money is played out. First is the question of what costs will be categorized as *distribution*, as opposed to transmission or generation in the case of vertically integrated utilities, or perhaps competitive services in other instances. This is no small matter, since significant portions of a firm s joint and common costs (typically, administrative and general) are often attributed to the distribution business, even though there is no causal relationship between them. Then there is the designation of a cost as either *customer* or *demand*, which will affect both how costs are divvied up among classes and who within each class will pay them (*i.e.*, both inter- and intra-class allocations). While there is a touch of cynicism in the observation that there is no shortage of academic arguments to justify particular outcomes, it is nevertheless largely true. Always be aware of the revenue effects of a particular rate structure. Who benefits, who loses? Fixed prices, because they recover revenues by customer rather than by usage, invariably shift a larger proportion of the system s costs to the lower-volume consumers (residential and small business). The positions that interested parties take with respect to rate design should, in part, be considered in light of their impacts on class revenue burdens and on the profitability of the utility. Here the admonition to be practical cannot be stressed enough. Seemingly small changes in a rate design can have very significant consequences for different customers.[52]

52. Consider the following example (the hypothetical rates cover distribution services only). A residential customer using 500 kWh per month and paying $0.05 per delivered kWh and a monthly customer charge of $5.00 sees a monthly bill of $30. If rates were revised so that residential customers paid a fixed charge of $20 per month plus $0.02 cents per kWh, a customer using 500 kWh would receive the same total bill of $30. For this customer, the rate redesign is revenue neutral. However, for a customer using 300 kWh/month, the monthly bill under the original rate structure is $20 and, under the new rates, is $26 a 30% increase, even though there is no change in usage. For a customer using 700 kWh/month, the original bill is $40 and the revised bill is $34, a 15% reduction.

Consider again the customer using 500 kWh/month. If, under the original rate structure, she reduced her electricity use to 300 kWh per month (whether by load reduction, demand-side management, the installation of a rooftop solar electric system, or some combination of these options), she would reduce her bill by $10. However, under the revised rate structure, she would only reduce her bill by $4.

Whether the impacts of a rate design change are immediate and substantial depends, of course, on a variety of factors. The extent to which class cost allocations are altered will determine whether particular customers total bills (all else being equal) will go up or down. Even those changes that are meant to be class revenue-neutral will affect individual customer bills: as already noted, shifts from usage-based to fixed charges recover disproportionately higher revenues from low-volume users and then, more subtly, there are the effects (both positive and negative) on bills and revenues that flow from demand responses to the changes in rate structure.

5. Usage Sensitivity: What s Avoidable?

a. Peak Demand and Sizing the Wires

Distribution investment is made to serve an expected level of demand over a period of time, often determined by the useful life of the equipment. To the extent that, once a network (or component of it) is built, there is excess capacity in it, the marginal cost of using that excess capacity will be quite low (possibly very close to zero, insofar as there is little in the way of variable cost). It is this phenomenon that the short-run marginal cost of delivering a kilowatt-hour is zero that underlies the argument that there should be no per-kilowatt-hour charge for doing so.

As peak load grows, it will press up against the capacity limits of the system. At the time of constraint, the marginal cost of delivering a kilowatt-hour is, in fact, significantly greater than zero: at a minimum it is the cost of the additional investment needed to carry that marginal kilowatt-hour to end-users.[53] At that point, presumably, the new investment is made, and it is sized to minimize the total costs of delivery over the long term and thus, as before, there is suddenly excess capacity causing once again the marginal cost to fall to almost zero.

This non-linearity of investment with demand is a characteristic of much of the distribution system, the closer one gets to the end-user. To the extent that there are not an infinite number of equipment sizes to enable precise matching of investment and demand, excess capacity is almost necessarily built into the system, from substation facilities to feeders, transformers, customer service drops. But this has less to do with the finitude of equipment options than it does with the least total cost planning objective (optimizing total construction and operations costs over the investment horizon). The analytical key is to view the system over a time period long enough to smooth out the lumpiness of investment in relation to changes in demand.[54]

What emerges from such analysis is the recognition that there are costs associated with load growth, savings generated by reductions in load growth, and savings flowing from reductions in existing load. These values, not necessarily equal to each other, reflect in part the fungibility of significant portions of the system (*e.g.*, substations and feeders). Capacity unused, or freed up, by one customer can be used by others.[55]

Sometimes cited as an interesting and somewhat anomalous characteristic of some distribution investment, specifically that closest to customers (such as the service drop) is its manifestation of positive marginal costs with load growth but seemingly zero marginal (or avoided) costs with load reductions. This is because, so the argument goes, load reduction makes no capacity available for

53. And it may indeed be greater, if the value to consumers of that marginal delivery is greater than the cost of the additional investment. See Appendix A.

54. The justification for analyzing costs over the long run, and for setting prices on that basis, is discussed in Appendix A.

55. Chernick, Vol. 5, p. 68.

alternative uses, that did not already exist. This not so, however, because the inability to re-use capacity does not mean that there is no value to not using it. At the very least, future replacement costs can be deferred and the equipment installed on replacement can be down-sized, thereby reducing costs for all users.[56]

The differences in costs and savings associated with load growth, reduced growth rates, and reductions in existing load may leave some room for debate about their implications for rate design; but, given the declining-cost nature of the distribution system, these differences will probably have less of an impact than will the need to recover an embedded revenue requirement. The critical point here is that distribution costs vary primarily with load over the longer term.

b. Energy: The Costs of Throughput

As discussed earlier, to the extent that distribution investments are made to offset energy needs, there are necessarily costs associated with avoiding those investments. Losses, heat build-up, frequency of overloads, etc., are aspects of energy use that affect distribution investment and operations; thus there are marginal energy costs in distribution. Whether avoiding those costs make alternatives to distribution cost-effective is an empirical question. But, for purposes of rate design, it is sufficient to say that these marginal costs should be understood and appropriately reflected in rates. They are unquestionably volumetric in nature.

B. Conclusion: The Costs of Distribution Services

Cost studies are intended to provide useful information about the causes and magnitudes of costs, to inform a rate design process that is guided by the general principle that those who cause a cost should pay that cost. However, the usual drivers ascribed to distribution costs (both embedded and marginal) describe only part of the story, and the force-fitting of square costs into round drivers can lead to rate designs that will not best promote long-run dynamic efficiency. This is especially true of embedded cost studies, in which a central objective is to assign or allocate costs to particular services or classes of customers, even though many of those costs cannot be assigned unequivocally according to the principle of causation. By their very nature, many utility costs are joint or common to two or more services; consequently there can be no unshakeable assertion that any one service in fact caused a cost and, therefore, that a particular rate element should recover it. And marginal cost studies often suffer from this deficiency as well. This means that regulators should be very careful before relying upon what are essentially (though not necessarily

56. *Id.*, pp. 68-71. Also affected is the magnitude and cost of over-sizing equipment in order to serve forecast demand. See also NERA, pp. 17-18.

unreasonable) arbitrary cost assignments for the purposes of designing rates.[57] Too great a dependence on cost studies is to be captured by their underlying assumptions and methodological flaws. Utilities and commissions should be cautious before adopting a particular method on the basis of what may be a superficial appeal. More important, however, is the concern that a costing method, once adopted, becomes the predominant and unchallenged determinant of rate design.

Marginal cost analysis demonstrates that distribution costs vary with load in the long run. This has important implications for rate design. Embedded cost analysis, though it relies on *a priori* assumptions about causes (and allocations therefore) of historical costs, is useful in rate design at least insofar as it informs the process of reconciling marginal cost-based rates with revenue requirements.[58] We recognize that there are honest disagreements over approaches to both kinds of analysis.[59] But what is important here is for regulators to be aware of the fundamental relationships between costs and demand for electric service, in order to devise rates that best serve the objectives they seek.

57. To ensure that [embedded distribution plant] costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst s evaluation of how the costs in these accounts were incurred. NARUC, p. 89. Interestingly, the manual, in a table on page 34, acknowledges that there is an energy-related component to embedded distribution costs, but is otherwise silent on the question.

58. Bonbright, pp. 366-367. Bonbright expresses some skepticism as to the usefulness of most embedded cost studies for rate design, on the ground that they often ignore the relationship between cost causation and apportionment. One may suspect that the choice of [allocation] formula depends, not on principles of cost imputation but rather on types of apportionment which tend to justify whatever rate structure is advocated for non-cost reasons. *Id.*, p. 368.

59. See, *e.g.*, Chernick, Vol. 5, pp. 58-83, and NARUC, pp. 86-104 and 137-146.

LOUISVILLE GAS AND ELECTRIC COMPANY

Base Intermediate Peak- 100% Demand

Rate of Return Summary

	Allocation Factor Name	Allocation Factor No.	Total Kentucky	Residential (RS) (RS	General Service (GS)	Pwr Svc Primary PS-Pri	Pwr Svc Secondary PS-Sec	Time of Day Primary TOD-Pri	Time of Day Secondary TOD-Sec	Retail Transmission RTS	Special Contract #1	Special Contract #2	Street Lighting RLS,LS,DSK	Street Lighting LE	Traffic Lighting TLE
Revenues At Current Rates															
Operating Revenues															
Sales	DIR		$965,204,065	$379,200,073	$135,825,835	$11,517,853	$151,571,212	$116,918,595	$77,629,237	$64,284,636	$6,341,748	$3,292,762	$18,141,167	$210,819	$270,128
Sales for Resale	E01	2	$42,971,045	$15,545,980	$5,051,887	$601,688	$6,971,340	$6,729,278	$2,959,628	$4,097,615	$399,948	$211,291	$378,490	$12,337	$11,561
Curtailable Service Rider	INTCRE	Intermed + Peak	-$4,334,522	-$1,568,135	-$509,588	-$60,693	-$703,204	-$678,787	-$298,540	-$413,330	-$40,343	-$21,313	-$38,179	-$1,244	-$1,166
Forfeited Discounts	LPAY		$2,623,527	$2,068,557	$375,660	$4,867	$83,927	$29,247	$50,540	$10,395	$0	$0	$334	$0	$0
Misc Service Revenues	MISCSERV		$3,775,989	$3,513,478	$227,290	$848	$33,247	$100	$262	$12	$0	$0	$751	$0	$0
Rent From Electric Property	RBT	Rate Base	$3,785,840	$1,632,744	$468,664	$43,397	$523,144	$471,781	$245,343	$227,950	$28,511	$14,694	$127,954	$867	$793
Other Electric Revenue	RBT	Rate Base	$11,598,968	$5,002,361	$1,435,880	$132,957	$1,602,798	$1,445,430	$751,675	$698,387	$87,351	$45,018	$392,023	$2,655	$2,431
Total Unadjusted Revenues			$1,025,624,912	$405,395,059	$142,875,629	$12,240,917	$160,082,463	$124,915,644	$81,338,145	$68,905,666	$6,817,214	$3,542,452	$19,002,542	$225,434	$283,748
Adj to eliminate Off System ECR revenues	ECRREV		(8,423,260)	-$3,297,837	-$1,848,542	-$80,619	-$1,002,890	-$833,194	-$537,754	-$461,699	-$42,712	-$23,117	-$290,133	-$2,399	-$2,365
Total Adjusted Revenues At Current Rates			$1,017,201,653	$402,097,222	$141,027,087	$12,160,299	$159,079,573	$124,082,450	$80,800,392	$68,443,967	$6,774,502	$3,519,335	$18,712,409	$223,035	$281,383
Total O&M Expense			$685,621,902	$277,617,016	$85,626,781	$8,747,020	$102,237,035	$95,764,881	$44,632,877	$54,747,699	$5,705,487	$2,984,527	$7,181,625	$178,961	$197,992
Depreciation Expense			$138,842,527	$59,512,468	$17,158,998	$1,601,754	$19,332,766	$17,442,471	$9,029,835	$8,451,463	$1,053,533	$542,147	$4,656,181	$31,662	$29,250
Taxes Other Than Income Taxes			$32,529,209	$14,063,188	$4,026,578	$371,463	$4,483,380	$4,037,382	$2,108,101	$1,933,347	$244,127	$125,726	$1,121,784	$7,407	$6,726
Amortization of ITCs			-$1,002,535	-$433,421	-$124,097	-$11,448	-$138,176	-$124,430	-$64,971	-$59,585	-$7,524	-$3,875	-$34,573	-$228	-$207
Eliminate Advertising Expense			-$984,863	-$733,845	-$182,346	-$726	-$28,460	-$5,317	-$13,907	-$655	-$10	-$10	-$19,348	-$36	-$204
Total Expenses Before Interest and Taxes			$855,006,240	$350,025,407	$106,505,913	$10,708,062	$125,886,545	$117,114,987	$55,691,936	$65,072,270	$6,995,614	$3,648,515	$12,905,669	$217,765	$233,557
Earnings Before Interest and Taxes			$162,195,413	$52,071,815	$34,521,174	$1,452,236	$33,193,028	$6,967,463	$25,108,456	$3,371,697	-$221,112	-$129,181	$5,806,740	$5,270	$47,826
Interest			$62,185,554	$26,884,365	$7,697,543	$710,119	$8,570,804	$7,718,196	$4,030,022	$3,695,949	$466,694	$240,349	$2,144,495	$14,160	$12,858
Taxable Income			$100,009,859	$25,187,450	$26,823,631	$742,117	$24,622,225	-$750,733	$21,078,434	-$324,252	-$687,806	-$369,530	$3,662,245	-$8,890	$34,967
Income Taxes		TAXINC	$45,082,535	$11,354,021	$12,091,581	$334,532	$11,099,229	-$338,416	$9,501,756	-$146,167	-$310,050	-$166,577	$1,650,870	-$4,007	$15,763
Net Operating Income			$117,112,878	$40,717,794	$22,429,593	$1,117,704	$22,093,799	$7,305,879	$15,606,700	$3,517,863	$88,938	$37,396	$4,155,870	$9,277	$32,063
Rate Base															
Total Gross Plant (including Plant Held for Future Use)			$4,331,626,534	$1,873,660,812	$536,230,131	$49,432,334	$596,634,420	$537,215,045	$280,641,854	$257,025,493	$32,485,563	$16,730,925	$149,688,968	$986,215	$894,774
CWIP			$123,541,730	$52,419,507	$15,245,995	$1,442,812	$17,404,857	$15,740,745	$8,081,547	$7,763,863	$949,852	$488,451	$3,949,410	$28,256	$26,436
Accumulated Depreciation			$1,684,052,746	$725,344,077	$208,349,340	$19,320,341	$233,134,175	$210,137,374	$109,382,043	$101,346,343	$12,701,840	$6,539,787	$57,063,296	$383,912	$350,216
Net Plant			$2,771,115,518	$1,200,736,241	$343,126,786	$31,554,805	$380,905,102	$342,818,416	$179,341,358	$163,443,014	$20,733,575	$10,679,588	$96,575,081	$630,559	$570,994
Working Capital															
Cash Working Capital			$75,842,724	$30,932,027	$9,473,126	$964,098	$11,219,969	$10,546,457	$4,883,262	$6,001,268	$627,744	$329,942	$822,366	$20,186	$22,279
Materials & Supplies			$36,896,266	$15,959,614	$4,567,543	$421,059	$5,082,059	$4,575,932	$2,390,473	$2,189,312	$276,708	$142,512	$1,275,032	$8,400	$7,622
Fuel Stock			$36,289,311	$13,302,782	$4,407,616	$494,166	$5,900,862	$5,491,520	$2,589,602	$3,321,291	$328,614	$167,898	$267,249	$8,711	$9,001
Prepayments			$13,972,166	$6,043,711	$1,729,673	$159,450	$1,924,514	$1,732,850	$905,243	$829,066	$104,786	$53,968	$482,839	$3,181	$2,886
Total Working Capital			$163,000,467	$66,238,134	$20,177,957	$2,038,772	$24,127,404	$22,346,758	$10,768,579	$12,340,936	$1,337,853	$694,320	$2,847,486	$40,479	$41,788
Less:															
ADIT			$546,457,652	$236,372,245	$67,648,274	$6,236,151	$75,268,595	$67,772,526	$35,404,458	$32,425,129	$4,098,226	$2,110,695	$18,884,057	$124,416	$112,881
Accumulated ITCs			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Advances			$6,724,404	$3,761,473	$911,602	$65,112	$755,725	$687,478	$408,189	$0	$42,622	$22,308	$67,425	$1,567	$903
Net Rate Base			$2,380,933,929	$1,026,840,657	$294,744,868	$27,292,313	$329,008,186	$296,705,170	$154,297,290	$143,358,821	$17,930,580	$9,240,905	$80,471,085	$545,055	$498,998
Rate of Return At Current Rates			4.92%	3.97%	7.61%	4.10%	6.72%	2.46%	10.11%	2.45%	0.50%	0.40%	5.16%	1.70%	6.43%
Indexed Rate of Return At Current Rates			100%	81%	155%	83%	137%	50%	206%	50%	10%	8%	105%	35%	131%

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Rate of Return Summary

	Allocation Factor Name	Allocation Factor No	Total Kentucky	Residential (RS) (RS	General Service (GS)	Pwr Svc Primary PS-Pri	Pwr Svc Secondary PS-Sec	Time of Day Primary TOD-Pri	Time of Day Secondary TOD-Sec	Retail Transmission RTS	Special Contract #1	Special Contract #2	Street Lighting RLS,LS,DSK	Street Lighting LE	Traffic Lighting TLE
Revenues At Current Rates															
Operating Revenues															
Sales	DIR		$965,204,065	$379,200,073	$135,825,835	$11,517,853	$151,571,212	$116,918,595	$77,629,237	$64,284,636	$6,341,748	$3,292,762	$18,141,167	$210,819	$270,128
Sales for Resale	E01	2	$42,971,045	$15,545,980	$5,051,887	$601,688	$6,971,340	$6,729,278	$2,959,628	$4,097,615	$399,948	$211,291	$378,490	$12,337	$11,561
Curtailable Service Rider		W/S Peak	-$4,334,522	-$1,773,618	-$609,313	-$48,825	-$673,637	-$522,179	-$351,477	-$306,999	-$34,278	-$13,445	$0	$0	-$753
Forfeited Discounts	LPAY		$2,623,527	$2,068,557	$375,660	$4,867	$83,927	$29,247	$50,540	$10,395	$0	$0	$334	$0	$0
Misc Service Revenues	MISCSERV		$3,775,989	$3,513,478	$227,290	$848	$33,247	$100	$262	$12	$0	$0	$751	$0	$0
Rent From Electric Property	RBT	Rate Base	$3,785,840	$1,604,287	$454,615	$43,500	$515,996	$474,108	$287,248	$230,122	$28,632	$15,365	$130,186	$940	$841
Other Electric Revenue	RBT	Rate Base	$11,598,968	$4,915,177	$1,392,838	$133,273	$1,580,897	$1,452,560	$880,064	$705,043	$87,723	$47,075	$398,860	$2,881	$2,577
Total Unadjusted Revenues			$1,025,624,912	$405,073,935	$142,718,813	$12,253,204	$160,082,982	$125,081,709	$81,455,503	$69,020,824	$6,823,774	$3,553,048	$19,049,788	$226,978	$284,355
Adj to eliminate Off System ECR revenues	ECRREV		(8,423,260)	-$3,297,837	-$1,848,542	-$80,619	-$1,002,890	-$833,194	-$537,754	-$461,699	-$42,712	-$23,117	-$290,133	-$2,399	-$2,365
Total Adjusted Revenues At Current Rates			$1,017,201,653	$401,776,098	$140,870,271	$12,172,585	$159,080,092	$124,248,515	$80,917,749	$68,559,125	$6,781,061	$3,529,931	$18,759,655	$224,579	$281,990
Total O&M Expense			$685,621,902	$277,842,463	$85,796,685	$8,685,049	$102,124,809	$94,953,947	$46,148,213	$53,972,741	$5,656,712	$3,009,186	$7,057,970	$174,824	$199,303
Depreciation Expense			$138,842,527	$58,497,282	$16,600,019	$1,603,707	$19,030,142	$17,501,349	$10,678,324	$8,505,588	$1,057,056	$567,153	$4,736,620	$34,304	$30,983
Taxes Other Than Income Taxes			$32,529,209	$13,838,624	$3,902,929	$371,895	$4,416,438	$4,050,406	$2,472,754	$1,945,320	$244,906	$131,258	$1,139,577	$7,992	$7,110
Amortization of ITCs			-$1,002,535	-$426,500	-$120,286	-$11,462	-$136,113	-$124,832	-$76,209	-$59,954	-$7,548	-$4,045	-$35,121	-$246	-$219
Eliminate Advertising Expense			-$984,863	-$733,845	-$182,346	-$726	-$28,460	-$5,317	-$13,907	-$655	-$10	-$10	-$19,348	-$36	-$204
Total Expenses Before Interest and Taxes			$855,006,240	$349,018,024	$105,997,000	$10,648,464	$125,406,817	$116,375,553	$59,209,174	$64,363,039	$6,951,116	$3,703,542	$12,879,698	$216,837	$236,974
Earnings Before Interest and Taxes			$162,195,413	$52,758,074	$34,873,270	$1,524,121	$33,673,275	$7,872,962	$21,708,575	$4,196,085	-$170,055	-$173,611	$5,879,957	$7,742	$45,017
Interest			$62,185,554	$26,455,070	$7,461,166	$710,945	$8,442,832	$7,743,094	$4,727,123	$3,718,836	$468,184	$250,924	$2,178,511	$15,277	$13,591
Taxable Income			$100,009,859	$26,303,004	$27,412,105	$813,176	$25,230,443	$129,868	$16,981,451	$477,249	-$638,239	-$424,535	$3,701,446	-$7,535	$31,425
Income Taxes		TAXINC	$45,082,535	$11,856,892	$12,356,854	$366,564	$11,373,402	$58,542	$7,654,914	$215,135	-$287,706	-$191,372	$1,668,541	-$3,397	$14,166
Net Operating Income			$117,112,878	$40,901,182	$22,516,417	$1,157,557	$22,299,873	$7,814,420	$14,053,660	$3,980,951	$117,651	$17,761	$4,211,416	$11,139	$30,851
Rate Base															
Total Gross Plant (including Plant Held for Future Use)			$4,331,626,534	$1,843,856,744	$519,819,502	$49,489,674	$587,749,938	$538,943,604	$329,038,546	$258,614,493	$32,588,983	$17,465,070	$152,050,525	$1,063,782	$945,673
CWIP			$123,541,730	$51,467,531	$14,721,821	$1,444,643	$17,121,077	$15,795,957	$9,627,393	$7,814,618	$953,155	$511,900	$4,024,840	$30,734	$28,061
Accumulated Depreciation			$1,684,052,746	$715,476,100	$201,902,575	$19,301,592	$229,331,663	$210,188,379	$128,338,251	$101,368,896	$12,715,902	$6,804,994	$57,847,248	$409,374	$367,771
Net Plant			$2,771,115,518	$1,179,848,175	$332,638,748	$31,632,725	$375,539,352	$344,551,182	$210,327,687	$165,060,215	$20,826,236	$11,171,976	$98,228,117	$685,141	$605,963
Working Capital															
Cash Working Capital			$75,842,724	$30,959,095	$9,493,525	$956,658	$11,206,495	$10,449,092	$5,065,199	$5,908,223	$621,888	$332,903	$807,519	$19,690	$22,436
Materials & Supplies			$36,896,266	$15,705,747	$4,427,759	$421,547	$5,006,382	$4,590,656	$2,802,710	$2,202,847	$277,589	$148,765	$1,295,148	$9,061	$8,055
Fuel Stock			$36,289,311	$12,857,339	$4,162,348	$495,022	$5,768,077	$5,517,354	$3,312,924	$3,345,040	$330,160	$178,870	$302,544	$9,871	$9,762
Prepayments			$13,972,166	$5,947,575	$1,676,738	$159,635	$1,895,856	$1,738,425	$1,061,352	$834,191	$105,120	$56,336	$490,457	$3,431	$3,050
Total Working Capital			$163,000,467	$65,469,756	$19,760,370	$2,032,862	$23,876,810	$22,295,528	$12,242,185	$12,290,300	$1,334,757	$716,874	$2,895,668	$42,053	$43,304
Less:															
ADIT			$546,457,652	$232,612,304	$65,577,986	$6,243,385	$74,147,771	$67,990,593	$41,509,957	$32,625,589	$4,111,273	$2,203,311	$19,181,980	$134,202	$119,302
Accumulated ITCs			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Advances			$6,724,404	$3,761,473	$911,602	$65,112	$755,725	$687,478	$408,189	$0	$42,622	$22,308	$67,425	$1,567	$903
Net Rate Base			$2,380,933,929	$1,008,944,154	$285,909,530	$27,357,090	$324,512,666	$298,168,639	$180,651,726	$144,724,926	$18,007,098	$9,663,231	$81,874,380	$591,426	$529,062
Rate of Return At Current Rates			4.92%	4.05%	7.88%	4.23%	6.87%	2.62%	7.78%	2.75%	0.65%	0.18%	5.14%	1.88%	5.83%
Indexed Rate of Return At Current Rates			100%	82%	160%	86%	140%	53%	158%	56%	13%	4%	105%	38%	119%

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Residential (RS)			General Service (GS)			Power Service-Primary (PS-Pri)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base																		
Plant in Service																		
Intangible Plant																		
301.00 ORGANIZATION	PT&D	23	$2,240	$2,043	$0	$198	$840	$0	$114	$250	$0	$19	$25	$0	$0	$302	$0	$2
302.00 FRANCHISE AND CONSENTS	PT&D	23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
303.00 SOFTWARE	PT&D	23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Intangible Plant			$2,240	$2,043	$0	$198	$840	$0	$114	$250	$0	$19	$25	$0	$0	$302	$0	$2
Production Plant																		
Total Production Plant																		
Demand	PODPLT	52	$2,305,549,928	$2,305,549,928	$0	$0	$816,858,645	$0	$0	$264,444,271	$0	$0	$31,450,007	$0	$0	$366,460,244	$0	$0
Energy	Energy	2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Plant			**$2,305,549,928**	**$2,305,549,928**	**$0**	**$0**	**$816,858,645**	**$0**	**$0**	**$264,444,271**	**$0**	**$0**	**$31,450,007**	**$0**	**$0**	**$366,460,244**	**$0**	**$0**
Transmission																		
KENTUCKY SYSTEM PROPERTY	NCPT	13	$442,223,222	$442,223,222	$0	$0	$196,518,630	$0	$0	$56,567,341	$0	$0	$5,026,113	$0	$0	$58,335,555	$0	$0
VIRGINIA PROPERTY - 500 KV LINE	NCPT	13	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Transmission Plant			$442,223,222	$442,223,222	$0	$0	$196,518,630	$0	$0	$56,567,341	$0	$0	$5,026,113	$0	$0	$58,335,555	$0	$0
Distribution																		
TOTAL ACCTS 360-362	NCPP	14	$152,675,045	$152,675,045	$0	$0	$73,253,213	$0	$0	$21,085,734	$0	$0	$1,873,507	$0	$0	$21,744,843	$0	$0
364 & 365-OVERHEAD LINES																		
Primary:																		
Demand	NCPP	14	$386,565,842	$386,565,842	$0	$0	$185,473,598	$0	$0	$53,388,059	$0	$0	$4,743,628	$0	$0	$55,056,893	$0	$0
Customer	CUST08	11	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary:																		
Demand	SICD	16	$57,817,118	$57,817,118	$0	$0	$48,520,593	$0	$0	$8,879,053	$0	$0	$0	$0	$0	$0	$0	$0
Customer	CUST07	10	$83,856,780	$0	$0	$83,856,780	$0	$0	$72,859,839	$0	$0	$9,052,126	$0	$0	$0	$0	$0	$0
366 & 367-UNDERGROUND LINES																		
Primary:																		
Demand	NCPP	14	$290,015,468	$290,015,468	$0	$0	$139,148,902	$0	$0	$40,053,624	$0	$0	$3,558,839	$0	$0	$41,305,643	$0	$0
Customer	CUST08	11	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary:																		
Demand	SICD	16	$13,957,513	$13,957,513	$0	$0	$11,713,257	$0	$0	$2,143,474	$0	$0	$0	$0	$0	$0	$0	$0
Customer	CUST07	10	$25,215,972	$0	$0	$25,215,972	$0	$0	$21,909,161	$0	$0	$2,722,000	$0	$0	$0	$0	$0	$0
368-TRANSFORMERS - POWER POOL																		
Demand	SICDT	15	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer	CUST09	12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
368-TRANSFORMERS - ALL OTHER																		
Demand	SICDT	15	$99,214,198	$99,214,198	$0	$0	$68,834,886	$0	$0	$12,596,478	$0	$0	$0	$0	$0	$11,093,811	$0	$0
Customer	CUST09	12	$69,385,677	$0	$0	$69,385,677	$0	$0	$59,843,780	$0	$0	$7,435,007	$0	$0	$0	$0	$0	$464,144
369-SERVICES	C02	20	$34,458,226	$0	$0	$34,458,226	$0	$0	$26,485,178	$0	$0	$6,665,461	$0	$0	$0	$0	$0	$1,162,827
370-METERS	C03	21	$39,970,580	$0	$0	$39,970,580	$0	$0	$27,976,208	$0	$0	$8,225,146	$0	$0	$320,204	$0	$0	$2,212,651
371-CUSTOMER INSTALLATION	C04	22	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
373-STREET LIGHTING	C04	22	$109,522,342	$0	$0	$109,522,342	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Distribution Plant			$1,362,654,761	$1,000,245,184	$0	$362,409,577	$526,944,449	$0	$209,074,166	$138,146,422	$0	$34,099,741	$10,175,973	$0	$320,204	$129,201,191	$0	$3,839,622
Total Prod, Trans, and Dist Plant			**$4,110,427,911**	**$3,748,018,334**	**$0**	**$362,409,577**	**$1,540,321,725**	**$0**	**$209,074,166**	**$459,158,034**	**$0**	**$34,099,741**	**$46,652,093**	**$0**	**$320,204**	**$553,996,990**	**$0**	**$3,839,622**
General Plant																		
Total General Plant	PT&D	23	$15,832,612	$14,436,677	$0	$1,395,935	$5,933,036	$0	$805,315	$1,768,592	$0	$131,346	$179,695	$0	$1,233	$2,133,894	$0	$14,790
TOTAL COMMON PLANT		23	$202,237,020	$184,406,119	$0	$17,830,901	$75,785,315	$0	$10,286,651	$22,591,018	$0	$1,677,740	$2,295,328	$0	$15,754	$27,257,187	$0	$188,913
106.00 COMPLETED CONSTR NOT CLASSIFIED			$0	$0	$0	$0												
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	Prod	24	$211,410	$211,410	$0	$0	$74,903	$0	$0	$24,249	$0	$0	$2,884	$0	$0	$33,603	$0	$0
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	Dist	26	$2,915,340	$2,139,981	$0	$775,359	$1,127,375	$0	$447,305	$295,558	$0	$72,955	$21,771	$0	$685	$276,420	$0	$8,215
OTHER			$0	$0	$0	$0												
Total Plant in Service			$4,331,626,534	$3,949,214,564	$0	$382,411,970	$1,623,243,193	$0	$220,613,551	$483,837,702	$0	$35,981,800	$49,151,797	$0	$337,877	$583,698,396	$0	$4,051,542
Construction Work in Progress (CWIP)																		
CWIP Production	Prod	24	$67,084,848	$67,084,848	$0	$0	$23,768,229	$0	$0	$7,694,565	$0	$0	$915,104	$0	$0	$10,662,935	$0	$0
CWIP Transmission	Trans	25	$6,861,294	$6,861,294	$0	$0	$3,049,076	$0	$0	$877,668	$0	$0	$77,982	$0	$0	$905,103	$0	$0
CWIP Distribution Plant	Dist	26	$30,927,921	$22,702,378	$0	$8,225,543	$11,959,960	$0	$4,745,317	$3,135,484	$0	$773,955	$230,962	$0	$7,268	$2,932,455	$0	$87,147
CWIP General Plant	PT&D	23	$18,667,667	$17,021,770	$0	$1,645,897	$6,995,431	$0	$949,518	$2,085,284	$0	$154,865	$211,872	$0	$1,454	$2,515,999	$0	$17,438
RWIP			$0	$0	$0	$0												
Total Construction Work in Progress			$123,541,730	$113,670,290	$0	$9,871,440	$45,772,695	$0	$5,694,836	$13,793,000	$0	$928,821	$1,435,921	$0	$8,722	$17,016,492	$0	$104,585
Total Gross Utility Plant			$4,455,168,264	$4,062,884,854	$0	$392,283,410	$1,669,015,888	$0	$226,308,387	$497,630,702	$0	$36,910,621	$50,587,718	$0	$346,599	$600,714,888	$0	$4,156,127

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Time of Day-Pri (TOD-Pri)			Time of Day-Sec (TOD-Sec)			Retail Transmission (RTS)			Special Contract 1		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base																		
Plant in Service																		
Intangible Plant																		
301.00 ORGANIZATION	PT&D	23	$2,240	$2,043	$0	$198	$279	$0	$0	$170	$0	$0	$134	$0	$0	$17	$0	$0
302.00 FRANCHISE AND CONSENTS	PT&D	23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
303.00 SOFTWARE	PT&D	23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Intangible Plant			$2,240	$2,043	$0	$198	$279	$0	$0	$170	$0	$0	$134	$0	$0	$17	$0	$0
Production Plant																		
Total Production Plant																		
Demand	PODPLT	52	$2,305,549,928	$2,305,549,928	$0	$0	$350,531,200	$0	$0	$210,478,264	$0	$0	$212,518,676	$0	$0	$20,975,893	$0	$0
Energy	Energy	2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Plant			**$2,305,549,928**	**$2,305,549,928**	**$0**	**$0**	**$350,531,200**	**$0**	**$0**	**$210,478,264**	**$0**	**$0**	**$212,518,676**	**$0**	**$0**	**$20,975,893**	**$0**	**$0**
Transmission																		
KENTUCKY SYSTEM PROPERTY	NCPT	13	$442,223,222	$442,223,222	$0	$0	$53,067,462	$0	$0	$31,508,739	$0	$0	$32,637,220	$0	$0	$3,290,037	$0	$0
VIRGINIA PROPERTY - 500 KV LINE	NCPT	13	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Transmission Plant			$442,223,222	$442,223,222	$0	$0	$53,067,462	$0	$0	$31,508,739	$0	$0	$32,637,220	$0	$0	$3,290,037	$0	$0
Distribution																		
TOTAL ACCTS 360-362	NCPP	14	$152,675,045	$152,675,045	$0	$0	$19,781,138	$0	$0	$11,745,026	$0	$0	$0	$0	$0	$1,226,376	$0	$0
364 & 365-OVERHEAD LINES																		
Primary:																		
Demand	NCPP	14	$386,565,842	$386,565,842	$0	$0	$50,084,886	$0	$0	$29,737,838	$0	$0	$0	$0	$0	$3,105,126	$0	$0
Customer	CUST08	11	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary:																		
Demand	SICD	16	$57,817,118	$57,817,118	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer	CUST07	10	$83,856,780	$0	$0	$83,856,780	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
366 & 367-UNDERGROUND LINES																		
Primary:																		
Demand	NCPP	14	$290,015,468	$290,015,468	$0	$0	$37,575,466	$0	$0	$22,310,385	$0	$0	$0	$0	$0	$2,329,576	$0	$0
Customer	CUST08	11	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary:																		
Demand	SICD	16	$13,957,513	$13,957,513	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer	CUST07	10	$25,215,972	$0	$0	$25,215,972	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
368-TRANSFORMERS - POWER POOL																		
Demand	SICDT	15	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer	CUST09	12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
368-TRANSFORMERS - ALL OTHER																		
Demand	SICDT	15	$99,214,198	$99,214,198	$0	$0	$0	$0	$0	$6,096,766	$0	$0	$0	$0	$0	$0	$0	$0
Customer	CUST09	12	$69,385,677	$0	$0	$69,385,677	$0	$0	$0	$0	$0	$45,362	$0	$0	$0	$0	$0	$0
369-SERVICES	C02	20	$34,458,226	$0	$0	$34,458,226	$0	$0	$0	$0	$0	$144,759	$0	$0	$0	$0	$0	$0
370-METERS	C03	21	$39,970,580	$0	$0	$39,970,580	$0	$0	$501,391	$0	$0	$233,108	$0	$0	$410,138	$0	$0	$4,756
371-CUSTOMER INSTALLATION	C04	22	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
373-STREET LIGHTING	C04	22	$109,522,342	$0	$0	$109,522,342	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Distribution Plant			$1,362,654,761	$1,000,245,184	$0	$362,409,577	$107,441,490	$0	$501,391	$69,890,015	$0	$423,230	$0	$0	$410,138	$6,661,078	$0	$4,756
Total Prod, Trans, and Dist Plant			**$4,110,427,911**	**$3,748,018,334**	**$0**	**$362,409,577**	**$511,040,152**	**$0**	**$501,391**	**$311,877,017**	**$0**	**$423,230**	**$245,155,895**	**$0**	**$410,138**	**$30,927,008**	**$0**	**$4,756**
General Plant																		
Total General Plant	PT&D	23	$15,832,612	$14,436,677	$0	$1,395,935	$1,968,433	$0	$1,931	$1,201,293	$0	$1,630	$944,295	$0	$1,580	$119,125	$0	$18
TOTAL COMMON PLANT		23	$202,237,020	$184,406,119	$0	$17,830,901	$25,143,669	$0	$24,669	$15,344,650	$0	$20,823	$12,061,907	$0	$20,179	$1,521,639	$0	$234
106.00 COMPLETED CONSTR NOT CLASSIFIED			$0	$0	$0	$0												
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	Prod	24	$211,410	$211,410	$0	$0	$32,142	$0	$0	$19,300	$0	$0	$19,487	$0	$0	$1,923	$0	$0
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	Dist	26	$2,915,340	$2,139,981	$0	$775,359	$229,866	$0	$1,073	$149,527	$0	$905	$0	$0	$877	$14,251	$0	$10
OTHER			$0	$0	$0	$0												
Total Plant in Service			$4,331,626,534	$3,949,214,564	$0	$382,411,970	$538,414,540	$0	$529,064	$328,591,957	$0	$446,589	$258,181,718	$0	$432,775	$32,583,964	$0	$5,019
Construction Work in Progress (CWIP)																		
CWIP Production	Prod	24	$67,084,848	$67,084,848	$0	$0	$10,199,446	$0	$0	$6,124,310	$0	$0	$6,183,680	$0	$0	$610,338	$0	$0
CWIP Transmission	Trans	25	$6,861,294	$6,861,294	$0	$0	$823,366	$0	$0	$488,872	$0	$0	$506,381	$0	$0	$51,046	$0	$0
CWIP Distribution Plant	Dist	26	$30,927,921	$22,702,378	$0	$8,225,543	$2,438,579	$0	$11,380	$1,586,281	$0	$9,606	$0	$0	$9,309	$151,185	$0	$108
CWIP General Plant	PT&D	23	$18,667,667	$17,021,770	$0	$1,645,897	$2,320,909	$0	$2,277	$1,416,402	$0	$1,922	$1,113,385	$0	$1,863	$140,456	$0	$22
RWIP			$0	$0	$0	$0												
Total Construction Work in Progress			$123,541,730	$113,670,290	$0	$9,871,440	$15,782,300	$0	$13,657	$9,615,864	$0	$11,528	$7,803,446	$0	$11,171	$953,026	$0	$130
Total Gross Utility Plant			$4,455,168,264	$4,062,884,854	$0	$392,283,410	$554,196,840	$0	$542,721	$338,207,822	$0	$458,117	$265,985,164	$0	$443,946	$33,536,989	$0	$5,149

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Special Contract 2			Street Lighting (RLS, LS, DSK)			Street Lighting-LE			Traffic Street Lighting (TLE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base																		
Plant in Service																		
Intangible Plant																		
301.00 ORGANIZATION	PT&D	23	$2,240	$2,043	$0	$198	$9	$0	$0	$17	$0	$62	$1	$0	$0	$0	$0	$0
302.00 FRANCHISE AND CONSENTS	PT&D	23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
303.00 SOFTWARE	PT&D	23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Intangible Plant			$2,240	$2,043	$0	$198	$9	$0	$0	$17	$0	$62	$1	$0	$0	$0	$0	$0
Production Plant																		
Total Production Plant																		
Demand	PODPLT	52	$2,305,549,928	$2,305,549,928	$0	$0	$11,364,056	$0	$0	$19,221,370	$0	$0	$627,110	$0	$0	$620,193	$0	$0
Energy	Energy	2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Plant			**$2,305,549,928**	**$2,305,549,928**	**$0**	**$0**	**$11,364,056**	**$0**	**$0**	**$19,221,370**	**$0**	**$0**	**$627,110**	**$0**	**$0**	**$620,193**	**$0**	**$0**
Transmission																		
KENTUCKY SYSTEM PROPERTY	NCPT	13	$442,223,222	$442,223,222	$0	$0	$1,721,960	$0	$0	$3,392,248	$0	$0	$108,513	$0	$0	$49,404	$0	$0
VIRGINIA PROPERTY - 500 KV LINE	NCPT	13	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Transmission Plant			$442,223,222	$442,223,222	$0	$0	$1,721,960	$0	$0	$3,392,248	$0	$0	$108,513	$0	$0	$49,404	$0	$0
Distribution																		
TOTAL ACCTS 360-362	NCPP	14	$152,675,045	$152,675,045	$0	$0	$641,869	$0	$0	$1,264,476	$0	$0	$40,449	$0	$0	$18,416	$0	$0
364 & 365-OVERHEAD LINES																		
Primary:																		
Demand	NCPP	14	$386,565,842	$386,565,842	$0	$0	$1,625,180	$0	$0	$3,201,592	$0	$0	$102,414	$0	$0	$46,627	$0	$0
Customer	CUST08	11	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary:																		
Demand	SICD	16	$57,817,118	$57,817,118	$0	$0	$0	$0	$0	$398,903	$0	$0	$12,760	$0	$0	$5,810	$0	$0
Customer	CUST07	10	$83,856,780	$0	$0	$83,856,780	$0	$0	$0	$0	$0	$1,921,003	$0	$0	$3,602	$0	$0	$20,211
366 & 367-UNDERGROUND LINES																		
Primary:																		
Demand	NCPP	14	$290,015,468	$290,015,468	$0	$0	$1,219,268	$0	$0	$2,401,948	$0	$0	$76,835	$0	$0	$34,982	$0	$0
Customer	CUST08	11	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Secondary:																		
Demand	SICD	16	$13,957,513	$13,957,513	$0	$0	$0	$0	$0	$96,298	$0	$0	$3,080	$0	$0	$1,402	$0	$0
Customer	CUST07	10	$25,215,972	$0	$0	$25,215,972	$0	$0	$0	$0	$0	$577,651	$0	$0	$1,083	$0	$0	$6,077
368-TRANSFORMERS - POWER POOL																		
Demand	SICDT	15	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer	CUST09	12	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
368-TRANSFORMERS - ALL OTHER																		
Demand	SICDT	15	$99,214,198	$99,214,198	$0	$0	$0	$0	$0	$565,913	$0	$0	$18,103	$0	$0	$8,242	$0	$0
Customer	CUST09	12	$69,385,677	$0	$0	$69,385,677	$0	$0	$0	$0	$0	$1,577,825	$0	$0	$2,958	$0	$0	$16,600
369-SERVICES	C02	20	$34,458,226	$0	$0	$34,458,226	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
370-METERS	C03	21	$39,970,580	$0	$0	$39,970,580	$0	$0	$4,756	$0	$0	$0	$0	$0	$12,671	$0	$0	$69,549
371-CUSTOMER INSTALLATION	C04	22	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
373-STREET LIGHTING	C04	22	$109,522,342	$0	$0	$109,522,342	$0	$0	$0	$0	$0	$109,522,342	$0	$0	$0	$0	$0	$0
Total Distribution Plant			$1,362,654,761	$1,000,245,184	$0	$362,409,577	$3,486,317	$0	$4,756	$7,929,130	$0	$113,598,821	$253,640	$0	$20,314	$115,478	$0	$112,437
Total Prod, Trans, and Dist Plant			**$4,110,427,911**	**$3,748,018,334**	**$0**	**$362,409,577**	**$16,572,333**	**$0**	**$4,756**	**$30,542,748**	**$0**	**$113,598,821**	**$989,262**	**$0**	**$20,314**	**$785,076**	**$0**	**$112,437**
General Plant																		
Total General Plant	PT&D	23	$15,832,612	$14,436,677	$0	$1,395,935	$63,834	$0	$18	$117,645	$0	$437,562	$3,810	$0	$78	$3,024	$0	$433
TOTAL COMMON PLANT		23	$202,237,020	$184,406,119	$0	$17,830,901	$815,375	$0	$234	$1,502,733	$0	$5,589,172	$48,673	$0	$999	$38,626	$0	$5,532
106.00 COMPLETED CONSTR NOT CLASSIFIED			$0	$0	$0	$0												
105.00 PLANT HELD FOR FUTURE USE - PRODUCTION	Prod	24	$211,410	$211,410	$0	$0	$1,042	$0	$0	$1,763	$0	$0	$58	$0	$0	$57	$0	$0
105.00 PLANT HELD FOR FUTURE USE - DISTRIBUTION	Dist	26	$2,915,340	$2,139,981	$0	$775,359	$7,459	$0	$10	$16,964	$0	$243,040	$543	$0	$43	$247	$0	$241
OTHER			$0	$0	$0	$0												
Total Plant in Service			$4,331,626,534	$3,949,214,564	$0	$382,411,970	$17,460,051	$0	$5,019	$32,181,869	$0	$119,868,656	$1,042,346	$0	$21,435	$827,030	$0	$118,642
Construction Work in Progress (CWIP)																		
CWIP Production	Prod	24	$67,084,848	$67,084,848	$0	$0	$330,661	$0	$0	$559,286	$0	$0	$18,247	$0	$0	$18,046	$0	$0
CWIP Transmission	Trans	25	$6,861,294	$6,861,294	$0	$0	$26,717	$0	$0	$52,632	$0	$0	$1,684	$0	$0	$767	$0	$0
CWIP Distribution Plant	Dist	26	$30,927,921	$22,702,378	$0	$8,225,543	$79,128	$0	$108	$179,966	$0	$2,578,331	$5,757	$0	$461	$2,621	$0	$2,552
CWIP General Plant	PT&D	23	$18,667,667	$17,021,770	$0	$1,645,897	$75,264	$0	$22	$138,711	$0	$515,913	$4,493	$0	$92	$3,565	$0	$511
RWIP			$0	$0	$0	$0												
Total Construction Work in Progress			$123,541,730	$113,670,290	$0	$9,871,440	$511,770	$0	$130	$930,596	$0	$3,094,245	$30,180	$0	$553	$24,999	$0	$3,063
Total Gross Utility Plant			$4,455,168,264	$4,062,884,854	$0	$392,283,410	$17,971,822	$0	$5,149	$33,112,465	$0	$122,962,901	$1,072,527	$0	$21,989	$852,029	$0	$121,705

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Class Allocation

	Allocation Factor		Total Kentucky				Residential (RS)			General Service (GS)			Power Service-Primary (PS-Pri)			Power Service-Secondary (PS-Sec)		
	Name	**No**	**Total**	**Demand**	**Energy**	**Customer**	**Demand**	**Energy**	**Customer**	**Demand**	**Energy**	**Customer**	**Demand**	**Energy**	**Customer**	**Demand**	**Energy**	**Customer**
Less: Acummulated Provision for Depreciation																		
Steam Production	PODRES	53	$903,942,138	$903,942,138	$0	$0	$322,267,123	$0	$0	$103,768,942	$0	$0	$12,289,093	$0	$0	$143,414,036	$0	$0
Hydraulic Production	PODRES	53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Production	PODRES	53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission - Kentucky System Property	Trans	25	$159,969,049	$159,969,049	$0	$0	$71,088,303	$0	$0	$20,462,570	$0	$0	$1,818,137	$0	$0	$21,102,201	$0	$0
Distribution	Dist	26	$508,037,556	$372,920,664	$0	$135,116,892	$196,460,305	$0	$77,948,965	$51,505,027	$0	$12,713,381	$3,793,901	$0	$119,382	$48,169,983	$0	$1,431,523
General Plant	PT&D	23	$71,121,012	$64,850,391	$0	$6,270,621	$26,651,541	$0	$3,617,523	$7,944,619	$0	$590,014	$807,202	$0	$5,540	$9,585,578	$0	$66,435
Intangible Plant	PT&D	23	$40,982,991	$37,369,589	$0	$3,613,402	$15,357,766	$0	$2,084,572	$4,578,032	$0	$339,991	$465,144	$0	$3,193	$5,523,623	$0	$38,283
Total Accumulated Depreciation			$1,684,052,746	$1,539,051,831	$0	$145,000,915	$631,825,039	$0	$83,651,060	$188,259,190	$0	$13,643,386	$19,173,477	$0	$128,114	$227,795,421	$0	$1,536,242
Net Utility Plant			$2,771,115,518	$2,523,833,023	$0	$247,282,495	$1,037,190,848	$0	$142,657,327	$309,371,512	$0	$23,267,235	$31,414,241	$0	$218,485	$372,919,467	$0	$2,619,885
Working Capital																		
Cash Working Capital - Operation and Maintenance Expenses	O&MxPurcl	49	$75,842,724	$18,273,306	$51,365,920	$6,203,497	$7,790,166	$18,635,357	$4,533,572	$2,345,516	$6,056,919	$1,091,090	$221,309	$716,609	$18,739	$2,662,317	$8,341,010	$203,168
Materials and Supplies	TPIS	27	$36,896,266	$33,638,928	$0	$3,257,338	$13,826,587	$0	$1,879,159	$4,121,270	$0	$306,489	$418,669	$0	$2,878	$4,971,872	$0	$34,511
Fuel Stock	Prod	24	$36,289,311	$36,289,311	$0	$0	$12,857,339	$0	$0	$4,162,348	$0	$0	$495,022	$0	$0	$5,768,077	$0	$0
Prepayments	TPIS	27	$13,972,166	$12,738,652	$0	$1,233,514	$5,235,960	$0	$711,615	$1,560,675	$0	$116,063	$158,545	$0	$1,090	$1,882,787	$0	$13,069
Total Working Capital			$163,000,467	$100,940,196	$51,365,920	$10,694,350	$39,710,053	$18,635,357	$7,124,346	$12,189,809	$6,056,919	$1,513,643	$1,293,545	$716,609	$22,707	$15,285,053	$8,341,010	$250,747
Emission Allowance			$0	$0	$0	$0												
Deferred Debits																		
Service Pension Cost			$0	$0	$0	$0												
Accumulated Deferred Income Tax																		
Total	TPIS	27	$546,457,652	$498,214,355	$0	$48,243,297	$204,780,735	$0	$27,831,569	$61,038,691	$0	$4,539,295	$6,200,760	$0	$42,625	$73,636,647	$0	$511,123
Total Accumulated Deferred Income Tax			$546,457,652	$498,214,355	$0	$48,243,297	$204,780,735	$0	$27,831,569	$61,038,691	$0	$4,539,295	$6,200,760	$0	$42,625	$73,636,647	$0	$511,123
Accumulated Deferred Investment Tax Credits																		
Production	Prod	24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission			$0	$0	$0	$0												
Transmission VA			$0	$0	$0	$0												
Distribution VA			$0	$0	$0	$0												
Distribution Plant KY,FERC & TN			$0	$0	$0	$0												
General			$0	$0	$0	$0												
Total Accum. Deferred Investment Tax Credits			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Deferred Debits			$546,457,652	$498,214,355	$0	$48,243,297	$204,780,735	$0	$27,831,569	$61,038,691	$0	$4,539,295	$6,200,760	$0	$42,625	$73,636,647	$0	$511,123
Less: Customer Advances	DLINES	28	$6,724,404	$5,868,998	$0	$855,406	$3,018,245	$0	$743,228	$819,263	$0	$92,339	$65,112	$0	$0	$755,725	$0	$0
Less: Asset Retirement Obligations																		
Net Rate Base			$2,380,933,929	$2,120,689,866	$51,365,920	$208,878,142	$869,101,922	$18,635,357	$121,206,875	$259,703,367	$6,056,919	$20,149,244	$26,441,914	$716,609	$198,567	$313,812,148	$8,341,010	$2,359,509
Operation and Maintenance Expenses																		
Steam Power Generation Operation Expenses																		
500 OPERATION SUPERVISION & ENGINEERING	LBSUB1	36	$4,922,985	$4,163,687	$759,298	$0	$1,475,199	$275,626	$0	$477,571	$89,588	$0	$56,797	$10,585	$0	$661,806	$123,321	$0
501 FUEL	TDFUEL	51	$293,912,722	$0	$293,912,722	$0	$0	$106,690,674	$0	$0	$34,678,175	$0	$0	$4,097,369	$0	$0	$47,735,683	$0
502 STEAM EXPENSES	OM502	47	$18,526,106	$18,526,106	$0	$0	$7,244,639	$0	$0	$2,618,033	$0	$0	$215,912	$0	$0	$3,047,674	$0	$0
505 ELECTRIC EXPENSES	OM505	48	$2,617,219	$2,617,219	$0	$0	$1,023,464	$0	$0	$369,855	$0	$0	$30,502	$0	$0	$430,551	$0	$0
506 MISC. STEAM POWER EXPENSES	Prod	24	$9,946,165	$9,946,165	$0	$0	$3,523,936	$0	$0	$1,140,815	$0	$0	$135,676	$0	$0	$1,580,913	$0	$0
507 RENTS				$0	$0	$0												
509 ALLOWANCES				$0	$0	$0												
Total Steam Power Operation Expenses			$329,925,197	$35,253,177	$294,672,020	$0	$13,267,238	$106,966,300	$0	$4,606,273	$34,767,763	$0	$438,886	$4,107,955	$0	$5,720,943	$47,859,004	$0
Steam Power Generation Maintenance Expenses																		
510 MAINTENANCE SUPERVISION & ENGINEERING	LBSUB2	37	$4,351,845	$0	$4,351,845	$0	$0	$1,574,402	$0	$0	$511,624	$0	$0	$60,935	$0	$0	$706,015	$0
511 MAINTENANCE OF STRUCTURES	Prod	24	$4,128,301	$4,128,301	$0	$0	$1,462,661	$0	$0	$473,512	$0	$0	$56,314	$0	$0	$656,181	$0	$0
512 MAINTENANCE OF BOILER PLANT	Energy	2	$34,257,481	$0	$34,257,481	$0	$0	$12,393,604	$0	$0	$4,027,478	$0	$0	$479,679	$0	$0	$5,557,708	$0
513 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$15,421,014	$0	$15,421,014	$0	$0	$5,578,984	$0	$0	$1,812,970	$0	$0	$215,928	$0	$0	$2,501,804	$0
514 MAINTENANCE OF MISC STEAM PLANT	Energy	2	$1,072,820	$0	$1,072,820	$0	$0	$388,123	$0	$0	$126,126	$0	$0	$15,022	$0	$0	$174,047	$0
Total Steam Power Generation Maintenance Expense			$59,231,461	$4,128,301	$55,103,160	$0	$1,462,661	$19,935,113	$0	$473,512	$6,478,198	$0	$56,314	$771,564	$0	$656,181	$8,939,574	$0
Total Steam Power Generation Expense			$389,156,658	$39,381,478	$349,775,180	$0	$14,729,899	$126,901,413	$0	$5,079,785	$41,245,961	$0	$495,200	$4,879,519	$0	$6,377,124	$56,798,579	$0

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Time of Day-Pri (TOD-Pri)			Time of Day-Sec (TOD-Sec)			Retail Transmission (RTS)			Special Contract 1		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Less: Acummulated Provision for Depreciation																		
Steam Production	PODRES	53	$903,942,138	$903,942,138	$0	$0	$136,796,276	$0	$0	$82,208,114	$0	$0	$82,712,514	$0	$0	$8,196,947	$0	$0
Hydraulic Production	PODRES	53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Production	PODRES	53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission - Kentucky System Property	Trans	25	$159,969,049	$159,969,049	$0	$0	$19,196,530	$0	$0	$11,397,916	$0	$0	$11,806,130	$0	$0	$1,190,132	$0	$0
Distribution	Dist	26	$508,037,556	$372,920,664	$0	$135,116,892	$40,057,330	$0	$186,933	$26,057,042	$0	$157,792	$0	$0	$152,911	$2,483,445	$0	$1,773
General Plant	PT&D	23	$71,121,012	$64,850,391	$0	$6,270,621	$8,842,314	$0	$8,675	$5,396,277	$0	$7,323	$4,241,830	$0	$7,096	$535,117	$0	$82
Intangible Plant	PT&D	23	$40,982,991	$37,369,589	$0	$3,613,402	$5,095,322	$0	$4,999	$3,109,567	$0	$4,220	$2,444,325	$0	$4,089	$308,358	$0	$47
Total Accumulated Depreciation			$1,684,052,746	$1,539,051,831	$0	$145,000,915	$209,987,772	$0	$200,608	$128,168,916	$0	$169,335	$101,204,799	$0	$164,097	$12,713,999	$0	$1,903
Net Utility Plant			$2,771,115,518	$2,523,833,023	$0	$247,282,495	$344,209,068	$0	$342,113	$210,038,905	$0	$288,782	$164,780,366	$0	$279,849	$20,822,990	$0	$3,245
Working Capital																		
Cash Working Capital - Operation and Maintenance Expenses	O&MxPurcl	49	$75,842,724	$18,273,306	$51,365,920	$6,203,497	$2,397,151	$8,009,788	$42,154	$1,464,621	$3,545,729	$54,850	$1,034,970	$4,850,091	$23,162	$146,426	$475,186	$276
Materials and Supplies	TPIS	27	$36,896,266	$33,638,928	$0	$3,257,338	$4,586,149	$0	$4,507	$2,798,906	$0	$3,804	$2,199,160	$0	$3,686	$277,546	$0	$43
Fuel Stock	Prod	24	$36,289,311	$36,289,311	$0	$0	$5,517,354	$0	$0	$3,312,924	$0	$0	$3,345,040	$0	$0	$330,160	$0	$0
Prepayments	TPIS	27	$13,972,166	$12,738,652	$0	$1,233,514	$1,736,719	$0	$1,707	$1,059,912	$0	$1,441	$832,795	$0	$1,396	$105,103	$0	$16
Total Working Capital			$163,000,467	$100,940,196	$51,365,920	$10,694,350	$14,237,373	$8,009,788	$48,367	$8,636,363	$3,545,729	$60,094	$7,411,965	$4,850,091	$28,244	$859,235	$475,186	$335
Emission Allowance			$0	$0	$0	$0												
Deferred Debits																		
Service Pension Cost			$0	$0	$0	$0												
Accumulated Deferred Income Tax																		
Total	TPIS	27	$546,457,652	$498,214,355	$0	$48,243,297	$67,923,849	$0	$66,744	$41,453,617	$0	$56,340	$32,570,993	$0	$54,597	$4,110,640	$0	$633
Total Accumulated Deferred Income Tax			$546,457,652	$498,214,355	$0	$48,243,297	$67,923,849	$0	$66,744	$41,453,617	$0	$56,340	$32,570,993	$0	$54,597	$4,110,640	$0	$633
Accumulated Deferred Investment Tax Credits																		
Production	Prod	24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission			$0	$0	$0	$0												
Transmission VA			$0	$0	$0	$0												
Distribution VA			$0	$0	$0	$0												
Distribution Plant KY,FERC & TN			$0	$0	$0	$0												
General			$0	$0	$0	$0												
Total Accum. Deferred Investment Tax Credits			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Deferred Debits			$546,457,652	$498,214,355	$0	$48,243,297	$67,923,849	$0	$66,744	$41,453,617	$0	$56,340	$32,570,993	$0	$54,597	$4,110,640	$0	$633
Less: Customer Advances	DLINES	28	$6,724,404	$5,868,998	$0	$855,406	$687,478	$0	$0	$408,189	$0	$0	$0	$0	$0	$42,622	$0	$0
Less: Asset Retirement Obligations																		
Net Rate Base			$2,380,933,929	$2,120,689,866	$51,365,920	$208,878,142	$289,835,114	$8,009,788	$323,736	$176,813,461	$3,545,729	$292,537	$139,621,339	$4,850,091	$253,496	$17,528,964	$475,186	$2,947
Operation and Maintenance Expenses																		
Steam Power Generation Operation Expenses																		
500 OPERATION SUPERVISION & ENGINEERING	LBSUB1	36	$4,922,985	$4,163,687	$759,298	$0	$633,039	$118,300	$0	$380,111	$52,437	$0	$383,796	$71,552	$0	$37,881	$7,016	$0
501 FUEL	TDFUEL	51	$293,912,722	$0	$293,912,722	$0	$0	$45,792,188	$0	$0	$20,297,556	$0	$0	$27,696,561	$0	$0	$2,715,648	$0
502 STEAM EXPENSES	OM502	47	$18,526,106	$18,526,106	$0	$0	$2,305,035	$0	$0	$1,556,867	$0	$0	$1,333,122	$0	$0	$143,948	$0	$0
505 ELECTRIC EXPENSES	OM505	48	$2,617,219	$2,617,219	$0	$0	$325,637	$0	$0	$219,942	$0	$0	$188,333	$0	$0	$20,336	$0	$0
506 MISC. STEAM POWER EXPENSES	Prod	24	$9,946,165	$9,946,165	$0	$0	$1,512,195	$0	$0	$908,005	$0	$0	$916,808	$0	$0	$90,490	$0	$0
507 RENTS				$0	$0	$0												
509 ALLOWANCES				$0	$0	$0												
Total Steam Power Operation Expenses			$329,925,197	$35,253,177	$294,672,020	$0	$4,775,906	$45,910,488	$0	$3,064,926	$20,349,993	$0	$2,822,058	$27,768,112	$0	$292,655	$2,722,664	$0
Steam Power Generation Maintenance Expenses																		
510 MAINTENANCE SUPERVISION & ENGINEERING	LBSUB2	37	$4,351,845	$0	$4,351,845	$0	$0	$681,500	$0	$0	$299,733	$0	$0	$414,981	$0	$0	$40,504	$0
511 MAINTENANCE OF STRUCTURES	Prod	24	$4,128,301	$4,128,301	$0	$0	$627,659	$0	$0	$376,881	$0	$0	$380,534	$0	$0	$37,559	$0	$0
512 MAINTENANCE OF BOILER PLANT	Energy	2	$34,257,481	$0	$34,257,481	$0	$0	$5,364,732	$0	$0	$2,359,482	$0	$0	$3,266,711	$0	$0	$318,848	$0
513 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$15,421,014	$0	$15,421,014	$0	$0	$2,414,935	$0	$0	$1,062,121	$0	$0	$1,470,511	$0	$0	$143,529	$0
514 MAINTENANCE OF MISC STEAM PLANT	Energy	2	$1,072,820	$0	$1,072,820	$0	$0	$168,004	$0	$0	$73,890	$0	$0	$102,302	$0	$0	$9,985	$0
Total Steam Power Generation Maintenance Expense			$59,231,461	$4,128,301	$55,103,160	$0	$627,659	$8,629,171	$0	$376,881	$3,795,227	$0	$380,534	$5,254,504	$0	$37,559	$512,866	$0
Total Steam Power Generation Expense			$389,156,658	$39,381,478	$349,775,180	$0	$5,403,565	$54,539,659	$0	$3,441,807	$24,145,220	$0	$3,202,593	$33,022,617	$0	$330,214	$3,235,530	$0

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Class Allocation

	Allocation Factor			Total Kentucky			Special Contract 2			Street Lighting (RLS, LS, DSK)			Street Lighting-LE			Traffic Street Lighting (TLE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Less: Acummulated Provision for Depreciation																		
Steam Production	PODRES	53	$903,942,138	$903,942,138	$0	$0	$4,428,413	$0	$0	$7,379,784	$0	$0	$240,449	$0	$0	$240,449	$0	$0
Hydraulic Production	PODRES	53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Production	PODRES	53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission - Kentucky System Property	Trans	25	$159,969,049	$159,969,049	$0	$0	$622,899	$0	$0	$1,227,106	$0	$0	$39,253	$0	$0	$17,871	$0	$0
Distribution	Dist	26	$508,037,556	$372,920,664	$0	$135,116,892	$1,299,801	$0	$1,773	$2,956,212	$0	$42,352,964	$94,565	$0	$7,574	$43,054	$0	$41,920
General Plant	PT&D	23	$71,121,012	$64,850,391	$0	$6,270,621	$286,744	$0	$82	$528,468	$0	$1,965,553	$17,117	$0	$351	$13,584	$0	$1,945
Intangible Plant	PT&D	23	$40,982,991	$37,369,589	$0	$3,613,402	$165,234	$0	$47	$304,526	$0	$1,132,636	$9,863	$0	$203	$7,828	$0	$1,121
Total Accumulated Depreciation			$1,684,052,746	$1,539,051,831	$0	$145,000,915	$6,803,091	$0	$1,903	$12,396,096	$0	$45,451,153	$401,247	$0	$8,128	$322,785	$0	$44,986
Net Utility Plant			$2,771,115,518	$2,523,833,023	$0	$247,282,495	$11,168,731	$0	$3,245	$20,716,369	$0	$77,511,748	$671,280	$0	$13,861	$529,244	$0	$76,719
Working Capital																		
Cash Working Capital - Operation and Maintenance Expenses	O&MxPurc	49	$75,842,724	$18,273,306	$51,365,920	$6,203,497	$75,488	$257,139	$276	$127,941	$449,359	$230,219	$4,130	$14,633	$926	$3,271	$14,101	$5,065
Materials and Supplies	TPIS	27	$36,896,266	$33,638,928	$0	$3,257,338	$148,723	$0	$43	$274,121	$0	$1,021,027	$8,879	$0	$183	$7,045	$0	$1,011
Fuel Stock	Prod	24	$36,289,311	$36,289,311	$0	$0	$178,870	$0	$0	$302,544	$0	$0	$9,871	$0	$0	$9,762	$0	$0
Prepayments	TPIS	27	$13,972,166	$12,738,652	$0	$1,233,514	$56,319	$0	$16	$103,806	$0	$386,650	$3,362	$0	$69	$2,668	$0	$383
Total Working Capital			$163,000,467	$100,940,196	$51,365,920	$10,694,350	$459,400	$257,139	$335	$808,413	$449,359	$1,637,896	$26,242	$14,633	$1,178	$22,745	$14,101	$6,458
Emission Allowance			$0	$0	$0	$0												
Deferred Debits																		
Service Pension Cost			$0	$0	$0	$0												
Accumulated Deferred Income Tax																		
Total	TPIS	27	$546,457,652	$498,214,355	$0	$48,243,297	$2,202,678	$0	$633	$4,059,913	$0	$15,122,066	$131,498	$0	$2,704	$104,334	$0	$14,967
Total Accumulated Deferred Income Tax			$546,457,652	$498,214,355	$0	$48,243,297	$2,202,678	$0	$633	$4,059,913	$0	$15,122,066	$131,498	$0	$2,704	$104,334	$0	$14,967
Accumulated Deferred Investment Tax Credits																		
Production	Prod	24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission			$0	$0	$0	$0												
Transmission VA			$0	$0	$0	$0												
Distribution VA			$0	$0	$0	$0												
Distribution Plant KY,FERC & TN			$0	$0	$0	$0												
General			$0	$0	$0	$0												
Total Accum. Deferred Investment Tax Credits			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Deferred Debits			$546,457,652	$498,214,355	$0	$48,243,297	$2,202,678	$0	$633	$4,059,913	$0	$15,122,066	$131,498	$0	$2,704	$104,334	$0	$14,967
Less: Customer Advances	DLINES	28	$6,724,404	$5,868,998	$0	$855,406	$22,308	$0	$0	$47,830	$0	$19,596	$1,530	$0	$37	$697	$0	$206
Less: Asset Retirement Obligations																		
Net Rate Base			$2,380,933,929	$2,120,689,866	$51,365,920	$208,878,142	$9,403,145	$257,139	$2,947	$17,417,039	$449,359	$64,007,982	$564,494	$14,633	$12,298	$446,958	$14,101	$68,003
Operation and Maintenance Expenses																		
Steam Power Generation Operation Expenses																		
500 OPERATION SUPERVISION & ENGINEERING	LBSUB1	36	$4,922,985	$4,163,687	$759,298	$0	$20,523	$3,815	$0	$34,713	$6,633	$0	$1,133	$216	$0	$1,120	$209	$0
501 FUEL	TDFUEL	51	$293,912,722	$0	$293,912,722	$0	$0	$1,476,600	$0	$0	$2,567,664	$0	$0	$83,598	$0	$0	$81,006	$0
502 STEAM EXPENSES	OM502	47	$18,526,106	$18,526,106	$0	$0	$58,268	$0	$0	$0	$0	$0	$0	$0	$0	$2,609	$0	$0
505 ELECTRIC EXPENSES	OM505	48	$2,617,219	$2,617,219	$0	$0	$8,232	$0	$0	$0	$0	$0	$0	$0	$0	$369	$0	$0
506 MISC. STEAM POWER EXPENSES	Prod	24	$9,946,165	$9,946,165	$0	$0	$49,025	$0	$0	$82,921	$0	$0	$2,705	$0	$0	$2,676	$0	$0
507 RENTS				$0	$0	$0												
509 ALLOWANCES				$0	$0	$0												
Total Steam Power Operation Expenses			$329,925,197	$35,253,177	$294,672,020	$0	$136,047	$1,480,415	$0	$117,634	$2,574,298	$0	$3,838	$83,814	$0	$6,773	$81,215	$0
Steam Power Generation Maintenance Expenses																		
510 MAINTENANCE SUPERVISION & ENGINEERING	LBSUB2	37	$4,351,845	$0	$4,351,845	$0	$0	$21,398	$0	$0	$38,331	$0	$0	$1,249	$0	$0	$1,171	$0
511 MAINTENANCE OF STRUCTURES	Prod	24	$4,128,301	$4,128,301	$0	$0	$20,348	$0	$0	$34,418	$0	$0	$1,123	$0	$0	$1,111	$0	$0
512 MAINTENANCE OF BOILER PLANT	Energy	2	$34,257,481	$0	$34,257,481	$0	$0	$168,446	$0	$0	$301,741	$0	$0	$9,836	$0	$0	$9,217	$0
513 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$15,421,014	$0	$15,421,014	$0	$0	$75,826	$0	$0	$135,829	$0	$0	$4,428	$0	$0	$4,149	$0
514 MAINTENANCE OF MISC STEAM PLANT	Energy	2	$1,072,820	$0	$1,072,820	$0	$0	$5,275	$0	$0	$9,449	$0	$0	$308	$0	$0	$289	$0
Total Steam Power Generation Maintenance Expense			$59,231,461	$4,128,301	$55,103,160	$0	$20,348	$270,945	$0	$34,418	$485,350	$0	$1,123	$15,821	$0	$1,111	$14,826	$0
Total Steam Power Generation Expense			$389,156,658	$39,381,478	$349,775,180	$0	$156,395	$1,751,360	$0	$152,051	$3,059,648	$0	$4,961	$99,635	$0	$7,884	$96,040	$0

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Class Allocation

	Allocation Factor			Total Kentucky			Residential (RS)			General Service (GS)			Power Service-Primary (PS-Pri)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Hydraulic Power Generation Operation Expenses																		
535 OPERATION SUPERVISION & ENGINEERING	Prod	24	$121,406	$121,406	$0	$0	$43,014	$0	$0	$13,925	$0	$0	$1,656	$0	$0	$19,297	$0	$0
536 WATER FOR POWER	Prod	24	$40,614	$40,614	$0	$0	$14,390	$0	$0	$4,658	$0	$0	$554	$0	$0	$6,455	$0	$0
537 HYDRAULIC EXPENSES			$0	$0	$0	$0												
538 ELECTRIC EXPENSES	Prod	24	$180,161	$180,161	$0	$0	$63,831	$0	$0	$20,664	$0	$0	$2,458	$0	$0	$28,636	$0	$0
539 MISC. HYDRAULIC POWER EXPENSES	Prod	24	$348,792	$348,792	$0	$0	$123,577	$0	$0	$40,006	$0	$0	$4,758	$0	$0	$55,439	$0	$0
540 RENTS	Prod	24	$545,400	$545,400	$0	$0	$193,236	$0	$0	$62,557	$0	$0	$7,440	$0	$0	$86,690	$0	$0
Total Hydraulic Power Operation Expenses			$1,236,373	$1,236,373	$0	$0	$438,048	$0	$0	$141,811	$0	$0	$16,865	$0	$0	$196,518	$0	$0
Hydraulic Power Generation Maintenance Expenses																		
541 MAINTENANCE SUPERVISION & ENGINEERING	LBSUB4	38	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
542 MAINTENANCE OF STRUCTURES	Prod	24	$244,992	$244,992	$0	$0	$86,801	$0	$0	$28,100	$0	$0	$3,342	$0	$0	$38,941	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	Prod	24	$190,785	$190,785	$0	$0	$67,595	$0	$0	$21,883	$0	$0	$2,602	$0	$0	$30,325	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$371,119	$0	$371,119	$0	$0	$134,263	$0	$0	$43,631	$0	$0	$5,196	$0	$0	$60,208	$0
545 MAINTENANCE OF MISC HYDRAULIC PLANT	Energy	2	$58,972	$0	$58,972	$0	$0	$21,335	$0	$0	$6,933	$0	$0	$826	$0	$0	$9,567	$0
Total Hydraulic Power Generation Maint. Expense			$865,868	$435,777	$430,091	$0	$154,396	$155,597	$0	$49,983	$50,564	$0	$5,944	$6,022	$0	$69,265	$69,775	$0
Total Hydraulic Power Generation Expense			$2,102,241	$1,672,150	$430,091	$0	$592,444	$155,597	$0	$191,794	$50,564	$0	$22,810	$6,022	$0	$265,783	$69,775	$0
Other Power Generation Operation Expense																		
546 OPERATION SUPERVISION & ENGINEERING	LBSUB5	39	$604,185	$604,185	$0	$0	$214,063	$0	$0	$69,299	$0	$0	$8,242	$0	$0	$96,033	$0	$0
547 FUEL	TDFUEL	51	$57,317,664	$0	$57,317,664	$0	$0	$20,806,381	$0	$0	$6,762,797	$0	$0	$799,052	$0	$0	$9,309,219	$0
548 GENERATION EXPENSE	Prod	24	$280,735	$280,735	$0	$0	$99,465	$0	$0	$32,200	$0	$0	$3,830	$0	$0	$44,622	$0	$0
549 MISC OTHER POWER GENERATION	Prod	24	$1,105,538	$1,105,538	$0	$0	$391,693	$0	$0	$126,804	$0	$0	$15,081	$0	$0	$175,722	$0	$0
550 RENTS	Prod	24	$5,706	$5,706	$0	$0	$2,022	$0	$0	$654	$0	$0	$78	$0	$0	$907	$0	$0
Total Other Power Generation Expenses			$59,313,828	$1,996,164	$57,317,664	$0	$707,243	$20,806,381	$0	$228,958	$6,762,797	$0	$27,230	$799,052	$0	$317,284	$9,309,219	$0
Other Power Generation Maintenance Expense																		
551 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$256,698	$256,698	$0	$0	$90,948	$0	$0	$29,443	$0	$0	$3,502	$0	$0	$40,801	$0	$0
552 MAINTENANCE OF STRUCTURES	Prod	24	$560,673	$560,673	$0	$0	$198,647	$0	$0	$64,309	$0	$0	$7,648	$0	$0	$89,117	$0	$0
553 MAINTENANCE OF GENERATING & ELEC PLANT	Prod	24	$2,652,503	$2,652,503	$0	$0	$939,784	$0	$0	$304,239	$0	$0	$36,183	$0	$0	$421,607	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	Prod	24	$1,112,788	$1,112,788	$0	$0	$394,262	$0	$0	$127,636	$0	$0	$15,180	$0	$0	$176,874	$0	$0
Total Other Power Generation Maintenance Expense			$4,582,662	$4,582,662	$0	$0	$1,623,642	$0	$0	$525,627	$0	$0	$62,512	$0	$0	$728,400	$0	$0
Total Other Power Generation Expense			$63,896,490	$6,578,826	$57,317,664	$0	$2,330,885	$20,806,381	$0	$754,585	$6,762,797	$0	$89,742	$799,052	$0	$1,045,685	$9,309,219	$0
Total Station Expense			$455,155,389	$47,632,454	$407,522,935	$0	$17,653,228	$147,863,391	$0	$6,026,164	$48,059,321	$0	$607,752	$5,684,593	$0	$7,688,592	$66,177,573	$0
Other Power Supply Expenses																		
555 PURCHASED POWER	PURCPWF	46	$53,937,678	$16,216,788	$37,720,890	$0	$6,341,580	$13,646,589	$0	$2,291,689	$4,434,653	$0	$188,998	$528,175	$0	$2,667,775	$6,119,589	$0
555 PURCHASED POWER OPTIONS			$0	$0	$0	$0												
555 BROKERAGE FEES			$0	$0	$0	$0												
555 MISO TRANSMISSION EXPENSES			$0	$0	$0	$0												
556 SYSTEM CONTROL AND LOAD DISPATCH	Prod	24	$1,248,388	$1,248,388	$0	$0	$442,305	$0	$0	$143,189	$0	$0	$17,029	$0	$0	$198,428	$0	$0
557 OTHER EXPENSES	Prod	24	$3,807	$3,807	$0	$0	$1,349	$0	$0	$437	$0	$0	$52	$0	$0	$605	$0	$0
Total Other Power Supply Expenses			$55,189,873	$17,468,983	$37,720,890	$0	$6,785,234	$13,646,589	$0	$2,435,315	$4,434,653	$0	$206,079	$528,175	$0	$2,866,807	$6,119,589	$0
Total Electric Power Generation Expenses			$510,345,262	$65,101,437	$445,243,825	$0	$24,438,462	$161,509,981	$0	$8,461,479	$52,493,974	$0	$813,831	$6,212,768	$0	$10,555,399	$72,297,162	$0
Transmission Expenses																		
560 OPERATION SUPERVISION AND ENG	Trans	25	$1,013,327	$1,013,327	$0	$0	$450,310	$0	$0	$129,621	$0	$0	$11,517	$0	$0	$133,672	$0	$0
561 LOAD DISPATCHING	Trans	25	$2,208,583	$2,208,583	$0	$0	$981,467	$0	$0	$282,513	$0	$0	$25,102	$0	$0	$291,344	$0	$0
562 STATION EXPENSES	Trans	25	$928,949	$928,949	$0	$0	$412,814	$0	$0	$118,827	$0	$0	$10,558	$0	$0	$122,542	$0	$0
563 OVERHEAD LINE EXPENSES	Trans	25	$244,298	$244,298	$0	$0	$108,563	$0	$0	$31,250	$0	$0	$2,777	$0	$0	$32,226	$0	$0
565 TRANSMISSION OF ELECTRICITY BY OTHERS	Trans	25	$36,638	$36,638	$0	$0	$16,281	$0	$0	$4,687	$0	$0	$416	$0	$0	$4,833	$0	$0
566 MISC. TRANSMISSION EXPENSES	Trans	25	$6,948,940	$6,948,940	$0	$0	$3,088,025	$0	$0	$888,879	$0	$0	$78,979	$0	$0	$916,664	$0	$0
567 RENTS	Trans	25	$67,500	$67,500	$0	$0	$29,996	$0	$0	$8,634	$0	$0	$767	$0	$0	$8,904	$0	$0
568 MAINTENACE SUPERVISION AND ENG			$0	$0	$0	$0												
569 STRUCTURES			$0	$0	$0	$0												
570 MAINT OF STATION EQUIPMENT	Trans	25	$1,490,332	$1,490,332	$0	$0	$662,285	$0	$0	$190,637	$0	$0	$16,938	$0	$0	$196,596	$0	$0
571 MAINT OF OVERHEAD LINES	Trans	25	$3,342,881	$3,342,881	$0	$0	$1,485,536	$0	$0	$427,607	$0	$0	$37,994	$0	$0	$440,974	$0	$0
572 UNDERGROUND LINES			$0	$0	$0	$0												
573 MISC PLANT	Trans	25	$228,063	$228,063	$0	$0	$101,348	$0	$0	$29,173	$0	$0	$2,592	$0	$0	$30,085	$0	$0
575 MISO DAY 1&2 EXPENSE			$0	$0	$0	$0												
Total Transmission Expenses			$16,509,511	$16,509,511	$0	$0	$7,336,626	$0	$0	$2,111,827	$0	$0	$187,640	$0	$0	$2,177,840	$0	$0

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Class Allocation

	Allocation Factor			Total Kentucky			Time of Day-Pri (TOD-Pri)			Time of Day-Sec (TOD-Sec)			Retail Transmission (RTS)			Special Contract 1		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Hydraulic Power Generation Operation Expenses																		
535 OPERATION SUPERVISION & ENGINEERING	Prod	24	$121,406	$121,406	$0	$0	$18,458	$0	$0	$11,083	$0	$0	$11,191	$0	$0	$1,105	$0	$0
536 WATER FOR POWER	Prod	24	$40,614	$40,614	$0	$0	$6,175	$0	$0	$3,708	$0	$0	$3,744	$0	$0	$370	$0	$0
537 HYDRAULIC EXPENSES			$0	$0	$0	$0												
538 ELECTRIC EXPENSES	Prod	24	$180,161	$180,161	$0	$0	$27,391	$0	$0	$16,447	$0	$0	$16,607	$0	$0	$1,639	$0	$0
539 MISC. HYDRAULIC POWER EXPENSES	Prod	24	$348,792	$348,792	$0	$0	$53,030	$0	$0	$31,842	$0	$0	$32,151	$0	$0	$3,173	$0	$0
540 RENTS	Prod	24	$545,400	$545,400	$0	$0	$82,922	$0	$0	$49,791	$0	$0	$50,273	$0	$0	$4,962	$0	$0
Total Hydraulic Power Operation Expenses			$1,236,373	$1,236,373	$0	$0	$187,976	$0	$0	$112,871	$0	$0	$113,965	$0	$0	$11,249	$0	$0
Hydraulic Power Generation Maintenance Expenses																		
541 MAINTENANCE SUPERVISION & ENGINEERING	LBSUB4	38	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
542 MAINTENANCE OF STRUCTURES	Prod	24	$244,992	$244,992	$0	$0	$37,248	$0	$0	$22,366	$0	$0	$22,583	$0	$0	$2,229	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	Prod	24	$190,785	$190,785	$0	$0	$29,007	$0	$0	$17,417	$0	$0	$17,586	$0	$0	$1,736	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$371,119	$0	$371,119	$0	$0	$58,117	$0	$0	$25,561	$0	$0	$35,389	$0	$0	$3,454	$0
545 MAINTENANCE OF MISC HYDRAULIC PLANT	Energy	2	$58,972	$0	$58,972	$0	$0	$9,235	$0	$0	$4,062	$0	$0	$5,623	$0	$0	$549	$0
Total Hydraulic Power Generation Maint. Expense			$865,868	$435,777	$430,091	$0	$66,255	$67,352	$0	$39,783	$29,622	$0	$40,169	$41,012	$0	$3,965	$4,003	$0
Total Hydraulic Power Generation Expense			$2,102,241	$1,672,150	$430,091	$0	$254,230	$67,352	$0	$152,654	$29,622	$0	$154,134	$41,012	$0	$15,213	$4,003	$0
Other Power Generation Operation Expense																		
546 OPERATION SUPERVISION & ENGINEERING	LBSUB5	39	$604,185	$604,185	$0	$0	$91,859	$0	$0	$55,157	$0	$0	$55,692	$0	$0	$5,497	$0	$0
547 FUEL	TDFUEL	51	$57,317,664	$0	$57,317,664	$0	$0	$8,930,206	$0	$0	$3,958,347	$0	$0	$5,401,271	$0	$0	$529,595	$0
548 GENERATION EXPENSE	Prod	24	$280,735	$280,735	$0	$0	$42,682	$0	$0	$25,629	$0	$0	$25,877	$0	$0	$2,554	$0	$0
549 MISC OTHER POWER GENERATION	Prod	24	$1,105,538	$1,105,538	$0	$0	$168,084	$0	$0	$100,927	$0	$0	$101,905	$0	$0	$10,058	$0	$0
550 RENTS	Prod	24	$5,706	$5,706	$0	$0	$868	$0	$0	$521	$0	$0	$526	$0	$0	$52	$0	$0
Total Other Power Generation Expenses			$59,313,828	$1,996,164	$57,317,664	$0	$303,493	$8,930,206	$0	$182,234	$3,958,347	$0	$184,000	$5,401,271	$0	$18,161	$529,595	$0
Other Power Generation Maintenance Expense																		
551 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$256,698	$256,698	$0	$0	$39,028	$0	$0	$23,434	$0	$0	$23,662	$0	$0	$2,335	$0	$0
552 MAINTENANCE OF STRUCTURES	Prod	24	$560,673	$560,673	$0	$0	$85,244	$0	$0	$51,185	$0	$0	$51,681	$0	$0	$5,101	$0	$0
553 MAINTENANCE OF GENERATING & ELEC PLANT	Prod	24	$2,652,503	$2,652,503	$0	$0	$403,281	$0	$0	$242,152	$0	$0	$244,500	$0	$0	$24,132	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	Prod	24	$1,112,788	$1,112,788	$0	$0	$169,186	$0	$0	$101,589	$0	$0	$102,573	$0	$0	$10,124	$0	$0
Total Other Power Generation Maintenance Expense			$4,582,662	$4,582,662	$0	$0	$696,739	$0	$0	$418,360	$0	$0	$422,416	$0	$0	$41,693	$0	$0
Total Other Power Generation Expense			$63,896,490	$6,578,826	$57,317,664	$0	$1,000,232	$8,930,206	$0	$600,594	$3,958,347	$0	$606,416	$5,401,271	$0	$59,854	$529,595	$0
Total Station Expense			$455,155,389	$47,632,454	$407,522,935	$0	$6,658,027	$63,537,217	$0	$4,195,055	$28,133,189	$0	$3,963,143	$38,464,900	$0	$405,282	$3,769,128	$0
Other Power Supply Expenses																		
555 PURCHASED POWER	PURCPWF	46	$53,937,678	$16,216,788	$37,720,890	$0	$2,017,708	$5,907,102	$0	$1,362,801	$2,598,024	$0	$1,166,945	$3,596,973	$0	$126,004	$351,083	$0
555 PURCHASED POWER OPTIONS			$0	$0	$0	$0												
555 BROKERAGE FEES			$0	$0	$0	$0												
555 MISO TRANSMISSION EXPENSES			$0	$0	$0	$0												
556 SYSTEM CONTROL AND LOAD DISPATCH	Prod	24	$1,248,388	$1,248,388	$0	$0	$189,802	$0	$0	$113,968	$0	$0	$115,073	$0	$0	$11,358	$0	$0
557 OTHER EXPENSES	Prod	24	$3,807	$3,807	$0	$0	$579	$0	$0	$348	$0	$0	$351	$0	$0	$35	$0	$0
Total Other Power Supply Expenses			$55,189,873	$17,468,983	$37,720,890	$0	$2,208,089	$5,907,102	$0	$1,477,116	$2,598,024	$0	$1,282,369	$3,596,973	$0	$137,397	$351,083	$0
Total Electric Power Generation Expenses			$510,345,262	$65,101,437	$445,243,825	$0	$8,866,116	$69,444,320	$0	$5,672,171	$30,731,213	$0	$5,245,512	$42,061,873	$0	$542,679	$4,120,211	$0
Transmission Expenses																		
560 OPERATION SUPERVISION AND ENG	Trans	25	$1,013,327	$1,013,327	$0	$0	$121,601	$0	$0	$72,200	$0	$0	$74,786	$0	$0	$7,539	$0	$0
561 LOAD DISPATCHING	Trans	25	$2,208,583	$2,208,583	$0	$0	$265,033	$0	$0	$157,363	$0	$0	$162,999	$0	$0	$16,431	$0	$0
562 STATION EXPENSES	Trans	25	$928,949	$928,949	$0	$0	$111,475	$0	$0	$66,188	$0	$0	$68,559	$0	$0	$6,911	$0	$0
563 OVERHEAD LINE EXPENSES	Trans	25	$244,298	$244,298	$0	$0	$29,316	$0	$0	$17,406	$0	$0	$18,030	$0	$0	$1,818	$0	$0
565 TRANSMISSION OF ELECTRICITY BY OTHERS	Trans	25	$36,638	$36,638	$0	$0	$4,397	$0	$0	$2,610	$0	$0	$2,704	$0	$0	$273	$0	$0
566 MISC. TRANSMISSION EXPENSES	Trans	25	$6,948,940	$6,948,940	$0	$0	$833,883	$0	$0	$495,117	$0	$0	$512,850	$0	$0	$51,698	$0	$0
567 RENTS	Trans	25	$67,500	$67,500	$0	$0	$8,100	$0	$0	$4,809	$0	$0	$4,982	$0	$0	$502	$0	$0
568 MAINTENACE SUPERVISION AND ENG			$0	$0	$0	$0												
569 STRUCTURES			$0	$0	$0	$0												
570 MAINT OF STATION EQUIPMENT	Trans	25	$1,490,332	$1,490,332	$0	$0	$178,842	$0	$0	$106,187	$0	$0	$109,990	$0	$0	$11,088	$0	$0
571 MAINT OF OVERHEAD LINES	Trans	25	$3,342,881	$3,342,881	$0	$0	$401,151	$0	$0	$238,183	$0	$0	$246,713	$0	$0	$24,870	$0	$0
572 UNDERGROUND LINES			$0	$0	$0	$0												
573 MISC PLANT	Trans	25	$228,063	$228,063	$0	$0	$27,368	$0	$0	$16,250	$0	$0	$16,832	$0	$0	$1,697	$0	$0
575 MISO DAY 1&2 EXPENSE			$0	$0	$0	$0												
Total Transmission Expenses			$16,509,511	$16,509,511	$0	$0	$1,981,167	$0	$0	$1,176,315	$0	$0	$1,218,445	$0	$0	$122,827	$0	$0

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Class Allocation

	Allocation Factor			Total Kentucky			Special Contract 2			Street Lighting (RLS, LS, DSK)			Street Lighting-LE			Traffic Street Lighting (TLE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Hydraulic Power Generation Operation Expenses																		
535 OPERATION SUPERVISION & ENGINEERING	Prod	24	$121,406	$121,406	$0	$0	$598	$0	$0	$1,012	$0	$0	$33	$0	$0	$33	$0	$0
536 WATER FOR POWER	Prod	24	$40,614	$40,614	$0	$0	$200	$0	$0	$339	$0	$0	$11	$0	$0	$11	$0	$0
537 HYDRAULIC EXPENSES			$0	$0	$0	$0												
538 ELECTRIC EXPENSES	Prod	24	$180,161	$180,161	$0	$0	$888	$0	$0	$1,502	$0	$0	$49	$0	$0	$48	$0	$0
539 MISC. HYDRAULIC POWER EXPENSES	Prod	24	$348,792	$348,792	$0	$0	$1,719	$0	$0	$2,908	$0	$0	$95	$0	$0	$94	$0	$0
540 RENTS	Prod	24	$545,400	$545,400	$0	$0	$2,688	$0	$0	$4,547	$0	$0	$148	$0	$0	$147	$0	$0
Total Hydraulic Power Operation Expenses			$1,236,373	$1,236,373	$0	$0	$6,094	$0	$0	$10,308	$0	$0	$336	$0	$0	$333	$0	$0
Hydraulic Power Generation Maintenance Expenses																		
541 MAINTENANCE SUPERVISION & ENGINEERING	LBSUB4	38	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
542 MAINTENANCE OF STRUCTURES	Prod	24	$244,992	$244,992	$0	$0	$1,208	$0	$0	$2,042	$0	$0	$67	$0	$0	$66	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	Prod	24	$190,785	$190,785	$0	$0	$940	$0	$0	$1,591	$0	$0	$52	$0	$0	$51	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$371,119	$0	$371,119	$0	$0	$1,825	$0	$0	$3,269	$0	$0	$107	$0	$0	$100	$0
545 MAINTENANCE OF MISC HYDRAULIC PLANT	Energy	2	$58,972	$0	$58,972	$0	$0	$290	$0	$0	$519	$0	$0	$17	$0	$0	$16	$0
Total Hydraulic Power Generation Maint. Expense			$865,868	$435,777	$430,091	$0	$2,148	$2,115	$0	$3,633	$3,788	$0	$119	$123	$0	$117	$116	$0
Total Hydraulic Power Generation Expense			$2,102,241	$1,672,150	$430,091	$0	$8,242	$2,115	$0	$13,941	$3,788	$0	$455	$123	$0	$450	$116	$0
Other Power Generation Operation Expense																		
546 OPERATION SUPERVISION & ENGINEERING	LBSUB5	39	$604,185	$604,185	$0	$0	$2,978	$0	$0	$5,037	$0	$0	$164	$0	$0	$163	$0	$0
547 FUEL	TDFUEL	51	$57,317,664	$0	$57,317,664	$0	$0	$287,961	$0	$0	$500,735	$0	$0	$16,303	$0	$0	$15,797	$0
548 GENERATION EXPENSE	Prod	24	$280,735	$280,735	$0	$0	$1,384	$0	$0	$2,340	$0	$0	$76	$0	$0	$76	$0	$0
549 MISC OTHER POWER GENERATION	Prod	24	$1,105,538	$1,105,538	$0	$0	$5,449	$0	$0	$9,217	$0	$0	$301	$0	$0	$297	$0	$0
550 RENTS	Prod	24	$5,706	$5,706	$0	$0	$28	$0	$0	$48	$0	$0	$2	$0	$0	$2	$0	$0
Total Other Power Generation Expenses			$59,313,828	$1,996,164	$57,317,664	$0	$9,839	$287,961	$0	$16,642	$500,735	$0	$543	$16,303	$0	$537	$15,797	$0
Other Power Generation Maintenance Expense																		
551 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$256,698	$256,698	$0	$0	$1,265	$0	$0	$2,140	$0	$0	$70	$0	$0	$69	$0	$0
552 MAINTENANCE OF STRUCTURES	Prod	24	$560,673	$560,673	$0	$0	$2,764	$0	$0	$4,674	$0	$0	$153	$0	$0	$151	$0	$0
553 MAINTENANCE OF GENERATING & ELEC PLANT	Prod	24	$2,652,503	$2,652,503	$0	$0	$13,074	$0	$0	$22,114	$0	$0	$721	$0	$0	$714	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	Prod	24	$1,112,788	$1,112,788	$0	$0	$5,485	$0	$0	$9,277	$0	$0	$303	$0	$0	$299	$0	$0
Total Other Power Generation Maintenance Expense			$4,582,662	$4,582,662	$0	$0	$22,588	$0	$0	$38,206	$0	$0	$1,246	$0	$0	$1,233	$0	$0
Total Other Power Generation Expense			$63,896,490	$6,578,826	$57,317,664	$0	$32,427	$287,961	$0	$54,848	$500,735	$0	$1,789	$16,303	$0	$1,770	$15,797	$0
Total Station Expense			$455,155,389	$47,632,454	$407,522,935	$0	$197,064	$2,041,435	$0	$220,840	$3,564,172	$0	$7,205	$116,061	$0	$10,103	$111,954	$0
Other Power Supply Expenses																		
555 PURCHASED POWER	PURCPWF	46	$53,937,678	$16,216,788	$37,720,890	$0	$51,004	$185,476	$0	$0	$332,247	$0	$0	$10,830	$0	$2,284	$10,149	$0
555 PURCHASED POWER OPTIONS			$0	$0	$0	$0												
555 BROKERAGE FEES			$0	$0	$0	$0												
555 MISO TRANSMISSION EXPENSES			$0	$0	$0	$0												
556 SYSTEM CONTROL AND LOAD DISPATCH	Prod	24	$1,248,388	$1,248,388	$0	$0	$6,153	$0	$0	$10,408	$0	$0	$340	$0	$0	$336	$0	$0
557 OTHER EXPENSES	Prod	24	$3,807	$3,807	$0	$0	$19	$0	$0	$32	$0	$0	$1	$0	$0	$1	$0	$0
Total Other Power Supply Expenses			$55,189,873	$17,468,983	$37,720,890	$0	$57,177	$185,476	$0	$10,440	$332,247	$0	$341	$10,830	$0	$2,621	$10,149	$0
Total Electric Power Generation Expenses			$510,345,262	$65,101,437	$445,243,825	$0	$254,241	$2,226,911	$0	$231,279	$3,896,419	$0	$7,546	$126,891	$0	$12,724	$122,102	$0
Transmission Expenses																		
560 OPERATION SUPERVISION AND ENG	Trans	25	$1,013,327	$1,013,327	$0	$0	$3,946	$0	$0	$7,773	$0	$0	$249	$0	$0	$113	$0	$0
561 LOAD DISPATCHING	Trans	25	$2,208,583	$2,208,583	$0	$0	$8,600	$0	$0	$16,942	$0	$0	$542	$0	$0	$247	$0	$0
562 STATION EXPENSES	Trans	25	$928,949	$928,949	$0	$0	$3,617	$0	$0	$7,126	$0	$0	$228	$0	$0	$104	$0	$0
563 OVERHEAD LINE EXPENSES	Trans	25	$244,298	$244,298	$0	$0	$951	$0	$0	$1,874	$0	$0	$60	$0	$0	$27	$0	$0
565 TRANSMISSION OF ELECTRICITY BY OTHERS	Trans	25	$36,638	$36,638	$0	$0	$143	$0	$0	$281	$0	$0	$9	$0	$0	$4	$0	$0
566 MISC. TRANSMISSION EXPENSES	Trans	25	$6,948,940	$6,948,940	$0	$0	$27,058	$0	$0	$53,305	$0	$0	$1,705	$0	$0	$776	$0	$0
567 RENTS	Trans	25	$67,500	$67,500	$0	$0	$263	$0	$0	$518	$0	$0	$17	$0	$0	$8	$0	$0
568 MAINTENACE SUPERVISION AND ENG			$0	$0	$0	$0												
569 STRUCTURES			$0	$0	$0	$0												
570 MAINT OF STATION EQUIPMENT	Trans	25	$1,490,332	$1,490,332	$0	$0	$5,803	$0	$0	$11,432	$0	$0	$366	$0	$0	$166	$0	$0
571 MAINT OF OVERHEAD LINES	Trans	25	$3,342,881	$3,342,881	$0	$0	$13,017	$0	$0	$25,643	$0	$0	$820	$0	$0	$373	$0	$0
572 UNDERGROUND LINES			$0	$0	$0	$0												
573 MISC PLANT	Trans	25	$228,063	$228,063	$0	$0	$888	$0	$0	$1,749	$0	$0	$56	$0	$0	$25	$0	$0
575 MISO DAY 1&2 EXPENSE			$0	$0	$0	$0												
Total Transmission Expenses			$16,509,511	$16,509,511	$0	$0	$64,286	$0	$0	$126,643	$0	$0	$4,051	$0	$0	$1,844	$0	$0

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Residential (RS)			General Service (GS)			Power Service-Primary (PS-Pri)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Expense																		
580 OPERATION SUPERVISION AND ENGI	LBDO	40	$1,814,624	$880,033	$0	$934,591	$448,414	$0	$653,828	$122,186	$0	$176,717	$9,788	$0	$6,384	$116,247	$0	$44,498
581 LOAD DISPATCHING	Acct362	29	$741,674	$741,674	$0	$0	$355,854	$0	$0	$102,432	$0	$0	$9,101	$0	$0	$105,633	$0	$0
582 STATION EXPENSES	Acct362	29	$1,941,657	$1,941,657	$0	$0	$931,604	$0	$0	$268,159	$0	$0	$23,826	$0	$0	$276,542	$0	$0
583 OVERHEAD LINE EXPENSES	Acct365	30	$5,880,672	$4,947,130	$0	$933,542	$2,604,959	$0	$811,118	$693,194	$0	$100,774	$52,809	$0	$0	$612,925	$0	$0
584 UNDERGROUND LINE EXPENSES	Acct367	31	$535,725	$494,688	$0	$41,037	$245,514	$0	$35,655	$68,672	$0	$4,430	$5,792	$0	$0	$67,221	$0	$0
585 STREET LIGHTING EXPENSE			$0	$0	$0	$0												
586 METER EXPENSES	C03	21	$8,277,541	$0	$0	$8,277,541	$0	$0	$5,793,616	$0	$0	$1,703,352	$0	$0	$66,311	$0	$0	$458,220
586 METER EXPENSES - LOAD MANAGEMENT			$0	$0	$0	$0												
587 CUSTOMER INSTALLATIONS EXPENSE	Dist	26	-$79,200	-$58,136	$0	-$21,064	-$30,627	$0	-$12,152	-$8,029	$0	-$1,982	-$591	$0	-$19	-$7,509	$0	-$223
588 MISCELLANEOUS DISTRIBUTION EXP	Dist	26	$5,593,730	$4,106,030	$0	$1,487,700	$2,163,119	$0	$858,254	$567,094	$0	$139,980	$41,773	$0	$1,314	$530,374	$0	$15,762
588 MISC DISTR EXP -- MAPPIN			$0	$0	$0	$0												
589 RENTS	Dist	26	$8,165	$5,993	$0	$2,172	$3,157	$0	$1,253	$828	$0	$204	$61	$0	$2	$774	$0	$23
Total Distribution Operation Expense			$24,714,588	$13,059,070	$0	$11,655,518	$6,721,995	$0	$8,141,573	$1,814,535	$0	$2,123,476	$142,558	$0	$73,993	$1,702,207	$0	$518,280
Distribution Maintenance Expense																		
590 MAINTENANCE SUPERVISION AND ENG	LBDM	41	$77,850	$66,429	$0	$11,421	$34,671	$0	$9,778	$9,273	$0	$1,215	$714	$0	$0	$8,411	$0	$5
591 STRUCTURES			$0	$0	$0	$0												
592 MAINTENANCE OF STATION EQUIPME	Acct362	29	$1,167,866	$1,167,866	$0	$0	$560,340	$0	$0	$161,292	$0	$0	$14,331	$0	$0	$166,334	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct365	30	$23,665,349	$19,908,532	$0	$3,756,817	$10,483,032	$0	$3,264,150	$2,789,591	$0	$405,539	$212,516	$0	$0	$2,466,571	$0	$0
594 MAINTENANCE OF UNDERGROUND LIN	Acct367	31	$1,604,057	$1,481,186	$0	$122,871	$735,114	$0	$106,758	$205,616	$0	$13,264	$17,341	$0	$0	$201,272	$0	$0
595 MAINTENANCE OF LINE TRANSFORMERS	Acct368	32	$334,735	$196,978	$0	$137,757	$136,663	$0	$118,813	$25,009	$0	$14,761	$0	$0	$0	$22,025	$0	$922
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	C04	22	$355,341	$0	$0	$355,341	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
597 MAINTENANCE OF METERS	C03	21	$1,427,898	$0	$0	$1,427,898	$0	$0	$999,414	$0	$0	$293,833	$0	$0	$11,439	$0	$0	$79,044
598 MISCELLANEOUS DISTRIBUTION EXPENSES	Dist	26	$671,832	$493,153	$0	$178,679	$259,800	$0	$103,080	$68,111	$0	$16,812	$5,017	$0	$158	$63,700	$0	$1,893
Total Distribution Maintenance Expense			$29,304,928	$23,314,143	$0	$5,990,785	$12,209,621	$0	$4,601,993	$3,258,892	$0	$745,424	$249,920	$0	$11,597	$2,928,314	$0	$81,864
Total Distribution Expense			$54,019,516	$36,373,213	$0	$17,646,303	$18,931,616	$0	$12,743,566	$5,073,427	$0	$2,868,899	$392,479	$0	$85,589	$4,630,521	$0	$600,143
Customer Accounts Expense																		
901 SUPERVISION/CUSTOMER ACCTS	C05	33	$1,267,537	$0	$0	$1,267,537	$0	$0	$944,471	$0	$0	$234,683	$0	$0	$934	$0	$0	$36,629
902 METER READING EXPENSES	MREAD	50	$2,546,374	$0	$0	$2,546,374	$0	$0	$1,931,450	$0	$0	$479,928	$0	$0	$1,910	$0	$0	$74,906
903 RECORDS AND COLLECTION	C05	33	$7,699,624	$0	$0	$7,699,624	$0	$0	$5,737,170	$0	$0	$1,425,575	$0	$0	$5,672	$0	$0	$222,501
904 UNCOLLECTIBLE ACCOUNTS	C05	33	$2,477,177	$0	$0	$2,477,177	$0	$0	$1,845,802	$0	$0	$458,646	$0	$0	$1,825	$0	$0	$71,585
905 MISC CUST ACCOUNTS	C05	33	$1,288	$0	$0	$1,288	$0	$0	$960	$0	$0	$238	$0	$0	$1	$0	$0	$37
Total Customer Accounts Expense			$13,992,000	$0	$0	$13,992,000	$0	$0	$10,459,853	$0	$0	$2,599,070	$0	$0	$10,342	$0	$0	$405,658
Customer Service Expense																		
907 SUPERVISION	C05	33	$364,585	$0	$0	$364,585	$0	$0	$271,661	$0	$0	$67,502	$0	$0	$269	$0	$0	$10,536
908 CUSTOMER ASSISTANCE EXPENSES	C05	33	$289,821	$0	$0	$289,821	$0	$0	$215,952	$0	$0	$53,660	$0	$0	$214	$0	$0	$8,375
908 CUSTOMER ASSISTANCE EXP-INCENTIVES			$0	$0	$0	$0												
909 INFORMATIONAL AND INSTRUCTIONA	C05	33	$257,472	$0	$0	$257,472	$0	$0	$191,848	$0	$0	$47,671	$0	$0	$190	$0	$0	$7,440
909 INFORM AND INSTRUC -LOAD MGMT			$0	$0	$0	$0												
910 MISCELLANEOUS CUSTOMER SERVICE	C05	33	$823,663	$0	$0	$823,663	$0	$0	$613,731	$0	$0	$152,500	$0	$0	$607	$0	$0	$23,802
911 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
912 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
913 ADVERTISING EXPENSES	C05	33	$950,847	$0	$0	$950,847	$0	$0	$708,498	$0	$0	$176,048	$0	$0	$701	$0	$0	$27,477
916 MISC SALES EXPENSE			$0	$0	$0	$0												
Total Customer Service Expense			$2,686,388	$0	$0	$2,686,388	$0	$0	$2,001,690	$0	$0	$497,381	$0	$0	$1,979	$0	$0	$77,630
Administrative and General Expense																		
920 ADMIN. & GEN. SALARIES-	LBSUB7	35	$27,330,835	$14,754,105	$6,907,180	$5,669,550	$5,993,550	$2,500,573	$4,138,193	$1,808,412	$812,633	$1,040,620	$187,250	$96,630	$19,589	$2,188,974	$1,120,828	$204,689
921 OFFICE SUPPLIES AND EXPENSES	LBSUB7	35	$5,910,353	$3,190,608	$1,493,693	$1,226,053	$1,296,118	$540,754	$894,893	$391,073	$175,734	$225,036	$40,493	$20,896	$4,236	$473,370	$242,382	$44,264
922 ADMINISTRATIVE EXPENSES TRANSFERRED	LBSUB7	35	-$4,320,827	-$2,332,528	-$1,091,980	-$896,319	-$947,541	-$395,324	-$654,221	-$285,898	-$128,472	-$164,515	-$29,603	-$15,277	-$3,097	-$346,063	-$177,196	-$32,360
923 OUTSIDE SERVICES EMPLOYED	LBSUB7	35	$15,873,533	$8,569,068	$4,011,635	$3,292,830	$3,481,007	$1,452,313	$2,403,430	$1,050,311	$471,971	$604,384	$108,753	$56,122	$11,377	$1,271,339	$650,968	$118,882
924 PROPERTY INSURANCE	TUP	34	$4,610,558	$4,204,592	$0	$405,966	$1,727,229	$0	$234,202	$514,987	$0	$38,198	$52,352	$0	$359	$621,667	$0	$4,301
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	35	$2,835,056	$1,530,459	$716,489	$588,108	$621,717	$259,387	$429,259	$187,588	$84,295	$107,945	$19,424	$10,024	$2,032	$227,065	$116,265	$21,233
926 EMPLOYEE BENEFITS	LBSUB7	35	$29,197,096	$15,761,576	$7,378,830	$6,056,690	$6,402,814	$2,671,323	$4,420,765	$1,931,897	$868,122	$1,111,678	$200,036	$103,228	$20,927	$2,338,446	$1,197,363	$218,666
928 REGULATORY COMMISSION FEES	TUP	34	$1,404,080	$1,280,449	$0	$123,631	$526,003	$0	$71,323	$156,832	$0	$11,633	$15,943	$0	$109	$189,320	$0	$1,310
929 DUPLICATE CHARGES	LBSUB7	35	-$229,428	-$123,853	-$57,982	-$47,593	-$50,313	-$20,991	-$34,738	-$15,181	-$6,822	-$8,735	-$1,572	-$811	-$164	-$18,375	-$9,409	-$1,718
930 MISCELLANEOUS GENERAL EXPENSES	LBSUB7	35	$3,716,685	$2,006,392	$939,298	$770,995	$815,055	$340,050	$562,747	$245,924	$110,509	$141,513	$25,464	$13,141	$2,664	$297,676	$152,420	$27,835
931 RENTS AND LEASES	PT&D	23	$1,123,825	$1,024,739	$0	$99,086	$421,137	$0	$57,163	$125,538	$0	$9,323	$12,755	$0	$88	$151,467	$0	$1,050
935 MAINTENANCE OF GENERAL PLANT	PT&D	23	$617,459	$563,019	$0	$54,440	$231,384	$0	$31,407	$68,974	$0	$5,122	$7,008	$0	$48	$83,220	$0	$577
Total Administrative and General Expense			$88,069,225	$50,428,626	$20,297,163	$17,343,436	$20,518,160	$7,348,086	$12,554,422	$6,180,457	$2,387,970	$3,122,201	$638,302	$283,953	$58,167	$7,478,107	$3,293,621	$608,728
Total Operation and Maintenance Expenses			$685,621,902	$168,412,787	$465,540,988	$51,668,127	$71,224,865	$168,858,066	$37,759,532	$21,827,190	$54,881,944	$9,087,551	$2,032,252	$6,496,720	$156,077	$24,841,867	$75,590,783	$1,692,159
Total Operation and Maintenance Exp. Less Purchased Power			$631,684,224	$152,195,999	$427,820,098	$51,668,127	$64,883,285	$155,211,477	$37,759,532	$19,535,501	$50,447,291	$9,087,551	$1,843,254	$5,968,546	$156,077	$22,174,093	$69,471,194	$1,692,159

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Class Allocation

	Allocation Factor			Total Kentucky			Time of Day-Pri (TOD-Pri)			Time of Day-Sec (TOD-Sec)			Retail Transmission (RTS)			Special Contract 1		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Expense																		
580 OPERATION SUPERVISION AND ENGI	LBDO	40	$1,814,624	$880,033	$0	$934,591	$103,346	$0	$9,996	$62,813	$0	$4,692	$0	$0	$8,176	$6,407	$0	$95
581 LOAD DISPATCHING	Acct362	29	$741,674	$741,674	$0	$0	$96,094	$0	$0	$57,056	$0	$0	$0	$0	$0	$5,958	$0	$0
582 STATION EXPENSES	Acct362	29	$1,941,657	$1,941,657	$0	$0	$251,568	$0	$0	$149,368	$0	$0	$0	$0	$0	$15,597	$0	$0
583 OVERHEAD LINE EXPENSES	Acct365	30	$5,880,672	$4,947,130	$0	$933,542	$557,574	$0	$0	$331,059	$0	$0	$0	$0	$0	$34,568	$0	$0
584 UNDERGROUND LINE EXPENSES	Acct367	31	$535,725	$494,688	$0	$41,037	$61,151	$0	$0	$36,308	$0	$0	$0	$0	$0	$3,791	$0	$0
585 STREET LIGHTING EXPENSE			$0	$0	$0	$0												
586 METER EXPENSES	C03	21	$8,277,541	$0	$0	$8,277,541	$0	$0	$103,833	$0	$0	$48,275	$0	$0	$84,936	$0	$0	$985
586 METER EXPENSES - LOAD MANAGEMENT			$0	$0	$0	$0												
587 CUSTOMER INSTALLATIONS EXPENSE	Dist	26	-$79,200	-$58,136	$0	-$21,064	-$6,245	$0	-$29	-$4,062	$0	-$25	$0	$0	-$24	-$387	$0	$0
588 MISCELLANEOUS DISTRIBUTION EXP	Dist	26	$5,593,730	$4,106,030	$0	$1,487,700	$441,050	$0	$2,058	$286,900	$0	$1,737	$0	$0	$1,684	$27,344	$0	$20
588 MISC DISTR EXP -- MAPPIN			$0	$0	$0	$0												
589 RENTS	Dist	26	$8,165	$5,993	$0	$2,172	$644	$0	$3	$419	$0	$3	$0	$0	$2	$40	$0	$0
Total Distribution Operation Expense			$24,714,588	$13,059,070	$0	$11,655,518	$1,505,182	$0	$115,861	$919,861	$0	$54,682	$0	$0	$94,774	$93,317	$0	$1,099
Distribution Maintenance Expense																		
590 MAINTENANCE SUPERVISION AND ENG	LBDM	41	$77,850	$66,429	$0	$11,421	$7,541	$0	$0	$4,544	$0	$0	$0	$0	$0	$468	$0	$0
591 STRUCTURES			$0	$0	$0	$0												
592 MAINTENANCE OF STATION EQUIPME	Acct362	29	$1,167,866	$1,167,866	$0	$0	$151,313	$0	$0	$89,842	$0	$0	$0	$0	$0	$9,381	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct365	30	$23,665,349	$19,908,532	$0	$3,756,817	$2,243,823	$0	$0	$1,332,267	$0	$0	$0	$0	$0	$139,111	$0	$0
594 MAINTENANCE OF UNDERGROUND LIN	Acct367	31	$1,604,057	$1,481,186	$0	$122,871	$183,096	$0	$0	$108,713	$0	$0	$0	$0	$0	$11,351	$0	$0
595 MAINTENANCE OF LINE TRANSFORMERS	Acct368	32	$334,735	$196,978	$0	$137,757	$0	$0	$0	$12,104	$0	$90	$0	$0	$0	$0	$0	$0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	C04	22	$355,341	$0	$0	$355,341	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
597 MAINTENANCE OF METERS	C03	21	$1,427,898	$0	$0	$1,427,898	$0	$0	$17,912	$0	$0	$8,328	$0	$0	$14,652	$0	$0	$170
598 MISCELLANEOUS DISTRIBUTION EXPENSES	Dist	26	$671,832	$493,153	$0	$178,679	$52,972	$0	$247	$34,458	$0	$209	$0	$0	$202	$3,284	$0	$2
Total Distribution Maintenance Expense			$29,304,928	$23,314,143	$0	$5,990,785	$2,638,745	$0	$18,159	$1,581,928	$0	$8,627	$0	$0	$14,854	$163,595	$0	$172
Total Distribution Expense			$54,019,516	$36,373,213	$0	$17,646,303	$4,143,927	$0	$134,020	$2,501,789	$0	$63,309	$0	$0	$109,628	$256,912	$0	$1,271
Customer Accounts Expense																		
901 SUPERVISION/CUSTOMER ACCTS	C05	33	$1,267,537	$0	$0	$1,267,537	$0	$0	$6,843	$0	$0	$17,898	$0	$0	$843	$0	$0	$13
902 METER READING EXPENSES	MREAD	50	$2,546,374	$0	$0	$2,546,374	$0	$0	$13,994	$0	$0	$36,602	$0	$0	$1,724	$0	$0	$27
903 RECORDS AND COLLECTION	C05	33	$7,699,624	$0	$0	$7,699,624	$0	$0	$41,566	$0	$0	$108,721	$0	$0	$5,121	$0	$0	$79
904 UNCOLLECTIBLE ACCOUNTS	C05	33	$2,477,177	$0	$0	$2,477,177	$0	$0	$13,373	$0	$0	$34,979	$0	$0	$1,648	$0	$0	$25
905 MISC CUST ACCOUNTS	C05	33	$1,288	$0	$0	$1,288	$0	$0	$7	$0	$0	$18	$0	$0	$1	$0	$0	$0
Total Customer Accounts Expense			$13,992,000	$0	$0	$13,992,000	$0	$0	$75,783	$0	$0	$198,218	$0	$0	$9,336	$0	$0	$144
Customer Service Expense																		
907 SUPERVISION	C05	33	$364,585	$0	$0	$364,585	$0	$0	$1,968	$0	$0	$5,148	$0	$0	$242	$0	$0	$4
908 CUSTOMER ASSISTANCE EXPENSES	C05	33	$289,821	$0	$0	$289,821	$0	$0	$1,565	$0	$0	$4,092	$0	$0	$193	$0	$0	$3
908 CUSTOMER ASSISTANCE EXP-INCENTIVES			$0	$0	$0	$0												
909 INFORMATIONAL AND INSTRUCTIONA	C05	33	$257,472	$0	$0	$257,472	$0	$0	$1,390	$0	$0	$3,636	$0	$0	$171	$0	$0	$3
909 INFORM AND INSTRUC -LOAD MGMT			$0	$0	$0	$0												
910 MISCELLANEOUS CUSTOMER SERVICE	C05	33	$823,663	$0	$0	$823,663	$0	$0	$4,447	$0	$0	$11,630	$0	$0	$548	$0	$0	$8
911 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
912 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
913 ADVERTISING EXPENSES	C05	33	$950,847	$0	$0	$950,847	$0	$0	$5,133	$0	$0	$13,426	$0	$0	$632	$0	$0	$10
916 MISC SALES EXPENSE			$0	$0	$0	$0												
Total Customer Service Expense			$2,686,388	$0	$0	$2,686,388	$0	$0	$14,502	$0	$0	$37,933	$0	$0	$1,787	$0	$0	$27
Administrative and General Expense																		
920 ADMIN. & GEN. SALARIES-	LBSUB7	35	$27,330,835	$14,754,105	$6,907,180	$5,669,550	$2,051,134	$1,080,552	$42,826	$1,232,730	$475,990	$53,284	$973,326	$657,083	$24,293	$124,132	$64,193	$289
921 OFFICE SUPPLIES AND EXPENSES	LBSUB7	35	$5,910,353	$3,190,608	$1,493,693	$1,226,053	$443,562	$233,672	$9,261	$266,581	$102,934	$11,523	$210,484	$142,096	$5,253	$26,844	$13,882	$62
922 ADMINISTRATIVE EXPENSES TRANSFERRED	LBSUB7	35	-$4,320,827	-$2,332,528	-$1,091,980	-$896,319	-$324,271	-$170,828	-$6,770	-$194,887	-$75,251	-$8,424	-$153,876	-$103,881	-$3,841	-$19,624	-$10,149	-$46
923 OUTSIDE SERVICES EMPLOYED	LBSUB7	35	$15,873,533	$8,569,068	$4,011,635	$3,292,830	$1,191,282	$627,576	$24,873	$715,960	$276,451	$30,947	$565,300	$381,629	$14,109	$72,095	$37,283	$168
924 PROPERTY INSURANCE	TUP	34	$4,610,558	$4,204,592	$0	$405,966	$573,526	$0	$562	$350,004	$0	$474	$275,262	$0	$459	$34,707	$0	$5
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	35	$2,835,056	$1,530,459	$716,489	$588,108	$212,766	$112,087	$4,442	$127,872	$49,375	$5,527	$100,964	$68,160	$2,520	$12,876	$6,659	$30
926 EMPLOYEE BENEFITS	LBSUB7	35	$29,197,096	$15,761,576	$7,378,830	$6,056,690	$2,191,194	$1,154,336	$45,750	$1,316,906	$508,492	$56,923	$1,039,788	$701,952	$25,952	$132,608	$68,577	$309
928 REGULATORY COMMISSION FEES	TUP	34	$1,404,080	$1,280,449	$0	$123,631	$174,659	$0	$171	$106,589	$0	$144	$83,827	$0	$140	$10,569	$0	$2
929 DUPLICATE CHARGES	LBSUB7	35	-$229,428	-$123,853	-$57,982	-$47,593	-$17,218	-$9,071	-$359	-$10,348	-$3,996	-$447	-$8,171	-$5,516	-$204	-$1,042	-$539	-$2
930 MISCELLANEOUS GENERAL EXPENSES	LBSUB7	35	$3,716,685	$2,006,392	$939,298	$770,995	$278,931	$146,943	$5,824	$167,637	$64,729	$7,246	$132,361	$89,356	$3,304	$16,881	$8,730	$39
931 RENTS AND LEASES	PT&D	23	$1,123,825	$1,024,739	$0	$99,086	$139,723	$0	$137	$85,270	$0	$116	$67,028	$0	$112	$8,456	$0	$1
935 MAINTENANCE OF GENERAL PLANT	PT&D	23	$617,459	$563,019	$0	$54,440	$76,767	$0	$75	$46,849	$0	$64	$36,827	$0	$62	$4,646	$0	$1
Total Administrative and General Expense			$88,069,225	$50,428,626	$20,297,163	$17,343,436	$6,992,056	$3,175,267	$126,791	$4,211,164	$1,398,724	$157,376	$3,323,120	$1,930,879	$72,161	$423,147	$188,636	$858
Total Operation and Maintenance Expenses			$685,621,902	$168,412,787	$465,540,988	$51,668,127	$21,983,265	$72,619,587	$351,096	$13,561,439	$32,129,938	$456,836	$9,787,076	$43,992,752	$192,912	$1,345,565	$4,308,846	$2,301
Total Operation and Maintenance Exp. Less Purchased Power			$631,684,224	$152,195,999	$427,820,098	$51,668,127	$19,965,557	$66,712,484	$351,096	$12,198,638	$29,531,914	$456,836	$8,620,131	$40,395,779	$192,912	$1,219,560	$3,957,764	$2,301

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Class Allocation

	Allocation Factor			Total Kentucky			Special Contract 2			Street Lighting (RLS, LS, DSK)			Street Lighting-LE			Traffic Street Lighting (TLE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Expense																		
580 OPERATION SUPERVISION AND ENGI	LBDO	40	$1,814,624	$880,033	$0	$934,591	$3,353	$0	$95	$7,146	$0	$28,441	$229	$0	$257	$104	$0	$1,411
581 LOAD DISPATCHING	Acct362	29	$741,674	$741,674	$0	$0	$3,118	$0	$0	$6,143	$0	$0	$196	$0	$0	$89	$0	$0
582 STATION EXPENSES	Acct362	29	$1,941,657	$1,941,657	$0	$0	$8,163	$0	$0	$16,081	$0	$0	$514	$0	$0	$234	$0	$0
583 OVERHEAD LINE EXPENSES	Acct365	30	$5,880,672	$4,947,130	$0	$933,542	$18,092	$0	$0	$40,083	$0	$21,386	$1,282	$0	$40	$584	$0	$225
584 UNDERGROUND LINE EXPENSES	Acct367	31	$535,725	$494,688	$0	$41,037	$1,984	$0	$0	$4,066	$0	$940	$130	$0	$2	$59	$0	$10
585 STREET LIGHTING EXPENSE			$0	$0	$0	$0												
586 METER EXPENSES	C03	21	$8,277,541	$0	$0	$8,277,541	$0	$0	$985	$0	$0	$0	$0	$0	$2,624	$0	$0	$14,403
586 METER EXPENSES - LOAD MANAGEMENT			$0	$0	$0	$0												
587 CUSTOMER INSTALLATIONS EXPENSE	Dist	26	-$79,200	-$58,136	$0	-$21,064	-$203	$0	$0	-$461	$0	-$6,603	-$15	$0	-$1	-$7	$0	-$7
588 MISCELLANEOUS DISTRIBUTION EXP	Dist	26	$5,593,730	$4,106,030	$0	$1,487,700	$14,311	$0	$20	$32,549	$0	$466,326	$1,041	$0	$83	$474	$0	$462
588 MISC DISTR EXP -- MAPPIN			$0	$0	$0	$0												
589 RENTS	Dist	26	$8,165	$5,993	$0	$2,172	$21	$0	$0	$48	$0	$681	$2	$0	$0	$1	$0	$1
Total Distribution Operation Expense			$24,714,588	$13,059,070	$0	$11,655,518	$48,841	$0	$1,099	$105,655	$0	$511,171	$3,380	$0	$3,005	$1,539	$0	$16,505
Distribution Maintenance Expense																		
590 MAINTENANCE SUPERVISION AND ENG	LBDM	41	$77,850	$66,429	$0	$11,421	$245	$0	$0	$537	$0	$420	$17	$0	$0	$8	$0	$3
591 STRUCTURES			$0	$0	$0	$0												
592 MAINTENANCE OF STATION EQUIPME	Acct362	29	$1,167,866	$1,167,866	$0	$0	$4,910	$0	$0	$9,672	$0	$0	$309	$0	$0	$141	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct365	30	$23,665,349	$19,908,532	$0	$3,756,817	$72,809	$0	$0	$161,304	$0	$86,062	$5,160	$0	$161	$2,349	$0	$905
594 MAINTENANCE OF UNDERGROUND LIN	Acct367	31	$1,604,057	$1,481,186	$0	$122,871	$5,941	$0	$0	$12,173	$0	$2,815	$389	$0	$5	$177	$0	$30
595 MAINTENANCE OF LINE TRANSFORMERS	Acct368	32	$334,735	$196,978	$0	$137,757	$0	$0	$0	$1,124	$0	$3,133	$36	$0	$6	$16	$0	$33
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	C04	22	$355,341	$0	$0	$355,341	$0	$0	$0	$0	$0	$355,341	$0	$0	$0	$0	$0	$0
597 MAINTENANCE OF METERS	C03	21	$1,427,898	$0	$0	$1,427,898	$0	$0	$170	$0	$0	$0	$0	$0	$453	$0	$0	$2,485
598 MISCELLANEOUS DISTRIBUTION EXPENSES	Dist	26	$671,832	$493,153	$0	$178,679	$1,719	$0	$2	$3,909	$0	$56,008	$125	$0	$10	$57	$0	$55
Total Distribution Maintenance Expense			$29,304,928	$23,314,143	$0	$5,990,785	$85,623	$0	$172	$188,720	$0	$503,777	$6,037	$0	$636	$2,748	$0	$3,511
Total Distribution Expense			$54,019,516	$36,373,213	$0	$17,646,303	$134,464	$0	$1,271	$294,374	$0	$1,014,948	$9,417	$0	$3,641	$4,287	$0	$20,016
Customer Accounts Expense																		
901 SUPERVISION/CUSTOMER ACCTS	C05	33	$1,267,537	$0	$0	$1,267,537	$0	$0	$13	$0	$0	$24,902	$0	$0	$47	$0	$0	$262
902 METER READING EXPENSES	MREAD	50	$2,546,374	$0	$0	$2,546,374	$0	$0	$27	$0	$0	$0	$0	$0	$934	$0	$0	$4,875
903 RECORDS AND COLLECTION	C05	33	$7,699,624	$0	$0	$7,699,624	$0	$0	$79	$0	$0	$151,265	$0	$0	$284	$0	$0	$1,591
904 UNCOLLECTIBLE ACCOUNTS	C05	33	$2,477,177	$0	$0	$2,477,177	$0	$0	$25	$0	$0	$48,666	$0	$0	$91	$0	$0	$512
905 MISC CUST ACCOUNTS	C05	33	$1,288	$0	$0	$1,288	$0	$0	$0	$0	$0	$25	$0	$0	$0	$0	$0	$0
Total Customer Accounts Expense			$13,992,000	$0	$0	$13,992,000	$0	$0	$144	$0	$0	$224,858	$0	$0	$1,355	$0	$0	$7,241
Customer Service Expense																		
907 SUPERVISION	C05	33	$364,585	$0	$0	$364,585	$0	$0	$4	$0	$0	$7,163	$0	$0	$13	$0	$0	$75
908 CUSTOMER ASSISTANCE EXPENSES	C05	33	$289,821	$0	$0	$289,821	$0	$0	$3	$0	$0	$5,694	$0	$0	$11	$0	$0	$60
908 CUSTOMER ASSISTANCE EXP-INCENTIVES			$0	$0	$0	$0												
909 INFORMATIONAL AND INSTRUCTIONA	C05	33	$257,472	$0	$0	$257,472	$0	$0	$3	$0	$0	$5,058	$0	$0	$9	$0	$0	$53
909 INFORM AND INSTRUC -LOAD MGMT			$0	$0	$0	$0												
910 MISCELLANEOUS CUSTOMER SERVICE	C05	33	$823,663	$0	$0	$823,663	$0	$0	$8	$0	$0	$16,181	$0	$0	$30	$0	$0	$170
911 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
912 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
913 ADVERTISING EXPENSES	C05	33	$950,847	$0	$0	$950,847	$0	$0	$10	$0	$0	$18,680	$0	$0	$35	$0	$0	$197
916 MISC SALES EXPENSE			$0	$0	$0	$0												
Total Customer Service Expense			$2,686,388	$0	$0	$2,686,388	$0	$0	$27	$0	$0	$52,776	$0	$0	$99	$0	$0	$555
Administrative and General Expense																		
920 ADMIN. & GEN. SALARIES-	LBSUB7	35	$27,330,835	$14,754,105	$6,907,180	$5,669,550	$66,515	$34,112	$289	$121,034	$60,738	$139,781	$3,921	$1,979	$878	$3,127	$1,868	$4,819
921 OFFICE SUPPLIES AND EXPENSES	LBSUB7	35	$5,910,353	$3,190,608	$1,493,693	$1,226,053	$14,384	$7,377	$62	$26,174	$13,135	$30,228	$848	$428	$190	$676	$404	$1,042
922 ADMINISTRATIVE EXPENSES TRANSFERRED	LBSUB7	35	-$4,320,827	-$2,332,528	-$1,091,980	-$896,319	-$10,516	-$5,393	-$46	-$19,135	-$9,602	-$22,098	-$620	-$313	-$139	-$494	-$295	-$762
923 OUTSIDE SERVICES EMPLOYED	LBSUB7	35	$15,873,533	$8,569,068	$4,011,635	$3,292,830	$38,632	$19,812	$168	$70,296	$35,276	$81,184	$2,277	$1,150	$510	$1,816	$1,085	$2,799
924 PROPERTY INSURANCE	TUP	34	$4,610,558	$4,204,592	$0	$405,966	$18,599	$0	$5	$34,267	$0	$127,252	$1,110	$0	$23	$882	$0	$126
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	35	$2,835,056	$1,530,459	$716,489	$588,108	$6,900	$3,538	$30	$12,555	$6,300	$14,500	$407	$205	$91	$324	$194	$500
926 EMPLOYEE BENEFITS	LBSUB7	35	$29,197,096	$15,761,576	$7,378,830	$6,056,690	$71,057	$36,442	$309	$129,299	$64,886	$149,326	$4,189	$2,115	$938	$3,341	$1,995	$5,148
928 REGULATORY COMMISSION FEES	TUP	34	$1,404,080	$1,280,449	$0	$123,631	$5,664	$0	$2	$10,436	$0	$38,753	$338	$0	$7	$269	$0	$38
929 DUPLICATE CHARGES	LBSUB7	35	-$229,428	-$123,853	-$57,982	-$47,593	-$558	-$286	-$2	-$1,016	-$510	-$1,173	-$33	-$17	-$7	-$26	-$16	-$40
930 MISCELLANEOUS GENERAL EXPENSES	LBSUB7	35	$3,716,685	$2,006,392	$939,298	$770,995	$9,045	$4,639	$39	$16,459	$8,260	$19,009	$533	$269	$119	$425	$254	$655
931 RENTS AND LEASES	PT&D	23	$1,123,825	$1,024,739	$0	$99,086	$4,531	$0	$1	$8,351	$0	$31,059	$270	$0	$6	$215	$0	$31
935 MAINTENANCE OF GENERAL PLANT	PT&D	23	$617,459	$563,019	$0	$54,440	$2,489	$0	$1	$4,588	$0	$17,065	$149	$0	$3	$118	$0	$17
Total Administrative and General Expense			$88,069,225	$50,428,626	$20,297,163	$17,343,436	$226,743	$100,241	$858	$413,307	$178,483	$624,883	$13,389	$5,817	$2,620	$10,673	$5,488	$14,373
Total Operation and Maintenance Expenses			$685,621,902	$168,412,787	$465,540,988	$51,668,127	$679,734	$2,327,152	$2,301	$1,065,604	$4,074,902	$1,917,465	$34,402	$132,708	$7,715	$29,529	$127,590	$42,184
Total Operation and Maintenance Exp. Less Purchased Power			$631,684,224	$152,195,999	$427,820,098	$51,668,127	$628,729	$2,141,676	$2,301	$1,065,604	$3,742,655	$1,917,465	$34,402	$121,878	$7,715	$27,245	$117,441	$42,184

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Residential (RS)			General Service (GS)			Power Service-Primary (PS-Pri)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Labor Expenses																		
Labor-Steam Power Generation Operation Expenses																		
500 OPERATION SUPERVISION & ENGINEERING	FO19	42	$3,138,068	$2,654,067	$484,001	$0	$940,339	$175,693	$0	$304,419	$57,106	$0	$36,204	$6,747	$0	$421,856	$78,609	$0
501 FUEL	TDFUEL	51	$2,187,724	$0	$2,187,724	$0	$0	$794,146	$0	$0	$258,125	$0	$0	$30,499	$0	$0	$355,318	$0
502 STEAM EXPENSES	Prod	24	$8,374,877	$8,374,877	$0	$0	$2,967,227	$0	$0	$960,590	$0	$0	$114,242	$0	$0	$1,331,162	$0	$0
505 ELECTRIC EXPENSES	Prod	24	$2,130,001	$2,130,001	$0	$0	$754,661	$0	$0	$244,309	$0	$0	$29,055	$0	$0	$338,557	$0	$0
506 MISC. STEAM POWER EXPENSES	Prod	24	$1,491,734	$1,491,734	$0	$0	$528,523	$0	$0	$171,100	$0	$0	$20,349	$0	$0	$237,107	$0	$0
507 RENTS			$0	$0	$0	$0												
Total Steam Power Operation Expenses			$17,322,404	$14,650,679	$2,671,725	$0	$5,190,750	$969,839	$0	$1,680,418	$315,231	$0	$199,850	$37,246	$0	$2,328,682	$433,927	$0
Labor-Steam Power Generation Maintenance Expenses																		
510 MAINTENANCE SUPERVISION & ENGINEERING	FO20	43	$3,390,539	$0	$3,390,539	$0	$0	$1,226,623	$0	$0	$398,608	$0	$0	$47,475	$0	$0	$550,059	$0
511 MAINTENANCE OF STRUCTURES	Prod	24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
512 MAINTENANCE OF BOILER PLANT	Energy	2	$4,117,208	$0	$4,117,208	$0	$0	$1,489,515	$0	$0	$484,039	$0	$0	$57,650	$0	$0	$667,949	$0
513 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$2,830,954	$0	$2,830,954	$0	$0	$1,024,177	$0	$0	$332,821	$0	$0	$39,640	$0	$0	$459,275	$0
514 MAINTENANCE OF MISC STEAM PLANT	Energy	2	$57,828	$0	$57,828	$0	$0	$20,921	$0	$0	$6,799	$0	$0	$810	$0	$0	$9,382	$0
Total Steam Power Generation Maintenance Expense			$10,396,529	$0	$10,396,529	$0	$0	$3,761,236	$0	$0	$1,222,267	$0	$0	$145,574	$0	$0	$1,686,665	$0
Total Steam Power Generation Expense			$27,718,933	$14,650,679	$13,068,254	$0	$5,190,750	$4,731,075	$0	$1,680,418	$1,537,498	$0	$199,850	$182,820	$0	$2,328,682	$2,120,591	$0
Labor-Hydraulic Power Generation Operation Expenses																		
535 OPERATION SUPERVISION & ENGINEERING	Prod	24	$95,870	$95,870	$0	$0	$33,967	$0	$0	$10,996	$0	$0	$1,308	$0	$0	$15,238	$0	$0
536 WATER FOR POWER			$0	$0	$0	$0												
537 HYDRAULIC EXPENSES			$0	$0	$0	$0												
538 ELECTRIC EXPENSES	Prod	24	$180,161	$180,161	$0	$0	$63,831	$0	$0	$20,664	$0	$0	$2,458	$0	$0	$28,636	$0	$0
539 MISC. HYDRAULIC POWER EXPENSES	Prod	24	$60,427	$60,427	$0	$0	$21,409	$0	$0	$6,931	$0	$0	$824	$0	$0	$9,605	$0	$0
540 RENTS			$0	$0	$0	$0												
Total Hydraulic Power Operation Expenses			$336,458	$336,458	$0	$0	$119,207	$0	$0	$38,591	$0	$0	$4,590	$0	$0	$53,479	$0	$0
Labor-Hydraulic Power Generation Maintenance Expenses																		
541 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
542 MAINTENANCE OF STRUCTURES	Prod	24	$46,873	$46,873	$0	$0	$16,607	$0	$0	$5,376	$0	$0	$639	$0	$0	$7,450	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	Prod	24	$46,873	$46,873	$0	$0	$16,607	$0	$0	$5,376	$0	$0	$639	$0	$0	$7,450	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$151,040	$0	$151,040	$0	$0	$54,643	$0	$0	$17,757	$0	$0	$2,115	$0	$0	$24,504	$0
545 MAINTENANCE OF MISC HYDRAULIC PLANT			$0	$0	$0	$0												
Total Hydraulic Power Generation Maint. Expense			$244,786	$93,746	$151,040	$0	$33,214	$54,643	$0	$10,753	$17,757	$0	$1,279	$2,115	$0	$14,901	$24,504	$0
Total Hydraulic Power Generation Expense			$581,244	$430,204	$151,040	$0	$152,422	$54,643	$0	$49,344	$17,757	$0	$5,868	$2,115	$0	$68,380	$24,504	$0
Labor-Other Power Generation Operation Expense																		
546 OPERATION SUPERVISION & ENGINEERING	Prod	24	$468,874	$468,874	$0	$0	$166,123	$0	$0	$53,779	$0	$0	$6,396	$0	$0	$74,526	$0	$0
547 FUEL			$0	$0	$0	$0												
548 GENERATION EXPENSE	Prod	24	$161,301	$161,301	$0	$0	$57,149	$0	$0	$18,501	$0	$0	$2,200	$0	$0	$25,638	$0	$0
549 MISC OTHER POWER GENERATION	Prod	24	$354,300	$354,300	$0	$0	$125,529	$0	$0	$40,638	$0	$0	$4,833	$0	$0	$56,315	$0	$0
550 RENTS			$0	$0	$0	$0												
Total Other Power Generation Expenses			$984,475	$984,475	$0	$0	$348,800	$0	$0	$112,918	$0	$0	$13,429	$0	$0	$156,479	$0	$0
Labor-Other Power Generation Maintenance Expense																		
551 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$230,613	$230,613	$0	$0	$81,706	$0	$0	$26,451	$0	$0	$3,146	$0	$0	$36,655	$0	$0
552 MAINTENANCE OF STRUCTURES			$0	$0	$0	$0												
553 MAINTENANCE OF GENERATING & ELEC PLANT	Prod	24	$606,788	$606,788	$0	$0	$214,986	$0	$0	$69,598	$0	$0	$8,277	$0	$0	$96,447	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	Prod	24	-$160,951	-$160,951	$0	$0	-$57,025	$0	$0	-$18,461	$0	$0	-$2,196	$0	$0	-$25,583	$0	$0
Total Other Power Generation Maintenance Expense			$676,450	$676,450	$0	$0	$239,667	$0	$0	$77,588	$0	$0	$9,227	$0	$0	$107,520	$0	$0
Total Other Power Generation Expense			$1,660,925	$1,660,925	$0	$0	$588,467	$0	$0	$190,506	$0	$0	$22,657	$0	$0	$263,999	$0	$0
Total Production Expense			$29,961,102	$16,741,808	$13,219,294	$0	$5,931,639	$4,785,718	$0	$1,920,269	$1,555,255	$0	$228,375	$184,935	$0	$2,661,060	$2,145,095	$0
Labor-Purchased Power																		
555 PURCHASED POWER			$0	$0	$0	$0												
556 SYSTEM CONTROL AND LOAD DISPATCH	Prod	24	$956,703	$956,703	$0	$0	$338,961	$0	$0	$109,733	$0	$0	$13,050	$0	$0	$152,065	$0	$0
557 OTHER EXPENSES			$0	$0	$0	$0												
Total Purchased Power Labor			$956,703	$956,703	$0	$0	$338,961	$0	$0	$109,733	$0	$0	$13,050	$0	$0	$152,065	$0	$0
Transmission Labor Expenses																		
560 OPERATION SUPERVISION AND ENG	Trans	25	$642,049	$642,049	$0	$0	$285,319	$0	$0	$82,128	$0	$0	$7,297	$0	$0	$84,695	$0	$0
561 LOAD DISPATCHING	Trans	25	$1,454,366	$1,454,366	$0	$0	$646,303	$0	$0	$186,036	$0	$0	$16,530	$0	$0	$191,852	$0	$0
562 STATION EXPENSES	Trans	25	$433,996	$433,996	$0	$0	$192,863	$0	$0	$55,515	$0	$0	$4,933	$0	$0	$57,250	$0	$0
563 OVERHEAD LINE EXPENSES			$0	$0	$0	$0												
566 MISC. TRANSMISSION EXPENSES	Trans	25	$105,592	$105,592	$0	$0	$46,924	$0	$0	$13,507	$0	$0	$1,200	$0	$0	$13,929	$0	$0
568 MAINTENACE SUPERVISION AND ENG			$0	$0	$0	$0												
570 MAINT OF STATION EQUIPMENT	Trans	25	$416,335	$416,335	$0	$0	$185,014	$0	$0	$53,256	$0	$0	$4,732	$0	$0	$54,921	$0	$0
571 MAINT OF OVERHEAD LINES	Trans	25	$83,079	$83,079	$0	$0	$36,919	$0	$0	$10,627	$0	$0	$944	$0	$0	$10,959	$0	$0
572 UNDERGROUND LINES			$0	$0	$0	$0												
573 MISC PLANT			$0	$0	$0	$0												
Total Transmission Labor Expenses			$3,135,417	$3,135,417	$0	$0	$1,393,341	$0	$0	$401,069	$0	$0	$35,636	$0	$0	$413,606	$0	$0

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Time of Day-Pri (TOD-Pri)			Time of Day-Sec (TOD-Sec)			Retail Transmission (RTS)			Special Contract 1		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Labor Expenses																		
Labor-Steam Power Generation Operation Expenses																		
500 OPERATION SUPERVISION & ENGINEERING	FO19	42	$3,138,068	$2,654,067	$484,001	$0	$403,519	$75,408	$0	$242,295	$33,425	$0	$244,644	$45,609	$0	$24,147	$4,472	$0
501 FUEL	TDFUEL	51	$2,187,724	$0	$2,187,724	$0	$0	$340,852	$0	$0	$151,084	$0	$0	$206,158	$0	$0	$20,214	$0
502 STEAM EXPENSES	Prod	24	$8,374,877	$8,374,877	$0	$0	$1,273,300	$0	$0	$764,559	$0	$0	$771,971	$0	$0	$76,195	$0	$0
505 ELECTRIC EXPENSES	Prod	24	$2,130,001	$2,130,001	$0	$0	$323,841	$0	$0	$194,452	$0	$0	$196,337	$0	$0	$19,379	$0	$0
506 MISC. STEAM POWER EXPENSES	Prod	24	$1,491,734	$1,491,734	$0	$0	$226,800	$0	$0	$136,183	$0	$0	$137,504	$0	$0	$13,572	$0	$0
507 RENTS			$0	$0	$0	$0												
Total Steam Power Operation Expenses			$17,322,404	$14,650,679	$2,671,725	$0	$2,227,460	$416,260	$0	$1,337,490	$184,509	$0	$1,350,456	$251,767	$0	$133,292	$24,686	$0
Labor-Steam Power Generation Maintenance Expenses																		
510 MAINTENANCE SUPERVISION & ENGINEERING	FO20	43	$3,390,539	$0	$3,390,539	$0	$0	$530,959	$0	$0	$233,523	$0	$0	$323,314	$0	$0	$31,557	$0
511 MAINTENANCE OF STRUCTURES	Prod	24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
512 MAINTENANCE OF BOILER PLANT	Energy	2	$4,117,208	$0	$4,117,208	$0	$0	$644,756	$0	$0	$283,572	$0	$0	$392,607	$0	$0	$38,320	$0
513 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$2,830,954	$0	$2,830,954	$0	$0	$443,328	$0	$0	$194,982	$0	$0	$269,953	$0	$0	$26,349	$0
514 MAINTENANCE OF MISC STEAM PLANT	Energy	2	$57,828	$0	$57,828	$0	$0	$9,056	$0	$0	$3,983	$0	$0	$5,514	$0	$0	$538	$0
Total Steam Power Generation Maintenance Expense			$10,396,529	$0	$10,396,529	$0	$0	$1,628,099	$0	$0	$716,060	$0	$0	$991,388	$0	$0	$96,764	$0
Total Steam Power Generation Expense			$27,718,933	$14,650,679	$13,068,254	$0	$2,227,460	$2,044,359	$0	$1,337,490	$900,569	$0	$1,350,456	$1,243,155	$0	$133,292	$121,450	$0
Labor-Hydraulic Power Generation Operation Expenses																		
535 OPERATION SUPERVISION & ENGINEERING	Prod	24	$95,870	$95,870	$0	$0	$14,576	$0	$0	$8,752	$0	$0	$8,837	$0	$0	$872	$0	$0
536 WATER FOR POWER			$0	$0	$0	$0												
537 HYDRAULIC EXPENSES			$0	$0	$0	$0												
538 ELECTRIC EXPENSES	Prod	24	$180,161	$180,161	$0	$0	$27,391	$0	$0	$16,447	$0	$0	$16,607	$0	$0	$1,639	$0	$0
539 MISC. HYDRAULIC POWER EXPENSES	Prod	24	$60,427	$60,427	$0	$0	$9,187	$0	$0	$5,517	$0	$0	$5,570	$0	$0	$550	$0	$0
540 RENTS			$0	$0	$0	$0												
Total Hydraulic Power Operation Expenses			$336,458	$336,458	$0	$0	$51,154	$0	$0	$30,716	$0	$0	$31,014	$0	$0	$3,061	$0	$0
Labor-Hydraulic Power Generation Maintenance Expenses																		
541 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
542 MAINTENANCE OF STRUCTURES	Prod	24	$46,873	$46,873	$0	$0	$7,126	$0	$0	$4,279	$0	$0	$4,321	$0	$0	$426	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	Prod	24	$46,873	$46,873	$0	$0	$7,126	$0	$0	$4,279	$0	$0	$4,321	$0	$0	$426	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$151,040	$0	$151,040	$0	$0	$23,653	$0	$0	$10,403	$0	$0	$14,403	$0	$0	$1,406	$0
545 MAINTENANCE OF MISC HYDRAULIC PLANT			$0	$0	$0	$0												
Total Hydraulic Power Generation Maint. Expense			$244,786	$93,746	$151,040	$0	$14,253	$23,653	$0	$8,558	$10,403	$0	$8,641	$14,403	$0	$853	$1,406	$0
Total Hydraulic Power Generation Expense			$581,244	$430,204	$151,040	$0	$65,407	$23,653	$0	$39,274	$10,403	$0	$39,655	$14,403	$0	$3,914	$1,406	$0
Labor-Other Power Generation Operation Expense																		
546 OPERATION SUPERVISION & ENGINEERING	Prod	24	$468,874	$468,874	$0	$0	$71,287	$0	$0	$42,804	$0	$0	$43,219	$0	$0	$4,266	$0	$0
547 FUEL			$0	$0	$0	$0												
548 GENERATION EXPENSE	Prod	24	$161,301	$161,301	$0	$0	$24,524	$0	$0	$14,725	$0	$0	$14,868	$0	$0	$1,468	$0	$0
549 MISC OTHER POWER GENERATION	Prod	24	$354,300	$354,300	$0	$0	$53,867	$0	$0	$32,345	$0	$0	$32,658	$0	$0	$3,223	$0	$0
550 RENTS			$0	$0	$0	$0												
Total Other Power Generation Expenses			$984,475	$984,475	$0	$0	$149,678	$0	$0	$89,875	$0	$0	$90,746	$0	$0	$8,957	$0	$0
Labor-Other Power Generation Maintenance Expense																		
551 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$230,613	$230,613	$0	$0	$35,062	$0	$0	$21,053	$0	$0	$21,257	$0	$0	$2,098	$0	$0
552 MAINTENANCE OF STRUCTURES			$0	$0	$0	$0												
553 MAINTENANCE OF GENERATING & ELEC PLANT	Prod	24	$606,788	$606,788	$0	$0	$92,255	$0	$0	$55,395	$0	$0	$55,932	$0	$0	$5,521	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	Prod	24	-$160,951	-$160,951	$0	$0	-$24,471	$0	$0	-$14,694	$0	$0	-$14,836	$0	$0	-$1,464	$0	$0
Total Other Power Generation Maintenance Expense			$676,450	$676,450	$0	$0	$102,846	$0	$0	$61,754	$0	$0	$62,353	$0	$0	$6,154	$0	$0
Total Other Power Generation Expense			$1,660,925	$1,660,925	$0	$0	$252,524	$0	$0	$151,629	$0	$0	$153,099	$0	$0	$15,111	$0	$0
Total Production Expense			$29,961,102	$16,741,808	$13,219,294	$0	$2,545,391	$2,068,012	$0	$1,528,393	$910,972	$0	$1,543,210	$1,257,558	$0	$152,317	$122,856	$0
Labor-Purchased Power																		
555 PURCHASED POWER			$0	$0	$0	$0												
556 SYSTEM CONTROL AND LOAD DISPATCH	Prod	24	$956,703	$956,703	$0	$0	$145,455	$0	$0	$87,339	$0	$0	$88,186	$0	$0	$8,704	$0	$0
557 OTHER EXPENSES			$0	$0	$0	$0												
Total Purchased Power Labor			$956,703	$956,703	$0	$0	$145,455	$0	$0	$87,339	$0	$0	$88,186	$0	$0	$8,704	$0	$0
Transmission Labor Expenses																		
560 OPERATION SUPERVISION AND ENG	Trans	25	$642,049	$642,049	$0	$0	$77,047	$0	$0	$45,746	$0	$0	$47,385	$0	$0	$4,777	$0	$0
561 LOAD DISPATCHING	Trans	25	$1,454,366	$1,454,366	$0	$0	$174,526	$0	$0	$103,625	$0	$0	$107,336	$0	$0	$10,820	$0	$0
562 STATION EXPENSES	Trans	25	$433,996	$433,996	$0	$0	$52,080	$0	$0	$30,923	$0	$0	$32,030	$0	$0	$3,229	$0	$0
563 OVERHEAD LINE EXPENSES			$0	$0	$0	$0												
566 MISC. TRANSMISSION EXPENSES	Trans	25	$105,592	$105,592	$0	$0	$12,671	$0	$0	$7,524	$0	$0	$7,793	$0	$0	$786	$0	$0
568 MAINTENACE SUPERVISION AND ENG			$0	$0	$0	$0												
570 MAINT OF STATION EQUIPMENT	Trans	25	$416,335	$416,335	$0	$0	$49,961	$0	$0	$29,664	$0	$0	$30,727	$0	$0	$3,097	$0	$0
571 MAINT OF OVERHEAD LINES	Trans	25	$83,079	$83,079	$0	$0	$9,970	$0	$0	$5,919	$0	$0	$6,131	$0	$0	$618	$0	$0
572 UNDERGROUND LINES			$0	$0	$0	$0												
573 MISC PLANT			$0	$0	$0	$0												
Total Transmission Labor Expenses			$3,135,417	$3,135,417	$0	$0	$376,255	$0	$0	$223,401	$0	$0	$231,402	$0	$0	$23,327	$0	$0

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Class Allocation

	Allocation Factor			Total Kentucky			Special Contract 2			Street Lighting (RLS, LS, DSK)			Street Lighting-LE			Traffic Street Lighting (TLE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Labor Expenses																		
Labor-Steam Power Generation Operation Expenses																		
500 OPERATION SUPERVISION & ENGINEERING	FO19	42	$3,138,068	$2,654,067	$484,001	$0	$13,082	$2,432	$0	$22,127	$4,228	$0	$722	$138	$0	$714	$133	$0
501 FUEL	TDFUEL	51	$2,187,724	$0	$2,187,724	$0	$0	$10,991	$0	$0	$19,112	$0	$0	$622	$0	$0	$603	$0
502 STEAM EXPENSES	Prod	24	$8,374,877	$8,374,877	$0	$0	$41,280	$0	$0	$69,821	$0	$0	$2,278	$0	$0	$2,253	$0	$0
505 ELECTRIC EXPENSES	Prod	24	$2,130,001	$2,130,001	$0	$0	$10,499	$0	$0	$17,758	$0	$0	$579	$0	$0	$573	$0	$0
506 MISC. STEAM POWER EXPENSES	Prod	24	$1,491,734	$1,491,734	$0	$0	$7,353	$0	$0	$12,437	$0	$0	$406	$0	$0	$401	$0	$0
507 RENTS			$0	$0	$0	$0												
Total Steam Power Operation Expenses			$17,322,404	$14,650,679	$2,671,725	$0	$72,213	$13,423	$0	$122,143	$23,341	$0	$3,985	$760	$0	$3,941	$736	$0
Labor-Steam Power Generation Maintenance Expenses																		
510 MAINTENANCE SUPERVISION & ENGINEERING	FO20	43	$3,390,539	$0	$3,390,539	$0	$0	$16,671	$0	$0	$29,864	$0	$0	$973	$0	$0	$912	$0
511 MAINTENANCE OF STRUCTURES	Prod	24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
512 MAINTENANCE OF BOILER PLANT	Energy	2	$4,117,208	$0	$4,117,208	$0	$0	$20,245	$0	$0	$36,265	$0	$0	$1,182	$0	$0	$1,108	$0
513 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$2,830,954	$0	$2,830,954	$0	$0	$13,920	$0	$0	$24,935	$0	$0	$813	$0	$0	$762	$0
514 MAINTENANCE OF MISC STEAM PLANT	Energy	2	$57,828	$0	$57,828	$0	$0	$284	$0	$0	$509	$0	$0	$17	$0	$0	$16	$0
Total Steam Power Generation Maintenance Expense			$10,396,529	$0	$10,396,529	$0	$0	$51,120	$0	$0	$91,573	$0	$0	$2,985	$0	$0	$2,797	$0
Total Steam Power Generation Expense			$27,718,933	$14,650,679	$13,068,254	$0	$72,213	$64,543	$0	$122,143	$114,914	$0	$3,985	$3,745	$0	$3,941	$3,534	$0
Labor-Hydraulic Power Generation Operation Expenses																		
535 OPERATION SUPERVISION & ENGINEERING	Prod	24	$95,870	$95,870	$0	$0	$473	$0	$0	$799	$0	$0	$26	$0	$0	$26	$0	$0
536 WATER FOR POWER			$0	$0	$0	$0												
537 HYDRAULIC EXPENSES			$0	$0	$0	$0												
538 ELECTRIC EXPENSES	Prod	24	$180,161	$180,161	$0	$0	$888	$0	$0	$1,502	$0	$0	$49	$0	$0	$48	$0	$0
539 MISC. HYDRAULIC POWER EXPENSES	Prod	24	$60,427	$60,427	$0	$0	$298	$0	$0	$504	$0	$0	$16	$0	$0	$16	$0	$0
540 RENTS			$0	$0	$0	$0												
Total Hydraulic Power Operation Expenses			$336,458	$336,458	$0	$0	$1,658	$0	$0	$2,805	$0	$0	$92	$0	$0	$91	$0	$0
Labor-Hydraulic Power Generation Maintenance Expenses																		
541 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
542 MAINTENANCE OF STRUCTURES	Prod	24	$46,873	$46,873	$0	$0	$231	$0	$0	$391	$0	$0	$13	$0	$0	$13	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAYS	Prod	24	$46,873	$46,873	$0	$0	$231	$0	$0	$391	$0	$0	$13	$0	$0	$13	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT	Energy	2	$151,040	$0	$151,040	$0	$0	$743	$0	$0	$1,330	$0	$0	$43	$0	$0	$41	$0
545 MAINTENANCE OF MISC HYDRAULIC PLANT			$0	$0	$0	$0												
Total Hydraulic Power Generation Maint. Expense			$244,786	$93,746	$151,040	$0	$462	$743	$0	$782	$1,330	$0	$25	$43	$0	$25	$41	$0
Total Hydraulic Power Generation Expense			$581,244	$430,204	$151,040	$0	$2,120	$743	$0	$3,587	$1,330	$0	$117	$43	$0	$116	$41	$0
Labor-Other Power Generation Operation Expense																		
546 OPERATION SUPERVISION & ENGINEERING	Prod	24	$468,874	$468,874	$0	$0	$2,311	$0	$0	$3,909	$0	$0	$128	$0	$0	$126	$0	$0
547 FUEL			$0	$0	$0	$0												
548 GENERATION EXPENSE	Prod	24	$161,301	$161,301	$0	$0	$795	$0	$0	$1,345	$0	$0	$44	$0	$0	$43	$0	$0
549 MISC OTHER POWER GENERATION	Prod	24	$354,300	$354,300	$0	$0	$1,746	$0	$0	$2,954	$0	$0	$96	$0	$0	$95	$0	$0
550 RENTS			$0	$0	$0	$0												
Total Other Power Generation Expenses			$984,475	$984,475	$0	$0	$4,852	$0	$0	$8,208	$0	$0	$268	$0	$0	$265	$0	$0
Labor-Other Power Generation Maintenance Expense																		
551 MAINTENANCE SUPERVISION & ENGINEERING	Prod	24	$230,613	$230,613	$0	$0	$1,137	$0	$0	$1,923	$0	$0	$63	$0	$0	$62	$0	$0
552 MAINTENANCE OF STRUCTURES			$0	$0	$0	$0												
553 MAINTENANCE OF GENERATING & ELEC PLANT	Prod	24	$606,788	$606,788	$0	$0	$2,991	$0	$0	$5,059	$0	$0	$165	$0	$0	$163	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	Prod	24	-$160,951	-$160,951	$0	$0	-$793	$0	$0	-$1,342	$0	$0	-$44	$0	$0	-$43	$0	$0
Total Other Power Generation Maintenance Expense			$676,450	$676,450	$0	$0	$3,334	$0	$0	$5,640	$0	$0	$184	$0	$0	$182	$0	$0
Total Other Power Generation Expense			$1,660,925	$1,660,925	$0	$0	$8,187	$0	$0	$13,847	$0	$0	$452	$0	$0	$447	$0	$0
Total Production Expense			$29,961,102	$16,741,808	$13,219,294	$0	$82,520	$65,286	$0	$139,576	$116,244	$0	$4,554	$3,788	$0	$4,504	$3,574	$0
Labor-Purchased Power																		
555 PURCHASED POWER			$0	$0	$0	$0												
556 SYSTEM CONTROL AND LOAD DISPATCH	Prod	24	$956,703	$956,703	$0	$0	$4,716	$0	$0	$7,976	$0	$0	$260	$0	$0	$257	$0	$0
557 OTHER EXPENSES			$0	$0	$0	$0												
Total Purchased Power Labor			$956,703	$956,703	$0	$0	$4,716	$0	$0	$7,976	$0	$0	$260	$0	$0	$257	$0	$0
Transmission Labor Expenses																		
560 OPERATION SUPERVISION AND ENG	Trans	25	$642,049	$642,049	$0	$0	$2,500	$0	$0	$4,925	$0	$0	$158	$0	$0	$72	$0	$0
561 LOAD DISPATCHING	Trans	25	$1,454,366	$1,454,366	$0	$0	$5,663	$0	$0	$11,156	$0	$0	$357	$0	$0	$162	$0	$0
562 STATION EXPENSES	Trans	25	$433,996	$433,996	$0	$0	$1,690	$0	$0	$3,329	$0	$0	$106	$0	$0	$48	$0	$0
563 OVERHEAD LINE EXPENSES			$0	$0	$0	$0												
566 MISC. TRANSMISSION EXPENSES	Trans	25	$105,592	$105,592	$0	$0	$411	$0	$0	$810	$0	$0	$26	$0	$0	$12	$0	$0
568 MAINTENACE SUPERVISION AND ENG			$0	$0	$0	$0												
570 MAINT OF STATION EQUIPMENT	Trans	25	$416,335	$416,335	$0	$0	$1,621	$0	$0	$3,194	$0	$0	$102	$0	$0	$47	$0	$0
571 MAINT OF OVERHEAD LINES	Trans	25	$83,079	$83,079	$0	$0	$323	$0	$0	$637	$0	$0	$20	$0	$0	$9	$0	$0
572 UNDERGROUND LINES			$0	$0	$0	$0												
573 MISC PLANT			$0	$0	$0	$0												
Total Transmission Labor Expenses			$3,135,417	$3,135,417	$0	$0	$12,209	$0	$0	$24,051	$0	$0	$769	$0	$0	$350	$0	$0

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Class Allocation

	Allocation Factor			Total Kentucky			Time of Day-Pri (TOD-Pri)			Time of Day-Sec (TOD-Sec)			Retail Transmission (RTS)			Special Contract 1		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Labor Expense																		
580 OPERATION SUPERVISION AND ENGI	FO23	45	$898,041	$435,521	$0	$462,520	$51,145	$0	$4,947	$31,086	$0	$2,322	$0	$0	$4,046	$3,171	$0	$47
581 LOAD DISPATCHING	Acct362	29	$574,384	$574,384	$0	$0	$74,419	$0	$0	$44,186	$0	$0	$0	$0	$0	$4,614	$0	$0
582 STATION EXPENSES	Acct362	29	$851,000	$851,000	$0	$0	$110,259	$0	$0	$65,466	$0	$0	$0	$0	$0	$6,836	$0	$0
583 OVERHEAD LINE EXPENSES	Acct365	30	$1,741,898	$1,465,376	$0	$276,522	$165,158	$0	$0	$98,062	$0	$0	$0	$0	$0	$10,239	$0	$0
584 UNDERGROUND LINE EXPENSES	Acct367	31	$168,503	$155,596	$0	$12,907	$19,234	$0	$0	$11,420	$0	$0	$0	$0	$0	$1,192	$0	$0
585 STREET LIGHTING EXPENSE			$0	$0	$0	$0												
586 METER EXPENSES	C03	21	$3,736,471	$0	$0	$3,736,471	$0	$0	$46,870	$0	$0	$21,791	$0	$0	$38,340	$0	$0	$445
586 METER EXPENSES - LOAD MANAGEMENT			$0	$0	$0	$0												
587 CUSTOMER INSTALLATIONS EXPENSE			$0	$0	$0	$0												
588 MISCELLANEOUS DISTRIBUTION EXP	Dist	26	$1,539,532	$1,130,080	$0	$409,452	$121,388	$0	$566	$78,962	$0	$478	$0	$0	$463	$7,526	$0	$5
589 RENTS			$0	$0	$0	$0												
Total Distribution Operation Labor Expense			$9,509,829	$4,611,957	$0	$4,897,872	$541,602	$0	$52,383	$329,182	$0	$24,592	$0	$0	$42,850	$33,578	$0	$497
Distribution Maintenance Labor Expense																		
590 MAINTENANCE SUPERVISION AND EN			$0	$0	$0	$0												
591 MAINTENANCE OF STRUCTURES			$0	$0	$0	$0												
592 MAINTENANCE OF STATION EQUIPME	Acct362	29	$199,000	$199,000	$0	$0	$25,783	$0	$0	$15,309	$0	$0	$0	$0	$0	$1,598	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct365	30	$2,584,023	$2,173,816	$0	$410,207	$245,003	$0	$0	$145,470	$0	$0	$0	$0	$0	$15,190	$0	$0
594 MAINTENANCE OF UNDERGROUND LIN	Acct367	31	$403,600	$372,684	$0	$30,916	$46,069	$0	$0	$27,354	$0	$0	$0	$0	$0	$2,856	$0	$0
595 MAINTENANCE OF LINE TRANSFORME	Acct368	32	$77,717	$45,733	$0	$31,984	$0	$0	$0	$2,810	$0	$21	$0	$0	$0	$0	$0	$0
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	C04	22	$6,800	$0	$0	$6,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
597 MAINTENANCE OF METERS			$0	$0	$0	$0												
598 MAINTENANCE OF MISC DISTR PLANT			$0	$0	$0	$0												
Total Distribution Maintenance Labor Expense			$3,271,140	$2,791,233	$0	$479,907	$316,856	$0	$0	$190,943	$0	$21	$0	$0	$0	$19,644	$0	$0
Total Distribution Labor Expense			$12,780,969	$7,403,190	$0	$5,377,779	$858,458	$0	$52,383	$520,125	$0	$24,612	$0	$0	$42,850	$53,222	$0	$497
Customer Accounts Expense																		
901 SUPERVISION/CUSTOMER ACCTS	C05	33	$869,231	$0	$0	$869,231	$0	$0	$4,693	$0	$0	$12,274	$0	$0	$578	$0	$0	$9
902 METER READING EXPENSES	MREAD	50	$340,095	$0	$0	$340,095	$0	$0	$1,869	$0	$0	$4,889	$0	$0	$230	$0	$0	$4
903 RECORDS AND COLLECTION	C05	33	$3,084,679	$0	$0	$3,084,679	$0	$0	$16,653	$0	$0	$43,557	$0	$0	$2,052	$0	$0	$32
904 UNCOLLECTIBLE ACCOUNTS			$0	$0	$0	$0												
905 MISC CUST ACCOUNTS			$0	$0	$0	$0												
Total Customer Accounts Labor Expense			$4,294,005	$0	$0	$4,294,005	$0	$0	$23,214	$0	$0	$60,719	$0	$0	$2,860	$0	$0	$44
Customer Service Expense																		
907 SUPERVISION	C05	33	$262,521	$0	$0	$262,521	$0	$0	$1,417	$0	$0	$3,707	$0	$0	$175	$0	$0	$3
908 CUSTOMER ASSISTANCE EXPENSES	C05	33	$916,352	$0	$0	$916,352	$0	$0	$4,947	$0	$0	$12,939	$0	$0	$609	$0	$0	$9
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT			$0	$0	$0	$0												
909 INFORMATIONAL AND INSTRUCTIONA			$0	$0	$0	$0												
909 INFORM AND INSTRUC -LOAD MGMT			$0	$0	$0	$0												
910 MISCELLANEOUS CUSTOMER SERVICE			$0	$0	$0	$0												
911 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
912 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
913 WATER HEATER - HEAT PUMP PROGRAM			$0	$0	$0	$0												
916 MISC SALES EXPENSE			$0	$0	$0	$0												
Total Customer Service Labor Expense			$1,178,873	$0	$0	$1,178,873	$0	$0	$6,364	$0	$0	$16,646	$0	$0	$784	$0	$0	$12
Total Labor Excluding A&G			$52,307,069	$28,237,118	$13,219,294	$10,850,657	$3,925,559	$2,068,012	$81,962	$2,359,258	$910,972	$101,978	$1,862,798	$1,257,558	$46,494	$237,570	$122,856	$553

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Class Allocation

	Allocation Factor			Total Kentucky			Special Contract 2			Street Lighting (RLS, LS, DSK)			Street Lighting-LE			Traffic Street Lighting (TLE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Labor Expense																		
580 OPERATION SUPERVISION AND ENGI	FO23	45	$898,041	$435,521	$0	$462,520	$1,660	$0	$47	$3,537	$0	$14,075	$113	$0	$127	$52	$0	$698
581 LOAD DISPATCHING	Acct362	29	$574,384	$574,384	$0	$0	$2,415	$0	$0	$4,757	$0	$0	$152	$0	$0	$69	$0	$0
582 STATION EXPENSES	Acct362	29	$851,000	$851,000	$0	$0	$3,578	$0	$0	$7,048	$0	$0	$225	$0	$0	$103	$0	$0
583 OVERHEAD LINE EXPENSES	Acct365	30	$1,741,898	$1,465,376	$0	$276,522	$5,359	$0	$0	$11,873	$0	$6,335	$380	$0	$12	$173	$0	$67
584 UNDERGROUND LINE EXPENSES	Acct367	31	$168,503	$155,596	$0	$12,907	$624	$0	$0	$1,279	$0	$296	$41	$0	$1	$19	$0	$3
585 STREET LIGHTING EXPENSE			$0	$0	$0	$0												
586 METER EXPENSES	C03	21	$3,736,471	$0	$0	$3,736,471	$0	$0	$445	$0	$0	$0	$0	$0	$1,184	$0	$0	$6,501
586 METER EXPENSES - LOAD MANAGEMENT			$0	$0	$0	$0												
587 CUSTOMER INSTALLATIONS EXPENSE			$0	$0	$0	$0												
588 MISCELLANEOUS DISTRIBUTION EXP	Dist	26	$1,539,532	$1,130,080	$0	$409,452	$3,939	$0	$5	$8,958	$0	$128,344	$287	$0	$23	$130	$0	$127
589 RENTS			$0	$0	$0	$0												
Total Distribution Operation Labor Expense			$9,509,829	$4,611,957	$0	$4,897,872	$17,574	$0	$497	$37,452	$0	$149,050	$1,198	$0	$1,347	$545	$0	$7,397
Distribution Maintenance Labor Expense																		
590 MAINTENANCE SUPERVISION AND EN			$0	$0	$0	$0												
591 MAINTENANCE OF STRUCTURES			$0	$0	$0	$0												
592 MAINTENANCE OF STATION EQUIPME	Acct362	29	$199,000	$199,000	$0	$0	$837	$0	$0	$1,648	$0	$0	$53	$0	$0	$24	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct365	30	$2,584,023	$2,173,816	$0	$410,207	$7,950	$0	$0	$17,613	$0	$9,397	$563	$0	$18	$257	$0	$99
594 MAINTENANCE OF UNDERGROUND LIN	Acct367	31	$403,600	$372,684	$0	$30,916	$1,495	$0	$0	$3,063	$0	$708	$98	$0	$1	$45	$0	$7
595 MAINTENANCE OF LINE TRANSFORME	Acct368	32	$77,717	$45,733	$0	$31,984	$0	$0	$0	$261	$0	$727	$8	$0	$1	$4	$0	$8
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	C04	22	$6,800	$0	$0	$6,800	$0	$0	$0	$0	$0	$6,800	$0	$0	$0	$0	$0	$0
597 MAINTENANCE OF METERS			$0	$0	$0	$0												
598 MAINTENANCE OF MISC DISTR PLANT			$0	$0	$0	$0												
Total Distribution Maintenance Labor Expense			$3,271,140	$2,791,233	$0	$479,907	$10,281	$0	$0	$22,585	$0	$17,633	$722	$0	$20	$329	$0	$114
Total Distribution Labor Expense			$12,780,969	$7,403,190	$0	$5,377,779	$27,856	$0	$497	$60,037	$0	$166,682	$1,920	$0	$1,367	$874	$0	$7,511
Customer Accounts Expense																		
901 SUPERVISION/CUSTOMER ACCTS	C05	33	$869,231	$0	$0	$869,231	$0	$0	$9	$0	$0	$17,077	$0	$0	$32	$0	$0	$180
902 METER READING EXPENSES	MREAD	50	$340,095	$0	$0	$340,095	$0	$0	$4	$0	$0	$0	$0	$0	$125	$0	$0	$651
903 RECORDS AND COLLECTION	C05	33	$3,084,679	$0	$0	$3,084,679	$0	$0	$32	$0	$0	$60,601	$0	$0	$114	$0	$0	$638
904 UNCOLLECTIBLE ACCOUNTS			$0	$0	$0	$0												
905 MISC CUST ACCOUNTS			$0	$0	$0	$0												
Total Customer Accounts Labor Expense			$4,294,005	$0	$0	$4,294,005	$0	$0	$44	$0	$0	$77,677	$0	$0	$270	$0	$0	$1,468
Customer Service Expense																		
907 SUPERVISION	C05	33	$262,521	$0	$0	$262,521	$0	$0	$3	$0	$0	$5,157	$0	$0	$10	$0	$0	$54
908 CUSTOMER ASSISTANCE EXPENSES	C05	33	$916,352	$0	$0	$916,352	$0	$0	$9	$0	$0	$18,002	$0	$0	$34	$0	$0	$189
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT			$0	$0	$0	$0												
909 INFORMATIONAL AND INSTRUCTIONA			$0	$0	$0	$0												
909 INFORM AND INSTRUC -LOAD MGMT			$0	$0	$0	$0												
910 MISCELLANEOUS CUSTOMER SERVICE			$0	$0	$0	$0												
911 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
912 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
913 WATER HEATER - HEAT PUMP PROGRAM			$0	$0	$0	$0												
916 MISC SALES EXPENSE			$0	$0	$0	$0												
Total Customer Service Labor Expense			$1,178,873	$0	$0	$1,178,873	$0	$0	$12	$0	$0	$23,160	$0	$0	$43	$0	$0	$244
Total Labor Excluding A&G			$52,307,069	$28,237,118	$13,219,294	$10,850,657	$127,301	$65,286	$553	$231,641	$116,244	$267,520	$7,504	$3,788	$1,681	$5,986	$3,574	$9,223

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor		Total Kentucky				Residential (RS)			General Service (GS)			Power Service-Primary (PS-Pri)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Labor Expense																		
580 OPERATION SUPERVISION AND ENGI	FO23	45	$898,041	$435,521	$0	$462,520	$221,916	$0	$323,574	$60,469	$0	$87,456	$4,844	$0	$3,159	$57,529	$0	$22,022
581 LOAD DISPATCHING	Acct362	29	$574,384	$574,384	$0	$0	$275,588	$0	$0	$79,327	$0	$0	$7,048	$0	$0	$81,807	$0	$0
582 STATION EXPENSES	Acct362	29	$851,000	$851,000	$0	$0	$408,308	$0	$0	$117,530	$0	$0	$10,443	$0	$0	$121,204	$0	$0
583 OVERHEAD LINE EXPENSES	Acct365	30	$1,741,898	$1,465,376	$0	$276,522	$771,608	$0	$240,259	$205,329	$0	$29,850	$15,642	$0	$0	$181,553	$0	$0
584 UNDERGROUND LINE EXPENSES	Acct367	31	$168,503	$155,596	$0	$12,907	$77,222	$0	$11,215	$21,600	$0	$1,393	$1,822	$0	$0	$21,143	$0	$0
585 STREET LIGHTING EXPENSE			$0	$0	$0	$0												
586 METER EXPENSES	C03	21	$3,736,471	$0	$0	$3,736,471	$0	$0	$2,615,231	$0	$0	$768,891	$0	$0	$29,933	$0	$0	$206,840
586 METER EXPENSES - LOAD MANAGEMENT			$0	$0	$0	$0												
587 CUSTOMER INSTALLATIONS EXPENSE			$0	$0	$0	$0												
588 MISCELLANEOUS DISTRIBUTION EXP	Dist	26	$1,539,532	$1,130,080	$0	$409,452	$595,344	$0	$236,213	$156,078	$0	$38,526	$11,497	$0	$362	$145,972	$0	$4,338
589 RENTS			$0	$0	$0	$0												
Total Distribution Operation Labor Expense			$9,509,829	$4,611,957	$0	$4,897,872	$2,349,987	$0	$3,426,491	$640,333	$0	$926,116	$51,296	$0	$33,454	$609,209	$0	$233,200
Distribution Maintenance Labor Expense																		
590 MAINTENANCE SUPERVISION AND EN			$0	$0	$0	$0												
591 MAINTENANCE OF STRUCTURES			$0	$0	$0	$0												
592 MAINTENANCE OF STATION EQUIPME	Acct362	29	$199,000	$199,000	$0	$0	$95,480	$0	$0	$27,484	$0	$0	$2,442	$0	$0	$28,343	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct365	30	$2,584,023	$2,173,816	$0	$410,207	$1,144,644	$0	$356,413	$304,596	$0	$44,281	$23,205	$0	$0	$269,325	$0	$0
594 MAINTENANCE OF UNDERGROUND LIN	Acct367	31	$403,600	$372,684	$0	$30,916	$184,964	$0	$26,862	$51,735	$0	$3,337	$4,363	$0	$0	$50,643	$0	$0
595 MAINTENANCE OF LINE TRANSFORME	Acct368	32	$77,717	$45,733	$0	$31,984	$31,730	$0	$27,585	$5,806	$0	$3,427	$0	$0	$0	$5,114	$0	$214
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	C04	22	$6,800	$0	$0	$6,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
597 MAINTENANCE OF METERS			$0	$0	$0	$0												
598 MAINTENANCE OF MISC DISTR PLANT			$0	$0	$0	$0												
Total Distribution Maintenance Labor Expense			$3,271,140	$2,791,233	$0	$479,907	$1,456,817	$0	$410,860	$389,621	$0	$51,045	$30,010	$0	$0	$353,424	$0	$214
Total Distribution Labor Expense			$12,780,969	$7,403,190	$0	$5,377,779	$3,806,804	$0	$3,837,351	$1,029,955	$0	$977,161	$81,306	$0	$33,454	$962,633	$0	$233,414
Customer Accounts Expense																		
901 SUPERVISION/CUSTOMER ACCTS	C05	33	$869,231	$0	$0	$869,231	$0	$0	$647,684	$0	$0	$160,937	$0	$0	$640	$0	$0	$25,119
902 METER READING EXPENSES	MREAD	50	$340,095	$0	$0	$340,095	$0	$0	$257,965	$0	$0	$64,099	$0	$0	$255	$0	$0	$10,005
903 RECORDS AND COLLECTION	C05	33	$3,084,679	$0	$0	$3,084,679	$0	$0	$2,298,466	$0	$0	$571,124	$0	$0	$2,273	$0	$0	$89,140
904 UNCOLLECTIBLE ACCOUNTS			$0	$0	$0	$0												
905 MISC CUST ACCOUNTS			$0	$0	$0	$0												
Total Customer Accounts Labor Expense			$4,294,005	$0	$0	$4,294,005	$0	$0	$3,204,116	$0	$0	$796,160	$0	$0	$3,168	$0	$0	$124,263
Customer Service Expense																		
907 SUPERVISION	C05	33	$262,521	$0	$0	$262,521	$0	$0	$195,611	$0	$0	$48,605	$0	$0	$193	$0	$0	$7,586
908 CUSTOMER ASSISTANCE EXPENSES	C05	33	$916,352	$0	$0	$916,352	$0	$0	$682,795	$0	$0	$169,661	$0	$0	$675	$0	$0	$26,480
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT			$0	$0	$0	$0												
909 INFORMATIONAL AND INSTRUCTIONA			$0	$0	$0	$0												
909 INFORM AND INSTRUC -LOAD MGMT			$0	$0	$0	$0												
910 MISCELLANEOUS CUSTOMER SERVICE			$0	$0	$0	$0												
911 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
912 DEMONSTRATION AND SELLING EXP			$0	$0	$0	$0												
913 WATER HEATER - HEAT PUMP PROGRAM			$0	$0	$0	$0												
916 MISC SALES EXPENSE			$0	$0	$0	$0												
Total Customer Service Labor Expense			$1,178,873	$0	$0	$1,178,873	$0	$0	$878,406	$0	$0	$218,267	$0	$0	$868	$0	$0	$34,067
Total Labor Excluding A&G			$52,307,069	$28,237,118	$13,219,294	$10,850,657	$11,470,745	$4,785,718	$7,919,873	$3,461,026	$1,555,255	$1,991,589	$358,367	$184,935	$37,490	$4,189,365	$2,145,095	$391,743

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Class Allocation

	Allocation Factor			Total Kentucky			Residential (RS)			General Service (GS)			Power Service-Primary (PS-Pri)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Administrative and General Expense																		
920 ADMIN. & GEN. SALARIES-	LBSUB7	35	$21,224,500	$11,457,700	$5,363,958	$4,402,842	$4,654,454	$1,941,888	$3,213,626	$1,404,371	$631,072	$808,122	$145,414	$75,041	$15,212	$1,699,907	$870,409	$158,957
921 OFFICE SUPPLIES AND EXPENSES			$0	$0	$0	$0												
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LBSUB7	35	-$2,423,558	-$1,308,318	-$612,493	-$502,747	-$531,477	-$221,738	-$366,954	-$160,361	-$72,060	-$92,277	-$16,604	-$8,569	-$1,737	-$194,107	-$99,389	-$18,151
923 OUTSIDE SERVICES EMPLOYED			$0	$0	$0	$0												
924 PROPERTY INSURANCE			$0	$0	$0	$0												
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	35	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
926 EMPLOYEE BENEFITS	LBSUB7	35	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
928 REGULATORY COMMISSION FEES			$0	$0	$0	$0												
929 DUPLICATE CHARGES-CR			$0	$0	$0	$0												
930 MISCELLANEOUS GENERAL EXPENSES			$0	$0	$0	$0												
931 RENTS AND LEASES			$0	$0	$0	$0												
935 MAINTENANCE OF GENERAL PLANT	PT&D	23	$430,713	$392,738	$0	$37,975	$161,403	$0	$21,908	$48,113	$0	$3,573	$4,888	$0	$34	$58,051	$0	$402
Total Labor Administrative and General Expense			$19,231,655	$10,542,120	$4,751,464	$3,938,071	$4,284,380	$1,720,150	$2,868,580	$1,292,124	$559,012	$719,418	$133,698	$66,472	$13,509	$1,563,851	$771,020	$141,208
Total Labor Operation and Maintenance Expenses			$71,538,724	$38,779,238	$17,970,758	$14,788,729	$15,755,125	$6,505,868	$10,788,453	$4,753,149	$2,114,267	$2,711,007	$492,065	$251,407	$50,999	$5,753,216	$2,916,115	$532,951
Depreciation Expenses																		
Steam Production	Prod	24	$51,173,949	$51,173,949	$0	$0	$18,130,981	$0	$0	$5,869,601	$0	$0	$698,064	$0	$0	$8,133,946	$0	$0
Hydraulic Production	Prod	24	$4,023,933	$4,023,933	$0	$0	$1,425,683	$0	$0	$461,541	$0	$0	$54,890	$0	$0	$639,592	$0	$0
Other Production	Prod	24	$16,258,222	$16,258,222	$0	$0	$5,760,304	$0	$0	$1,864,802	$0	$0	$221,778	$0	$0	$2,584,196	$0	$0
Transmission - Kentucky System Property	Trans	25	$9,613,105	$9,613,105	$0	$0	$4,271,947	$0	$0	$1,229,668	$0	$0	$109,258	$0	$0	$1,268,106	$0	$0
Transmission - Virginia Property	Trans	25	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	Dist	26	$37,717,920	$27,686,520	$0	$10,031,400	$14,585,682	$0	$5,787,117	$3,823,856	$0	$943,872	$281,668	$0	$8,863	$3,576,254	$0	$106,280
General Plant	PT&D	23	$20,055,398	$18,287,147	$0	$1,768,251	$7,515,462	$0	$1,020,104	$2,240,301	$0	$166,378	$227,623	$0	$1,562	$2,703,035	$0	$18,734
Intangible Plant	PT&D	23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Depreciation Expense			$138,842,527	$127,042,876	$0	$11,799,651	$51,690,060	$0	$6,807,222	$15,489,769	$0	$1,110,249	$1,593,282	$0	$10,425	$18,905,128	$0	$125,014
Regulatory Credits and Accretion Expenses																		
Production Plant			$0	$0	$0	$0												
Transmission Plant			$0	$0	$0	$0												
Distribution Plant			$0	$0	$0	$0												
Total Regulatory Credits and Accretion Expenses			$0	$0	$0	$0												
Property Taxes	TUP	34	$32,529,209	$29,664,969	$0	$2,864,240	$12,186,244	$0	$1,652,380	$3,633,428	$0	$269,501	$369,364	$0	$2,531	$4,386,093	$0	$30,346
Other Taxes	TUP	34	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Amortization of ITCs	TUP	34	-$1,002,535	-$914,260	$0	-$88,275	-$375,574	$0	-$50,926	-$111,981	$0	-$8,306	-$11,384	$0	-$78	-$135,177	$0	-$935
Interest	TUP	34	$62,185,554	$56,710,034	$0	$5,475,520	$23,296,242	$0	$3,158,828	$6,945,965	$0	$515,201	$706,107	$0	$4,838	$8,384,821	$0	$58,012
Other Expenses			$0	$0	$0	$0												
Total Other Expenses			$918,176,657	$380,916,406	$465,540,988	$71,719,263	$158,021,836	$168,858,066	$49,327,036	$47,784,371	$54,881,944	$10,974,197	$4,689,621	$6,496,720	$173,793	$56,382,732	$75,590,783	$1,904,595

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Class Allocation

	Allocation Factor			Total Kentucky			Time of Day-Pri (TOD-Pri)			Time of Day-Sec (TOD-Sec)			Retail Transmission (RTS)			Special Contract 1		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Administrative and General Expense																		
920 ADMIN. & GEN. SALARIES-	LBSUB7	35	$21,224,500	$11,457,700	$5,363,958	$4,402,842	$1,592,864	$839,132	$33,257	$957,310	$369,643	$41,379	$755,862	$510,276	$18,866	$96,398	$49,851	$224
921 OFFICE SUPPLIES AND EXPENSES			$0	$0	$0	$0												
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LBSUB7	35	-$2,423,558	-$1,308,318	-$612,493	-$502,747	-$181,884	-$95,818	-$3,798	-$109,312	-$42,208	-$4,725	-$86,310	-$58,267	-$2,154	-$11,007	-$5,692	-$26
923 OUTSIDE SERVICES EMPLOYED			$0	$0	$0	$0												
924 PROPERTY INSURANCE			$0	$0	$0	$0												
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	35	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
926 EMPLOYEE BENEFITS	LBSUB7	35	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
928 REGULATORY COMMISSION FEES			$0	$0	$0	$0												
929 DUPLICATE CHARGES-CR			$0	$0	$0	$0												
930 MISCELLANEOUS GENERAL EXPENSES			$0	$0	$0	$0												
931 RENTS AND LEASES			$0	$0	$0	$0												
935 MAINTENANCE OF GENERAL PLANT	PT&D	23	$430,713	$392,738	$0	$37,975	$53,550	$0	$53	$32,680	$0	$44	$25,689	$0	$43	$3,241	$0	$0
Total Labor Administrative and General Expense			$19,231,655	$10,542,120	$4,751,464	$3,938,071	$1,464,529	$743,314	$29,512	$880,678	$327,434	$36,699	$695,242	$452,009	$16,754	$88,631	$44,159	$199
Total Labor Operation and Maintenance Expenses			$71,538,724	$38,779,238	$17,970,758	$14,788,729	$5,390,088	$2,811,326	$111,474	$3,239,936	$1,238,406	$138,676	$2,558,039	$1,709,567	$63,248	$326,201	$167,015	$752
Depreciation Expenses																		
Steam Production	Prod	24	$51,173,949	$51,173,949	$0	$0	$7,780,385	$0	$0	$4,671,772	$0	$0	$4,717,061	$0	$0	$465,581	$0	$0
Hydraulic Production	Prod	24	$4,023,933	$4,023,933	$0	$0	$611,791	$0	$0	$367,353	$0	$0	$370,914	$0	$0	$36,610	$0	$0
Other Production	Prod	24	$16,258,222	$16,258,222	$0	$0	$2,471,868	$0	$0	$1,484,246	$0	$0	$1,498,634	$0	$0	$147,917	$0	$0
Transmission - Kentucky System Property	Trans	25	$9,613,105	$9,613,105	$0	$0	$1,153,587	$0	$0	$684,941	$0	$0	$709,472	$0	$0	$71,519	$0	$0
Transmission - Virginia Property	Trans	25	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	Dist	26	$37,717,920	$27,686,520	$0	$10,031,400	$2,973,952	$0	$13,878	$1,934,537	$0	$11,715	$0	$0	$11,353	$184,377	$0	$132
General Plant	PT&D	23	$20,055,398	$18,287,147	$0	$1,768,251	$2,493,442	$0	$2,446	$1,521,695	$0	$2,065	$1,196,153	$0	$2,001	$150,898	$0	$23
Intangible Plant	PT&D	23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Depreciation Expense			$138,842,527	$127,042,876	$0	$11,799,651	$17,485,024	$0	$16,325	$10,664,544	$0	$13,780	$8,492,234	$0	$13,354	$1,056,901	$0	$155
Regulatory Credits and Accretion Expenses																		
Production Plant			$0	$0	$0	$0												
Transmission Plant			$0	$0	$0	$0												
Distribution Plant			$0	$0	$0	$0												
Total Regulatory Credits and Accretion Expenses			$0	$0	$0	$0												
Property Taxes	TUP	34	$32,529,209	$29,664,969	$0	$2,864,240	$4,046,443	$0	$3,963	$2,469,409	$0	$3,345	$1,942,079	$0	$3,241	$244,869	$0	$38
Other Taxes	TUP	34	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Amortization of ITCs	TUP	34	-$1,002,535	-$914,260	$0	-$88,275	-$124,709	$0	-$122	-$76,106	$0	-$103	-$59,854	$0	-$100	-$7,547	$0	-$1
Interest	TUP	34	$62,185,554	$56,710,034	$0	$5,475,520	$7,735,519	$0	$7,575	$4,720,729	$0	$6,394	$3,712,640	$0	$6,197	$468,112	$0	$72
Other Expenses			$0	$0	$0	$0												
Total Other Expenses			$918,176,657	$380,916,406	$465,540,988	$71,719,263	$51,125,541	$72,619,587	$378,836	$31,340,014	$32,129,938	$480,252	$23,874,175	$43,992,752	$215,604	$3,107,900	$4,308,846	$2,564

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Class Allocation

	Allocation Factor			Total Kentucky			Special Contract 2			Street Lighting (RLS, LS, DSK)			Street Lighting-LE			Traffic Street Lighting (TLE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Administrative and General Expense																		
920 ADMIN. & GEN. SALARIES-	LBSUB7	35	$21,224,500	$11,457,700	$5,363,958	$4,402,842	$51,654	$26,491	$224	$93,992	$47,168	$108,551	$3,045	$1,537	$682	$2,429	$1,450	$3,742
921 OFFICE SUPPLIES AND EXPENSES			$0	$0	$0	$0												
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LBSUB7	35	-$2,423,558	-$1,308,318	-$612,493	-$502,747	-$5,898	-$3,025	-$26	-$10,733	-$5,386	-$12,395	-$348	-$176	-$78	-$277	-$166	-$427
923 OUTSIDE SERVICES EMPLOYED			$0	$0	$0	$0												
924 PROPERTY INSURANCE			$0	$0	$0	$0												
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	35	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
926 EMPLOYEE BENEFITS	LBSUB7	35	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
928 REGULATORY COMMISSION FEES			$0	$0	$0	$0												
929 DUPLICATE CHARGES-CR			$0	$0	$0	$0												
930 MISCELLANEOUS GENERAL EXPENSES			$0	$0	$0	$0												
931 RENTS AND LEASES			$0	$0	$0	$0												
935 MAINTENANCE OF GENERAL PLANT	PT&D	23	$430,713	$392,738	$0	$37,975	$1,737	$0	$0	$3,200	$0	$11,904	$104	$0	$2	$82	$0	$12
Total Labor Administrative and General Expense			$19,231,655	$10,542,120	$4,751,464	$3,938,071	$47,493	$23,466	$199	$86,460	$41,782	$108,059	$2,801	$1,362	$606	$2,234	$1,285	$3,327
Total Labor Operation and Maintenance Expenses			$71,538,724	$38,779,238	$17,970,758	$14,788,729	$174,793	$88,751	$752	$318,100	$158,026	$375,579	$10,305	$5,150	$2,288	$8,219	$4,859	$12,549
Depreciation Expenses																		
Steam Production	Prod	24	$51,173,949	$51,173,949	$0	$0	$252,236	$0	$0	$426,637	$0	$0	$13,919	$0	$0	$13,766	$0	$0
Hydraulic Production	Prod	24	$4,023,933	$4,023,933	$0	$0	$19,834	$0	$0	$33,548	$0	$0	$1,095	$0	$0	$1,082	$0	$0
Other Production	Prod	24	$16,258,222	$16,258,222	$0	$0	$80,137	$0	$0	$135,545	$0	$0	$4,422	$0	$0	$4,373	$0	$0
Transmission - Kentucky System Property	Trans	25	$9,613,105	$9,613,105	$0	$0	$37,432	$0	$0	$73,741	$0	$0	$2,359	$0	$0	$1,074	$0	$0
Transmission - Virginia Property	Trans	25	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	Dist	26	$37,717,920	$27,686,520	$0	$10,031,400	$96,500	$0	$132	$219,476	$0	$3,144,385	$7,021	$0	$562	$3,196	$0	$3,112
General Plant	PT&D	23	$20,055,398	$18,287,147	$0	$1,768,251	$80,859	$0	$23	$149,023	$0	$554,266	$4,827	$0	$99	$3,831	$0	$549
Intangible Plant	PT&D	23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Depreciation Expense			$138,842,527	$127,042,876	$0	$11,799,651	$566,999	$0	$155	$1,037,970	$0	$3,698,651	$33,642	$0	$661	$27,323	$0	$3,661
Regulatory Credits and Accretion Expenses																		
Production Plant			$0	$0	$0	$0												
Transmission Plant			$0	$0	$0	$0												
Distribution Plant			$0	$0	$0	$0												
Total Regulatory Credits and Accretion Expenses			$0	$0	$0	$0												
Property Taxes	TUP	34	$32,529,209	$29,664,969	$0	$2,864,240	$131,220	$0	$38	$241,769	$0	$897,808	$7,831	$0	$161	$6,221	$0	$889
Other Taxes	TUP	34	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Amortization of ITCs	TUP	34	-$1,002,535	-$914,260	$0	-$88,275	-$4,044	$0	-$1	-$7,451	$0	-$27,670	-$241	$0	-$5	-$192	$0	-$27
Interest	TUP	34	$62,185,554	$56,710,034	$0	$5,475,520	$250,852	$0	$72	$462,186	$0	$1,716,325	$14,970	$0	$307	$11,893	$0	$1,699
Other Expenses			$0	$0	$0	$0												
Total Other Expenses			$918,176,657	$380,916,406	$465,540,988	$71,719,263	$1,624,761	$2,327,152	$2,564	$2,800,077	$4,074,902	$8,202,578	$90,604	$132,708	$8,838	$74,773	$127,590	$48,405

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand
Allocation Amount

	Allocation Factor		Total Kentucky				Residential (RS)			General Service (GS)			Power Service-Primary (PS-Pri)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Energy (at the Meter)		1	11,646,473,901	-	11,646,473,901	-		4,180,088,831			1,358,379,221			165,297,553			1,874,492,273	
Energy (Loss Adjusted)(at Source)	Energy	2	12,308,166,695	-	12,308,166,695	-		4,452,824,321			1,447,008,491			172,341,135			1,996,796,030	
Customers (Monthly Bills)	Bills	3	6,001,330	-	-	6,001,330			4,369,310			542,844			864			33,890
Average Customers (Bills/12)	Cust	4	500,111	-	-	500,111			364,109			45,237			72			2,824
Average Customers (Lighting = Lights)	Cust	5	500,111	-	-	500,111			364,109			45,237			72			2,824
Weighted Average Customers (Lighting =9 Lights per Cust)	WghtCust	6	488,656	-	-	488,656			364,109			90,474			360			14,121
Street Lighting	Lighting	7	86,402	-	-	86,402			-			-			-			-
Average Customers	Customers	8	500,111	-	-	500,111			364,109			45,237			72			2,824
Average Customers (Lighting = 9 Lights per Cust)	WghtCust	9	422,358	-	-	422,358			364,109			45,237			72			2,824
Average Secondary Customers	CUST07	10	419,065	-	-	419,065			364,109			45,237						-
Average Primary Customers	CUST08	11	422,345	-	-	422,345			364,109			45,237			72			2,824
Average Transformer Customers	CUST09	12	422,165	-	-	422,165			364,109			45,237			-			2,824
Maximum Class Non-Coincident Peak Demands (Transmission)	NCPT	13	3,508,847	3,508,847	-	-	1,559,289			448,837			39,880			462,867		
Maximum Class Non-Coincident Peak Demands (Primary)	NCPP	14	3,249,885	3,249,885	-	-	1,559,289			448,837			39,880			462,867		
Sum of the Individual Customer Demands (Transformer)	SICDT	15	4,718,836	4,718,836	-	-	3,273,932			599,115			-			527,645		
Sum of the Individual Customer Demands (Secondary)	SICD	16	3,901,216	3,901,216	-	-	3,273,932			599,115						-		
Summer Peak Period Demand Allocator	SCP	17	2,733,720	2,733,720	-	-	1,069,022			386,318			31,860			449,716		
Winter Peak Period Demand Allocator	WCP	18	1,868,157	1,868,157	-	-	798,297			261,221			20,314			273,343		
Base Demand Allocator	BDEM	19	1,405,042	1,405,042	-	-	508,313			165,184			19,674			227,945		
Weighted cost of Services	C02	20	100.000000%	-	-	1			76.86170%			19.34360%			0.00000%			3.37460%
Weighted Cost of Meters	C03	21	100.000000%	-	-	1			69.99200%			20.57800%			0.80110%			5.53570%
Lighting Systems -- Lighting Customers	C04	22	100.000000%	-	-	1												
PT&D Plant	PT&D	23	4,110,427,911	3,748,018,334	-	362,409,577	$1,540,321,725	$0	$209,074,166	$459,158,034	$0	$34,099,741	$46,652,093	$0	$320,204	$553,996,990	$0	$3,839,622
Production Plant	Prod	24	2,305,549,928	2,305,549,928	-	-	$816,858,645	$0	$0	$264,444,271	$0	$0	$31,450,007	$0	$0	$366,460,244	$0	$0
Transmission Plant	Trans	25	442,223,222	442,223,222	-	-	$196,518,630	$0	$0	$56,567,341	$0	$0	$5,026,113	$0	$0	$58,335,555	$0	$0
Distribution Plant	Dist	26	1,362,654,761	1,000,245,184	-	362,409,577	$526,944,449	$0	$209,074,166	$138,146,422	$0	$34,099,741	$10,175,973	$0	$320,204	$129,201,191	$0	$3,839,622
Total Plant in Service	TPIS	27	4,331,626,534	3,949,214,564	-	382,411,970	$1,623,243,193	$0	$220,613,551	$483,837,702	$0	$35,981,800	$49,151,797	$0	$337,877	$583,698,396	$0	$4,051,542
Distrib Overhead + Underground Lines Plant	DLINES	28	857,428,693	748,355,940	-	109,072,753	$384,856,350	$0	$94,769,000	$104,464,210	$0	$11,774,126	$8,302,467	$0	$0	$96,362,536	$0	$0
Account 362	Acct362	29	152,675,045	152,675,045	-	-	$73,253,213	$0	$0	$21,085,734	$0	$0	$1,873,507	$0	$0	$21,744,843	$0	$0
Account 365	Acct365	30	528,239,740	444,382,960	-	83,856,780	$233,994,191	$0	$72,859,839	$62,267,112	$0	$9,052,126	$4,743,628	$0	$0	$55,056,893	$0	$0
Account 367	Acct367	31	329,188,953	303,972,981	-	25,215,972	$150,862,159	$0	$21,909,161	$42,197,098	$0	$2,722,000	$3,558,839	$0	$0	$41,305,643	$0	$0
Account 368	Acct368	32	168,599,875	99,214,198	-	69,385,677	$68,834,886	$0	$59,843,780	$12,596,478	$0	$7,435,007	$0	$0	$0	$11,093,811	$0	$464,144
Weighted Average Customers (Lighting =9 Lights per Cust)	C05	33	488,656	-	-	488,656			364,109			90,474			360			14,121
Total Utility Plant	TUP	34	4,455,168,264	4,062,884,854	-	392,283,410	$1,669,015,888	$0	$226,308,387	$497,630,702	$0	$36,910,621	$50,587,718	$0	$346,599	$600,714,888	$0	$4,156,127
Total Labor Excluding A&G	LBSUB7	35	52,307,069	28,237,118	13,219,294	10,850,657	$11,470,745	$4,785,718	$7,919,873	$3,461,026	$1,555,255	$1,991,589	$358,367	$184,935	$37,490	$4,189,365	$2,145,095	$391,743
Steam Power Operation Labor	LBSUB1	36	14,184,336	11,996,612	2,187,724	-	$4,250,412	$794,146	$0	$1,375,999	$258,125	$0	$163,646	$30,499	$0	$1,906,825	$355,318	$0
Total Steam Power Maintenance Labor Expense	LBSUB2	37	10,396,529	-	10,396,529	-	$ -	$ 3,761,236	$ -	$ -	$ 1,222,267	$ -	$ -	$ 145,574	$ -	$ -	$ 1,686,665	$ -
Total Hydraulic Power Maintenance Labor Expense	LBSUB4	38	244,786	93,746	151,040	-	$33,214	$54,643	$0	$10,753	$17,757	$0	$1,279	$2,115	$0	$14,901	$24,504	$0
Total Other Power Operating Labor Expense	LBSUB5	39	984,475	984,475	-	-	$348,800	$0	$0	$112,918	$0	$0	$13,429	$0	$0	$156,479	$0	$0
Total Distribution Operation Labor Expense	LBDO	40	9,509,829	4,611,957	-	4,897,872	$2,349,987	$0	$3,426,491	$640,333	$0	$926,116	$51,296	$0	$33,454	$609,209	$0	$233,200
Total Distribution Maintenance Labor Expense	LBDM	41	3,271,140	2,791,233	-	479,907	$1,456,817	$0	$410,860	$389,621	$0	$51,045	$30,010	$0	$0	$353,424	$0	$214
Total Steam Power Operation Labor Excl Superv. & Eng.	FO19	42	14,184,336	11,996,612	2,187,724	-	$4,250,412	$794,146	$0	$1,375,999	$258,125	$0	$163,646	$30,499	$0	$1,906,825	$355,318	$0
Total Steam Power Maintenance Labor Excl Superv. & Eng.	FO20	43	7,005,990	-	7,005,990	-	$0	$2,534,613	$0	$0	$823,659	$0	$0	$98,099	$0	$0	$1,136,606	$0
Total Hydraulic Power Maintenance Labor Excl. Super. & Eng.	FO22	44																
Distribution Operation Labor Excl. Super. & Eng	FO23	45	8,611,788	4,176,436	-	4,435,352	$2,128,071	$0	$3,102,917	$579,865	$0	$838,660	$46,452	$0	$30,295	$551,679	$0	$211,178
Purchased Power	PURCPWR	46	53,937,678	16,216,788	37,720,890	-	$6,341,580	$13,646,589	$0	$2,291,689	$4,434,653	$0	$188,998	$528,175	$0	$2,667,775	$6,119,589	$0
Acct 502: Steam Expense	OM502	47	18,526,106	18,526,106	-	-	$7,244,639	$0	$0	$2,618,033	$0	$0	$215,912	$0	$0	$3,047,674	$0	$0
Acct 505: Electric Expense	OM505	48	2,617,219	2,617,219	-	-	$1,023,464	$0	$0	$369,855	$0	$0	$30,502	$0	$0	$430,551	$0	$0
Total O&M Expense Less Purchased Power	O&MxPurch	49	631,684,224	152,195,999	427,820,098	51,668,127	$64,883,285	$155,211,477	$37,759,532	$19,535,501	$50,447,291	$9,087,551	$1,843,254	$5,968,546	$156,077	$22,174,093	$69,471,194	$1,692,159
Meter Reading	MREAD	50	480032						364,109			90,474			$360			$14,121
Time Differentiated Fuel Cost	TDFUEL	51	100.000000%		100.000000%			36.3001%			11.7988%			1.3941%			16.2414%	
Probability of Dispatch Gross Plant	PODPLT	52	100.000000%	100.000000%			0.354301			0.114699			0.013641			0.158947		
Probability of Dispatch Depreciation Reserve	PODRES	53	100.000000%	100.000000%			0.356513			0.114796			0.013595			0.158654		
Memo: Purchased Pwer Expense																		
Demand	Production Plant		$16,216,788	$16,216,788			$6,341,580	$0	$0	$2,291,689	$0	$0	$188,998	$0	$0	$2,667,775	$0	$0
Energy	Energy @ Source		$37,720,890		$37,720,890		$0	$13,646,589	$0	$0	$4,434,653	$0	$0	$528,175	$0	$0	$6,119,589	$0
Total			$53,937,678				$6,341,580	$13,646,589	$0	$2,291,689	$4,434,653	$0	$188,998	$528,175	$0	$2,667,775	$6,119,589	$0
Memo: Acct 502: Steam Expense																		
Demand	Production Plant		$18,526,106	$18,526,106			$7,244,639	$0	$0	$2,618,033	$0	$0	$215,912	$0	$0	$3,047,674	$0	$0
Energy	Energy @ Source		$0		$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total			$18,526,106				$7,244,639	$0	$0	$2,618,033	$0	$0	$215,912	$0	$0	$3,047,674	$0	$0
Memo: Acct 505: Electric Expense																		
Demand	Production Plant		$2,617,219	$2,617,219			$1,023,464	$0	$0	$369,855	$0	$0	$30,502	$0	$0	$430,551	$0	$0
Energy	Energy @ Source		$0		$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total			$2,617,219				$1,023,464	$0	$0	$369,855	$0	$0	$30,502	$0	$0	$430,551	$0	$0
Time Differentiated Fuel Cost																		
Fuel Cost Per KWH @ Meter								0.023036			0.023041			0.022372			0.022984	
KWH @ Meter								4,180,088,831			1,358,379,221			165,297,553			1,874,492,273	
Time Differentiated Fuel Cost			$265,267,783		$265,267,783			96,292,526			31,298,416			3,698,037			43,083,330	
Pct Allocation			100.0000%					36.3001%			11.7988%			1.3941%			16.2414%	

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Allocation Amount

	Allocation Factor			Total Kentucky			Time of Day-Pri (TOD-Pri)			Time of Day-Sec (TOD-Sec)			Retail Transmission (RTS)			Special Contract 1		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Energy (at the Meter)		1	11,646,473,901	-	11,646,473,901	-		1,848,687,110			795,801,135			1,147,609,709			109,874,900	
Energy (Loss Adjusted)(at Source)	Energy	2	12,308,166,695	-	12,308,166,695	-		1,927,462,502			847,724,245			1,173,677,077			114,556,838	
Customers (Monthly Bills)	Bills	3	6,001,330	-	-	6,001,330			1,266			3,312			156			12
Average Customers (Bills/12)	Cust	4	500,111	-	-	500,111			106			276			13			1
Average Customers (Lighting = Lights)	Cust	5	500,111	-	-	500,111			106			276			13			1
Weighted Average Customers (Lighting =9 Lights per Cust)	WghtCust	6	488,656	-	-	488,656			2,638			6,900			325			5
Street Lighting	Lighting	7	86,402	-	-	86,402			-			-			-			-
Average Customers	Customers	8	500,111	-	-	500,111			106			276			13			1
Average Customers (Lighting = 9 Lights per Cust)	WghtCust	9	422,358	-	-	422,358			106			276			13			1
Average Secondary Customers	CUST07	10	419,065	-	-	419,065			-			-			-			-
Average Primary Customers	CUST08	11	422,345	-	-	422,345			106			276						1
Average Transformer Customers	CUST09	12	422,165	-	-	422,165			-			276			-			-
Maximum Class Non-Coincident Peak Demands (Transmission)	NCPT	13	3,508,847	3,508,847	-	-	421,067			250,008			258,962			26,105		
Maximum Class Non-Coincident Peak Demands (Primary)	NCPP	14	3,249,885	3,249,885	-	-	421,067			250,008						26,105		
Sum of the Individual Customer Demands (Transformer)	SICDT	15	4,718,836	4,718,836	-	-	-			289,975			-			-		
Sum of the Individual Customer Demands (Secondary)	SICD	16	3,901,216	3,901,216	-	-	-			-			-			-		
Summer Peak Period Demand Allocator	SCP	17	2,733,720	2,733,720	-	-	340,132			229,732			196,716			21,241		
Winter Peak Period Demand Allocator	WCP	18	1,868,157	1,868,157	-	-	217,675			145,976			130,199			15,032		
Base Demand Allocator	BDEM	19	1,405,042	1,405,042	-	-	220,030			96,772			133,981			13,077		
Weighted cost of Services	C02	20	100.000000%	-	-	1			0.00000%			0.42010%			0.00000%			0.00000%
Weighted Cost of Meters	C03	21	100.000000%	-	-	1			1.25440%			0.58320%			1.02610%			0.01190%
Lighting Systems -- Lighting Customers	C04	22	100.000000%	-	-	1												
PT&D Plant	PT&D	23	4,110,427,911	3,748,018,334	-	362,409,577	$511,040,152	$0	$501,391	$311,877,017	$0	$423,230	$245,155,895	$0	$410,138	$30,927,008	$0	$4,756
Production Plant	Prod	24	2,305,549,928	2,305,549,928	-	-	$350,531,200	$0	$0	$210,478,264	$0	$0	$212,518,676	$0	$0	$20,975,893	$0	$0
Transmission Plant	Trans	25	442,223,222	442,223,222	-	-	$53,067,462	$0	$0	$31,508,739	$0	$0	$32,637,220	$0	$0	$3,290,037	$0	$0
Distribution Plant	Dist	26	1,362,654,761	1,000,245,184	-	362,409,577	$107,441,490	$0	$501,391	$69,890,015	$0	$423,230	$0	$0	$410,138	$6,661,078	$0	$4,756
Total Plant in Service	TPIS	27	4,331,626,534	3,949,214,564	-	382,411,970	$538,414,540	$0	$529,064	$328,591,957	$0	$446,589	$258,181,718	$0	$432,775	$32,583,964	$0	$5,019
Distrib Overhead + Underground Lines Plant	DLINES	28	857,428,693	748,355,940	-	109,072,753	$87,660,352	$0	$0	$52,048,223	$0	$0	$0	$0	$0	$5,434,702	$0	$0
Account 362	Acct362	29	152,675,045	152,675,045	-	-	$19,781,138	$0	$0	$11,745,026	$0	$0	$0	$0	$0	$1,226,376	$0	$0
Account 365	Acct365	30	528,239,740	444,382,960	-	83,856,780	$50,084,886	$0	$0	$29,737,838	$0	$0	$0	$0	$0	$3,105,126	$0	$0
Account 367	Acct367	31	329,188,953	303,972,981	-	25,215,972	$37,575,466	$0	$0	$22,310,385	$0	$0	$0	$0	$0	$2,329,576	$0	$0
Account 368	Acct368	32	168,599,875	99,214,198	-	69,385,677	$0	$0	$0	$6,096,766	$0	$45,362	$0	$0	$0	$0	$0	$0
Weighted Average Customers (Lighting =9 Lights per Cust)	C05	33	488,656	-	-	488,656			2,638			6,900			325			5
Total Utility Plant	TUP	34	4,455,168,264	4,062,884,854	-	392,283,410	$554,196,840	$0	$542,721	$338,207,822	$0	$458,117	$265,985,164	$0	$443,946	$33,536,989	$0	$5,149
Total Labor Excluding A&G	LBSUB7	35	52,307,069	28,237,118	13,219,294	10,850,657	$3,925,559	$2,068,012	$81,962	$2,359,258	$910,972	$101,978	$1,862,798	$1,257,558	$46,494	$237,570	$122,856	$553
Steam Power Operation Labor	LBSUB1	36	14,184,336	11,996,612	2,187,724	-	$1,823,941	$340,852	$0	$1,095,195	$151,084	$0	$1,105,812	$206,158	$0	$109,145	$20,214	$0
Total Steam Power Maintenance Labor Expense	LBSUB2	37	10,396,529	-	10,396,529	-	$ -	$ 1,628,099	$ -	$ -	$ 716,060	$ -	$ -	$ 991,388	$ -	$ -	$ 96,764	$ -
Total Hydraulic Power Maintenance Labor Expense	LBSUB4	38	244,786	93,746	151,040	-	$14,253	$23,653	$0	$8,558	$10,403	$0	$8,641	$14,403	$0	$853	$1,406	$0
Total Other Power Operating Labor Expense	LBSUB5	39	984,475	984,475	-	-	$149,678	$0	$0	$89,875	$0	$0	$90,746	$0	$0	$8,957	$0	$0
Total Distribution Operation Labor Expense	LBDO	40	9,509,829	4,611,957	-	4,897,872	$541,602	$0	$52,383	$329,182	$0	$24,592	$0	$0	$42,850	$33,578	$0	$497
Total Distribution Maintenance Labor Expense	LBDM	41	3,271,140	2,791,233	-	479,907	$316,856	$0	$0	$190,943	$0	$21	$0	$0	$0	$19,644	$0	$0
Total Steam Power Operation Labor Excl Superv. & Eng.	FO19	42	14,184,336	11,996,612	2,187,724	-	$1,823,941	$340,852	$0	$1,095,195	$151,084	$0	$1,105,812	$206,158	$0	$109,145	$20,214	$0
Total Steam Power Maintenance Labor Excl Superv. & Eng.	FO20	43	7,005,990	-	7,005,990	-	$0	$1,097,140	$0	$0	$482,537	$0	$0	$668,074	$0	$0	$65,207	$0
Total Hydraulic Power Maintenance Labor Excl. Super. & Eng.	FO22	44																
Distribution Operation Labor Excl. Super. & Eng	FO23	45	8,611,788	4,176,436	-	4,435,352	$490,457	$0	$47,437	$298,096	$0	$22,269	$0	$0	$38,803	$30,407	$0	$450
Purchased Power	PURCPWR	46	53,937,678	16,216,788	37,720,890	-	$2,017,708	$5,907,102	$0	$1,362,801	$2,598,024	$0	$1,166,945	$3,596,973	$0	$126,004	$351,083	$0
Acct 502: Steam Expense	OM502	47	18,526,106	18,526,106	-	-	$2,305,035	$0	$0	$1,556,867	$0	$0	$1,333,122	$0	$0	$143,948	$0	$0
Acct 505: Electric Expense	OM505	48	2,617,219	2,617,219	-	-	$325,637	$0	$0	$219,942	$0	$0	$188,333	$0	$0	$20,336	$0	$0
Total O&M Expense Less Purchased Power	O&MxPurch	49	631,684,224	152,195,999	427,820,098	51,668,127	$19,965,557	$66,712,484	$351,096	$12,198,638	$29,531,914	$456,836	$8,620,131	$40,395,779	$192,912	$1,219,560	$3,957,764	$2,301
Meter Reading	MREAD	50	480032						$2,638			$6,900			$325			$5
Time Differentiated Fuel Cost	TDFUEL	51	100.000000%		100.000000%			15.5802%			6.9060%			9.4234%			0.9240%	
Probability of Dispatch Gross Plant	PODPLT	52	100.000000%	100.000000%			0.152038			0.091292			0.092177			0.009098		
Probability of Dispatch Depreciation Reserve	PODRES	53	100.000000%	100.000000%			0.151333			0.090944			0.091502			0.009068		
Memo: Purchased Pwer Expense																		
Demand	Production Plant		$16,216,788	$16,216,788			$2,017,708	$0	$0	$1,362,801	$0	$0	$1,166,945	$0	$0	$126,004	$0	$0
Energy	Energy @ Source		$37,720,890		$37,720,890		$0	$5,907,102	$0	$0	$2,598,024	$0	$0	$3,596,973	$0	$0	$351,083	$0
Total			$53,937,678				$2,017,708	$5,907,102	$0	$1,362,801	$2,598,024	$0	$1,166,945	$3,596,973	$0	$126,004	$351,083	$0
Memo: Acct 502: Steam Expense																		
Demand	Production Plant		$18,526,106	$18,526,106			$2,305,035	$0	$0	$1,556,867	$0	$0	$1,333,122	$0	$0	$143,948	$0	$0
Energy	Energy @ Source		$0		$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total			$18,526,106				$2,305,035	$0	$0	$1,556,867	$0	$0	$1,333,122	$0	$0	$143,948	$0	$0
Memo: Acct 505: Electric Expense																		
Demand	Production Plant		$2,617,219	$2,617,219			$325,637	$0	$0	$219,942	$0	$0	$188,333	$0	$0	$20,336	$0	$0
Energy	Energy @ Source		$0		$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total			$2,617,219				$325,637	$0	$0	$219,942	$0	$0	$188,333	$0	$0	$20,336	$0	$0
Time Differentiated Fuel Cost																		
Fuel Cost Per KWH @ Meter								0.022356			0.02302			0.021782			0.022307	
KWH @ Meter								1,848,687,110			795,801,135			1,147,609,709			109,874,900	
Time Differentiated Fuel Cost			$265,267,783		$265,267,783			41,329,249			18,319,342			24,997,235			2,450,979	
Pct Allocation			100.0000%					15.5802%			6.9060%			9.4234%			0.9240%	

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Allocation Amount

	Allocation Factor		Total Kentucky				Special Contract 2			Street Lighting (RLS, LS, DSK)			Street Lighting-LE			Traffic Street Lighting (TLE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Energy (at the Meter)		1	11,646,473,901	-	11,646,473,901	-		58,046,500			101,770,582			3,317,374			3,108,713	
Energy (Loss Adjusted)(at Source)	Energy	2	12,308,166,695	-	12,308,166,695	-		60,519,950			108,410,740			3,533,821			3,311,545	
Customers (Monthly Bills)	Bills	3	6,001,330	-	-	6,001,330			12			1,036,824			1,980			10,860
Average Customers (Bills/12)	Cust	4	500,111	-	-	500,111			1			86,402			165			905
Average Customers (Lighting = Lights)	Cust	5	500,111	-	-	500,111			1			86,402			165			905
Weighted Average Customers (Lighting =9 Lights per Cust)	WghtCust	6	488,656	-	-	488,656			5			9,600			18			101
Street Lighting	Lighting	7	86,402	-	-	86,402			-			86,402			-			-
Average Customers	Customers	8	500,111	-	-	500,111			1			86,402			165			905
Average Customers (Lighting = 9 Lights per Cust)	WghtCust	9	422,358	-	-	422,358			1			9,600			18			101
Average Secondary Customers	CUST07	10	419,065	-	-	419,065			-			9,600			18			101
Average Primary Customers	CUST08	11	422,345	-	-	422,345			1			9,600			18			101
Average Transformer Customers	CUST09	12	422,165	-	-	422,165			-			9,600			18			101
Maximum Class Non-Coincident Peak Demands (Transmission)	NCPT	13	3,508,847	3,508,847	-	-	13,663			26,916			861			392		
Maximum Class Non-Coincident Peak Demands (Primary)	NCPP	14	3,249,885	3,249,885	-	-	13,663			26,916			861			392		
Sum of the Individual Customer Demands (Transformer)	SICDT	15	4,718,836	4,718,836	-	-	-			26,916			861			392		
Sum of the Individual Customer Demands (Secondary)	SICD	16	3,901,216	3,901,216	-	-	-			26,916			861			392		
Summer Peak Period Demand Allocator	SCP	17	2,733,720	2,733,720	-	-	8,598			-			-			385		
Winter Peak Period Demand Allocator	WCP	18	1,868,157	1,868,157	-	-	5,714			-			-			386		
Base Demand Allocator	BDEM	19	1,405,042	1,405,042	-	-	6,909			12,376			403			378		
Weighted cost of Services	C02	20	100.000000%	-	-	1			0.00000%			0.00000%			0.00000%			0.00000%
Weighted Cost of Meters	C03	21	100.000000%	-	-	1			0.01190%			0.00000%			0.03170%			0.17400%
Lighting Systems -- Lighting Customers	C04	22	100.000000%	-	-	1						100.00000%						
PT&D Plant	PT&D	23	4,110,427,911	3,748,018,334	-	362,409,577	$16,572,333	$0	$4,756	$30,542,748	$0	$113,598,821	$989,262	$0	$20,314	$785,076	$0	$112,437
Production Plant	Prod	24	2,305,549,928	2,305,549,928	-	-	$11,364,056	$0	$0	$19,221,370	$0	$0	$627,110	$0	$0	$620,193	$0	$0
Transmission Plant	Trans	25	442,223,222	442,223,222	-	-	$1,721,960	$0	$0	$3,392,248	$0	$0	$108,513	$0	$0	$49,404	$0	$0
Distribution Plant	Dist	26	1,362,654,761	1,000,245,184	-	362,409,577	$3,486,317	$0	$4,756	$7,929,130	$0	$113,598,821	$253,640	$0	$20,314	$115,478	$0	$112,437
Total Plant in Service	TPIS	27	4,331,626,534	3,949,214,564	-	382,411,970	$17,460,051	$0	$5,019	$32,181,869	$0	$119,868,656	$1,042,346	$0	$21,435	$827,030	$0	$118,642
Distrib Overhead + Underground Lines Plant	DLINES	28	857,428,693	748,355,940	-	109,072,753	$2,844,448	$0	$0	$6,098,742	$0	$2,498,654	$195,089	$0	$4,685	$88,821	$0	$26,288
Account 362	Acct362	29	152,675,045	152,675,045	-	-	$641,869	$0	$0	$1,264,476	$0	$0	$40,449	$0	$0	$18,416	$0	$0
Account 365	Acct365	30	528,239,740	444,382,960	-	83,856,780	$1,625,180	$0	$0	$3,600,495	$0	$1,921,003	$115,174	$0	$3,602	$52,437	$0	$20,211
Account 367	Acct367	31	329,188,953	303,972,981	-	25,215,972	$1,219,268	$0	$0	$2,498,247	$0	$577,651	$79,915	$0	$1,083	$36,384	$0	$6,077
Account 368	Acct368	32	168,599,875	99,214,198	-	69,385,677	$0	$0	$0	$565,913	$0	$1,577,825	$18,103	$0	$2,958	$8,242	$0	$16,600
Weighted Average Customers (Lighting =9 Lights per Cust)	C05	33	488,656	-	-	488,656			5			9,600			18			101
Total Utility Plant	TUP	34	4,455,168,264	4,062,884,854	-	392,283,410	$17,971,822	$0	$5,149	$33,112,465	$0	$122,962,901	$1,072,527	$0	$21,989	$852,029	$0	$121,705
Total Labor Excluding A&G	LBSUB7	35	52,307,069	28,237,118	13,219,294	10,850,657	$127,301	$65,286	$553	$231,641	$116,244	$267,520	$7,504	$3,788	$1,681	$5,986	$3,574	$9,223
Steam Power Operation Labor	LBSUB1	36	14,184,336	11,996,612	2,187,724	-	$59,131	$10,991	$0	$100,016	$19,112	$0	$3,263	$622	$0	$3,227	$603	$0
Total Steam Power Maintenance Labor Expense	LBSUB2	37	10,396,529	-	10,396,529	-	$ -	$ 51,120	$ -	$ -	$ 91,573	$ -	$ -	$ 2,985	$ -	$ -	$ 2,797	$ -
Total Hydraulic Power Maintenance Labor Expense	LBSUB4	38	244,786	93,746	151,040	-	$462	$743	$0	$782	$1,330	$0	$25	$43	$0	$25	$41	$0
Total Other Power Operating Labor Expense	LBSUB5	39	984,475	984,475	-	-	$4,852	$0	$0	$8,208	$0	$0	$268	$0	$0	$265	$0	$0
Total Distribution Operation Labor Expense	LBDO	40	9,509,829	4,611,957	-	4,897,872	$17,574	$0	$497	$37,452	$0	$149,050	$1,198	$0	$1,347	$545	$0	$7,397
Total Distribution Maintenance Labor Expense	LBDM	41	3,271,140	2,791,233	-	479,907	$10,281	$0	$0	$22,585	$0	$17,633	$722	$0	$20	$329	$0	$114
Total Steam Power Operation Labor Excl Superv. & Eng.	FO19	42	14,184,336	11,996,612	2,187,724	-	$59,131	$10,991	$0	$100,016	$19,112	$0	$3,263	$622	$0	$3,227	$603	$0
Total Steam Power Maintenance Labor Excl Superv. & Eng.	FO20	43	7,005,990	-	7,005,990	-	$0	$34,449	$0	$0	$61,709	$0	$0	$2,012	$0	$0	$1,885	$0
Total Hydraulic Power Maintenance Labor Excl. Super. & Eng.	FO22	44																
Distribution Operation Labor Excl. Super. & Eng	FO23	45	8,611,788	4,176,436	-	4,435,352	$15,915	$0	$450	$33,915	$0	$134,975	$1,085	$0	$1,220	$494	$0	$6,698
Purchased Power	PURCPWR	46	53,937,678	16,216,788	37,720,890	-	$51,004	$185,476	$0	$0	$332,247	$0	$0	$10,830	$0	$2,284	$10,149	$0
Acct 502: Steam Expense	OM502	47	18,526,106	18,526,106	-	-	$58,268	$0	$0	$0	$0	$0	$0	$0	$0	$2,609	$0	$0
Acct 505: Electric Expense	OM505	48	2,617,219	2,617,219	-	-	$8,232	$0	$0	$0	$0	$0	$0	$0	$0	$369	$0	$0
Total O&M Expense Less Purchased Power	O&MxPurch	49	631,684,224	152,195,999	427,820,098	51,668,127	$628,729	$2,141,676	$2,301	$1,065,604	$3,742,655	$1,917,465	$34,402	$121,878	$7,715	$27,245	$117,441	$42,184
Meter Reading	MREAD	50	480032						$5			0			176			919
Time Differentiated Fuel Cost	TDFUEL	51	100.000000%		100.000000%			0.5024%			0.8736%			0.0284%			0.0276%	
Probability of Dispatch Gross Plant	PODPLT	52	100.000000%	100.000000%			0.004929			0.008337			0.000272			0.000269		
Probability of Dispatch Depreciation Reserve	PODRES	53	100.000000%	100.000000%			0.004899			0.008164			0.000266			0.000266		
Memo: Purchased Pwer Expense																		
Demand	Production Plant		$16,216,788	$16,216,788			$51,004	$0	$0	$0	$0	$0	$0	$0	$0	$2,284	$0	$0
Energy	Energy @ Source		$37,720,890		$37,720,890		$0	$185,476	$0	$0	$332,247	$0	$0	$10,830	$0	$0	$10,149	$0
Total			$53,937,678				$51,004	$185,476	$0	$0	$332,247	$0	$0	$10,830	$0	$2,284	$10,149	$0
Memo: Acct 502: Steam Expense																		
Demand	Production Plant		$18,526,106	$18,526,106			$58,268	$0	$0	$0	$0	$0	$0	$0	$0	$2,609	$0	$0
Energy	Energy @ Source		$0		$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total			$18,526,106				$58,268	$0	$0	$0	$0	$0	$0	$0	$0	$2,609	$0	$0
Memo: Acct 505: Electric Expense																		
Demand	Production Plant		$2,617,219	$2,617,219			$8,232	$0	$0	$0	$0	$0	$0	$0	$0	$369	$0	$0
Energy	Energy @ Source		$0		$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total			$2,617,219				$8,232	$0	$0	$0	$0	$0	$0	$0	$0	$369	$0	$0
Time Differentiated Fuel Cost																		
Fuel Cost Per KWH @ Meter								0.022959			0.022771			0.022744			0.023518	
KWH @ Meter								58,046,500			101,770,582			3,317,374			3,108,713	
Time Differentiated Fuel Cost			$265,267,783		$265,267,783			1,332,690			2,317,418			75,450			73,111	
Pct Allocation			100.0000%					0.5024%			0.8736%			0.0284%			0.0276%	

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Allocation Percentge

	Allocation Factor		Total Kentucky				Residential (RS)			General Service (GS)			Power Service-Primary (PS-Pri)			Power Service-Secondary (PS-Sec)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Energy (at the Meter)	0	1	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	35.89145%	0.00000%	0.00000%	11.66344%	0.00000%	0.00000%	1.41929%	0.00000%	0.00000%	16.09493%	0.00000%
Energy (Loss Adjusted)(at Source)	Energy	2	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	36.17780%	0.00000%	0.00000%	11.75649%	0.00000%	0.00000%	1.40022%	0.00000%	0.00000%	16.22334%	0.00000%
Customers (Monthly Bills)	Bills	3	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	72.80569%	0.00000%	0.00000%	9.04539%	0.00000%	0.00000%	0.01440%	0.00000%	0.00000%	0.56471%
Average Customers (Bills/12)	Cust	4	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	72.80569%	0.00000%	0.00000%	9.04539%	0.00000%	0.00000%	0.01440%	0.00000%	0.00000%	0.56471%
Average Customers (Lighting = Lights)	Cust	5	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	72.80569%	0.00000%	0.00000%	9.04539%	0.00000%	0.00000%	0.01440%	0.00000%	0.00000%	0.56471%
Weighted Average Customers (Lighting =9 Lights per Cust)	WghtCust	6	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	74.51234%	0.00000%	0.00000%	18.51487%	0.00000%	0.00000%	0.07367%	0.00000%	0.00000%	2.88976%
Street Lighting	Lighting	7	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Average Customers	Customers	8	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	72.80569%	0.00000%	0.00000%	9.04539%	0.00000%	0.00000%	0.01440%	0.00000%	0.00000%	0.56471%
Average Customers (Lighting = 9 Lights per Cust)	WghtCust	9	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	86.20862%	0.00000%	0.00000%	10.71058%	0.00000%	0.00000%	0.01705%	0.00000%	0.00000%	0.66863%
Average Secondary Customers	CUST07	10	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	86.88604%	0.00000%	0.00000%	10.79475%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Average Primary Customers	CUST08	11	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	86.21127%	0.00000%	0.00000%	10.71091%	0.00000%	0.00000%	0.01705%	0.00000%	0.00000%	0.66865%
Average Transformer Customers	CUST09	12	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	86.24803%	0.00000%	0.00000%	10.71548%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.66893%
Maximum Class Non-Coincident Peak Demands (Transmission)	NCPT	13	100.00000%	100.00000%	0.00000%	0.00000%	44.43879%	0.00000%	0.00000%	12.79158%	0.00000%	0.00000%	1.13656%	0.00000%	0.00000%	13.19143%	0.00000%	0.00000%
Maximum Class Non-Coincident Peak Demands (Primary)	NCPP	14	100.00000%	100.00000%	0.00000%	0.00000%	47.97982%	0.00000%	0.00000%	13.81086%	0.00000%	0.00000%	1.22712%	0.00000%	0.00000%	14.24257%	0.00000%	0.00000%
Sum of the Individual Customer Demands (Transformer)	SICDT	15	100.00000%	100.00000%	0.00000%	0.00000%	69.38008%	0.00000%	0.00000%	12.69625%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	11.18168%	0.00000%	0.00000%
Sum of the Individual Customer Demands (Secondary)	SICD	16	100.00000%	100.00000%	0.00000%	0.00000%	83.92081%	0.00000%	0.00000%	15.35713%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Summer Peak Period Demand Allocator	SCP	17	100.00000%	100.00000%	0.00000%	0.00000%	39.10503%	0.00000%	0.00000%	14.13159%	0.00000%	0.00000%	1.16544%	0.00000%	0.00000%	16.45070%	0.00000%	0.00000%
Winter Peak Period Demand Allocator	WCP	18	100.00000%	100.00000%	0.00000%	0.00000%	42.73179%	0.00000%	0.00000%	13.98282%	0.00000%	0.00000%	1.08738%	0.00000%	0.00000%	14.63169%	0.00000%	0.00000%
Base Demand Allocator	BDEM	19	100.00000%	100.00000%	0.00000%	0.00000%	36.17780%	0.00000%	0.00000%	11.75649%	0.00000%	0.00000%	1.40022%	0.00000%	0.00000%	16.22334%	0.00000%	0.00000%
Weighted cost of Services	C02	20	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	76.86170%	0.00000%	0.00000%	19.34360%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	3.37460%
Weighted Cost of Meters	C03	21	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	69.99200%	0.00000%	0.00000%	20.57800%	0.00000%	0.00000%	0.80110%	0.00000%	0.00000%	5.53570%
Lighting Systems -- Lighting Customers	C04	22	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
PT&D Plant	PT&D	23	100.00000%	91.18317%	0.00000%	8.81683%	37.47351%	0.00000%	5.08643%	11.17057%	0.00000%	0.82959%	1.13497%	0.00000%	0.00779%	13.47784%	0.00000%	0.09341%
Production Plant	Prod	24	100.00000%	100.00000%	0.00000%	0.00000%	35.43010%	0.00000%	0.00000%	11.46990%	0.00000%	0.00000%	1.36410%	0.00000%	0.00000%	15.89470%	0.00000%	0.00000%
Transmission Plant	Trans	25	100.00000%	100.00000%	0.00000%	0.00000%	44.43879%	0.00000%	0.00000%	12.79158%	0.00000%	0.00000%	1.13656%	0.00000%	0.00000%	13.19143%	0.00000%	0.00000%
Distribution Plant	Dist	26	100.00000%	73.40415%	0.00000%	26.59585%	38.67043%	0.00000%	15.34315%	10.13804%	0.00000%	2.50245%	0.74678%	0.00000%	0.02350%	9.48158%	0.00000%	0.28178%
Total Plant in Service	TPIS	27	100.00000%	91.17163%	0.00000%	8.82837%	37.47422%	0.00000%	5.09309%	11.16988%	0.00000%	0.83068%	1.13472%	0.00000%	0.00780%	13.47527%	0.00000%	0.09353%
Distrib Overhead + Underground Lines Plant	DLINES	28	100.00000%	87.27909%	0.00000%	12.72091%	44.88494%	0.00000%	11.05270%	12.18343%	0.00000%	1.37319%	0.96830%	0.00000%	0.00000%	11.23855%	0.00000%	0.00000%
Account 362	Acct362	29	100.00000%	100.00000%	0.00000%	0.00000%	47.97982%	0.00000%	0.00000%	13.81086%	0.00000%	0.00000%	1.22712%	0.00000%	0.00000%	14.24257%	0.00000%	0.00000%
Account 365	Acct365	30	100.00000%	84.12524%	0.00000%	15.87476%	44.29697%	0.00000%	13.79295%	11.78766%	0.00000%	1.71364%	0.89801%	0.00000%	0.00000%	10.42271%	0.00000%	0.00000%
Account 367	Acct367	31	100.00000%	92.33997%	0.00000%	7.66003%	45.82844%	0.00000%	6.65550%	12.81850%	0.00000%	0.82688%	1.08109%	0.00000%	0.00000%	12.54770%	0.00000%	0.00000%
Account 368	Acct368	32	100.00000%	58.84595%	0.00000%	41.15405%	40.82736%	0.00000%	35.49456%	7.47123%	0.00000%	4.40985%	0.00000%	0.00000%	0.00000%	6.57996%	0.00000%	0.27529%
Weighted Average Customers (Lighting =9 Lights per Cust)	C05	33	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	74.51234%	0.00000%	0.00000%	18.51487%	0.00000%	0.00000%	0.07367%	0.00000%	0.00000%	2.88976%
Total Utility Plant	TUP	34	100.00000%	91.19487%	0.00000%	8.80513%	37.46247%	0.00000%	5.07968%	11.16974%	0.00000%	0.82849%	1.13548%	0.00000%	0.00778%	13.48355%	0.00000%	0.09329%
Total Labor Excluding A&G	LBSUB7	35	100.00000%	53.98337%	25.27248%	20.74415%	21.92963%	9.14928%	15.14111%	6.61675%	2.97332%	3.80749%	0.68512%	0.35356%	0.07167%	8.00917%	4.10097%	0.74893%
Steam Power Operation Labor	LBSUB1	36	100.00000%	84.57648%	15.42352%	0.00000%	29.96553%	5.59876%	0.00000%	9.70084%	1.81979%	0.00000%	1.15371%	0.21502%	0.00000%	13.44318%	2.50500%	0.00000%
Total Steam Power Maintenance Labor Expense	LBSUB2	37	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	36.17780%	0.00000%	0.00000%	11.75649%	0.00000%	0.00000%	1.40022%	0.00000%	0.00000%	16.22334%	0.00000%
Total Hydraulic Power Maintenance Labor Expense	LBSUB4	38	100.00000%	38.29712%	61.70288%	0.00000%	13.56871%	22.32274%	0.00000%	4.39264%	7.25409%	0.00000%	0.52241%	0.86397%	0.00000%	6.08721%	10.01027%	0.00000%
Total Other Power Operating Labor Expense	LBSUB5	39	100.00000%	100.00000%	0.00000%	0.00000%	35.43010%	0.00000%	0.00000%	11.46990%	0.00000%	0.00000%	1.36410%	0.00000%	0.00000%	15.89470%	0.00000%	0.00000%
Total Distribution Operation Labor Expense	LBDO	40	100.00000%	48.49673%	0.00000%	51.50327%	24.71114%	0.00000%	36.03105%	6.73338%	0.00000%	9.73851%	0.53940%	0.00000%	0.35178%	6.40610%	0.00000%	2.45220%
Total Distribution Maintenance Labor Expense	LBDM	41	100.00000%	85.32906%	0.00000%	14.67094%	44.53545%	0.00000%	12.56014%	11.91087%	0.00000%	1.56048%	0.91742%	0.00000%	0.00000%	10.80431%	0.00000%	0.00654%
Total Steam Power Operation Labor Excl Superv. & Eng.	FO19	42	100.00000%	84.57648%	15.42352%	0.00000%	29.96553%	5.59876%	0.00000%	9.70084%	1.81979%	0.00000%	1.15371%	0.21502%	0.00000%	13.44318%	2.50500%	0.00000%
Total Steam Power Maintenance Labor Excl Superv. & Eng.	FO20	43	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	36.17780%	0.00000%	0.00000%	11.75649%	0.00000%	0.00000%	1.40022%	0.00000%	0.00000%	16.22334%	0.00000%
Total Hydraulic Power Maintenance Labor Excl. Super. & Eng.	FO22	44																
Distribution Operation Labor Excl. Super. & Eng	FO23	45	100.00000%	48.49673%	0.00000%	51.50327%	24.71114%	0.00000%	36.03105%	6.73338%	0.00000%	9.73851%	0.53940%	0.00000%	0.35178%	6.40610%	0.00000%	2.45220%
Purchased Power	PURCPWR	46	100.00000%	30.06579%	69.93421%	0.00000%	11.75724%	25.30066%	0.00000%	4.24877%	8.22181%	0.00000%	0.35040%	0.97923%	0.00000%	4.94603%	11.34567%	0.00000%
Acct 502: Steam Expense	OM502	47	100.00000%	100.00000%	0.00000%	0.00000%	39.10503%	0.00000%	0.00000%	14.13159%	0.00000%	0.00000%	1.16544%	0.00000%	0.00000%	16.45070%	0.00000%	0.00000%
Acct 505: Electric Expense	OM505	48	100.00000%	100.00000%	0.00000%	0.00000%	39.10503%	0.00000%	0.00000%	14.13159%	0.00000%	0.00000%	1.16544%	0.00000%	0.00000%	16.45070%	0.00000%	0.00000%
Total O&M Expense Less Purchased Power	O&MxPurch	49	100.00000%	24.09368%	67.72689%	8.17942%	10.27147%	24.57105%	5.97760%	3.09261%	7.98616%	1.43862%	0.29180%	0.94486%	0.02471%	3.51031%	10.99777%	0.26788%
Meter Reading	MREAD	50	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	75.85098%	0.00000%	0.00000%	18.84749%	0.00000%	0.00000%	0.07500%	0.00000%	0.00000%	2.94168%
Time Differentiated Fuel Cost	TDFUEL	51	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	36.30012%	0.00000%	0.00000%	11.79880%	0.00000%	0.00000%	1.39408%	0.00000%	0.00000%	16.24145%	0.00000%
Probability of Dispatch Gross Plant	PODPLT	52	100.00000%	100.00000%	0.00000%	0.00000%	35.43010%	0.00000%	0.00000%	11.46990%	0.00000%	0.00000%	1.36410%	0.00000%	0.00000%	15.89470%	0.00000%	0.00000%
Probability of Dispatch Depreciation Reserve	PODRES	53	100.00000%	100.00000%	0.00000%	0.00000%	35.65130%	0.00000%	0.00000%	11.47960%	0.00000%	0.00000%	1.35950%	0.00000%	0.00000%	15.86540%	0.00000%	0.00000%
Memo: Purchased Pwer Expense																		
Demand	Production Plant		100.00000%	100.00000%	0.00000%	0.00000%	39.10503%	0.00000%	0.00000%	14.13159%	0.00000%	0.00000%	1.16544%	0.00000%	0.00000%	16.45070%	0.00000%	0.00000%
Energy	Energy @ Source		100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	36.17780%	0.00000%	0.00000%	11.75649%	0.00000%	0.00000%	1.40022%	0.00000%	0.00000%	16.22334%	0.00000%
Total			100.00000%	0.00000%	0.00000%	0.00000%	11.75724%	25.30066%	0.00000%	4.24877%	8.22181%	0.00000%	0.35040%	0.97923%	0.00000%	4.94603%	11.34567%	0.00000%
Memo: Acct 502: Steam Expense																		
Demand	Production Plant		100.00000%	100.00000%	0.00000%	0.00000%	39.10503%	0.00000%	0.00000%	14.13159%	0.00000%	0.00000%	1.16544%	0.00000%	0.00000%	16.45070%	0.00000%	0.00000%
Energy	Energy @ Source																	
Total			100.00000%	0.00000%	0.00000%	0.00000%	39.10503%	0.00000%	0.00000%	14.13159%	0.00000%	0.00000%	1.16544%	0.00000%	0.00000%	16.45070%	0.00000%	0.00000%
Memo: Acct 505: Electric Expense																		
Demand	Production Plant		100.00000%	100.00000%	0.00000%	0.00000%	39.10503%	0.00000%	0.00000%	14.13159%	0.00000%	0.00000%	1.16544%	0.00000%	0.00000%	16.45070%	0.00000%	0.00000%

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Allocation Percentge

	Allocation Factor		Total Kentucky				Time of Day-Pri (TOD-Pri)			Time of Day-Sec (TOD-Sec)			Retail Transmission (RTS)			Special Contract 1		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Energy (at the Meter)	0	1	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	15.87336%	0.00000%	0.00000%	6.83298%	0.00000%	0.00000%	9.85371%	0.00000%	0.00000%	0.94342%	0.00000%
Energy (Loss Adjusted)(at Source)	Energy	2	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	15.66003%	0.00000%	0.00000%	6.88749%	0.00000%	0.00000%	9.53576%	0.00000%	0.00000%	0.93074%	0.00000%
Customers (Monthly Bills)	Bills	3	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.02110%	0.00000%	0.00000%	0.05519%	0.00000%	0.00000%	0.00260%	0.00000%	0.00000%	0.00020%
Average Customers (Bills/12)	Cust	4	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.02110%	0.00000%	0.00000%	0.05519%	0.00000%	0.00000%	0.00260%	0.00000%	0.00000%	0.00020%
Average Customers (Lighting = Lights)	Cust	5	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.02110%	0.00000%	0.00000%	0.05519%	0.00000%	0.00000%	0.00260%	0.00000%	0.00000%	0.00020%
Weighted Average Customers (Lighting =9 Lights per Cust)	WghtCust	6	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.53985%	0.00000%	0.00000%	1.41204%	0.00000%	0.00000%	0.06651%	0.00000%	0.00000%	0.00102%
Street Lighting	Lighting	7	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Average Customers	Customers	8	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.02110%	0.00000%	0.00000%	0.05519%	0.00000%	0.00000%	0.00260%	0.00000%	0.00000%	0.00020%
Average Customers (Lighting = 9 Lights per Cust)	WghtCust	9	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.02510%	0.00000%	0.00000%	0.06535%	0.00000%	0.00000%	0.00308%	0.00000%	0.00000%	0.00024%
Average Secondary Customers	CUST07	10	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Average Primary Customers	CUST08	11	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.02510%	0.00000%	0.00000%	0.06535%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00024%
Average Transformer Customers	CUST09	12	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.06538%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Maximum Class Non-Coincident Peak Demands (Transmission)	NCPT	13	100.00000%	100.00000%	0.00000%	0.00000%	12.00015%	0.00000%	0.00000%	7.12508%	0.00000%	0.00000%	7.38026%	0.00000%	0.00000%	0.74398%	0.00000%	0.00000%
Maximum Class Non-Coincident Peak Demands (Primary)	NCPP	14	100.00000%	100.00000%	0.00000%	0.00000%	12.95637%	0.00000%	0.00000%	7.69283%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.80326%	0.00000%	0.00000%
Sum of the Individual Customer Demands (Transformer)	SICDT	15	100.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	6.14505%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Sum of the Individual Customer Demands (Secondary)	SICD	16	100.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Summer Peak Period Demand Allocator	SCP	17	100.00000%	100.00000%	0.00000%	0.00000%	12.44209%	0.00000%	0.00000%	8.40364%	0.00000%	0.00000%	7.19591%	0.00000%	0.00000%	0.77700%	0.00000%	0.00000%
Winter Peak Period Demand Allocator	WCP	18	100.00000%	100.00000%	0.00000%	0.00000%	11.65186%	0.00000%	0.00000%	7.81390%	0.00000%	0.00000%	6.96938%	0.00000%	0.00000%	0.80464%	0.00000%	0.00000%
Base Demand Allocator	BDEM	19	100.00000%	100.00000%	0.00000%	0.00000%	15.66003%	0.00000%	0.00000%	6.88749%	0.00000%	0.00000%	9.53576%	0.00000%	0.00000%	0.93074%	0.00000%	0.00000%
Weighted cost of Services	C02	20	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.42010%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Weighted Cost of Meters	C03	21	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	1.25440%	0.00000%	0.00000%	0.58320%	0.00000%	0.00000%	1.02610%	0.00000%	0.00000%	0.01190%
Lighting Systems -- Lighting Customers	C04	22	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
PT&D Plant	PT&D	23	100.00000%	91.18317%	0.00000%	8.81683%	12.43277%	0.00000%	0.01220%	7.58746%	0.00000%	0.01030%	5.96424%	0.00000%	0.00998%	0.75240%	0.00000%	0.00012%
Production Plant	Prod	24	100.00000%	100.00000%	0.00000%	0.00000%	15.20380%	0.00000%	0.00000%	9.12920%	0.00000%	0.00000%	9.21770%	0.00000%	0.00000%	0.90980%	0.00000%	0.00000%
Transmission Plant	Trans	25	100.00000%	100.00000%	0.00000%	0.00000%	12.00015%	0.00000%	0.00000%	7.12508%	0.00000%	0.00000%	7.38026%	0.00000%	0.00000%	0.74398%	0.00000%	0.00000%
Distribution Plant	Dist	26	100.00000%	73.40415%	0.00000%	26.59585%	7.88472%	0.00000%	0.03680%	5.12896%	0.00000%	0.03106%	0.00000%	0.00000%	0.03010%	0.48883%	0.00000%	0.00035%
Total Plant in Service	TPIS	27	100.00000%	91.17163%	0.00000%	8.82837%	12.42985%	0.00000%	0.01221%	7.58588%	0.00000%	0.01031%	5.96039%	0.00000%	0.00999%	0.75223%	0.00000%	0.00012%
Distrib Overhead + Underground Lines Plant	DLINES	28	100.00000%	87.27909%	0.00000%	12.72091%	10.22363%	0.00000%	0.00000%	6.07027%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.63384%	0.00000%	0.00000%
Account 362	Acct362	29	100.00000%	100.00000%	0.00000%	0.00000%	12.95637%	0.00000%	0.00000%	7.69283%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.80326%	0.00000%	0.00000%
Account 365	Acct365	30	100.00000%	84.12524%	0.00000%	15.87476%	9.48147%	0.00000%	0.00000%	5.62961%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.58783%	0.00000%	0.00000%
Account 367	Acct367	31	100.00000%	92.33997%	0.00000%	7.66003%	11.41456%	0.00000%	0.00000%	6.77738%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.70767%	0.00000%	0.00000%
Account 368	Acct368	32	100.00000%	58.84595%	0.00000%	41.15405%	0.00000%	0.00000%	0.00000%	3.61612%	0.00000%	0.02691%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Weighted Average Customers (Lighting =9 Lights per Cust)	C05	33	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.53985%	0.00000%	0.00000%	1.41204%	0.00000%	0.00000%	0.06651%	0.00000%	0.00000%	0.00102%
Total Utility Plant	TUP	34	100.00000%	91.19487%	0.00000%	8.80513%	12.43941%	0.00000%	0.01218%	7.59136%	0.00000%	0.01028%	5.97026%	0.00000%	0.00996%	0.75277%	0.00000%	0.00012%
Total Labor Excluding A&G	LBSUB7	35	100.00000%	53.98337%	25.27248%	20.74415%	7.50483%	3.95360%	0.15669%	4.51040%	1.74158%	0.19496%	3.56127%	2.40418%	0.08889%	0.45418%	0.23487%	0.00106%
Steam Power Operation Labor	LBSUB1	36	100.00000%	84.57648%	15.42352%	0.00000%	12.85884%	2.40302%	0.00000%	7.72116%	1.06515%	0.00000%	7.79601%	1.45342%	0.00000%	0.76948%	0.14251%	0.00000%
Total Steam Power Maintenance Labor Expense	LBSUB2	37	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	15.66003%	0.00000%	0.00000%	6.88749%	0.00000%	0.00000%	9.53576%	0.00000%	0.00000%	0.93074%	0.00000%
Total Hydraulic Power Maintenance Labor Expense	LBSUB4	38	100.00000%	38.29712%	61.70288%	0.00000%	5.82262%	9.66269%	0.00000%	3.49622%	4.24978%	0.00000%	3.53011%	5.88384%	0.00000%	0.34843%	0.57429%	0.00000%
Total Other Power Operating Labor Expense	LBSUB5	39	100.00000%	100.00000%	0.00000%	0.00000%	15.20380%	0.00000%	0.00000%	9.12920%	0.00000%	0.00000%	9.21770%	0.00000%	0.00000%	0.90980%	0.00000%	0.00000%
Total Distribution Operation Labor Expense	LBDO	40	100.00000%	48.49673%	0.00000%	51.50327%	5.69518%	0.00000%	0.55084%	3.46149%	0.00000%	0.25859%	0.00000%	0.00000%	0.45058%	0.35309%	0.00000%	0.00523%
Total Distribution Maintenance Labor Expense	LBDM	41	100.00000%	85.32906%	0.00000%	14.67094%	9.68640%	0.00000%	0.00000%	5.83720%	0.00000%	0.00064%	0.00000%	0.00000%	0.00000%	0.60053%	0.00000%	0.00000%
Total Steam Power Operation Labor Excl Superv. & Eng.	FO19	42	100.00000%	84.57648%	15.42352%	0.00000%	12.85884%	2.40302%	0.00000%	7.72116%	1.06515%	0.00000%	7.79601%	1.45342%	0.00000%	0.76948%	0.14251%	0.00000%
Total Steam Power Maintenance Labor Excl Superv. & Eng.	FO20	43	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	15.66003%	0.00000%	0.00000%	6.88749%	0.00000%	0.00000%	9.53576%	0.00000%	0.00000%	0.93074%	0.00000%
Total Hydraulic Power Maintenance Labor Excl. Super. & Eng.	FO22	44																
Distribution Operation Labor Excl. Super. & Eng	FO23	45	100.00000%	48.49673%	0.00000%	51.50327%	5.69518%	0.00000%	0.55084%	3.46149%	0.00000%	0.25859%	0.00000%	0.00000%	0.45058%	0.35309%	0.00000%	0.00523%
Purchased Power	PURCPWR	46	100.00000%	30.06579%	69.93421%	0.00000%	3.74081%	10.95172%	0.00000%	2.52662%	4.81671%	0.00000%	2.16351%	6.66876%	0.00000%	0.23361%	0.65090%	0.00000%
Acct 502: Steam Expense	OM502	47	100.00000%	100.00000%	0.00000%	0.00000%	12.44209%	0.00000%	0.00000%	8.40364%	0.00000%	0.00000%	7.19591%	0.00000%	0.00000%	0.77700%	0.00000%	0.00000%
Acct 505: Electric Expense	OM505	48	100.00000%	100.00000%	0.00000%	0.00000%	12.44209%	0.00000%	0.00000%	8.40364%	0.00000%	0.00000%	7.19591%	0.00000%	0.00000%	0.77700%	0.00000%	0.00000%
Total O&M Expense Less Purchased Power	O&MxPurch	49	100.00000%	24.09368%	67.72689%	8.17942%	3.16069%	10.56105%	0.05558%	1.93113%	4.67511%	0.07232%	1.36463%	6.39493%	0.03054%	0.19306%	0.62654%	0.00036%
Meter Reading	MREAD	50	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.54955%	0.00000%	0.00000%	1.43740%	0.00000%	0.00000%	0.06770%	0.00000%	0.00000%	0.00104%
Time Differentiated Fuel Cost	TDFUEL	51	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	15.58020%	0.00000%	0.00000%	6.90598%	0.00000%	0.00000%	9.42340%	0.00000%	0.00000%	0.92396%	0.00000%
Probability of Dispatch Gross Plant	PODPLT	52	100.00000%	100.00000%	0.00000%	0.00000%	15.20380%	0.00000%	0.00000%	9.12920%	0.00000%	0.00000%	9.21770%	0.00000%	0.00000%	0.90980%	0.00000%	0.00000%
Probability of Dispatch Depreciation Reserve	PODRES	53	100.00000%	100.00000%	0.00000%	0.00000%	15.13330%	0.00000%	0.00000%	9.09440%	0.00000%	0.00000%	9.15020%	0.00000%	0.00000%	0.90680%	0.00000%	0.00000%
Memo: Purchased Pwer Expense																		
Demand	Production Plant		100.00000%	100.00000%	0.00000%	0.00000%	12.44209%	0.00000%	0.00000%	8.40364%	0.00000%	0.00000%	7.19591%	0.00000%	0.00000%	0.77700%	0.00000%	0.00000%
Energy	Energy @ Source		100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	15.66003%	0.00000%	0.00000%	6.88749%	0.00000%	0.00000%	9.53576%	0.00000%	0.00000%	0.93074%	0.00000%
Total			100.00000%	0.00000%	0.00000%	0.00000%	3.74081%	10.95172%	0.00000%	2.52662%	4.81671%	0.00000%	2.16351%	6.66876%	0.00000%	0.23361%	0.65090%	0.00000%
Memo: Acct 502: Steam Expense																		
Demand	Production Plant		100.00000%	100.00000%	0.00000%	0.00000%	12.44209%	0.00000%	0.00000%	8.40364%	0.00000%	0.00000%	7.19591%	0.00000%	0.00000%	0.77700%	0.00000%	0.00000%
Energy	Energy @ Source																	
Total			100.00000%	0.00000%	0.00000%	0.00000%	12.44209%	0.00000%	0.00000%	8.40364%	0.00000%	0.00000%	7.19591%	0.00000%	0.00000%	0.77700%	0.00000%	0.00000%
Memo: Acct 505: Electric Expense																		
Demand	Production Plant		100.00000%	100.00000%	0.00000%	0.00000%	12.44209%	0.00000%	0.00000%	8.40364%	0.00000%	0.00000%	7.19591%	0.00000%	0.00000%	0.77700%	0.00000%	0.00000%

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Allocation Percentge

	Allocation Factor		Total Kentucky				Special Contract 2			Street Lighting (RLS, LS, DSK)			Street Lighting-LE			Traffic Street Lighting (TLE)		
	Name	No	Total	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Energy (at the Meter)	0	1	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.49840%	0.00000%	0.00000%	0.87383%	0.00000%	0.00000%	0.02848%	0.00000%	0.00000%	0.02669%	0.00000%
Energy (Loss Adjusted)(at Source)	Energy	2	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.49171%	0.00000%	0.00000%	0.88080%	0.00000%	0.00000%	0.02871%	0.00000%	0.00000%	0.02691%	0.00000%
Customers (Monthly Bills)	Bills	3	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00020%	0.00000%	0.00000%	17.27657%	0.00000%	0.00000%	0.03299%	0.00000%	0.00000%	0.18096%
Average Customers (Bills/12)	Cust	4	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00020%	0.00000%	0.00000%	17.27657%	0.00000%	0.00000%	0.03299%	0.00000%	0.00000%	0.18096%
Average Customers (Lighting = Lights)	Cust	5	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00020%	0.00000%	0.00000%	17.27657%	0.00000%	0.00000%	0.03299%	0.00000%	0.00000%	0.18096%
Weighted Average Customers (Lighting =9 Lights per Cust)	WghtCust	6	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00102%	0.00000%	0.00000%	1.96457%	0.00000%	0.00000%	0.00368%	0.00000%	0.00000%	0.02067%
Street Lighting	Lighting	7	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Average Customers	Customers	8	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00020%	0.00000%	0.00000%	17.27657%	0.00000%	0.00000%	0.03299%	0.00000%	0.00000%	0.18096%
Average Customers (Lighting = 9 Lights per Cust)	WghtCust	9	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00024%	0.00000%	0.00000%	2.27295%	0.00000%	0.00000%	0.00426%	0.00000%	0.00000%	0.02391%
Average Secondary Customers	CUST07	10	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	2.29081%	0.00000%	0.00000%	0.00430%	0.00000%	0.00000%	0.02410%
Average Primary Customers	CUST08	11	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00024%	0.00000%	0.00000%	2.27302%	0.00000%	0.00000%	0.00426%	0.00000%	0.00000%	0.02391%
Average Transformer Customers	CUST09	12	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	2.27399%	0.00000%	0.00000%	0.00426%	0.00000%	0.00000%	0.02392%
Maximum Class Non-Coincident Peak Demands (Transmission)	NCPT	13	100.00000%	100.00000%	0.00000%	0.00000%	0.38939%	0.00000%	0.00000%	0.76709%	0.00000%	0.00000%	0.02454%	0.00000%	0.00000%	0.01117%	0.00000%	0.00000%
Maximum Class Non-Coincident Peak Demands (Primary)	NCPP	14	100.00000%	100.00000%	0.00000%	0.00000%	0.42041%	0.00000%	0.00000%	0.82821%	0.00000%	0.00000%	0.02649%	0.00000%	0.00000%	0.01206%	0.00000%	0.00000%
Sum of the Individual Customer Demands (Transformer)	SICDT	15	100.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.57039%	0.00000%	0.00000%	0.01825%	0.00000%	0.00000%	0.00831%	0.00000%	0.00000%
Sum of the Individual Customer Demands (Secondary)	SICD	16	100.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.68994%	0.00000%	0.00000%	0.02207%	0.00000%	0.00000%	0.01005%	0.00000%	0.00000%
Summer Peak Period Demand Allocator	SCP	17	100.00000%	100.00000%	0.00000%	0.00000%	0.31452%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.01408%	0.00000%	0.00000%
Winter Peak Period Demand Allocator	WCP	18	100.00000%	100.00000%	0.00000%	0.00000%	0.30586%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.02066%	0.00000%	0.00000%
Base Demand Allocator	BDEM	19	100.00000%	100.00000%	0.00000%	0.00000%	0.49171%	0.00000%	0.00000%	0.88080%	0.00000%	0.00000%	0.02871%	0.00000%	0.00000%	0.02691%	0.00000%	0.00000%
Weighted cost of Services	C02	20	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
Weighted Cost of Meters	C03	21	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.01190%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.03170%	0.00000%	0.00000%	0.17400%
Lighting Systems -- Lighting Customers	C04	22	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
PT&D Plant	PT&D	23	100.00000%	91.18317%	0.00000%	8.81683%	0.40318%	0.00000%	0.00012%	0.74306%	0.00000%	2.76367%	0.02407%	0.00000%	0.00049%	0.01910%	0.00000%	0.00274%
Production Plant	Prod	24	100.00000%	100.00000%	0.00000%	0.00000%	0.49290%	0.00000%	0.00000%	0.83370%	0.00000%	0.00000%	0.02720%	0.00000%	0.00000%	0.02690%	0.00000%	0.00000%
Transmission Plant	Trans	25	100.00000%	100.00000%	0.00000%	0.00000%	0.38939%	0.00000%	0.00000%	0.76709%	0.00000%	0.00000%	0.02454%	0.00000%	0.00000%	0.01117%	0.00000%	0.00000%
Distribution Plant	Dist	26	100.00000%	73.40415%	0.00000%	26.59585%	0.25585%	0.00000%	0.00035%	0.58189%	0.00000%	8.33658%	0.01861%	0.00000%	0.00149%	0.00847%	0.00000%	0.00825%
Total Plant in Service	TPIS	27	100.00000%	91.17163%	0.00000%	8.82837%	0.40308%	0.00000%	0.00012%	0.74295%	0.00000%	2.76729%	0.02406%	0.00000%	0.00049%	0.01909%	0.00000%	0.00274%
Distrib Overhead + Underground Lines Plant	DLINES	28	100.00000%	87.27909%	0.00000%	12.72091%	0.33174%	0.00000%	0.00000%	0.71128%	0.00000%	0.29141%	0.02275%	0.00000%	0.00055%	0.01036%	0.00000%	0.00307%
Account 362	Acct362	29	100.00000%	100.00000%	0.00000%	0.00000%	0.42041%	0.00000%	0.00000%	0.82821%	0.00000%	0.00000%	0.02649%	0.00000%	0.00000%	0.01206%	0.00000%	0.00000%
Account 365	Acct365	30	100.00000%	84.12524%	0.00000%	15.87476%	0.30766%	0.00000%	0.00000%	0.68160%	0.00000%	0.36366%	0.02180%	0.00000%	0.00068%	0.00993%	0.00000%	0.00383%
Account 367	Acct367	31	100.00000%	92.33997%	0.00000%	7.66003%	0.37039%	0.00000%	0.00000%	0.75891%	0.00000%	0.17548%	0.02428%	0.00000%	0.00033%	0.01105%	0.00000%	0.00185%
Account 368	Acct368	32	100.00000%	58.84595%	0.00000%	41.15405%	0.00000%	0.00000%	0.00000%	0.33565%	0.00000%	0.93584%	0.01074%	0.00000%	0.00175%	0.00489%	0.00000%	0.00985%
Weighted Average Customers (Lighting =9 Lights per Cust)	C05	33	100.00000%	0.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.00102%	0.00000%	0.00000%	1.96457%	0.00000%	0.00000%	0.00368%	0.00000%	0.00000%	0.02067%
Total Utility Plant	TUP	34	100.00000%	91.19487%	0.00000%	8.80513%	0.40339%	0.00000%	0.00012%	0.74324%	0.00000%	2.76001%	0.02407%	0.00000%	0.00049%	0.01912%	0.00000%	0.00273%
Total Labor Excluding A&G	LBSUB7	35	100.00000%	53.98337%	25.27248%	20.74415%	0.24337%	0.12481%	0.00106%	0.44285%	0.22223%	0.51144%	0.01435%	0.00724%	0.00321%	0.01144%	0.00683%	0.01763%
Steam Power Operation Labor	LBSUB1	36	100.00000%	84.57648%	15.42352%	0.00000%	0.41688%	0.07749%	0.00000%	0.70511%	0.13474%	0.00000%	0.02300%	0.00439%	0.00000%	0.02275%	0.00425%	0.00000%
Total Steam Power Maintenance Labor Expense	LBSUB2	37	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.49171%	0.00000%	0.00000%	0.88080%	0.00000%	0.00000%	0.02871%	0.00000%	0.00000%	0.02691%	0.00000%
Total Hydraulic Power Maintenance Labor Expense	LBSUB4	38	100.00000%	38.29712%	61.70288%	0.00000%	0.18877%	0.30340%	0.00000%	0.31928%	0.54348%	0.00000%	0.01042%	0.01772%	0.00000%	0.01030%	0.01660%	0.00000%
Total Other Power Operating Labor Expense	LBSUB5	39	100.00000%	100.00000%	0.00000%	0.00000%	0.49290%	0.00000%	0.00000%	0.83370%	0.00000%	0.00000%	0.02720%	0.00000%	0.00000%	0.02690%	0.00000%	0.00000%
Total Distribution Operation Labor Expense	LBDO	40	100.00000%	48.49673%	0.00000%	51.50327%	0.18480%	0.00000%	0.00523%	0.39382%	0.00000%	1.56732%	0.01260%	0.00000%	0.01416%	0.00574%	0.00000%	0.07778%
Total Distribution Maintenance Labor Expense	LBDM	41	100.00000%	85.32906%	0.00000%	14.67094%	0.31431%	0.00000%	0.00000%	0.69042%	0.00000%	0.53904%	0.02209%	0.00000%	0.00062%	0.01006%	0.00000%	0.00348%
Total Steam Power Operation Labor Excl Superv. & Eng.	FO19	42	100.00000%	84.57648%	15.42352%	0.00000%	0.41688%	0.07749%	0.00000%	0.70511%	0.13474%	0.00000%	0.02300%	0.00439%	0.00000%	0.02275%	0.00425%	0.00000%
Total Steam Power Maintenance Labor Excl Superv. & Eng.	FO20	43	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.49171%	0.00000%	0.00000%	0.88080%	0.00000%	0.00000%	0.02871%	0.00000%	0.00000%	0.02691%	0.00000%
Total Hydraulic Power Maintenance Labor Excl. Super. & Eng.	FO22	44																
Distribution Operation Labor Excl. Super. & Eng	FO23	45	100.00000%	48.49673%	0.00000%	51.50327%	0.18480%	0.00000%	0.00523%	0.39382%	0.00000%	1.56732%	0.01260%	0.00000%	0.01416%	0.00574%	0.00000%	0.07778%
Purchased Power	PURCPWR	46	100.00000%	30.06579%	69.93421%	0.00000%	0.09456%	0.34387%	0.00000%	0.00000%	0.61598%	0.00000%	0.00000%	0.02008%	0.00000%	0.00423%	0.01882%	0.00000%
Acct 502: Steam Expense	OM502	47	100.00000%	100.00000%	0.00000%	0.00000%	0.31452%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.01408%	0.00000%	0.00000%
Acct 505: Electric Expense	OM505	48	100.00000%	100.00000%	0.00000%	0.00000%	0.31452%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.01408%	0.00000%	0.00000%
Total O&M Expense Less Purchased Power	O&MxPurch	49	100.00000%	24.09368%	67.72689%	8.17942%	0.09953%	0.33904%	0.00036%	0.16869%	0.59249%	0.30355%	0.00545%	0.01929%	0.00122%	0.00431%	0.01859%	0.00668%
Meter Reading	MREAD	50	100.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00104%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.03666%	0.00000%	0.00000%	0.19145%
Time Differentiated Fuel Cost	TDFUEL	51	100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.50239%	0.00000%	0.00000%	0.87361%	0.00000%	0.00000%	0.02844%	0.00000%	0.00000%	0.02756%	0.00000%
Probability of Dispatch Gross Plant	PODPLT	52	100.00000%	100.00000%	0.00000%	0.00000%	0.49290%	0.00000%	0.00000%	0.83370%	0.00000%	0.00000%	0.02720%	0.00000%	0.00000%	0.02690%	0.00000%	0.00000%
Probability of Dispatch Depreciation Reserve	PODRES	53	100.00000%	100.00000%	0.00000%	0.00000%	0.48990%	0.00000%	0.00000%	0.81640%	0.00000%	0.00000%	0.02660%	0.00000%	0.00000%	0.02660%	0.00000%	0.00000%
Memo: Purchased Pwer Expense																		
Demand	Production Plant		100.00000%	100.00000%	0.00000%	0.00000%	0.31452%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.01408%	0.00000%	0.00000%
Energy	Energy @ Source		100.00000%	0.00000%	100.00000%	0.00000%	0.00000%	0.49171%	0.00000%	0.00000%	0.88080%	0.00000%	0.00000%	0.02871%	0.00000%	0.00000%	0.02691%	0.00000%
Total			100.00000%	0.00000%	0.00000%	0.00000%	0.09456%	0.34387%	0.00000%	0.00000%	0.61598%	0.00000%	0.00000%	0.02008%	0.00000%	0.00423%	0.01882%	0.00000%
Memo: Acct 502: Steam Expense																		
Demand	Production Plant		100.00000%	100.00000%	0.00000%	0.00000%	0.31452%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.01408%	0.00000%	0.00000%
Energy	Energy @ Source																	
Total			100.00000%	0.00000%	0.00000%	0.00000%	0.31452%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.01408%	0.00000%	0.00000%
Memo: Acct 505: Electric Expense																		
Demand	Production Plant		100.00000%	100.00000%	0.00000%	0.00000%	0.31452%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.01408%	0.00000%	0.00000%
Energy	Energy @ Source																	

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100%
Demand Functionalization/Classification

Functionalization ---->	Classification Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->	Name	No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Rate Base															
Plant in Service															
Intangible Plant															
301.00 ORGANIZATION	PT&D	1	$2,240	$1,257	$0	$0	$241	$0	$0	$545	$0	$198	$2,043	$0	$198
302.00 FRANCHISE AND CONSENTS	PT&D	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
303.00 SOFTWARE	PT&D	1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Intangible Plant			$2,240	$1,257	$0	$0	$241	$0	$0	$545	$0	$198	$2,043	$0	$198
Production Plant															
Total Production Plant		$2,305,549,928													
Demand	100.0000%		$2,305,549,928	$2,305,549,928									$2,305,549,928	$0	$0
Energy	0.0000%		$0		$0								$0	$0	$0
Total Production Plant			**$2,305,549,928**	**$2,305,549,928**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$2,305,549,928**	**$0**	**$0**
Transmission															
KENTUCKY SYSTEM PROPERTY		Dir	$442,223,222				$442,223,222						$442,223,222	$0	$0
VIRGINIA PROPERTY - 500 KV LINE		Dir					$0						$0	$0	$0
Total Transmission Plant			$442,223,222	$0	$0	$0	$442,223,222	$0	$0	$0	$0	$0	$442,223,222	$0	$0
Distribution															
TOTAL ACCTS 360-362		Dir	$152,675,045							$152,675,045			$152,675,045	$0	$0
364 & 365-OVERHEAD LINES		$528,239,740													
Primary:			$386,565,842												
Demand	100.0000%	Demand								$386,565,842			$386,565,842	$0	$0
Customer	0.0000%	Cust										$0	$0	$0	$0
Secondary:			$141,673,898												
Demand	40.8100%	Demand								$57,817,118			$57,817,118	$0	$0
Customer	59.1900%	Cust										$83,856,780	$0	$0	$83,856,780
366 & 367-UNDERGROUND LINES		$329,188,953													
Primary:			$290,015,468												
Demand	100.0000%	Demand								$290,015,468			$290,015,468	$0	$0
Customer	0.0000%	Cust										$0	$0	$0	$0
Secondary:			$39,173,485												
Demand	35.6300%	Demand								$13,957,513			$13,957,513	$0	$0
Customer	64.3700%	Cust										$25,215,972	$0	$0	$25,215,972
368-TRANSFORMERS - POWER POOL:															
Demand		Demand								$0.00			$0	$0	$0
Customer		Customer										$0	$0	$0	$0
368-TRANSFORMERS - ALL OTHER:		Demand	$168,599,875												
Demand	58.8460%	Demand								$99,214,198			$99,214,198	$0	$0
Customer	41.1541%	Customer										$69,385,677	$0	$0	$69,385,677
369-SERVICES		Dir	$34,458,226									$34,458,226	$0	$0	$34,458,226
370-METERS		370-METERS	$39,970,580									$39,970,580	$0	$0	$39,970,580
371-CUSTOMER INSTALLATION		371-CUSTOMER INSTALLATION										$0	$0	$0	$0
373-STREET LIGHTING		373-STREET LIGHTING	$109,522,342									$109,522,342	$0	$0	$109,522,342
Total Distribution Plant	Dist		$1,362,654,761	$0	$0	$0	$0	$0	$0	$1,000,245,184	$0	$362,409,577	$1,000,245,184	$0	$362,409,577
Total Prod, Trans, and Dist Plant			**$4,110,427,911**	**$2,305,549,928**	**$0**	**$0**	**$442,223,222**	**$0**	**$0**	**$1,000,245,184**	**$0**	**$362,409,577**	**$3,748,018,334**	**$0**	**$362,409,577**
General Plant															
Total General Plant	PT&D	1	$15,832,612	$8,880,554	$0	$0	$1,703,362	$0	$0	$3,852,760	$0	$1,395,935	$14,436,677	$0	$1,395,935
TOTAL COMMON PLANT	PT&D	1	$202,237,020	$113,435,281	$0	$0	$21,757,809	$0	$0	$49,213,028	$0	$17,830,901	$184,406,119	$0	$17,830,901
106.00 COMPLETED CONSTR NOT CLASSIFIED			$0												
105.00 PLANT HELD FOR FUTURE USE - PRODUCT	PROD	2	$211,410	$211,410	$0	$0	$0	$0	$0	$0	$0	$0	$211,410	$0	$0
105.00 PLANT HELD FOR FUTURE USE - DISTRIBU	DIST	4	$2,915,340	$0	$0	$0	$0	$0	$0	$2,139,981	$0	$775,359	$2,139,981	$0	$775,359
OTHER			$0												
Total Plant in Service			$4,331,626,534	$2,428,078,430	$0	$0	$465,684,635	$0	$0	$1,055,451,498	$0	$382,411,970	$3,949,214,564	$0	$382,411,970
Construction Work in Progress (CWIP)															
CWIP Production	PROD	2	$67,084,848	$67,084,848	$0	$0	$0	$0	$0	$0	$0	$0	$67,084,848	$0	$0
CWIP Transmission	TRANS	3	$6,861,294	$0	$0	$0	$6,861,294	$0	$0	$0	$0	$0	$6,861,294	$0	$0
CWIP Distribution Plant	DIST	4	$30,927,921	$0	$0	$0	$0	$0	$0	$22,702,378	$0	$8,225,543	$22,702,378	$0	$8,225,543
CWIP General Plant	PT&D	1	$18,667,667	$10,470,744	$0	$0	$2,008,374	$0	$0	$4,542,652	$0	$1,645,897	$17,021,770	$0	$1,645,897
RWIP			$0												
Total Construction Work in Progress			$123,541,730	$77,555,592	$0	$0	$8,869,668	$0	$0	$27,245,031	$0	$9,871,440	$113,670,290	$0	$9,871,440
Total Gross Utility Plant			$4,455,168,264	$2,505,634,022	$0	$0	$474,554,303	$0	$0	$1,082,696,529	$0	$392,283,410	$4,062,884,854	$0	$392,283,410

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100%
Demand Functionalization/Classification

Functionalization ---->	Classification Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->	Name	No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Less: Acummulated Provision for Depreciation															
Production	PROD	2	$903,942,138	$903,942,138	$0	$0	$0	$0	$0	$0	$0	$0	$903,942,138	$0	$0
	PROD	2		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	PROD	2		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission - Kentucky System Property	TRANS	3	$159,969,049	$0	$0	$0	$159,969,049	$0	$0	$0	$0	$0	$159,969,049	$0	$0
	TRANS	3		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	DIST	4	$508,037,556	$0	$0	$0	$0	$0	$0	$372,920,664	$0	$135,116,892	$372,920,664	$0	$135,116,892
General Plant	PT&D	1	$71,121,012	$39,891,964	$0	$0	$7,651,603	$0	$0	$17,306,823	$0	$6,270,621	$64,850,391	$0	$6,270,621
Intangible Plant	PT&D	1	$40,982,991	$22,987,468	$0	$0	$4,409,183	$0	$0	$9,972,937	$0	$3,613,402	$37,369,589	$0	$3,613,402
Total Accumulated Depreciation			$1,684,052,746	$966,821,571	$0	$0	$172,029,835	$0	$0	$400,200,425	$0	$145,000,915	$1,539,051,831	$0	$145,000,915
Net Utility Plant			$2,771,115,518	$1,538,812,451	$0	$0	$302,524,468	$0	$0	$682,496,104	$0	$247,282,495	$2,523,833,023	$0	$247,282,495
Working Capital															
Cash Working Capital - Operation and Maintenance Expens	O&MxPurch	9	$75,842,724	$9,655,412	$51,365,920	$0	$2,659,628	$0	$0	$5,958,266	$0	$6,203,497	$18,273,306	$51,365,920	$6,203,497
Materials and Supplies	TPIS	5	$36,896,266	$20,682,076	$0	$0	$3,966,645	$0	$0	$8,990,207	$0	$3,257,338	$33,638,928	$0	$3,257,338
Fuel Stock	PROD	2	$36,289,311	$36,289,311	$0	$0	$0	$0	$0	$0	$0	$0	$36,289,311	$0	$0
Prepayments	TPIS	5	$13,972,166	$7,832,050	$0	$0	$1,502,120	$0	$0	$3,404,482	$0	$1,233,514	$12,738,652	$0	$1,233,514
Total Working Capital			$163,000,467	$74,458,849	$51,365,920	$0	$8,128,393	$0	$0	$18,352,955	$0	$10,694,350	$100,940,196	$51,365,920	$10,694,350
Emission Allowance			$0										$0	$0	$0
Deferred Debits															
Service Pension Cost			$0										$0	$0	$0
Accumulated Deferred Income Tax													$0	$0	$0
Total ADIT	TPIS	5	$546,457,652	$306,314,967	$0	$0	$58,748,586	$0	$0	$133,150,802	$0	$48,243,297	$498,214,355	$0	$48,243,297
Total Accumulated Deferred Income Tax			$546,457,652	$306,314,967	$0	$0	$58,748,586	$0	$0	$133,150,802	$0	$48,243,297	$498,214,355	$0	$48,243,297
Accumulated Deferred Investment Tax Credits															
Production			$0												
Transmission			$0										$0	$0	$0
Transmission VA			$0										$0	$0	$0
Distribution VA			$0										$0	$0	$0
Distribution Plant KY,FERC & TN			$0										$0	$0	$0
General			$0										$0	$0	$0
Total Accum. Deferred Investment Tax Credits			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Deferred Debits			$546,457,652	$306,314,967	$0	$0	$58,748,586	$0	$0	$133,150,802	$0	$48,243,297	$498,214,355	$0	$48,243,297
Less: Customer Advances	DLINES	6	$6,724,404	$0	$0	$0	$0	$0	$0	$5,868,998	$0	$855,406	$5,868,998	$0	$855,406
Less: Asset Retirement Obligations															
Net Rate Base			$2,380,933,929	$1,306,956,333	$51,365,920	$0	$251,904,275	$0	$0	$561,829,258	$0	$208,878,142	$2,120,689,866	$51,365,920	$208,878,142
Operation and Maintenance Expenses															
Steam Power Generation Operation Expenses															
500 OPERATION SUPERVISION & ENGINEERIN(	LBSUB1	10	$4,922,985	$4,163,687	$759,298	$0	$0	$0	$0	$0	$0	$0	$4,163,687	$759,298	$0
501 FUEL		Dir	$293,912,722		$293,912,722								$0	$293,912,722	$0
502 STEAM EXPENSES	PROD	2	$18,526,106	$18,526,106	$0	$0	$0	$0	$0	$0	$0	$0	$18,526,106	$0	$0
505 ELECTRIC EXPENSES	PROD	2	$2,617,219	$2,617,219	$0	$0	$0	$0	$0	$0	$0	$0	$2,617,219	$0	$0
506 MISC. STEAM POWER EXPENSES	PROD	2	$9,946,165	$9,946,165	$0	$0	$0	$0	$0	$0	$0	$0	$9,946,165	$0	$0
507 RENTS			$0										$0	$0	$0
509 ALLOWANCES			$0										$0	$0	$0
Total Steam Power Operation Expenses			$329,925,197	$35,253,177	$294,672,020	$0	$0	$0	$0	$0	$0	$0	$35,253,177	$294,672,020	$0
Steam Power Generation Maintenance Expenses															
510 MAINTENANCE SUPERVISION & ENGINEEI	LBSUB2	11	$4,351,845	$0	$4,351,845	$0	$0	$0	$0	$0	$0	$0	$0	$4,351,845	$0
511 MAINTENANCE OF STRUCTURES	PROD	2	$4,128,301	$4,128,301	$0	$0	$0	$0	$0	$0	$0	$0	$4,128,301	$0	$0
512 MAINTENANCE OF BOILER PLANT		Dir	$34,257,481		$34,257,481								$0	$34,257,481	$0
513 MAINTENANCE OF ELECTRIC PLANT		Dir	$15,421,014		$15,421,014								$0	$15,421,014	$0
514 MAINTENANCE OF MISC STEAM PLANT		Dir	$1,072,820		$1,072,820								$0	$1,072,820	$0
Total Steam Power Generation Maintenance Expense			$59,231,461	$4,128,301	$55,103,160	$0	$0	$0	$0	$0	$0	$0	$4,128,301	$55,103,160	$0
Total Steam Power Generation Expense			$389,156,658	$39,381,478	$349,775,180	$0	$0	$0	$0	$0	$0	$0	$39,381,478	$349,775,180	$0

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100%
Demand Functionalization/Classification

Functionalization ---->	Classification Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->	Name	No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Hydraulic Power Generation Operation Expenses															
535 OPERATION SUPERVISION & ENGINEERIN(	PROD	2	$121,406	$121,406	$0	$0	$0	$0	$0	$0	$0	$0	$121,406	$0	$0
536 WATER FOR POWER	PROD	2	$40,614	$40,614	$0	$0	$0	$0	$0	$0	$0	$0	$40,614	$0	$0
537 HYDRAULIC EXPENSES	PROD	2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
538 ELECTRIC EXPENSES	PROD	2	$180,161	$180,161	$0	$0	$0	$0	$0	$0	$0	$0	$180,161	$0	$0
539 MISC. HYDRAULIC POWER EXPENSES	PROD	2	$348,792	$348,792	$0	$0	$0	$0	$0	$0	$0	$0	$348,792	$0	$0
540 RENTS	PROD	2	$545,400	$545,400	$0	$0	$0	$0	$0	$0	$0	$0	$545,400	$0	$0
Total Hydraulic Power Operation Expenses			$1,236,373	$1,236,373	$0	$0	$0	$0	$0	$0	$0	$0	$1,236,373	$0	$0
Hydraulic Power Generation Maintenance Expenses															
541 MAINTENANCE SUPERVISION & ENGINEERING			$0												
542 MAINTENANCE OF STRUCTURES	PROD	2	$244,992	$244,992	$0	$0	$0	$0	$0	$0	$0	$0	$244,992	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATEF	PROD	2	$190,785	$190,785	$0	$0	$0	$0	$0	$0	$0	$0	$190,785	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT		DIR	$371,119		$371,119								$0	$371,119	$0
545 MAINTENANCE OF MISC HYDRAULIC PLANT		Dir	$58,972		$58,972								$0	$58,972	$0
Total Hydraulic Power Generation Maint. Expense			$865,868	$435,777	$430,091	$0	$0	$0	$0	$0	$0	$0	$435,777	$430,091	$0
Total Hydraulic Power Generation Expense			$2,102,241	$1,672,150	$430,091	$0	$0	$0	$0	$0	$0	$0	$1,672,150	$430,091	$0
Other Power Generation Operation Expense															
546 OPERATION SUPERVISION & ENGINEERIN(	LBSUB5	13	$604,185	$604,185	$0	$0	$0	$0	$0	$0	$0	$0	$604,185	$0	$0
547 FUEL		Dir	$57,317,664		$57,317,664								$0	$57,317,664	$0
548 GENERATION EXPENSE	PROD	2	$280,735	$280,735	$0	$0	$0	$0	$0	$0	$0	$0	$280,735	$0	$0
549 MISC OTHER POWER GENERATION	PROD	2	$1,105,538	$1,105,538	$0	$0	$0	$0	$0	$0	$0	$0	$1,105,538	$0	$0
550 RENTS	PROD	2	$5,706	$5,706	$0	$0	$0	$0	$0	$0	$0	$0	$5,706	$0	$0
Total Other Power Generation Expenses			$59,313,828	$1,996,164	$57,317,664	$0	$0	$0	$0	$0	$0	$0	$1,996,164	$57,317,664	$0
Other Power Generation Maintenance Expense															
551 MAINTENANCE SUPERVISION & ENGINEEI	PROD	2	$256,698	$256,698	$0	$0	$0	$0	$0	$0	$0	$0	$256,698	$0	$0
552 MAINTENANCE OF STRUCTURES	PROD	2	$560,673	$560,673	$0	$0	$0	$0	$0	$0	$0	$0	$560,673	$0	$0
553 MAINTENANCE OF GENERATING & ELEC I	PROD	2	$2,652,503	$2,652,503	$0	$0	$0	$0	$0	$0	$0	$0	$2,652,503	$0	$0
554 MAINTENANCE OF MISC OTHER POWER G	PROD	2	$1,112,788	$1,112,788	$0	$0	$0	$0	$0	$0	$0	$0	$1,112,788	$0	$0
Total Other Power Generation Maintenance Expense			$4,582,662	$4,582,662	$0	$0	$0	$0	$0	$0	$0	$0	$4,582,662	$0	$0
Total Other Power Generation Expense			$63,896,490	$6,578,826	$57,317,664	$0	$0	$0	$0	$0	$0	$0	$6,578,826	$57,317,664	$0
Total Station Expense			$455,155,389	$47,632,454	$407,522,935	$0	$0	$0	$0	$0	$0	$0	$47,632,454	$407,522,935	$0
Other Power Supply Expenses															
555 PURCHASED POWER	OMPP	20	$53,937,678	$16,216,788	$37,720,890	$0	$0	$0	$0	$0	$0	$0	$16,216,788	$37,720,890	$0
555 PURCHASED POWER OPTIONS													$0	$0	$0
555 BROKERAGE FEES													$0	$0	$0
555 MISO TRANSMISSION EXPENSES													$0	$0	$0
556 SYSTEM CONTROL AND LOAD DISPATCH	PROD	2	$1,248,388	$1,248,388	$0	$0	$0	$0	$0	$0	$0	$0	$1,248,388	$0	$0
557 OTHER EXPENSES	PROD	2	$3,807	$3,807	$0	$0	$0	$0	$0	$0	$0	$0	$3,807	$0	$0
Total Other Power Supply Expenses			$55,189,873	$17,468,983	$37,720,890	$0	$0	$0	$0	$0	$0	$0	$17,468,983	$37,720,890	$0
Total Electric Power Generation Expenses			$510,345,262	$65,101,437	$445,243,825	$0	$0	$0	$0	$0	$0	$0	$65,101,437	$445,243,825	$0
Transmission Expenses															
560 OPERATION SUPERVISION AND ENG		Dir	$1,013,327				$1,013,327						$1,013,327	$0	$0
561 LOAD DISPATCHING		Dir	$2,208,583				$2,208,583						$2,208,583	$0	$0
562 STATION EXPENSES		Dir	$928,949				$928,949						$928,949	$0	$0
563 OVERHEAD LINE EXPENSES		Dir	$244,298				$244,298						$244,298	$0	$0
565 TRANSMISSION OF ELECTRICITY BY OTHERS		Dir	$36,638				$36,638						$36,638	$0	$0
566 MISC. TRANSMISSION EXPENSES		Dir	$6,948,940				$6,948,940						$6,948,940	$0	$0
567 RENTS		Dir	$67,500				$67,500						$67,500	$0	$0
568 MAINTENACE SUPERVISION AND ENG			$0										$0	$0	$0
569 STRUCTURES			$0										$0	$0	$0
570 MAINT OF STATION EQUIPMENT		Dir	$1,490,332				$1,490,332						$1,490,332	$0	$0
571 MAINT OF OVERHEAD LINES		Dir	$3,342,881				$3,342,881						$3,342,881	$0	$0
572 UNDERGROUND LINES			$0										$0	$0	$0
573 MISC PLANT		Dir	$228,063				$228,063						$228,063	$0	$0
575 MISO DAY 1&2 EXPENSE			$0										$0	$0	$0
Total Transmission Expenses			$16,509,511	$0	$0	$0	$16,509,511	$0	$0	$0	$0	$0	$16,509,511	$0	$0

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100%
Demand Functionalization/Classification

Functionalization ---->	Classification Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->	Name	No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Expense															
580 OPERATION SUPERVISION AND ENGI	LBDO	14	$1,814,624	$0	$0	$0	$0	$0	$0	$880,033	$0	$934,591	$880,033	$0	$934,591
581 LOAD DISPATCHING	Acct 362		$741,674	$0	$0	$0	$0	$0	$0	$741,674	$0	$0	$741,674	$0	$0
582 STATION EXPENSES	Acct 362		$1,941,657	$0	$0	$0	$0	$0	$0	$1,941,657	$0	$0	$1,941,657	$0	$0
583 OVERHEAD LINE EXPENSES	Acct 365		$5,880,672	$0	$0	$0	$0	$0	$0	$4,947,130	$0	$933,542	$4,947,130	$0	$933,542
584 UNDERGROUND LINE EXPENSES	P367	21	$535,725	$0	$0	$0	$0	$0	$0	$494,688	$0	$41,037	$494,688	$0	$41,037
585 STREET LIGHTING EXPENSE			$0										$0	$0	$0
586 METER EXPENSES	Acct 370		$8,277,541	$0	$0	$0	$0	$0	$0	$0	$0	$8,277,541	$0	$0	$8,277,541
586 METER EXPENSES - LOAD MANAGEMENT			$0										$0	$0	$0
587 CUSTOMER INSTALLATIONS EXPENSE	DIST	4	-$79,200	$0	$0	$0	$0	$0	$0	-$58,136	$0	-$21,064	-$58,136	$0	-$21,064
588 MISCELLANEOUS DISTRIBUTION EXP	DIST	4	$5,593,730	$0	$0	$0	$0	$0	$0	$4,106,030	$0	$1,487,700	$4,106,030	$0	$1,487,700
588 MISC DISTR EXP -- MAPPIN			$0										$0	$0	$0
589 RENTS	DIST	4	$8,165	$0	$0	$0	$0	$0	$0	$5,993	$0	$2,172	$5,993	$0	$2,172
Total Distribution Operation Expense			$24,714,588	$0	$0	$0	$0	$0	$0	$13,059,070	$0	$11,655,518	$13,059,070	$0	$11,655,518
Distribution Maintenance Expense															
590 MAINTENANCE SUPERVISION AND EN	LBDM	15	$77,850	$0	$0	$0	$0	$0	$0	$66,429	$0	$11,421	$66,429	$0	$11,421
591 STRUCTURES			$0										$0	$0	$0
592 MAINTENANCE OF STATION EQUIPME	Acct 362		$1,167,866	$0	$0	$0	$0	$0	$0	$1,167,866	$0	$0	$1,167,866	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct 365		$23,665,349	$0	$0	$0	$0	$0	$0	$19,908,532	$0	$3,756,817	$19,908,532	$0	$3,756,817
594 MAINTENANCE OF UNDERGROUND LIN	Acct 367		$1,604,057	$0	$0	$0	$0	$0	$0	$1,481,186	$0	$122,871	$1,481,186	$0	$122,871
595 MAINTENANCE OF LINE TRANSFORME	Acct 368		$334,735	$0	$0	$0	$0	$0	$0	$196,978	$0	$137,757	$196,978	$0	$137,757
596 MAINTENANCE OF ST LIGHTS & SIG SYSTI	Acct 373		$355,341									$355,341	$0	$0	$355,341
597 MAINTENANCE OF METERS	Acct 370		$1,427,898	$0	$0	$0	$0	$0	$0	$0	$0	$1,427,898	$0	$0	$1,427,898
598 MISCELLANEOUS DISTRIBUTION EXPENSI	DIST	4	$671,832	$0	$0	$0	$0	$0	$0	$493,153	$0	$178,679	$493,153	$0	$178,679
Total Distribution Maintenance Expense			$29,304,928	$0	$0	$0	$0	$0	$0	$23,314,143	$0	$5,990,785	$23,314,143	$0	$5,990,785
Total Distribution Expense			$54,019,516	$0	$0	$0	$0	$0	$0	$36,373,213	$0	$17,646,303	$36,373,213	$0	$17,646,303
Customer Accounts Expense															
901 SUPERVISION/CUSTOMER ACCTS		Dir	$1,267,537									$1,267,537	$0	$0	$1,267,537
902 METER READING EXPENSES		Dir	$2,546,374									$2,546,374	$0	$0	$2,546,374
903 RECORDS AND COLLECTION		Dir	$7,699,624									$7,699,624	$0	$0	$7,699,624
904 UNCOLLECTIBLE ACCOUNTS		Dir	$2,477,177									$2,477,177	$0	$0	$2,477,177
905 MISC CUST ACCOUNTS		Dir	$1,288									$1,288	$0	$0	$1,288
Total Customer Accounts Expense			$13,992,000	$0	$0	$0	$0	$0	$0	$0	$0	$13,992,000	$0	$0	$13,992,000
Customer Service Expense															
907 SUPERVISION		Dir	$364,585									$364,585	$0	$0	$364,585
908 CUSTOMER ASSISTANCE EXPENSES		Dir	$289,821									$289,821	$0	$0	$289,821
908 CUSTOMER ASSISTANCE EXP-INCENTIVES		Dir	$0										$0	$0	$0
909 INFORMATIONAL AND INSTRUCTIONA		Dir	$257,472									$257,472	$0	$0	$257,472
909 INFORM AND INSTRUC -LOAD MGMT		Dir	$0										$0	$0	$0
910 MISCELLANEOUS CUSTOMER SERVICE		Dir	$823,663									$823,663	$0	$0	$823,663
911 DEMONSTRATION AND SELLING EXP		Dir	$0										$0	$0	$0
912 DEMONSTRATION AND SELLING EXP		Dir	$0										$0	$0	$0
913 ADVERTISING EXPENSES		Dir	$950,847									$950,847	$0	$0	$950,847
916 MISC SALES EXPENSE		Dir	$0										$0	$0	$0
Total Customer Service Expense			$2,686,388	$0	$0	$0	$0	$0	$0	$0	$0	$2,686,388	$0	$0	$2,686,388
Administrative and General Expense															
920 ADMIN. & GEN. SALARIES-	LBSUB7	8	$27,330,835	$9,247,605	$6,907,180	$0	$1,638,279	$0	$0	$3,868,222	$0	$5,669,550	$14,754,105	$6,907,180	$5,669,550
921 OFFICE SUPPLIES AND EXPENSES	LBSUB7	8	$5,910,353	$1,999,815	$1,493,693	$0	$354,281	$0	$0	$836,511	$0	$1,226,053	$3,190,608	$1,493,693	$1,226,053
922 ADMINISTRATIVE EXPENSES TRANSFERRI	LBSUB7	8	-$4,320,827	-$1,461,986	-$1,091,980	$0	-$259,001	$0	$0	-$611,541	$0	-$896,319	-$2,332,528	-$1,091,980	-$896,319
923 OUTSIDE SERVICES EMPLOYED	LBSUB7	8	$15,873,533	$5,370,936	$4,011,635	$0	$951,499	$0	$0	$2,246,633	$0	$3,292,830	$8,569,068	$4,011,635	$3,292,830
924 PROPERTY INSURANCE	TUP	7	$4,610,558	$2,593,027	$0	$0	$491,106	$0	$0	$1,120,459	$0	$405,966	$4,204,592	$0	$405,966
925 INJURIES AND DAMAGES - INSURAN	LBSUB7	8	$2,835,056	$959,264	$716,489	$0	$169,940	$0	$0	$401,255	$0	$588,108	$1,530,459	$716,489	$588,108
926 EMPLOYEE BENEFITS	LBSUB7	8	$29,197,096	$9,879,069	$7,378,830	$0	$1,750,147	$0	$0	$4,132,360	$0	$6,056,690	$15,761,576	$7,378,830	$6,056,690
928 REGULATORY COMMISSION FEES	TUP	7	$1,404,080	$789,670	$0	$0	$149,559	$0	$0	$341,220	$0	$123,631	$1,280,449	$0	$123,631
929 DUPLICATE CHARGES	LBSUB7	8	-$229,428	-$77,629	-$57,982	$0	-$13,752	$0	$0	-$32,472	$0	-$47,593	-$123,853	-$57,982	-$47,593
930 MISCELLANEOUS GENERAL EXPENSES	LBSUB7	8	$3,716,685	$1,257,570	$939,298	$0	$222,787	$0	$0	$526,035	$0	$770,995	$2,006,392	$939,298	$770,995
931 RENTS AND LEASES	PT&D	1	$1,123,825	$630,356	$0	$0	$120,907	$0	$0	$273,475	$0	$99,086	$1,024,739	$0	$99,086
935 MAINTENANCE OF GENERAL PLANT	PT&D	1	$617,459	$346,334	$0	$0	$66,430	$0	$0	$150,255	$0	$54,440	$563,019	$0	$54,440
Total Administrative and General Expense			$88,069,225	$31,534,030	$20,297,163	$0	$5,642,184	$0	$0	$13,252,412	$0	$17,343,436	$50,428,626	$20,297,163	$17,343,436
Total Operation and Maintenance Expenses			$685,621,902	$96,635,467	$465,540,988	$0	$22,151,695	$0	$0	$49,625,625	$0	$51,668,127	$168,412,787	$465,540,988	$51,668,127
Total Operation and Maintenance Exp. Less Purchased Power			$631,684,224	$80,418,679	$427,820,098	$0	$22,151,695	$0	$0	$49,625,625	$0	$51,668,127	$152,195,999	$427,820,098	$51,668,127

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100%
Demand Functionalization/Classification

Functionalization ---->	Classification Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->	Name	No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Labor Expenses															
Labor-Steam Power Generation Operation Expenses															
500 OPERATION SUPERVISION & ENGINEERING	FO19	16	$3,138,068	$2,654,067	$484,001	$0	$0	$0	$0	$0	$0	$0	$2,654,067	$484,001	$0
501 FUEL		Dir	$2,187,724		$2,187,724								$0	$2,187,724	$0
502 STEAM EXPENSES	PROD	2	$8,374,877	$8,374,877	$0	$0	$0	$0	$0	$0	$0	$0	$8,374,877	$0	$0
505 ELECTRIC EXPENSES	PROD	2	$2,130,001	$2,130,001	$0	$0	$0	$0	$0	$0	$0	$0	$2,130,001	$0	$0
506 MISC. STEAM POWER EXPENSES	PROD	2	$1,491,734	$1,491,734	$0	$0	$0	$0	$0	$0	$0	$0	$1,491,734	$0	$0
507 RENTS			$0										$0	$0	$0
Total Steam Power Operation Expenses			$17,322,404	$14,650,679	$2,671,725	$0	$0	$0	$0	$0	$0	$0	$14,650,679	$2,671,725	$0
Labor-Steam Power Generation Maintenance Expenses															
510 MAINTENANCE SUPERVISION & ENGINEERING	FO20	17	$3,390,539	$0	$3,390,539	$0	$0	$0	$0	$0	$0	$0	$0	$3,390,539	$0
511 MAINTENANCE OF STRUCTURES															
512 MAINTENANCE OF BOILER PLANT		Dir	$4,117,208		$4,117,208								$0	$4,117,208	$0
513 MAINTENANCE OF ELECTRIC PLANT		Dir	$2,830,954		$2,830,954								$0	$2,830,954	$0
514 MAINTENANCE OF MISC STEAM PLANT		Dir	$57,828		$57,828								$0	$57,828	$0
Total Steam Power Generation Maintenance Expense			$10,396,529	$0	$10,396,529	$0	$0	$0	$0	$0	$0	$0	$0	$10,396,529	$0
Total Steam Power Generation Expense			$27,718,933	$14,650,679	$13,068,254	$0	$0	$0	$0	$0	$0	$0	$14,650,679	$13,068,254	$0
Labor-Hydraulic Power Generation Operation Expenses															
535 OPERATION SUPERVISION & ENGINEERING	PROD	2	$95,870	$95,870	$0	$0	$0	$0	$0	$0	$0	$0	$95,870	$0	$0
536 WATER FOR POWER			$0										$0	$0	$0
537 HYDRAULIC EXPENSES			$0										$0	$0	$0
538 ELECTRIC EXPENSES	PROD	2	$180,161	$180,161	$0	$0	$0	$0	$0	$0	$0	$0	$180,161	$0	$0
539 MISC. HYDRAULIC POWER EXPENSES	PROD	2	$60,427	$60,427	$0	$0	$0	$0	$0	$0	$0	$0	$60,427	$0	$0
540 RENTS			$0										$0	$0	$0
Total Hydraulic Power Operation Expenses			$336,458	$336,458	$0	$0	$0	$0	$0	$0	$0	$0	$336,458	$0	$0
Labor-Hydraulic Power Generation Maintenance Expenses															
541 MAINTENANCE SUPERVISION & ENGINEERING															
542 MAINTENANCE OF STRUCTURES	PROD	2	$46,873	$46,873	$0	$0	$0	$0	$0	$0	$0	$0	$46,873	$0	$0
543 MAINT. OF RESERVES, DAMS, AND WATERWAY	PROD	2	$46,873	$46,873	$0	$0	$0	$0	$0	$0	$0	$0	$46,873	$0	$0
544 MAINTENANCE OF ELECTRIC PLANT		Energy	$151,040		$151,040								$0	$151,040	$0
545 MAINTENANCE OF MISC HYDRAULIC PLANT			$0										$0	$0	$0
Total Hydraulic Power Generation Maint. Expense			$244,786	$93,746	$151,040	$0	$0	$0	$0	$0	$0	$0	$93,746	$151,040	$0
Total Hydraulic Power Generation Expense			$581,244	$430,204	$151,040	$0	$0	$0	$0	$0	$0	$0	$430,204	$151,040	$0
Labor-Other Power Generation Operation Expense															
546 OPERATION SUPERVISION & ENGINEERING	PROD	2	$468,874	$468,874	$0	$0	$0	$0	$0	$0	$0	$0	$468,874	$0	$0
547 FUEL			$0										$0	$0	$0
548 GENERATION EXPENSE	PROD	2	$161,301	$161,301	$0	$0	$0	$0	$0	$0	$0	$0	$161,301	$0	$0
549 MISC OTHER POWER GENERATION	PROD	2	$354,300	$354,300	$0	$0	$0	$0	$0	$0	$0	$0	$354,300	$0	$0
550 RENTS			$0										$0	$0	$0
Total Other Power Generation Expenses			$984,475	$984,475	$0	$0	$0	$0	$0	$0	$0	$0	$984,475	$0	$0
Labor-Other Power Generation Maintenance Expense															
551 MAINTENANCE SUPERVISION & ENGINEERING	PROD	2	$230,613	$230,613	$0	$0	$0	$0	$0	$0	$0	$0	$230,613	$0	$0
552 MAINTENANCE OF STRUCTURES			$0										$0	$0	$0
553 MAINTENANCE OF GENERATING & ELEC PLAN	PROD	2	$606,788	$606,788	$0	$0	$0	$0	$0	$0	$0	$0	$606,788	$0	$0
554 MAINTENANCE OF MISC OTHER POWER GEN PI	PROD	2	-$160,951	-$160,951	$0	$0	$0	$0	$0	$0	$0	$0	-$160,951	$0	$0
Total Other Power Generation Maintenance Expense			$676,450	$676,450	$0	$0	$0	$0	$0	$0	$0	$0	$676,450	$0	$0
Total Other Power Generation Expense			$1,660,925	$1,660,925	$0	$0	$0	$0	$0	$0	$0	$0	$1,660,925	$0	$0
Total Production Expense			$29,961,102	$16,741,808	$13,219,294	$0	$0	$0	$0	$0	$0	$0	$16,741,808	$13,219,294	$0
Labor-Purchased Power															
555 PURCHASED POWER			$0										$0	$0	$0
556 SYSTEM CONTROL AND LOAD DISPATCH	PROD	2	$956,703	$956,703	$0	$0	$0	$0	$0	$0	$0	$0	$956,703	$0	$0
557 OTHER EXPENSES			$0										$0	$0	$0
Total Purchased Power Labor			$956,703	$956,703	$0	$0	$0	$0	$0	$0	$0	$0	$956,703	$0	$0
Transmission Labor Expenses															
560 OPERATION SUPERVISION AND ENG		Dir	$642,049				$642,049						$642,049	$0	$0
561 LOAD DISPATCHING		Dir	$1,454,366				$1,454,366						$1,454,366	$0	$0
562 STATION EXPENSES		Dir	$433,996				$433,996						$433,996	$0	$0
563 OVERHEAD LINE EXPENSES			$0										$0	$0	$0
566 MISC. TRANSMISSION EXPENSES		Dir	$105,592				$105,592						$105,592	$0	$0
568 MAINTENACE SUPERVISION AND ENG		Dir	$0										$0	$0	$0
570 MAINT OF STATION EQUIPMENT		Dir	$416,335				$416,335						$416,335	$0	$0
571 MAINT OF OVERHEAD LINES		Dir	$83,079				$83,079						$83,079	$0	$0
572 UNDERGROUND LINES			$0										$0	$0	$0
573 MISC PLANT			$0										$0	$0	$0
Total Transmission Labor Expenses			$3,135,417	$0	$0	$0	$3,135,417	$0	$0	$0	$0	$0	$3,135,417	$0	$0

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100%
Demand Functionalization/Classification

Functionalization ---->	Classification Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->	Name	No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Distribution Operation Labor Expense															
580 OPERATION SUPERVISION AND ENGI	FO23	19	$898,041	$0	$0	$0	$0	$0	$0	$435,521	$0	$462,520	$435,521	$0	$462,520
581 LOAD DISPATCHING	Acct 362		$574,384	$0	$0	$0	$0	$0	$0	$574,384	$0	$0	$574,384	$0	$0
582 STATION EXPENSES	Acct 362		$851,000	$0	$0	$0	$0	$0	$0	$851,000	$0	$0	$851,000	$0	$0
583 OVERHEAD LINE EXPENSES	Acct 365		$1,741,898	$0	$0	$0	$0	$0	$0	$1,465,376	$0	$276,522	$1,465,376	$0	$276,522
584 UNDERGROUND LINE EXPENSES	P367	21	$168,503	$0	$0	$0	$0	$0	$0	$155,596	$0	$12,907	$155,596	$0	$12,907
585 STREET LIGHTING EXPENSE			$0										$0	$0	$0
586 METER EXPENSES	Acct 370		$3,736,471	$0	$0	$0	$0	$0	$0	$0	$0	$3,736,471	$0	$0	$3,736,471
586 METER EXPENSES - LOAD MANAGEMENT			$0										$0	$0	$0
587 CUSTOMER INSTALLATIONS EXPENSE			$0										$0	$0	$0
588 MISCELLANEOUS DISTRIBUTION EXP	DIST	4	$1,539,532	$0	$0	$0	$0	$0	$0	$1,130,080	$0	$409,452	$1,130,080	$0	$409,452
589 RENTS			$0										$0	$0	$0
Total Distribution Operation Labor Expense			$9,509,829	$0	$0	$0	$0	$0	$0	$4,611,957	$0	$4,897,872	$4,611,957	$0	$4,897,872
Distribution Maintenance Labor Expense															
590 MAINTENANCE SUPERVISION AND EN			$0										$0	$0	$0
591 MAINTENANCE OF STRUCTURES			$0										$0	$0	$0
592 MAINTENANCE OF STATION EQUIPME	Acct 362		$199,000	$0	$0	$0	$0	$0	$0	$199,000	$0	$0	$199,000	$0	$0
593 MAINTENANCE OF OVERHEAD LINES	Acct 365		$2,584,023	$0	$0	$0	$0	$0	$0	$2,173,816	$0	$410,207	$2,173,816	$0	$410,207
594 MAINTENANCE OF UNDERGROUND LIN	Acct 367		$403,600	$0	$0	$0	$0	$0	$0	$372,684	$0	$30,916	$372,684	$0	$30,916
595 MAINTENANCE OF LINE TRANSFORME	Acct 368		$77,717	$0	$0	$0	$0	$0	$0	$45,733	$0	$31,984	$45,733	$0	$31,984
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	Acct 373		$6,800	$0	$0	$0	$0	$0	$0	$0	$0	$6,800	$0	$0	$6,800
597 MAINTENANCE OF METERS			$0										$0	$0	$0
598 MAINTENANCE OF MISC DISTR PLANT			$0										$0	$0	$0
Total Distribution Maintenance Labor Expense			$3,271,140	$0	$0	$0	$0	$0	$0	$2,791,233	$0	$479,907	$2,791,233	$0	$479,907
Total Distribution Labor Expense			$12,780,969	$0	$0	$0	$0	$0	$0	$7,403,190	$0	$5,377,779	$7,403,190	$0	$5,377,779
Customer Accounts Expense															
901 SUPERVISION/CUSTOMER ACCTS		Dir	$869,231									$869,231	$0	$0	$869,231
902 METER READING EXPENSES		Dir	$340,095									$340,095	$0	$0	$340,095
903 RECORDS AND COLLECTION		Dir	$3,084,679									$3,084,679	$0	$0	$3,084,679
904 UNCOLLECTIBLE ACCOUNTS			$0										$0	$0	$0
905 MISC CUST ACCOUNTS			$0										$0	$0	$0
Total Customer Accounts Labor Expense			$4,294,005	$0	$0	$0	$0	$0	$0	$0	$0	$4,294,005	$0	$0	$4,294,005
Customer Service Expense															
907 SUPERVISION		Dir	$262,521									$262,521	$0	$0	$262,521
908 CUSTOMER ASSISTANCE EXPENSES		Dir	$916,352									$916,352	$0	$0	$916,352
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT			$0										$0	$0	$0
909 INFORMATIONAL AND INSTRUCTIONA			$0										$0	$0	$0
909 INFORM AND INSTRUC -LOAD MGMT			$0										$0	$0	$0
910 MISCELLANEOUS CUSTOMER SERVICE			$0										$0	$0	$0
911 DEMONSTRATION AND SELLING EXP			$0										$0	$0	$0
912 DEMONSTRATION AND SELLING EXP			$0										$0	$0	$0
913 WATER HEATER - HEAT PUMP PROGRAM			$0										$0	$0	$0
916 MISC SALES EXPENSE			$0										$0	$0	$0
Total Customer Service Labor Expense			$1,178,873	$0	$0	$0	$0	$0	$0	$0	$0	$1,178,873	$0	$0	$1,178,873
Total Labor Excluding A&G			$52,307,069	$17,698,511	$13,219,294	$0	$3,135,417	$0	$0	$7,403,190	$0	$10,850,657	$28,237,118	$13,219,294	$10,850,657

LOUISVILLE GAS AND ELECTRIC COMPANY
Probability of Dispatch Class Cost of Service Study - Primary Distribution 100%
Demand Functionalization/Classification

Functionalization ---->	Classification Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->	Name	No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Administrative and General Expense															
920 ADMIN. & GEN. SALARIES-	LBSUB7	8	$21,224,500	$7,181,477.82	$5,363,958	$0	$1,272,250	$0	$0	$3,003,972	$0	$4,402,842	$11,457,700	$5,363,958	$4,402,842
921 OFFICE SUPPLIES AND EXPENSES			$0										$0	$0	$0
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LBSUB7	8	-$2,423,558	-$820,030.06	-$612,493	$0	-$145,274	$0	$0	-$343,014	$0	-$502,747	-$1,308,318	-$612,493	-$502,747
923 OUTSIDE SERVICES EMPLOYED			$0										$0	$0	$0
924 PROPERTY INSURANCE			$0										$0	$0	$0
925 INJURIES AND DAMAGES - INSURAN													$0	$0	$0
926 EMPLOYEE BENEFITS													$0	$0	$0
928 REGULATORY COMMISSION FEES			$0										$0	$0	$0
929 DUPLICATE CHARGES-CR			$0										$0	$0	$0
930 MISCELLANEOUS GENERAL EXPENSES			$0										$0	$0	$0
931 RENTS AND LEASES			$0										$0	$0	$0
935 MAINTENANCE OF GENERAL PLANT	PT&D	1	$430,713	$241,588.07	$0	$0	$46,339	$0	$0	$104,811	$0	$37,975	$392,738	$0	$37,975
Total Labor Administrative and General Expense			$19,231,655	$6,603,036	$4,751,464	$0	$1,173,314	$0	$0	$2,765,770	$0	$3,938,071	$10,542,120	$4,751,464	$3,938,071
Total Labor Operation and Maintenance Expenses			$71,538,724	$24,301,547	$17,970,758	$0	$4,308,731	$0	$0	$10,168,959	$0	$14,788,729	$38,779,238	$17,970,758	$14,788,729
Depreciation Expenses															
Steam Production	PROD	2	$51,173,949	$51,173,949.00	$0	$0	$0	$0	$0	$0	$0	$0	$51,173,949	$0	$0
Hydraulic Production	PROD	2	$4,023,933	$4,023,933.00	$0	$0	$0	$0	$0	$0	$0	$0	$4,023,933	$0	$0
Other Production	PROD	2	$16,258,222	$16,258,222.00	$0	$0	$0	$0	$0	$0	$0	$0	$16,258,222	$0	$0
Transmission - Kentucky System Property	TRANS	3	$9,613,105	$0.00	$0	$0	$9,613,105	$0	$0	$0	$0	$0	$9,613,105	$0	$0
													$0	$0	$0
Distribution	DIST	4	$37,717,920	$0.00	$0	$0	$0	$0	$0	$27,686,520	$0	$10,031,400	$27,686,520	$0	$10,031,400
General Plant	PT&D	1	$20,055,398	$11,249,125.98	$0	$0	$2,157,674	$0	$0	$4,880,347	$0	$1,768,251	$18,287,147	$0	$1,768,251
Intangible Plant													$0	$0	$0
Total Depreciation Expense			$138,842,527	$82,705,230	$0	$0	$11,770,779	$0	$0	$32,566,867	$0	$11,799,651	$127,042,876	$0	$11,799,651
Regulatory Credits and Accretion Expenses															
Production Plant			$0										$0	$0	$0
Transmission Plant			$0										$0	$0	$0
Distribution Plant			$0										$0	$0	$0
Total Regulatory Credits and Accretion Expenses			$0	$0											
Property Taxes	TUP	7	$32,529,209	$18,294,773.16	$0	$0	$3,464,937	$0	$0	$7,905,260	$0	$2,864,240	$29,664,969	$0	$2,864,240
Other Taxes													$0	$0	$0
Amortization of ITCs	TUP	7	-$1,002,535	-$563,836.35	$0	$0	-$106,788	$0	$0	-$243,636	$0	-$88,275	-$914,260	$0	-$88,275
Interest	TUP	7	$62,185,554	$34,973,817.05	$0	$0	$6,623,863	$0	$0	$15,112,355	$0	$5,475,520	$56,710,034	$0	$5,475,520
Other Expenses			$0										$0	$0	$0
Total Other Expenses			$918,176,657	$232,045,451	$465,540,988	$0	$43,904,485	$0	$0	$104,966,470	$0	$71,719,263	$380,916,406	$465,540,988	$71,719,263

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Classification Factors

Functionalization ---->	Functional Factor		Total	Production			Transmission			Distribution			Total		
Classification ---->		No	Kentucky	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
PT&D Plant	PT&D	1	100.0000%	56.0903%	0.0000%	0.0000%	10.7586%	0.0000%	0.0000%	24.3343%	0.0000%	8.8168%	91.1832%	0.0000%	8.8168%
Production Plant	PROD	2	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
Transmission Plant	TRANS	3	100.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
Distribution Plant	DIST	4	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	73.4042%	0.0000%	26.5958%	73.4042%	0.0000%	26.5958%
Total Plant in Service	TPIS	5	100.0000%	56.0547%	0.0000%	0.0000%	10.7508%	0.0000%	0.0000%	24.3662%	0.0000%	8.8284%	91.1716%	0.0000%	8.8284%
Distrib Overhead + Underground Lines Plant	DLINES	6	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	87.2791%	0.0000%	12.7209%	87.2791%	0.0000%	12.7209%
Total Utility Plant	TUP	7	100.0000%	56.2411%	0.0000%	0.0000%	10.6518%	0.0000%	0.0000%	24.3020%	0.0000%	8.8051%	91.1949%	0.0000%	8.8051%
Total Labor Excluding A&G	LBSUB7	8	100.0000%	33.8358%	25.2725%	0.0000%	5.9943%	0.0000%	0.0000%	14.1533%	0.0000%	20.7442%	53.9834%	25.2725%	20.7442%
Total O&M Expense Less Purchased Power	O&MxPurch	9	100.0000%	12.7308%	67.7269%	0.0000%	3.5068%	0.0000%	0.0000%	7.8561%	0.0000%	8.1794%	24.0937%	67.7269%	8.1794%
Steam Power Operation Labor	LBSUB1	10	100.0000%	84.5765%	15.4235%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	84.5765%	15.4235%	0.0000%
Total Steam Power Maintenance Labor Expense	LBSUB2	11	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%
Total Hydraulic Power Maintenance Labor Expense	LBSUB4	12	100.0000%	38.2971%	61.7029%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	38.2971%	61.7029%	0.0000%
Total Other Power Operating Labor Expense	LBSUB5	13	100.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%
Total Distribution Operation Labor Expense	LBDO	14	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	48.4967%	0.0000%	51.5033%	48.4967%	0.0000%	51.5033%
Total Distribution Maintenance Labor Expense	LBDM	15	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	85.3291%	0.0000%	14.6709%	85.3291%	0.0000%	14.6709%
Total Steam Power Operation Labor Excl Superv. & Eng.	FO19	16	100.0000%	84.5765%	15.4235%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	84.5765%	15.4235%	0.0000%
Total Steam Power Maintenance Labor Excl Superv. & Eng.	FO20	17	100.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%
Total Hydraulic Power Maintenance Labor Excl. Super. & Eng.	FO22	18	100.0000%	38.2971%	61.7029%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	38.2971%	61.7029%	0.0000%
Distribution Operation Labor Excl. Super. & Eng	FO23	19	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	48.4967%	0.0000%	51.5033%	48.4967%	0.0000%	51.5033%
Purchased Power Expense	OMPP	20	100.0000%	30.0658%	69.9342%								30.0658%	69.9342%	0.0000%
Underground Lines Plant	P367	21	100.0000%	0	0	0	0	0	0	0.923399701	0	0.076600299	0.923399701	0	0.076600299
Total hydrolic Power Operation Labor Excl Superv. & Eng.	F021	22		100.0000%											

Memo: Purchased Power Expense				
Demand	Production Plant	20,765,366	$20,765,366	
Energy	Production Energy	48,301,062		$48,301,062
Total		$69,066,428	$20,765,366	$48,301,062
Pct			30.0658%	69.9342%

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Cost Summary

	Total Kentucky	Residential (RS)	General Service (GS)	Pwr Svc Primary PS-Pri	Pwr Svc Secondary PS-Sec	Time of Day Primary TOD-Pri	Time of Day Secondary TOD-Sec	Retail Transmission RTS	Special Contract #1	Special Contract #2	Street Lighting RLS,LS,DSK	Street Lighting LE	Traffic Lighting TLE
CLASSIFIED DEMAND COSTS													
Rate Base													
Plant in Service													
Intangible	$2,043	$840	$250	$25	$302	$279	$170	$134	$17	$9	$17	$1	$0
Production	$2,305,549,928	$816,858,645	$264,444,271	$31,450,007	$366,460,244	$350,531,200	$210,478,264	$212,518,676	$20,975,893	$11,364,056	$19,221,370	$627,110	$620,193
Transmission	$442,223,222	$196,518,630	$56,567,341	$5,026,113	$58,335,555	$53,067,462	$31,508,739	$32,637,220	$3,290,037	$1,721,960	$3,392,248	$108,513	$49,404
Distribution	$1,000,245,184	$526,944,449	$138,146,422	$10,175,973	$129,201,191	$107,441,490	$69,890,015	$0	$6,661,078	$3,486,317	$7,929,130	$253,640	$115,478
General	$14,436,677	$5,933,036	$1,768,592	$179,695	$2,133,894	$1,968,433	$1,201,293	$944,295	$119,125	$63,834	$117,645	$3,810	$3,024
Common	$184,406,119	$75,785,315	$22,591,018	$2,295,328	$27,257,187	$25,143,669	$15,344,650	$12,061,907	$1,521,639	$815,375	$1,502,733	$48,673	$38,626
Plant Held for Future Use	$2,351,391	$1,202,277	$319,807	$24,655	$310,023	$262,009	$168,827	$19,487	$16,174	$8,501	$18,727	$600	$304
Total Gross Plant	$3,949,214,564	$1,623,243,193	$483,837,702	$49,151,797	$583,698,396	$538,414,540	$328,591,957	$258,181,718	$32,583,964	$17,460,051	$32,181,869	$1,042,346	$827,030
Construction Work In Progress													
Production	$67,084,848	$23,768,229	$7,694,565	$915,104	$10,662,935	$10,199,446	$6,124,310	$6,183,680	$610,338	$330,661	$559,286	$18,247	$18,046
Transmission	$6,861,294	$3,049,076	$877,668	$77,982	$905,103	$823,366	$488,872	$506,381	$51,046	$26,717	$52,632	$1,684	$767
Distribution	$22,702,378	$11,959,960	$3,135,484	$230,962	$2,932,455	$2,438,579	$1,586,281	$0	$151,185	$79,128	$179,966	$5,757	$2,621
General	$17,021,770	$6,995,431	$2,085,284	$211,872	$2,515,999	$2,320,909	$1,416,402	$1,113,385	$140,456	$75,264	$138,711	$4,493	$3,565
Total CWIP	$113,670,290	$45,772,695	$13,793,000	$1,435,921	$17,016,492	$15,782,300	$9,615,864	$7,803,446	$953,026	$511,770	$930,596	$30,180	$24,999
Accumulated Depreciation													
Intangible	$37,369,589	$15,357,766	$4,578,032	$465,144	$5,523,623	$5,095,322	$3,109,567	$2,444,325	$308,358	$165,234	$304,526	$9,863	$7,828
Production	$903,942,138	$322,267,123	$103,768,942	$12,289,093	$143,414,036	$136,796,276	$82,208,114	$82,712,514	$8,196,947	$4,428,413	$7,379,784	$240,449	$240,449
Transmission	$159,969,049	$71,088,303	$20,462,570	$1,818,137	$21,102,201	$19,196,530	$11,397,916	$11,806,130	$1,190,132	$622,899	$1,227,106	$39,253	$17,871
Distribution	$372,920,664	$196,460,305	$51,505,027	$3,793,901	$48,169,983	$40,057,330	$26,057,042	$0	$2,483,445	$1,299,801	$2,956,212	$94,565	$43,054
General	$64,850,391	$26,651,541	$7,944,619	$807,202	$9,585,578	$8,842,314	$5,396,277	$4,241,830	$535,117	$286,744	$528,468	$17,117	$13,584
Total Depreciation Reserve	$1,539,051,831	$631,825,039	$188,259,190	$19,173,477	$227,795,421	$209,987,772	$128,168,916	$101,204,799	$12,713,999	$6,803,091	$12,396,096	$401,247	$322,785
Net Utility Plant													
	$2,523,833,023	$1,037,190,848	$309,371,512	$31,414,241	$372,919,467	$344,209,068	$210,038,905	$164,780,366	$20,822,990	$11,168,731	$20,716,369	$671,280	$529,244
Working Capital													
Cash Working Capital - Operation and Maintenance Expenses	$18,273,306	$7,790,166	$2,345,516	$221,309	$2,662,317	$2,397,151	$1,464,621	$1,034,970	$146,426	$75,488	$127,941	$4,130	$3,271
Materials and Supplies	$33,638,928	$13,826,587	$4,121,270	$418,669	$4,971,872	$4,586,149	$2,798,906	$2,199,160	$277,546	$148,723	$274,121	$8,879	$7,045
Fuel Stock	$36,289,311	$12,857,339	$4,162,348	$495,022	$5,768,077	$5,517,354	$3,312,924	$3,345,040	$330,160	$178,870	$302,544	$9,871	$9,762
Prepayments	$12,738,652	$5,235,960	$1,560,675	$158,545	$1,882,787	$1,736,719	$1,059,912	$832,795	$105,103	$56,319	$103,806	$3,362	$2,668
Total Working Capital	$100,940,196	$39,710,053	$12,189,809	$1,293,545	$15,285,053	$14,237,373	$8,636,363	$7,411,965	$859,235	$459,400	$808,413	$26,242	$22,745
Accumulated Deferred Income Taxes	$498,214,355	$204,780,735	$61,038,691	$6,200,760	$73,636,647	$67,923,849	$41,453,617	$32,570,993	$4,110,640	$2,202,678	$4,059,913	$131,498	$104,334
Accumulated ITCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Advances	$5,868,998	$3,018,245	$819,263	$65,112	$755,725	$687,478	$408,189	$0	$42,622	$22,308	$47,830	$1,530	$697
Net Rate Base	$2,120,689,866	$869,101,922	$259,703,367	$26,441,914	$313,812,148	$289,835,114	$176,813,461	$139,621,339	$17,528,964	$9,403,145	$17,417,039	$564,494	$446,958
Operation and Maintenance Expenses													
Production & Purchased Power	$65,101,437	$24,438,462	$8,461,479	$813,831	$10,555,399	$8,866,116	$5,672,171	$5,245,512	$542,679	$254,241	$231,279	$7,546	$12,724
Transmission	$16,509,511	$7,336,626	$2,111,827	$187,640	$2,177,840	$1,981,167	$1,176,315	$1,218,445	$122,827	$64,286	$126,643	$4,051	$1,844
Distribution	$36,373,213	$18,931,616	$5,073,427	$392,479	$4,630,521	$4,143,927	$2,501,789	$0	$256,912	$134,464	$294,374	$9,417	$4,287
Customer Accounts Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Service Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Administrative and General Expense	$50,428,626	$20,518,160	$6,180,457	$638,302	$7,478,107	$6,992,056	$4,211,164	$3,323,120	$423,147	$226,743	$413,307	$13,389	$10,673
Total Operation and Maintenance Expenses	$168,412,787	$71,224,865	$21,827,190	$2,032,252	$24,841,867	$21,983,265	$13,561,439	$9,787,076	$1,345,565	$679,734	$1,065,604	$34,402	$29,529
Depreciation Expense													
Intangible	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Production	$71,456,104	$25,316,969	$8,195,944	$974,733	$11,357,733	$10,864,043	$6,523,371	$6,586,609	$650,108	$352,207	$595,730	$19,436	$19,222
Transmission	$9,613,105	$4,271,947	$1,229,668	$109,258	$1,268,106	$1,153,587	$684,941	$709,472	$71,519	$37,432	$73,741	$2,359	$1,074
Distribution	$27,686,520	$14,585,682	$3,823,856	$281,668	$3,576,254	$2,973,952	$1,934,537	$0	$184,377	$96,500	$219,476	$7,021	$3,196
General	$18,287,147	$7,515,462	$2,240,301	$227,623	$2,703,035	$2,493,442	$1,521,695	$1,196,153	$150,898	$80,859	$149,023	$4,827	$3,831
Total Depreciation Expense	$127,042,876	$51,690,060	$15,489,769	$1,593,282	$18,905,128	$17,485,024	$10,664,544	$8,492,234	$1,056,901	$566,999	$1,037,970	$33,642	$27,323
Taxes Other Than Income Taxes													
Property Taxes	$29,664,969	$12,186,244	$3,633,428	$369,364	$4,386,093	$4,046,443	$2,469,409	$1,942,079	$244,869	$131,220	$241,769	$7,831	$6,221
Other Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total taxes Other Than Income Taxes	$29,664,969	$12,186,244	$3,633,428	$369,364	$4,386,093	$4,046,443	$2,469,409	$1,942,079	$244,869	$131,220	$241,769	$7,831	$6,221
Amortization of ITCs	-$914,260	-$375,574	-$111,981	-$11,384	-$135,177	-$124,709	-$76,106	-$59,854	-$7,547	-$4,044	-$7,451	-$241	-$192
Total Expenses Before Interest and Income Taxes	$325,120,632	$135,101,169	$40,950,387	$3,994,897	$48,133,088	$43,514,732	$26,695,391	$20,221,389	$2,647,335	$1,377,953	$2,345,342	$75,875	$63,072

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Cost Summary

	Total Kentucky	Residential (RS)	General Service (GS)	Pwr Svc Primary PS-Pri	Pwr Svc Secondary PS-Sec	Time of Day Primary TOD-Pri	Time of Day Secondary TOD-Sec	Retail Transmission RTS	Special Contract #1	Special Contract #2	Street Lighting RLS,LS,DSK	Street Lighting LE	Traffic Lighting TLE
CLASSIFIED ENERGY COSTS													
Rate Base													
Plant in Service													
Intangible	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Common	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Plant Held for Future Use	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Gross Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Construction Work In Progress													
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Accumulated Depreciation													
Intangible	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Depreciation Reserve	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Working Capital													
Cash Working Capital - Operation and Maintenance Expenses	$51,365,920	$18,635,357	$6,056,919	$716,609	$8,341,010	$8,009,788	$3,545,729	$4,850,091	$475,186	$257,139	$449,359	$14,633	$14,101
Materials and Supplies	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Stock	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Prepayments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Working Capital	$51,365,920	$18,635,357	$6,056,919	$716,609	$8,341,010	$8,009,788	$3,545,729	$4,850,091	$475,186	$257,139	$449,359	$14,633	$14,101
Accumulated Deferred Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Accumulated ITCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Advances	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Rate Base	$51,365,920	$18,635,357	$6,056,919	$716,609	$8,341,010	$8,009,788	$3,545,729	$4,850,091	$475,186	$257,139	$449,359	$14,633	$14,101
Operation and Maintenance Expenses													
Production & Purchased Power	$445,243,825	$161,509,981	$52,493,974	$6,212,768	$72,297,162	$69,444,320	$30,731,213	$42,061,873	$4,120,211	$2,226,911	$3,896,419	$126,891	$122,102
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Accounts Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Service Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Administrative and General Expense	$20,297,163	$7,348,086	$2,387,970	$283,953	$3,293,621	$3,175,267	$1,398,724	$1,930,879	$188,636	$100,241	$178,483	$5,817	$5,488
Total Operation and Maintenance Expenses	$465,540,988	$168,858,066	$54,881,944	$6,496,720	$75,590,783	$72,619,587	$32,129,938	$43,992,752	$4,308,846	$2,327,152	$4,074,902	$132,708	$127,590
Depreciation Expense													
Intangible	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Depreciation Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Taxes Other Than Income Taxes													
Property Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Amortization of ITCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Expenses Before Interest and Income Taxes	$465,540,988	$168,858,066	$54,881,944	$6,496,720	$75,590,783	$72,619,587	$32,129,938	$43,992,752	$4,308,846	$2,327,152	$4,074,902	$132,708	$127,590

LOUISVILLE GAS AND ELECTRIC COMPANY

Probability of Dispatch Class Cost of Service Study - Primary Distribution 100% Demand

Cost Summary

	Total Kentucky	Residential (RS)	General Service (GS)	Pwr Svc Primary PS-Pri	Pwr Svc Secondary PS-Sec	Time of Day Primary TOD-Pri	Time of Day Secondary TOD-Sec	Retail Transmission RTS	Special Contract #1	Special Contract #2	Street Lighting RLS,LS,DSK	Street Lighting LE	Traffic Lighting TLE
CLASSIFIED CUSTOMER COSTS													
Rate Base													
Plant in Service													
Intangible	$198	$114	$19	$0	$2	$0	$0	$0	$0	$0	$62	$0	$0
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$362,409,577	$209,074,166	$34,099,741	$320,204	$3,839,622	$501,391	$423,230	$410,138	$4,756	$4,756	$113,598,821	$20,314	$112,437
General	$1,395,935	$805,315	$131,346	$1,233	$14,790	$1,931	$1,630	$1,580	$18	$18	$437,562	$78	$433
Common	$17,830,901	$10,286,651	$1,677,740	$15,754	$188,913	$24,669	$20,823	$20,179	$234	$234	$5,589,172	$999	$5,532
Plant Held for Future Use	$775,359	$447,305	$72,955	$685	$8,215	$1,073	$905	$877	$10	$10	$243,040	$43	$241
Total Gross Plant	$382,411,970	$220,613,551	$35,981,800	$337,877	$4,051,542	$529,064	$446,589	$432,775	$5,019	$5,019	$119,868,656	$21,435	$118,642
Construction Work In Progress													
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$8,225,543	$4,745,317	$773,955	$7,268	$87,147	$11,380	$9,606	$9,309	$108	$108	$2,578,331	$461	$2,552
General	$1,645,897	$949,518	$154,865	$1,454	$17,438	$2,277	$1,922	$1,863	$22	$22	$515,913	$92	$511
Total CWIP	$9,871,440	$5,694,836	$928,821	$8,722	$104,585	$13,657	$11,528	$11,171	$130	$130	$3,094,245	$553	$3,063
Accumulated Depreciation													
Intangible	$3,613,402	$2,084,572	$339,991	$3,193	$38,283	$4,999	$4,220	$4,089	$47	$47	$1,132,636	$203	$1,121
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$135,116,892	$77,948,965	$12,713,381	$119,382	$1,431,523	$186,933	$157,792	$152,911	$1,773	$1,773	$42,352,964	$7,574	$41,920
General	$6,270,621	$3,617,523	$590,014	$5,540	$66,435	$8,675	$7,323	$7,096	$82	$82	$1,965,553	$351	$1,945
Total Depreciation Reserve	$145,000,915	$83,651,060	$13,643,386	$128,114	$1,536,242	$200,608	$169,335	$164,097	$1,903	$1,903	$45,451,153	$8,128	$44,986
Net Utility Plant	$247,282,495	$142,657,327	$23,267,235	$218,485	$2,619,885	$342,113	$288,782	$279,849	$3,245	$3,245	$77,511,748	$13,861	$76,719
Working Capital													
Cash Working Capital - Operation and Maintenance Expenses	$6,203,497	$4,533,572	$1,091,090	$18,739	$203,168	$42,154	$54,850	$23,162	$276	$276	$230,219	$926	$5,065
Materials and Supplies	$3,257,338	$1,879,159	$306,489	$2,878	$34,511	$4,507	$3,804	$3,686	$43	$43	$1,021,027	$183	$1,011
Fuel Stock	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Prepayments	$1,233,514	$711,615	$116,063	$1,090	$13,069	$1,707	$1,441	$1,396	$16	$16	$386,650	$69	$383
Total Working Capital	$10,694,350	$7,124,346	$1,513,643	$22,707	$250,747	$48,367	$60,094	$28,244	$335	$335	$1,637,896	$1,178	$6,458
Accumulated Deferred Income Taxes	$48,243,297	$27,831,569	$4,539,295	$42,625	$511,123	$66,744	$56,340	$54,597	$633	$633	$15,122,066	$2,704	$14,967
Accumulated ITCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Advances	$855,406	$743,228	$92,339	$0	$0	$0	$0	$0	$0	$0	$19,596	$37	$206
Net Rate Base	$208,878,142	$121,206,875	$20,149,244	$198,567	$2,359,509	$323,736	$292,537	$253,496	$2,947	$2,947	$64,007,982	$12,298	$68,003
Operation and Maintenance Expenses													
Production & Purchased Power	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$17,646,303	$12,743,566	$2,868,899	$85,589	$600,143	$134,020	$63,309	$109,628	$1,271	$1,271	$1,014,948	$3,641	$20,016
Customer Accounts Expense	$13,992,000	$10,459,853	$2,599,070	$10,342	$405,658	$75,783	$198,218	$9,336	$144	$144	$224,858	$1,355	$7,241
Customer Service Expense	$2,686,388	$2,001,690	$497,381	$1,979	$77,630	$14,502	$37,933	$1,787	$27	$27	$52,776	$99	$555
Administrative and General Expense	$17,343,436	$12,554,422	$3,122,201	$58,167	$608,728	$126,791	$157,376	$72,161	$858	$858	$624,883	$2,620	$14,373
Total Operation and Maintenance Expenses	$51,668,127	$37,759,532	$9,087,551	$156,077	$1,692,159	$351,096	$456,836	$192,912	$2,301	$2,301	$1,917,465	$7,715	$42,184
Depreciation Expense													
Intangible	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$10,031,400	$5,787,117	$943,872	$8,863	$106,280	$13,878	$11,715	$11,353	$132	$132	$3,144,385	$562	$3,112
General	$1,768,251	$1,020,104	$166,378	$1,562	$18,734	$2,446	$2,065	$2,001	$23	$23	$554,266	$99	$549
Total Depreciation Expense	$11,799,651	$6,807,222	$1,110,249	$10,425	$125,014	$16,325	$13,780	$13,354	$155	$155	$3,698,651	$661	$3,661
Taxes Other Than Income Taxes													
Property Taxes	$2,864,240	$1,652,380	$269,501	$2,531	$30,346	$3,963	$3,345	$3,241	$38	$38	$897,808	$161	$889
Other Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total taxes Other Than Income Taxes	$2,864,240	$1,652,380	$269,501	$2,531	$30,346	$3,963	$3,345	$3,241	$38	$38	$897,808	$161	$889
Amortization of ITCs	-$88,275	-$50,926	-$8,306	-$78	-$935	-$122	-$103	-$100	-$1	-$1	-$27,670	-$5	-$27
Total Expenses Before Interest and Income Taxes	$66,332,018	$46,219,134	$10,467,302	$169,033	$1,847,519	$371,383	$473,961	$209,507	$2,493	$2,493	$6,513,924	$8,537	$46,734

LOUSIVILLE GAS & ELECTRIC - ELECTRIC

Summary of Class RORs at Current Rates

ROR At Current Rates

	Customer/Demand Distribution			Primary Distribution 100% Demand				
Class	**Seeyle Modified BIP As Corrected**	**True BIP**	**Probability Of Dispatch**	**Seeyle Modified BIP As Corrected**	**True BIP**	**Probability Of Dispatch**	**Average (All Methods)**	**Average Primary Distribution 100% Demand**
Residential (RS)	2.76%	3.06%	3.13%	3.61%	3.97%	4.05%	**3.43%**	**3.88%**
General Service (GS)	7.32%	7.99%	8.27%	6.97%	7.61%	7.88%	**7.67%**	**7.49%**
Pwr Serv-Prim (PS-Pri)	6.38%	5.42%	5.57%	4.85%	4.10%	4.23%	**5.09%**	**4.39%**
Pwr Serv-Sec (PS-Sec)	8.59%	8.21%	8.41%	7.02%	6.72%	6.87%	**7.64%**	**6.87%**
Time of Day-Pri (TOU-Pri)	4.55%	3.58%	3.75%	3.23%	2.46%	2.62%	**3.37%**	**2.77%**
Time of Day-Sec (TOU-Sec)	11.52%	12.39%	9.43%	9.44%	10.10%	7.78%	**10.11%**	**9.11%**
Retail Trans (RTS)	3.53%	2.45%	2.75%	3.53%	2.45%	2.75%	**2.91%**	**2.91%**
Special Contract #1	1.82%	1.41%	1.59%	0.81%	0.50%	0.65%	**1.13%**	**0.65%**
Special Contract #2	2.54%	1.33%	1.04%	1.34%	0.40%	0.18%	**1.14%**	**0.64%**
Street Lighting (RLS, LS, DSK)	5.43%	4.66%	4.65%	6.01%	5.16%	5.14%	**5.18%**	**5.44%**
Lighting Energy (LE)	7.80%	2.66%	2.77%	5.62%	1.70%	1.88%	**3.74%**	**3.07%**
Traffic Energy (TE)	6.89%	5.70%	5.18%	7.78%	6.43%	5.83%	**6.30%**	**6.68%**
TOTAL	4.92%	4.92%	4.92%	4.92%	4.92%	4.92%	**4.92%**	**4.92%**

Indexed ROR At Current Rates

	Customer/Demand Distribution			Primary Distribution 100% Demand				
Class	**Seeyle Modified BIP As Corrected**	**True BIP**	**Probability Of Dispatch**	**Seeyle Modified BIP As Corrected**	**True BIP**	**Probability Of Dispatch**	**Average (All Methods)**	**Average Primary Distribution 100% Demand**
Residential (RS)	56%	62%	64%	73%	81%	82%	**70%**	**79%**
General Service (GS)	149%	162%	168%	142%	155%	160%	**156%**	**152%**
Pwr Serv-Prim (PS-Pri)	130%	110%	113%	99%	83%	86%	**103%**	**89%**
Pwr Serv-Sec (PS-Sec)	175%	167%	171%	143%	137%	140%	**155%**	**140%**
Time of Day-Pri (TOU-Pri)	92%	73%	76%	66%	50%	53%	**68%**	**56%**
Time of Day-Sec (TOU-Sec)	234%	252%	192%	192%	205%	158%	**205%**	**185%**
Retail Trans (RTS)	72%	50%	56%	72%	50%	56%	**59%**	**59%**
Special Contract #1	37%	29%	32%	16%	10%	13%	**23%**	**13%**
Special Contract #2	52%	27%	21%	27%	8%	4%	**23%**	**13%**
Street Lighting (RLS, LS, DSK)	110%	95%	95%	122%	105%	104%	**105%**	**111%**
Lighting Energy (LE)	159%	54%	56%	114%	35%	38%	**76%**	**62%**
Traffic Energy (TE)	140%	116%	105%	158%	131%	118%	**128%**	**136%**
TOTAL	100%	100%	100%	100%	100%	100%	**100%**	**100%**

LOUISVILLE GAS & ELECTRIC
Electric Residential Customer Cost Analysis

		Total Company	Residential
Gross Plant			
369	Services		$26,485,178
370	Meters		$27,976,208
	Total Gross Plant		**$54,461,386**
Depreciation Reserve			
	Services	$25,156,654	$19,335,832
	Meters	$25,678,088	$17,972,607
	Total Depreciation Reserve	**$50,834,742**	**$37,308,439**
Total Net Plant			**$17,152,947**
Operation & Maintenance Expenses			
586	Dist Oper - Meter		$5,793,616
597	Maintenance-Meters		$999,414
902	Meter Reading		$1,931,450
903	Records & Collections		$5,737,170
	Total O & M Expenses		**$14,461,650**
Depreciation Expense			
	Services	$1,216,714	$935,187
	Meters	$1,250,722	$875,405
	Total Depreciation Expense	$2,467,436	$1,810,592
Revenue Requirement			
	Interest		$307,038
	Equity return		$936,859
	State Income Taxes @ 6.00%		$91,999
	Federal Income Tax @35.00%		$504,463
	Revenue For Return		$1,840,359
	O & M Expenses		$14,461,650
	Depreciation Expense		$1,810,592
	Subtotal Customer Revenue Requirement		$18,112,601
	Total Revenue Requirement		**$18,112,601**
	Number of Customers		364,109
	Number of Bills		4,369,308
	TOTAL MONTHLY CUSTOMER COST		$4.15

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

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
Gas Plant at Original Cost											
Underground Storage Plant											
350-357	Underground Storage Plant	PT350	F003	$	153,419,352	-	-	153,419,352	-	-	-
358	Asset Retire Obligation Gas Plant	PT350	F003	$	-	-	-	-	-	-	-
Total Storage Plant		PTST		$	153,419,352	$ -	$ -	$ 153,419,352	$ -	$ -	$ -
Transmission Plant											
365-372	Transmission	PT365	F005	$	53,150,756	-	-	-	-	9,263,651	43,887,105
Distribution Plant											
374	Land and Land Rights	PT374	F008	$	134,497	-	-	-	-	-	-
375	Structures & Improvements	PT375	F008		1,155,812	-	-	-	-	-	-
376	Mains	PT376	F009		427,054,945	-	-	-	-	-	-
378	Meas. & Reg. Sta. Equip. - General	PT378	F008		23,937,002	-	-	-	-	-	-
379	Meas. & Reg. Sta. Equip. - City Gate	PT379	F008		12,352,333	-	-	-	-	-	-
380	Services	PT380	F010		374,861,864	-	-	-	-	-	-
381	Meters	PT381	F011		57,176,384	-	-	-	-	-	-
382	Meter Installations	PT382	F011			-	-	-	-	-	-
383	House Regulators	PT383	F011		25,550,380	-	-	-	-	-	-
384	House Regulator Installations	PT384	F011			-	-	-	-	-	-
385	Industrial Meas. & Reg. Equip.	PT385	F011		2,260,538	-	-	-	-	-	-
387	Other Equipment	PT387	F011		1,928,759	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-City Gate	PT388	F008		-	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	PT388	F009		-	-	-	-	-	-	-
Sub-Total Distribution Plant		PTDSUB		$	926,412,515	$ -	$ -	$ -	$ -	$ -	$ -
U-T-D Subtotal		PTSUB		$	1,132,982,623	-	-	153,419,352	-	9,263,651	43,887,105
117	Gas Stored Underground/Non-Current	PT117	F003	$	11,788,845	-	-	11,788,845	-	-	-
301-303	Intangible Plant	PT301	PTSUB		387	-	-	52	-	3	15
392-396	General Plant	PT389	PTSUB		13,168,757	-	-	1,783,207	-	107,672	510,104
389-399	Common Utility Plant	PTCP	PTSUB		86,673,008	-	-	11,736,558	-	708,668	3,357,357
Total Plant in Service		PTIS		$	1,244,613,621	-	-	178,728,015	-	10,079,995	47,754,581

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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									
365-372	Transmission	PT365	F005	-	-	-	-	-	-
Distribution Plant									
374	Land and Land Rights	PT374	F008	-	134,497	-	-	-	-
375	Structures & Improvements	PT375	F008	-	1,155,812	-	-	-	-
376	Mains	PT376	F009	-	-	384,817,184	-	42,237,761	-
378	Meas. & Reg. Sta. Equip. - General	PT378	F008	-	23,937,002	-	-	-	-
379	Meas. & Reg. Sta. Equip. - City Gate	PT379	F008	-	12,352,333	-	-	-	-
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	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	PT388	F009	-	-	-	-	-	-
Sub-Total Distribution Plant		PTDSUB		$ -	$ 37,579,644	$ 384,817,184	$ -	$ 42,237,761	$ -
U-T-D Subtotal		PTSUB		-	37,579,644	384,817,184	-	42,237,761	-
117	Gas Stored Underground/Non-Current	PT117	F003	-	-	-	-	-	-
301-303	Intangible Plant	PT301	PTSUB	-	13	132	-	14	-
392-396	General Plant	PT389	PTSUB	-	436,792	4,472,764	-	490,933	-
389-399	Common Utility Plant	PTCP	PTSUB	-	2,874,837	29,438,459	-	3,231,183	-
Total Plant in Service		PTIS		-	40,891,286	418,728,540	-	45,959,891	-

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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							
365-372	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	374,861,864	-	-	-
381	Meters	PT381	F011	-	57,176,384	-	-
382	Meter Installations	PT382	F011	-	-	-	-
383	House Regulators	PT383	F011	-	25,550,380	-	-
384	House Regulator Installations	PT384	F011	-	-	-	-
385	Industrial Meas. & Reg. Equip.	PT385	F011	-	2,260,538	-	-
387	Other Equipment	PT387	F011	-	1,928,759	-	-
388	Asset Retire Obligation Gas Plant-City Gate	PT388	F008	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	PT388	F009	-	-	-	-
Sub-Total Distribution Plant		PTDSUB		$ 374,861,864	$ 86,916,062	$ -	$ -
U-T-D Subtotal		PTSUB		374,861,864	86,916,062	-	-
117	Gas Stored Underground/Non-Current	PT117	F003	-	-	-	-
301-303	Intangible Plant	PT301	PTSUB	128	30	-	-
392-396	General Plant	PT389	PTSUB	4,357,053	1,010,233	-	-
389-399	Common Utility Plant	PTCP	PTSUB	28,676,879	6,649,066	-	-
Total Plant in Service		PTIS		407,895,923	94,575,391	-	-

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

Description	Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
Gas Plant at Original Cost (Continued)										
Construction Work in Progress										
Underground Storage	CWIPUS	F003	$	4,450,250	-	-	4,450,250	-	-	-
Transmission	CWIPTR	F005		6,876,704	-	-	-	-	1,198,542	5,678,163
Distribution Mains	CWIPDM	F009		5,653,869	-	-	-	-	-	-
Other Distribution	CWIPOD	PTDSUB		-	-	-	-	-	-	-
General	CWIPCO	PTSUB		119,481	-	-	16,179	-	977	4,628
Common		PTSUB		7,805,570	-	-	1,056,967	-	63,821	302,356
	CWIP		$	24,905,873	$ -	$ -	$ 5,523,396	$ -	$ 1,263,339	$ 5,985,147
	PTT		$	1,269,519,494	-	-	184,251,411	-	11,343,334	53,739,727

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	-	-	5,094,674	-	559,194	-
Other Distribution	CWIPOD	PTDSUB	-	-	-	-	-	-
General	CWIPCO	PTSUB	-	3,963	40,582	-	4,454	-
Common		PTSUB	-	258,901	2,651,159	-	290,993	-
	CWIP		$ -	$ 262,864	$ 7,786,415	$ -	$ 854,642	$ -
	PTT		-	41,154,150	426,514,955	-	46,814,533	-

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	-	-	-	-
General	CWIPCO	PTSUB	39,532	9,166	-	-
Common		PTSUB	2,582,573	598,799	-	-
	CWIP		$ 2,622,105	$ 607,965	$ -	$ -
	PTT		410,518,028	95,183,356	-	-
				$ 1,020,185,022		

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

Description	Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
<u>Net Cost Rate Base</u>									
Total Gas Utility Plant at Original Cost			$ 1,269,519,494	$ -	$ -	$ 184,251,411	$ -	$ 11,343,334	$ 53,739,727
Less:									
Reserve for Depreciation									
Underground Storage	DEPRUS	PTST	$ 39,041,082	-	-	39,041,082	-	-	-
Transmission	DEPTR	F005	11,949,641	-	-	-	-	2,082,704	9,866,937
Distribution	DEPRDI	DEPRDIS	271,564,808	-	-	-	-	-	-
General & Intangible	DEPRGE	PT389	5,985,030	-	-	810,444	-	48,936	231,836
Common	DEPRCO	PTCP	44,929,599	-	-	6,084,003	-	367,360	1,740,389
Total Depreciation Reserve	DEPR		$ 373,470,160	$ -	$ -	$ 45,935,530	$ -	$ 2,499,000	$ 11,839,161
Customer Advances For Construction	CAD	CADAL	$ 53,441	-	-	-	-	-	-
Accum. Deferred Income Taxes	DIT	PTSUB	221,284,688	-	-	29,964,584	-	1,809,299	8,571,662
PLUS:									
Materials and Supplies	MSP	PTSUB	$ 323,951	-	-	43,867	-	2,649	12,549
Prepayments	PPY	PTSUB	2,521,950	-	-	341,502	-	20,620	97,690
Gas Stored Underground	GSU	F003	24,895,211	-	-	24,895,211	-	-	-
Cash Working Capital	CWC	OMT	9,932,409	17,092	128,499	574,635	1,398,816	150,464	712,833
Adjustments:									
Unamortized Debt		PTSUB	$ -	-	-	-	-	-	-
Regulatory		PTSUB	-	-	-	-	-	-	-
Customer Advances for Construction		PTSUB	-	-	-	-	-	-	-
Depreciation Adjustment		PTSUB	-	-	-	-	-	-	-
Net Cost Rate Base	NCRB		$ 712,384,727	$ 17,092	$ 128,499	$ 134,206,512	$ 1,398,816	$ 7,208,769	$ 34,151,975

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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			$ -	$ 41,154,150	$ 426,514,955	$ -	$ 46,814,533	$ -
Less:								
Reserve for Depreciation								
Underground Storage	DEPRUS	PTST	-	-	-	-	-	-
Transmission	DEPTR	F005	-	-	-	-	-	-
Distribution	DEPRDI	DEPRDIS	-	5,019,928	119,838,172	-	13,153,508	-
General & Intangible	DEPRGE	PT389	-	198,516	2,032,814	-	223,123	-
Common	DEPRCO	PTCP	-	1,490,260	15,260,324	-	1,674,982	-
Total Depreciation Reserve	DEPR		$ -	$ 6,708,704	$ 137,131,310	$ -	$ 15,051,613	$ -
Customer Advances For Construction	CAD	CADAL	-	-	25,645	-	2,815	-
Accum. Deferred Income Taxes	DIT	PTSUB	-	7,339,742	75,159,273	-	8,249,526	-
PLUS:								
Materials and Supplies	MSP	PTSUB	-	10,745	110,030	-	12,077	-
Prepayments	PPY	PTSUB	-	83,650	856,580	-	94,019	-
Gas Stored Underground	GSU	F003	-	-	-	-	-	-
Cash Working Capital	CWC	OMT	231,676	468,397	2,512,657	-	275,791	-
Adjustments:								
Unamortized Debt		PTSUB	-	-	-	-	-	-
Regulatory		PTSUB	-	-	-	-	-	-
Customer Advances for Construction		PTSUB	-	-	-	-	-	-
Depreciation Adjustment		PTSUB	-	-	-	-	-	-
Net Cost Rate Base	NCRB		$ 231,676	$ 27,668,497	$ 217,677,994	$ -	$ 23,892,465	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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			$	410,518,028	$	95,183,356	$	-	$	-
Less:										
Reserve for Depreciation										
Underground Storage	DEPRUS	PTST		-		-		-		-
Transmission	DEPTR	F005		-		-		-		-
Distribution	DEPRDI	DEPRDIS		111,944,104		21,609,095		-		-
General & Intangible	DEPRGE	PT389		1,980,224		459,138		-		-
Common	DEPRCO	PTCP		14,865,535		3,446,746		-		-
Total Depreciation Reserve	DEPR		$	128,789,864	$	25,514,979	$	-	$	-
Customer Advances For Construction	CAD	CADAL		24,981		-		-		-
Accum. Deferred Income Taxes	DIT	PTSUB		73,214,883		16,975,718		-		-
PLUS:										
Materials and Supplies	MSP	PTSUB		107,183		24,852		-		-
Prepayments	PPY	PTSUB		834,420		193,470		-		-
Gas Stored Underground	GSU	F003		-		-		-		-
Cash Working Capital	CWC	OMT		944,227		605,331		1,808,350		103,640
Adjustments:										
Unamortized Debt		PTSUB		-		-		-		-
Regulatory		PTSUB		-		-		-		-
Customer Advances for Construction		PTSUB		-		-		-		-
Depreciation Adjustment		PTSUB		-		-		-		-
Net Cost Rate Base	NCRB		$	210,374,130	$	53,516,312	$	1,808,350	$	103,640

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

Description		Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
Labor Expenses										
807-813	Procurement Expenses	LB807	DMCM	614,676	72,163	542,513	-	-	-	-
Storage Expenses										
Operation										
814	Operations Supervision and Engineer	LB814	OSE	536,969	-	-	124,734	412,235	-	-
815	Maps and Records	LB815	F003	-	-	-	-	-	-	-
816	Well Expenses	LB816	F003	26,000	-	-	26,000	-	-	-
817	Lines Expenses	LB817	F003	393,901	-	-	393,901	-	-	-
818	Compressor Station Exp - Payroll	LB818	F004	708,539	-	-	-	708,539	-	-
819	Compressor Station Fuel and Power	LB819	F004	-	-	-	-	-	-	-
820	Measurement and Regulator Station	LB820	F003	-	-	-	-	-	-	-
821	Purification of Natural Gas	LB821	F004	679,199	-	-	-	679,199	-	-
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		$ 2,344,608	$ -	$ -	$ 544,635	$ 1,799,973	$ -	$ -
Storage Expense										
Maintenance										
830	Maintenance Super and Eng.	LB830	MSE	410,327	-	-	176,230	234,097	-	-
831	Maintenance of Structures	LB831	F003	-	-	-	-	-	-	-
832	Maintenance of Resevoirs	LB832	F003	234,554	-	-	234,554	-	-	-
833	Maintenance of Lines	LB833	F003	78,000	-	-	78,000	-	-	-
834	Main of Compressor Station Equipment	LB834	F004	368,303	-	-	-	368,303	-	-
835	Main of Meas and Reg Sta. Equip	LB835	F003	19,000	-	-	19,000	-	-	-
836	Main of Purification Equip	LB836	F004	337,789	-	-	-	337,789	-	-
837	Main of Other Equipment	LB837	F003	200,000	-	-	200,000	-	-	-
Total Maintenance Labor		LBSM		$ 1,647,973	$ -	$ -	$ 707,784	$ 940,189	$ -	$ -
Total Storage Labor		LBS		$ 3,992,581	-	-	1,252,419	2,740,162	-	-

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

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
Labor Expenses (Continued)											
Transmission											
850-867	Transmission Expenses	LB850	F005	$	2,082,630	-	-	-	-	362,982	1,719,648
Distribution Expenses											
Operation											
870	Operation Supr and Engr	LB870	DOES	$	-	-	-	-	-	-	-
871	Dist Load Dispatching	LB871	F007		678,000	-	-	-	-	-	-
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		944,124	-	-	-	-	-	-
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	$	695,000	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	LB876	F011	$	339,000	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	LB877	F008	$	53,000	-	-	-	-	-	-
878	Meter and House Reg. Expense	LB878	F011	$	656,175	-	-	-	-	-	-
879	Customer Installation Expense	LB879	F011	$	67,000	-	-	-	-	-	-
880	Other Expenses	LB880	PTDSUB	$	1,534,995	-	-	-	-	-	-
881	Rents	LB881	PTDSUB	$	-	-	-	-	-	-	-
Total Operations Distribution Labor		LBDO		$	4,967,294	$ -	$ -	$ -	$ -	$ -	$ -
Total Operations Transmission and Distribution Labor		LBTDO		$	7,049,924	$ -	$ -	$ -	$ -	$ 362,982	$ 1,719,648

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	678,000	-	-	-	-	-
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	-	-	453,058	-	49,728	-
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	-	695,000	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	LB876	F011	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	LB877	F008	-	53,000	-	-	-	-
878	Meter and House Reg. Expense	LB878	F011	-	-	-	-	-	-
879	Customer Installation Expense	LB879	F011	-	-	-	-	-	-
880	Other Expenses	LB880	PTDSUB	-	62,267	637,613	-	69,985	-
881	Rents	LB881	PTDSUB	-	-	-	-	-	-
Total Operations Distribution Labor		LBDO		$ 678,000	$ 810,267	$ 1,090,671	$ -	$ 119,713	$ -
Total Operations Transmission and Distribution Labor		LBTDO		$ 678,000	$ 810,267	$ 1,090,671	$ -	$ 119,713	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	441,338	-	-	-
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	-	339,000	-	-
877	Meas and Reg Station Exp. - City Gate	LB877	F008	-	-	-	-
878	Meter and House Reg. Expense	LB878	F011	-	656,175	-	-
879	Customer Installation Expense	LB879	F011	-	67,000	-	-
880	Other Expenses	LB880	PTDSUB	621,118	144,013	-	-
881	Rents	LB881	PTDSUB	-	-	-	-
Total Operations Distribution Labor		LBDO		$ 1,062,455	$ 1,206,188	$ -	$ -
Total Operations Transmission and Distribution Labor		LBTDO		$ 1,062,455	$ 1,206,188	$ -	$ -

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

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
Labor Expenses (Continued)											
Maintenance Expense -- Distribution											
885	Maintenance Supr and Engr	LB885	DMES	$	-	-	-	-	-	-	-
886	Maintenance Structures	LB886	F008		-	-	-	-	-	-	-
887	Maintenance Mains	LB887	F009		3,914,029	-	-	-	-	-	-
888	Maintenance Comp. Station Equip.	LB888	F007		-	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	LB889	F008		62,000	-	-	-	-	-	-
890	Maintenance Meas and Reg - Industrial	LB890	F011		168,000	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	LB891	F008		175,000	-	-	-	-	-	-
892	Maintenance Services	LB892	F010		604,557	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	LB893	F011		-	-	-	-	-	-	-
894	Maintenance Other Equipment	LB894	PTDSUB		129,000	-	-	-	-	-	-
Total Maintenance Labor		LBDM		$	5,052,586	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission & Distribution Labor		LBTD		$	12,102,510	$ -	$ -	$ -	$ -	$ 362,982	$ 1,719,648
Customer Accounts Expense											
901	Supervision	LB901	F012	$	687,661	-	-	-	-	-	-
902	Meter Reading	LB902	F012		267,218	-	-	-	-	-	-
903	Customer Records and Collections	LB903	F012		2,423,677	-	-	-	-	-	-
904	Uncollectible Accounts	LB904	F012		-	-	-	-	-	-	-
905	Misc. Cust Account Expenses	LB905	F012		-	-	-	-	-	-	-
Total Customer Accounts Labor		LBCA		$	3,378,555	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service Expenses											
907-910	Customer Service	LB907	F013	$	224,138	-	-	-	-	-	-
Sales Expenses											
911-916	Sales Expenses	LB911	F013	$	-	-	-	-	-	-	-

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	-	-	-	-	-	-
887	Maintenance Mains	LB887	F009	-	-	3,526,913	-	387,116	-
888	Maintenance Comp. Station Equip.	LB888	F007	-	-	-	-	-	-
889	Maintenance Meas and Reg. General	LB889	F008	-	62,000	-	-	-	-
890	Maintenance Meas and Reg - Industrial	LB890	F011	-	-	-	-	-	-
891	Maintenance Meas and Reg.-City Gate	LB891	F008	-	175,000	-	-	-	-
892	Maintenance Services	LB892	F010	-	-	-	-	-	-
893	Maintenance Meters and House Reg.	LB893	F011	-	-	-	-	-	-
894	Maintenance Other Equipment	LB894	PTDSUB	-	5,233	53,585	-	5,881	-
Total Maintenance Labor		LBDM		$ -	$ 242,233	$ 3,580,498	$ -	$ 392,998	$ -
Total Transmission & Distribution Labor		LBTD		$ 678,000	$ 1,052,499	$ 4,671,169	$ -	$ 512,710	$ -
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
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	-	168,000	-	-
891	Maintenance Meas and Reg.-City Gate	LB891	F008	-	-	-	-
892	Maintenance Services	LB892	F010	604,557	-	-	-
893	Maintenance Meters and House Reg.	LB893	F011	-	-	-	-
894	Maintenance Other Equipment	LB894	PTDSUB	52,198	12,103	-	-
Total Maintenance Labor		LBDM		$ 656,755	$ 180,103	$ -	$ -
Total Transmission & Distribution Labor		LBTD		$ 1,719,211	$ 1,386,291	$ -	$ -
Customer Accounts Expense							
901	Supervision	LB901	F012	-	-	687,661	-
902	Meter Reading	LB902	F012	-	-	267,218	-
903	Customer Records and Collections	LB903	F012	-	-	2,423,677	-
904	Uncollectible Accounts	LB904	F012	-	-	-	-
905	Misc. Cust Account Expenses	LB905	F012	-	-	-	-
Total Customer Accounts Labor		LBCA		$ -	$ -	$ 3,378,555	$ -
Customer Service Expenses							
907-910	Customer Service	LB907	F013	-	-	-	224,138
Sales Expenses							
911-916	Sales Expenses	LB911	F013	-	-	-	-

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

Description		Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
Labor Expenses (Continued)										
Administrative & General										
920	Admin and General Salaries	LB920	LBSUB	$6,056,882	21,518	161,770	373,453	817,077	108,236	512,774
921	Office Supplies and Expense	LB921	LBSUB	-	-	-	-	-	-	-
922	Admin. Expenses Transferred	LB922	LBSUB	(683,568)	(2,428)	(18,257)	(42,147)	(92,214)	(12,215)	(57,871)
923	Outside Services Employed	LB923	LBSUB	-	-	-	-	-	-	-
924	Property Insurance	LB924	PTT	-	-	-	-	-	-	-
925	Injuries and Damages	LB925	LBSUB	-	-	-	-	-	-	-
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	184,591	-	-	24,996	-	1,509	7,150
Total Administrative and General Labor		LBAG		$ 5,557,905	$ 19,089	$ 143,513	$ 356,302	$ 724,863	$ 97,530	$ 462,054
Total Labor Expense		LBTOT		$ 25,870,365	$ 91,252	$ 686,026	$ 1,608,721	$ 3,465,025	$ 460,512	$ 2,181,702

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	202,170	313,840	1,392,875	-	152,883	-
921	Office Supplies and Expense	LB921	LBSUB	-	-	-	-	-	-
922	Admin. Expenses Transferred	LB922	LBSUB	(22,816)	(35,419)	(157,197)	-	(17,254)	-
923	Outside Services Employed	LB923	LBSUB	-	-	-	-	-	-
924	Property Insurance	LB924	PTT	-	-	-	-	-	-
925	Injuries and Damages	LB925	LBSUB	-	-	-	-	-	-
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	-	6,123	62,696	-	6,882	-
Total Administrative and General Labor		LBAG		$ 179,353	$ 284,543	$ 1,298,374	$ -	$ 142,510	$ -
Total Labor Expense		LBTOT		$ 857,353	$ 1,337,043	$ 5,969,543	$ -	$ 655,221	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	512,644	413,372	1,007,436	66,835
921	Office Supplies and Expense	LB921	LBSUB	-	-	-	-
922	Admin. Expenses Transferred	LB922	LBSUB	(57,856)	(46,652)	(113,697)	(7,543)
923	Outside Services Employed	LB923	LBSUB	-	-	-	-
924	Property Insurance	LB924	PTT	-	-	-	-
925	Injuries and Damages	LB925	LBSUB	-	-	-	-
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	61,074	14,161	-	-
Total Administrative and General Labor		LBAG		$ 515,862	$ 380,880	$ 893,739	$ 59,292
Total Labor Expense		LBTOT		$ 2,235,073	$ 1,767,171	$ 4,272,294	$ 283,429

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

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
Operation & Maintenance Expenses											
807 & 813	Procurement Expenses	OM807	DMCM	$	356,999	41,912	315,087	-	-	-	-
Storage Expenses											
Operation											
814	Operations Supervision and Engineer	OM814	OSE		669,590	-	-	155,541	514,049	-	-
815	Maps and Records	OM815	F003		-	-	-	-	-	-	-
816	Well Expenses	OM816	F003		38,570	-	-	38,570	-	-	-
817	Lines Expenses	OM817	F003		908,360	-	-	908,360	-	-	-
818	Compressor Station Exp - Payroll	OM818	F004		3,082,282	-	-	-	3,082,282	-	-
819	Compressor Station Fuel and Power	OM819	F004		631,000	-	-	-	631,000	-	-
820	Measurement and Regulator Station	OM820	F003		-	-	-	-	-	-	-
821	Purification of Natural Gas *(1)*	OM821	F004		1,439,653	-	-	-	1,439,653	-	-
823	Gas losses *(2)*	OM823	F004		-	-	-	-	-	-	-
824	Other Expenses	OM824	F004		-	-	-	-	-	-	-
825	Storage Well Royalities	OM825	F003		136,735	-	-	136,735	-	-	-
826	Rents	OM826	F003		-	-	-	-	-	-	-
Total Operation Expenses		OMOE		$	6,906,190	$ -	$ -	$ 1,239,206	$ 5,666,984	$ -	$ -
Storage Expense											
Maintenance											
830	Maintenance Super and Eng.	OM830	MSE	$	481,346	-	-	206,732	274,614	-	-
831	Maintenance of Structures	OM831	F003		-	-	-	-	-	-	-
832	Maintenance of Resevoirs	OM832	F003		655,057	-	-	655,057	-	-	-
833	Maintenance of Lines	OM833	F003		148,661	-	-	148,661	-	-	-
834	Main of Compressor Station Equipment	OM834	F004		479,611	-	-	-	479,611	-	-
835	Main of Meas and Reg Sta. Equip	OM835	F003		27,400	-	-	27,400	-	-	-
836	Main of Purification Equip	OM836	F004		642,528	-	-	-	642,528	-	-
837	Main of Other Equipment	OM837	F003		344,250	-	-	344,250	-	-	-
Total Maintenance Expense		OMME		$	2,778,853	$ -	$ -	$ 1,382,100	$ 1,396,753	$ -	$ -
Total Storage Expense		OMS		$	9,685,043	-	-	2,621,306	7,063,737	-	-

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

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
Operation & Maintenance Expenses (Continued)											
Transmission											
850-867	Transmission Expenses	OM850	F005	$	3,862,617	-	-	-	-	673,216	3,189,401
Distribution Expenses											
Operation											
870	Operation Supr and Engr	OM870	DOES	$	-	-	-	-	-	-	-
871	Dist Load Dispatching	OM871	F007		912,592	-	-	-	-	-	-
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		3,602,301	-	-	-	-	-	-
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		1,161,507	-	-	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	OM876	F011		490,681	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	OM877	F008		250,192	-	-	-	-	-	-
878	Meter and House Reg. Expense	OM878	F011		1,371,331	-	-	-	-	-	-
879	Customer Installation Expense	OM879	F011		161,930	-	-	-	-	-	-
880	Other Expenses	OM880	PTDSUB		4,011,065	-	-	-	-	-	-
881	Rents	OM881	PTDSUB		6,755	-	-	-	-	-	-
Total Operations Distribution Expense		OMDO		$	11,968,354	-	-	-	-	-	-
Total Transmission and Distribution Oper Exp		OMTDO		$	15,830,971	$ -	$ -	$ -	$ -	$ 673,216	$ 3,189,401

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	912,592	-	-	-	-	-
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	-	-	1,728,642	-	189,737	-
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	-	1,161,507	-	-	-	-
876	Meas and Reg Station Exp.- Industrial	OM876	F011	-	-	-	-	-	-
877	Meas and Reg Station Exp. - City Gate	OM877	F008	-	250,192	-	-	-	-
878	Meter and House Reg. Expense	OM878	F011	-	-	-	-	-	-
879	Customer Installation Expense	OM879	F011	-	-	-	-	-	-
880	Other Expenses	OM880	PTDSUB	-	162,708	1,666,133	-	182,876	-
881	Rents	OM881	PTDSUB	-	274	2,806	-	308	-
Total Operations Distribution Expense		OMDO		912,592	1,574,681	3,397,582	-	372,921	-
Total Transmission and Distribution Oper Exp		OMTDO		$ 912,592	$ 1,574,681	$ 3,397,582	$ -	$ 372,921	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	1,683,922	-	-	-
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	-	490,681	-	-
877	Meas and Reg Station Exp. - City Gate	OM877	F008	-	-	-	-
878	Meter and House Reg. Expense	OM878	F011	-	1,371,331	-	-
879	Customer Installation Expense	OM879	F011	-	161,930	-	-
880	Other Expenses	OM880	PTDSUB	1,623,030	376,318	-	-
881	Rents	OM881	PTDSUB	2,733	634	-	-
Total Operations Distribution Expense		OMDO		3,309,685	2,400,894	-	-
Total Transmission and Distribution Oper Exp		OMTDO		$ 3,309,685	$ 2,400,894	$ -	$ -

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

Description		Name	Vector		Total Company		Procurement Demand		Procurement Commodity		Storage Demand		Storage Commodity		Transmission Non-Storage Related Demand		Transmission Storage Related Demand
Operation & Maintenance Expenses (Continued)																	
Maintenance Expense -- Distribution																	
885	Maintenance Supr and Engr	OM885	DMES		-		-		-		-		-		-		-
886	Maintenance Structures	OM886	F008		-		-		-		-		-		-		-
887	Maintenance Mains	OM887	F009		10,017,232		-		-		-		-		-		-
888	Maintenance Comp. Station Equip.	OM888	F007		-		-		-		-		-		-		-
889	Maintenance Meas and Reg. General	OM889	F008		166,690		-		-		-		-		-		-
890	Maintenance Meas and Reg - Industrial	OM890	F011		286,414		-		-		-		-		-		-
891	Maintenance Meas and Reg.-City Gate	OM891	F008		415,357		-		-		-		-		-		-
892	Maintenance Services	OM892	F010		1,072,829		-		-		-		-		-		-
893	Maintenance Meters and House Reg.	OM893	F011		15,198		-		-		-		-		-		-
894	Maintenance Other Equipment	OM894	PTDSUB		561,398		-		-		-		-		-		-
Total Maintenance Expenses		OMME		$	12,535,118	$	-	$	-	$	-	$	-	$	-	$	-
Total Transmission & Distribution Expenses		OMDE		$	28,366,089	$	-	$	-	$	-	$	-	$	673,216	$	3,189,401
Customer Accounts Expense																	
901	Supervision	OM901	F012		1,016,772		-		-		-		-		-		-
902	Meter Reading	OM902	F012		2,000,723		-		-		-		-		-		-
903	Customer Records and Collections	OM903	F012		5,889,512		-		-		-		-		-		-
904	Uncollectible Accounts	OM904	F012		411,866		-		-		-		-		-		-
905	Misc. Cust Account Expenses	OM905	F012		1,012		-		-		-		-		-		-
Total Customer Accounts Expense		OMCA		$	9,319,886	$	-	$	-	$	-	$	-	$	-	$	-
Customer Service Expenses																	
907-910	Customer Service	OM907	F013	$	499,125		-		-		-		-		-		-
Sales Expenses																	
911-916	Sales Expenses	OM911	F013	$	-		-		-		-		-		-		-

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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		-		-		-		-		-		-
887	Maintenance Mains	OM887	F009		-		-		9,026,480		-		990,752		-
888	Maintenance Comp. Station Equip.	OM888	F007		-		-		-		-		-		-
889	Maintenance Meas and Reg. General	OM889	F008		-		166,690		-		-		-		-
890	Maintenance Meas and Reg - Industrial	OM890	F011		-		-		-		-		-		-
891	Maintenance Meas and Reg.-City Gate	OM891	F008		-		415,357		-		-		-		-
892	Maintenance Services	OM892	F010		-		-		-		-		-		-
893	Maintenance Meters and House Reg.	OM893	F011		-		-		-		-		-		-
894	Maintenance Other Equipment	OM894	PTDSUB		-		22,773		233,196		-		25,596		-
Total Maintenance Expenses		OMME		$	-	$	604,820	$	9,259,676	$	-	$	1,016,348	$	-
Total Transmission & Distribution Expenses		OMDE		$	912,592	$	2,179,501	$	12,657,258	$	-	$	1,389,268	$	-
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
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		-		286,414		-		-
891	Maintenance Meas and Reg.-City Gate	OM891	F008		-		-		-		-
892	Maintenance Services	OM892	F010		1,072,829		-		-		-
893	Maintenance Meters and House Reg.	OM893	F011		-		15,198		-		-
894	Maintenance Other Equipment	OM894	PTDSUB		227,163		52,670		-		-
Total Maintenance Expenses		OMME		$	1,299,992	$	354,282	$	-	$	-
Total Transmission & Distribution Expenses		OMDE		$	4,609,677	$	2,755,176	$	-	$	-
Customer Accounts Expense											
901	Supervision	OM901	F012		-		-		1,016,772		-
902	Meter Reading	OM902	F012		-		-		2,000,723		-
903	Customer Records and Collections	OM903	F012		-		-		5,889,512		-
904	Uncollectible Accounts	OM904	F012		-		-		411,866		-
905	Misc. Cust Account Expenses	OM905	F012		-		-		1,012		-
Total Customer Accounts Expense		OMCA		$	-	$	-	$	9,319,886	$	-
Customer Service Expenses											
907-910	Customer Service	OM907	F013		-		-		-		499,125
Sales Expenses											
911-916	Sales Expenses	OM911	F013		-		-		-		-

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

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
Operation & Maintenance Expenses (Continued)											
Administrative & General											
920	Admin and General Salaries	OM920	LBSUB	$	7,797,587	27,702	208,261	480,781	1,051,899	139,342	660,142
921	Office Supplies and Expense	OM921	LBSUB		1,753,271	6,229	46,827	108,103	236,517	31,331	148,432
922	Admin. Expenses Transferred	OM922	LBSUB		(1,218,695)	(4,330)	(32,549)	(75,142)	(164,403)	(21,778)	(103,174)
923	Outside Services Employed	OM923	LBSUB		4,461,617	15,851	119,163	275,093	601,875	79,729	377,719
924	Property Insurance	OM924	PTT		178,474	-	-	25,903	-	1,595	7,555
925	Injuries and Damages	OM925	LBSUB		918,880	3,264	24,542	56,656	123,957	16,420	77,792
926	Employee Pensions and Benefits	OM926	LBSUB		9,609,082	34,138	256,643	592,474	1,296,270	171,713	813,503
927	Franchise Requirement	OM927	PTT		-	-	-	-	-	-	-
928	Regulatory Commission Fee	OM928	PTT		194,514	-	-	28,231	-	1,738	8,234
929	Duplicate Charges -Credit	OM929	LBSUB		(597,722)	(2,123)	(15,964)	(36,854)	(80,633)	(10,681)	(50,603)
930.1	General Advertising Expense	OM930.1	PTT		-	-	-	-	-	-	-
930.2	Misc. General Expense	OM930.2	LBSUB		593,100	2,107	15,841	36,569	80,009	10,599	50,212
931	Rents	OM931	PTT		316,976	-	-	46,004	-	2,832	13,418
935	Maintenance of General Plant	OM935	PT389		257,250	-	-	34,835	-	2,103	9,965
Total Administrative and General Expense		OMAGT		$	24,264,334	$ 82,837	$ 622,763	$ 1,572,652	$ 3,145,492	$ 424,943	$ 2,013,194
Total Operation & Maintenance Expense		OMT		$	72,491,476	$ 124,749	$ 937,850	$ 4,193,958	$ 10,209,229	$ 1,098,159	$ 5,202,595

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	260,272	404,036	1,793,177	-	196,820	-
921	Office Supplies and Expense	OM921	LBSUB	58,522	90,847	403,192	-	44,255	-
922	Admin. Expenses Transferred	OM922	LBSUB	(40,678)	(63,147)	(280,258)	-	(30,761)	-
923	Outside Services Employed	OM923	LBSUB	148,922	231,181	1,026,019	-	112,616	-
924	Property Insurance	OM924	PTT	-	5,786	59,961	-	6,581	-
925	Injuries and Damages	OM925	LBSUB	30,671	47,612	211,311	-	23,194	-
926	Employee Pensions and Benefits	OM926	LBSUB	320,737	497,899	2,209,759	-	242,544	-
927	Franchise Requirement	OM927	PTT	-	-	-	-	-	-
928	Regulatory Commission Fee	OM928	PTT	-	6,306	65,350	-	7,173	-
929	Duplicate Charges -Credit	OM929	LBSUB	(19,951)	(30,971)	(137,456)	-	(15,087)	-
930.1	General Advertising Expense	OM930.1	PTT	-	-	-	-	-	-
930.2	Misc. General Expense	OM930.2	LBSUB	19,797	30,732	136,393	-	14,971	-
931	Rents	OM931	PTT	-	10,275	106,493	-	11,689	-
935	Maintenance of General Plant	OM935	PT389	-	8,533	87,375	-	9,590	-
Total Administrative and General Expense		OMAGT		$ 778,291	$ 1,239,087	$ 5,681,317	$ -	$ 623,585	$ -
Total Operation & Maintenance Expense		OMT		$ 1,690,883	$ 3,418,587	$ 18,338,574	$ -	$ 2,012,853	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	659,974	532,172	1,296,966	86,042
921	Office Supplies and Expense	OM921	LBSUB	148,394	119,658	291,620	19,346
922	Admin. Expenses Transferred	OM922	LBSUB	(103,148)	(83,174)	(202,705)	(13,448)
923	Outside Services Employed	OM923	LBSUB	377,623	304,498	742,097	49,232
924	Property Insurance	OM924	PTT	57,712	13,381	-	-
925	Injuries and Damages	OM925	LBSUB	77,772	62,712	152,837	10,139
926	Employee Pensions and Benefits	OM926	LBSUB	813,296	655,804	1,598,271	106,031
927	Franchise Requirement	OM927	PTT	-	-	-	-
928	Regulatory Commission Fee	OM928	PTT	62,899	14,584	-	-
929	Duplicate Charges -Credit	OM929	LBSUB	(50,590)	(40,794)	(99,419)	(6,596)
930.1	General Advertising Expense	OM930.1	PTT	-	-	-	-
930.2	Misc. General Expense	OM930.2	LBSUB	50,199	40,478	98,650	6,545
931	Rents	OM931	PTT	102,499	23,766	-	-
935	Maintenance of General Plant	OM935	PT389	85,115	19,735	-	-
Total Administrative and General Expense		OMAGT		$ 2,281,744	$ 1,662,820	$ 3,878,318	$ 257,293
Total Operation & Maintenance Expense		OMT		$ 6,891,422	$ 4,417,996	$ 13,198,203	$ 756,418
					$ 36,770,315		

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

Description		Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
Depreciation Expenses											
Underground Storage											
350-357	Underground Storage Plant	DP350	F003	$	3,577,970	-	-	3,577,970	-	-	-
358	Asset Retire Obligation Gas Plant	DP350	F003	$	-	-	-	-	-	-	-
Total Underground Storage				$	3,577,970	-	-	3,577,970	-	-	-
Transmission											
365-372	Transmission Plant	DP365	F005	$	1,086,759	-	-	-	-	189,411	897,347
Distribution											
374	Land & Land Rights	DP374	F008	$	-	-	-	-	-	-	-
375	Structures & Improvements	DP375	F008		36,434	-	-	-	-	-	-
376	Mains	DP376	F009		8,512,130	-	-	-	-	-	-
378	Meas & Reg Station Eq.-Gen	DP378	F008		664,445	-	-	-	-	-	-
379	Meas & Reg Station Eq.-City Gate	DP379	F008		448,793	-	-	-	-	-	-
380	Services	DP380	F010		12,286,773	-	-	-	-	-	-
381	Meters	DP381	F011		2,192,731	-	-	-	-	-	-
382	Meter Installations	DP382	F011		-	-	-	-	-	-	-
383	House Regulators	DP383	F011		962,550	-	-	-	-	-	-
384	House Regulator Installations	DP384	F011		-	-	-	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011		52,324	-	-	-	-	-	-
387	Other Equipment	DP387	F011		38,167	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-City Gate	DP388	F008		-	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	DP388	F009		-	-	-	-	-	-	-
Total Distribution				$	25,194,348	$ -	$ -	$ -	$ -	$ -	$ -
117	Gas Stored Underground	DP117	F003	$	-	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB		48	-	-	6	-	0	2
389-399	General Plant	DP389	PTSUB		401,460	-	-	54,363	-	3,282	15,551
Common Utility Plant		DPCP	PTSUB		8,449,877	-	-	1,144,214	-	69,089	327,314
Common Utility Plant Amortization		DPCP	PTSUB		-	-	-	-	-	-	-
Total Depreciation Expense		DEPREX		$	38,710,461	$ -	$ -	$ 4,776,553	$ -	$ 261,783	$ 1,240,214
Regulatory Credits and Accretion											
	Regulatory Credits	REGCR	PTSUB	$	-	-	-	-	-	-	-
	Accretion	ACCRE	PTSUB	$	-	-	-	-	-	-	-
Amortization of Investment Tax Credits		ITCAM	PTSUB	$	(35,870)	-	-	(4,857)	-	(293)	(1,389)

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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									
365-372	Transmission Plant	DP365	F005	-	-	-	-	-	-
Distribution									
374	Land & Land Rights	DP374	F008	-	-	-	-	-	-
375	Structures & Improvements	DP375	F008	-	36,434	-	-	-	-
376	Mains	DP376	F009	-	-	7,670,240	-	841,890	-
378	Meas & Reg Station Eq.-Gen	DP378	F008	-	664,445	-	-	-	-
379	Meas & Reg Station Eq.-City Gate	DP379	F008	-	448,793	-	-	-	-
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	-	-	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	DP388	F009	-	-	-	-	-	-
Total Distribution				$ -	$ 1,149,673	$ 7,670,240	$ -	$ 841,890	$ -
117	Gas Stored Underground	DP117	F003	-	-	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB	-	2	16	-	2	-
389-399	General Plant	DP389	PTSUB	-	13,316	136,356	-	14,967	-
Common Utility Plant		DPCP	PTSUB	-	280,272	2,869,998	-	315,013	-
Common Utility Plant Amortization		DPCP	PTSUB	-	-	-	-	-	-
Total Depreciation Expense		DEPREX		$ -	$ 1,443,262	$ 10,676,610	$ -	$ 1,171,871	$ -
Regulatory Credits and Accretion									
	Regulatory Credits	REGCR	PTSUB	-	-	-	-	-	-
	Accretion	ACCRE	PTSUB	-	-	-	-	-	-
Amortization of Investment Tax Credits		ITCAM	PTSUB	-	(1,190)	(12,183)	-	(1,337)	-

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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							
365-372	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	12,286,773	-	-	-
381	Meters	DP381	F011	-	2,192,731	-	-
382	Meter Installations	DP382	F011	-	-	-	-
383	House Regulators	DP383	F011	-	962,550	-	-
384	House Regulator Installations	DP384	F011	-	-	-	-
385	Industrial Meas & Reg Equipment	DP385	F011	-	52,324	-	-
387	Other Equipment	DP387	F011	-	38,167	-	-
388	Asset Retire Obligation Gas Plant-City Gate	DP388	F008	-	-	-	-
388	Asset Retire Obligation Gas Plant-Mains	DP388	F009	-	-	-	-
Total Distribution				$ 12,286,773	$ 3,245,772	$ -	$ -
117	Gas Stored Underground	DP117	F003	-	-	-	-
301-303	Intangible Plant	DP301	PTSUB	16	4	-	-
389-399	General Plant	DP389	PTSUB	132,828	30,798	-	-
Common Utility Plant		DPCP	PTSUB	2,795,750	648,227	-	-
Common Utility Plant Amortization		DPCP	PTSUB	-	-	-	-
Total Depreciation Expense		DEPREX		$ 15,215,367	$ 3,924,800	$ -	$ -
Regulatory Credits and Accretion							
	Regulatory Credits	REGCR	PTSUB	-	-	-	-
	Accretion	ACCRE	PTSUB	-	-	-	-
Amortization of Investment Tax Credits		ITCAM	PTSUB	(11,868)	(2,752)	-	-

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

Description	Name	Vector		Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
Taxes Other Than Income Taxes										
	OTRE	PTT			-	-	-	-	-	-
Taxes Other Than Income Taxes	OTPP	PTT		11,113,566	-	-	1,612,965	-	99,301	470,446
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		$	11,113,566	$ -	$ -	$ 1,612,965	$ -	$ 99,301	$ 470,446
Interest Expenses	INT	PTT	$	12,736,800	-	-	1,848,552	-	113,805	539,158

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	-	-	-	-		
Taxes Other Than Income Taxes	OTPP	PTT	-	360,270	3,733,776	-	409,822	-
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		$ -	$ 360,270	$ 3,733,776	$ -	$ 409,822	$ -
Interest Expenses	INT	PTT	-	412,890	4,279,128	-	469,680	-

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	-	-	-	-
Taxes Other Than Income Taxes	OTPP	PTT	3,593,737	833,250	-	-
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		$ 3,593,737	$ 833,250	$ -	$ -
Interest Expenses	INT	PTT	4,118,634	954,953	-	-

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

Description	Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
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	0.174290	0.825710
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		$ 480,205,701	$ -	$ -	$ -	$ -	$ 9,263,651	$ 43,887,105

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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
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	0.901095	0.000000	0.098905	0.000000
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		$ -	$ -	$ 384,817,184	$ -	$ 42,237,761	$ -

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

Description	Name	Vector	Total Company	Procurement Demand	Procurement Commodity	Storage Demand	Storage Commodity	Transmission Non-Storage Related Demand	Transmission Storage Related Demand
Internally Generated Functional Vectors									
Sub-Total Distribution Plant		PTDSUB	1.000000	-	-	-	-	-	-
Storage-Transmission-Distribution Subtotal		PTSUB	1.000000	-	-	0.135412	-	0.008176	0.038736
Total Storage Plant		PTST	1.000000	-	-	1.000000	-	-	-
Transmission Plant		PT365	1.000000	-	-	-	-	0.174290	0.825710
General Plant		PT389	1.000000	-	-	0.135412	-	0.008176	0.038736
Total Distribution Plant		PTDSUB	1.000000	-	-	-	-	-	-
Sub-Total CWIP		CWIP	1.000000	-	-	0.221771	-	0.050725	0.240311
Total Operation and Maintenance Expenses		OMT	1.000000	0.001721	0.012937	0.057855	0.140834	0.015149	0.071768
Total Depreciation Reserve		DEPR	1.000000	-	-	0.122997	-	0.006691	0.031700
Storage-Transmission -Distribution Plant Subtotal		PTSUB	1.000000	-	-	0.135412	-	0.008176	0.038736
Total Labor Expenses		LBTOT	1.000000	0.003527	0.026518	0.062184	0.133938	0.017801	0.084332
Transmission and Distribution Payroll		LBTD	1.000000	-	-	-	-	0.029992	0.142090
Transmission and Distribution Mains		TDMSUB	1.000000	-	-	-	-	0.019291	0.091392
Storage Operation Expenses Labor Subtotal	OSE		1,807,639	-	-	419,901	1,387,738	-	-
Storage Maintenance Expenses Labor Subtotal	MSE		1,237,646	-	-	531,554	706,092	-	-
Mains & Services	CADAL		801,916,809	-	-	-	-	-	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM		1.00000	11.74%	88.26%				
Distribution Operation Expenses Labor Subtotal	DOES		4,967,294	-	-	-	-	-	-
Distribution Maintenance Expenses Labor Subtotal	DMES		5,052,586	-	-	-	-	-	-
Subtotal Labor Expenses	LBSUB		$ 20,312,460	$ 72,163	$ 542,513	$ 1,252,419	$ 2,740,162	$ 362,982	$ 1,719,648
Subtotal O&M Expenses	OMSUB		$ 48,227,142	$ 41,912	$ 315,087	$ 2,621,306	$ 7,063,737	$ 673,216	$ 3,189,401
Depreciation Reserve - Distribution	DEPRDIS		$ 271,564,810	$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	-	0.040565	0.415384	-	0.045593	-
Storage-Transmission-Distribution Subtotal		PTSUB	-	0.033169	0.339650	-	0	-
Total Storage Plant		PTST	-	-	-	-	-	-
Transmission Plant		PT365	-	-	-	-	-	-
General Plant		PT389	-	0.033169	0.339650	-	0	-
Total Distribution Plant		PTDSUB	-	0.040565	0.415384	-	0	-
Sub-Total CWIP		CWIP	-	0.010554	0.312634	-	0	-
Total Operation and Maintenance Expenses		OMT	0.023325	0.047158	0.252976	-	0	-
Total Depreciation Reserve		DEPR	-	0.017963	0.367181	-	0	-
Storage-Transmission -Distribution Plant Subtotal		PTSUB	-	0.033169	0.339650	-	0	-
Total Labor Expenses		LBTOT	0.033140	0.051682	0.230748	-	0	-
Transmission and Distribution Payroll		LBTD	0.056021	0.086965	0.385967	-	0	-
Transmission and Distribution Mains		TDMSUB	-	-	0.801359	-	0	-
Storage Operation Expenses Labor Subtotal	OSE		-	-	-	-	-	-
Storage Maintenance Expenses Labor Subtotal	MSE		-	-	-	-	-	-
Mains & Services	CADAL		-	-	384,817,184	-	42,237,761	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM							
Distribution Operation Expenses Labor Subtotal	DOES		678,000	810,267	1,090,671	-	119,713	-
Distribution Maintenance Expenses Labor Subtotal	DMES		-	242,233	3,580,498	-	392,998	-
Subtotal Labor Expenses	LBSUB		$ 678,000	$ 1,052,499	$ 4,671,169	$ -	$ 512,710	$ -
Subtotal O&M Expenses	OMSUB		$ 912,592	$ 2,179,501	$ 12,657,258	$ -	$ 1,389,268	$ -
Depreciation Reserve - Distribution	DEPRDIS		$ -	$ 5,019,928	$ 119,838,173	$ -	$ 13,153,509	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY
Cost of Service Study
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	0.404638	0.093820	-	-
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		374,861,864	-	-	-
Demand/Commodity Percent of Purchased Gas Cost	DMCM					
Distribution Operation Expenses Labor Subtotal	DOES		1,062,455	1,206,188	-	-
Distribution Maintenance Expenses Labor Subtotal	DMES		656,755	180,103	-	-
Subtotal Labor Expenses	LBSUB		$ 1,719,211	$ 1,386,291	$ 3,378,555	$ 224,138
Subtotal O&M Expenses	OMSUB		$ 4,609,677	$ 2,755,176	$ 9,319,886	$ 499,125
Depreciation Reserve - Distribution	DEPRDIS		$ 111,944,105	$ 21,609,095	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
Plant in Service									
Procurement Expenses									
Demand	PTIS	PTISGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	PTIS	PTISGSC	COM01	-	-	-	-	-	-
Total Procurement Expenses				$ -	$ -	$ -	$ -	$ -	$ -
Storage									
Demand	PTIS	PTISSD	DEM02	$ 178,728,015	$ 119,039,286	$ 53,570,566	$ 4,558,642	$ -	$ 1,559,520
Commodity	PTIS	PTISSC	COM02	-	-	-	-	-	-
Total Storage				$ 178,728,015	$ 119,039,286	$ 53,570,566	$ 4,558,642	$ -	$ 1,559,520
Transmission									
Demand Non-Storage Related	PTIS	PTISTD	DEM04	$ 10,079,995	$ 5,472,514	$ 2,501,058	$ 247,446	$ 55,309	$ 1,803,666
Storage Related	PTIS	PTISTC	DEM03	47,754,581	31,806,268	14,313,592	1,218,030	-	416,690
Total Transmission				$ 57,834,575	$ 37,278,783	$ 16,814,650	$ 1,465,476	$ 55,309	$ 2,220,357
Distribution Expenses									
Commodity	PTIS	PTISDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment									
Demand	PTIS	PTISDSD	DEM04	$ 40,891,286	$ 22,200,225	$ 10,145,986	$ 1,003,810	$ 224,372	$ 7,316,893
Distribution Mains									
Low/Medium Pressure - Demand	PTIS	PTISDMD	P&ALOW	$ 418,728,540	$ 255,973,756	$ 124,571,147	$ 17,025,093	$ 3,182,889	$ 17,975,654
Low/Medium Pressure - Customer	PTIS	PTISDMC	CUST01a	-	-	-	-	-	-
High Pressure - Demand	PTIS	PTISDMD	P&AHIGH	45,959,891	22,599,577	10,960,574	1,574,975	325,342	10,499,423
High Pressure - Customer	PTIS	PTISDMC	CUST01	-	-	-	-	-	-
Total Distribution Mains		PTISDIS		$ 464,688,431	$ 278,573,334	$ 135,531,721	$ 18,600,068	$ 3,508,231	$ 28,475,077
Services									
Customer	PTIS	PTISSC	CUST02	$ 407,895,923	$ 303,436,555	$ 97,935,054	$ 2,733,366	$ 61,309	$ 3,729,640
Meters									
Customer	PTIS	PTISMC	CUST03	$ 94,575,391	$ 63,557,579	$ 26,103,938	$ 2,145,267	$ 60,546	$ 2,708,061
Customer Accounts									
Customer	PTIS	PTISCAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service									
Customer	PTIS	PTISCSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -
Total		PLT		$ 1,244,613,621	$ 824,085,761	$ 340,101,915	$ 30,506,630	$ 3,909,767	$ 46,009,547

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
Rate Base									
Procurement Expenses									
Demand	NCRB	RBGSD	DEM01	$ 17,092	$ 11,302	$ 5,165	$ 511	$ 114	$ -
Commodity	NCRB	RBGSC	COM01	128,499	78,401	40,726	7,829	1,543	-
Total Procurement Expenses				$ 145,592	$ 89,703	$ 45,892	$ 8,340	$ 1,657	$ -
Storage									
Demand	NCRB	RBSD	DEM02	$ 134,206,512	$ 89,386,364	$ 40,226,032	$ 3,423,076	$ -	$ 1,171,040
Commodity	NCRB	RBSC	COM02	1,398,816	907,417	431,830	59,569	-	-
Total Storage				$ 135,605,328	$ 90,293,781	$ 40,657,861	$ 3,482,645	$ -	$ 1,171,040
Transmission									
Demand Non-Storage Related	NCRB	RBTD	DEM04	$ 7,208,769	$ 3,913,702	$ 1,788,647	$ 176,963	$ 39,555	$ 1,289,903
Storage Related	NCRB	RBTC	DEM03	34,151,975	22,746,444	10,236,452	871,081	-	297,999
Total Transmission				$ 41,360,744	$ 26,660,146	$ 12,025,098	$ 1,048,044	$ 39,555	$ 1,587,901
Distribution Expenses									
Commodity	NCRB	RBDEC	COM04	$ 231,676	$ 102,062	$ 53,017	$ 10,191	$ 2,009	$ 64,397
Distribution Structures & Equipment									
Demand	NCRB	RBDSD	DEM04	$ 27,668,497	$ 15,021,461	$ 6,865,134	$ 679,214	$ 151,818	$ 4,950,870
Distribution Mains									
Low/Medium Pressure - Demand	NCRB	RBDMD	P&ALOW	$ 217,677,994	$ 133,069,157	$ 64,758,894	$ 8,850,575	$ 1,654,640	$ 9,344,728
Low/Medium Pressure - Customer	NCRB	RBDMC	CUST01a	-	-	-	-	-	-
High Pressure - Demand	NCRB	RBDMD	P&AHIGH	23,892,465	11,748,496	5,697,906	818,758	169,130	5,458,174
High Pressure - Customer	NCRB	RBDMC	CUST01	-	-	-	-	-	-
Total Distribution Mains				$ 241,570,459	$ 144,817,653	$ 70,456,800	$ 9,669,333	$ 1,823,770	$ 14,802,902
Services									
Customer	NCRB	RBSC	CUST02	$ 210,374,130	$ 156,498,748	$ 50,510,438	$ 1,409,746	$ 31,620	$ 1,923,578
Meters									
Customer	NCRB	RBMC	CUST03	$ 53,516,312	$ 35,964,612	$ 14,771,142	$ 1,213,918	$ 34,260	$ 1,532,380
Customer Accounts									
Customer	NCRB	RBCAC	CUST04	$ 1,808,350	$ 1,542,101	$ 259,605	$ 2,784	$ 62	$ 3,798
Customer Service									
Customer	NCRB	RBCSC	CUST05	$ 103,640	$ 88,381	$ 14,879	$ 160	$ 4	$ 218
Total		RBT		$ 712,384,727	$ 471,078,648	$ 195,659,866	$ 17,524,373	$ 2,084,756	$ 26,037,085

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	**Ref**	**Name**	**Allocation Vector**		**Total System**		**Residential (RGS)**		**Commercial (CGS)**		**Industrial (IGS)**		**As Available Gas Service (AAGS)**		**Firm Transportation Service (FT)**
								$	65,556,063						
Operation and Maintenance Expenses															
Procurement Expenses															
Demand	OMT	OMGSD	DEM01	$	124,749	$	82,487	$	37,698	$	3,730	$	834	$	-
Commodity	OMT	OMGSC	COM01		937,850		572,212		297,240		57,136		11,262		-
Total Procurement Expenses		OMGST		$	1,062,599	$	654,699	$	334,938	$	60,866	$	12,096	$	-
Storage															
Demand	OMT	OMSD	DEM02	$	4,193,958	$	2,793,327	$	1,257,065	$	106,971	$	-	$	36,595
Commodity	OMT	OMSC	COM02		10,209,229		6,622,766		3,151,699		434,764		-		-
Total Storage		OMST		$	14,403,187	$	9,416,093	$	4,408,763	$	541,736	$	-	$	36,595
Transmission															
Demand Non-Storage Related	OMT	OMTD	DEM04	$	1,098,159	$	596,200	$	272,476	$	26,958	$	6,026	$	196,499
Storage Related	OMT	OMTC	DEM03		5,202,595		3,465,115		1,559,386		132,698		-		45,396
Total Transmission		OMTRT		$	6,300,754	$	4,061,315	$	1,831,862	$	159,655	$	6,026	$	241,895
Distribution Expenses															
Commodity	OMT	OMDEC	COM04	$	1,690,883	$	744,901	$	386,944	$	74,380	$	14,661	$	469,997
Distribution Structures & Equipment															
Demand	OMT	OMDSD	DEM04	$	3,418,587	$	1,855,980	$	848,223	$	83,920	$	18,758	$	611,706
Distribution Mains															
Low/Medium Pressure - Demand	OMT	OMDMD	P&ALOW	$	18,338,574	$	11,210,589	$	5,455,700	$	745,629	$	139,397	$	787,259
Low/Medium Pressure - Customer	OMT	OMDMC	CUST01a		-		-		-		-		-		-
High Pressure - Demand	OMT	OMDMD	P&AHIGH		2,012,853		989,768		480,028		68,977		14,249		459,831
High Pressure - Customer	OMT	OMDMD	CUST01		-		-		-		-		-		-
Total Distribution Mains				$	20,351,427	$	12,200,357	$	5,935,728	$	814,606	$	153,646	$	1,247,090
Services															
Customer	OMT	OMSC	CUST02	$	6,891,422	$	5,126,576	$	1,654,618	$	46,180	$	1,036	$	63,012
Meters															
Customer	OMT	OMMC	CUST03	$	4,417,996	$	2,969,030	$	1,219,420	$	100,214	$	2,828	$	126,504
Customer Accounts															
Customer	OMT	OMCAC	CUST04	$	13,198,203	$	11,254,990	$	1,894,719	$	20,317	$	456	$	27,722
Customer Service															
Customer	OMT	OMCSC	CUST05	$	756,418	$	645,048	$	108,590	$	1,164	$	26	$	1,589
Total		OMTT		$	72,491,476	$	48,928,987	$	18,623,805	$	1,903,039	$	209,532	$	2,826,112

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential (RGS)		Commercial (CGS)		Industrial (IGS)		As Available Gas Service (AAGS)		Firm Transportation Service (FT)
Payroll Expenses															
Procurement Expenses															
Demand	LBTOT	LBGSD	DEM01	$	91,252	$	60,338	$	27,576	$	2,728	$	610	$	-
Commodity	LBTOT	LBGSC	COM01		686,026		418,566		217,427		41,795		8,238		-
Total Procurement Expenses		LBGST		$	777,278	$	478,904	$	245,003	$	44,523	$	8,848	$	-
Storage															
Demand	LBTOT	LBSD	DEM02	$	1,608,721	$	1,071,466	$	482,186	$	41,032	$	-	$	14,037
Commodity	LBTOT	LBSC	COM02		3,465,025		2,247,775		1,069,690		147,560		-		-
Total Storage		LBST		$	5,073,746	$	3,319,241	$	1,551,876	$	188,592	$	-	$	14,037
Transmission															
Demand Non-Storage Related	LBTOT	LBTD	DEM04	$	460,512	$	250,016	$	114,263	$	11,305	$	2,527	$	82,402
Storage Related	LBTOT	LBTC	DEM03		2,181,702		1,453,092		653,927		55,647		-		19,037
Total Transmission		LBTRT		$	2,642,214	$	1,703,108	$	768,189	$	66,951	$	2,527	$	101,439
Distribution Expenses															
Commodity	LBTOT	LBDEC	COM04	$	857,353	$	377,698	$	196,198	$	37,714	$	7,434	$	238,310
Distribution Structures & Equipment															
Demand	LBTOT	LBDSD	DEM04	$	1,337,043	$	725,892	$	331,748	$	32,822	$	7,336	$	239,244
Distribution Mains															
Low/Medium Pressure - Demand	LBTOT	LBDMD	P&ALOW	$	5,969,543	$	3,649,253	$	1,775,931	$	242,716	$	45,376	$	256,267
Low/Medium Pressure - Customer	LBTOT	LBDMC	CUST01a		-		-		-		-		-		-
High Pressure - Demand	LBTOT	LBDMC	P&AHIGH		655,221		322,188		156,258		22,453		4,638		149,684
High Pressure - Customer	LBTOT	LBDMC	CUST01		-		-		-		-		-		-
Total Distribution Mains				$	6,624,763	$	3,971,440	$	1,932,188	$	265,169	$	50,015	$	405,951
Services															
Customer	LBTOT	LBSC	CUST02	$	2,235,073	$	1,662,686	$	536,637	$	14,978	$	336	$	20,437
Meters															
Customer	LBTOT	LBMC	CUST03	$	1,767,171	$	1,187,594	$	487,760	$	40,085	$	1,131	$	50,601
Customer Accounts															
Customer	LBTOT	LBCAC	CUST04	$	4,272,294	$	3,643,271	$	613,326	$	6,577	$	148	$	8,974
Customer Service															
Customer	LBTOT	LBCSC	CUST05	$	283,429	$	241,699	$	40,689	$	436	$	10	$	595
Total		LBTT		$	25,870,365	$	17,311,532	$	6,703,615	$	697,846	$	77,784	$	1,079,587

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
Depreciation Expenses									
Procurement Expenses									
Demand	DEPREX	DEGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	DEPREX	DEGSC	COM01	-	-	-	-	-	-
Total Procurement Expenses		DEGST		$ -	$ -	$ -	$ -	$ -	$ -
Storage									
Demand	DEPREX	DESD	DEM02	$ 4,776,553	$ 3,181,356	$ 1,431,687	$ 121,831	$ -	$ 41,679
Commodity	DEPREX	DESC	COM02	-	-	-	-	-	-
Total Storage		DEST		$ 4,776,553	$ 3,181,356	$ 1,431,687	$ 121,831	$ -	$ 41,679
Transmission									
Demand Non-Storage Related	DEPREX	DETD	DEM04	$ 261,783	$ 142,124	$ 64,954	$ 6,426	$ 1,436	$ 46,842
Storage Related	DEPREX	DETC	DEM03	1,240,214	826,027	371,732	31,633	-	10,822
Total Transmission		DETT		$ 1,501,997	$ 968,151	$ 436,686	$ 38,059	$ 1,436	$ 57,664
Distribution Expenses									
Commodity	DEPREX	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment									
Demand	DEPREX	DEDSD	DEM04	$ 1,443,262	$ 783,559	$ 358,104	$ 35,430	$ 7,919	$ 258,250
Distribution Mains									
Low/Medium Pressure - Demand	DEPREX	DEDMD	P&ALOW	$ 10,676,610	$ 6,526,739	$ 3,176,276	$ 434,101	$ 81,156	$ 458,338
Low/Medium Pressure - Customer	DEPREX	DEDMC	CUST01a	-	-	-	-	-	-
High Pressure - Demand	DEPREX	DEDMD	P&AHIGH	1,171,871	576,237	279,469	40,158	8,295	267,711
High Pressure - Customer	DEPREX	DEDMC	CUST01	-	-	-	-	-	-
Total Distribution Mains				$ 11,848,481	$ 7,102,976	$ 3,455,746	$ 474,259	$ 89,452	$ 726,049
Services									
Customer	DEPREX	DESC	CUST02	$ 15,215,367	$ 11,318,815	$ 3,653,181	$ 101,960	$ 2,287	$ 139,123
Meters									
Customer	DEPREX	DEMC	CUST03	$ 3,924,800	$ 2,637,587	$ 1,083,292	$ 89,027	$ 2,513	$ 112,382
Customer Accounts									
Customer	DEPREX	DECAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service									
Customer	DEPREX	DECSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -
Total		DET		$ 38,710,461	$ 25,992,445	$ 10,418,696	$ 860,566	$ 103,607	$ 1,335,147

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
Regulatory Credits									
Procurement Expenses									
Demand	REGCR	DEGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	REGCR	DEGSC	COM01	-	-	-	-	-	-
Total Procurement Expenses		DEGST		$ -	$ -	$ -	$ -	$ -	$ -
Storage									
Demand	REGCR	DESD	DEM02	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	REGCR	DESC	COM02	-	-	-	-	-	-
Total Storage		DEST		$ -	$ -	$ -	$ -	$ -	$ -
Transmission									
Demand Non-Storage Related	REGCR	DETD	DEM04	$ -	$ -	$ -	$ -	$ -	$ -
Storage Related	REGCR	DETC	DEM03	-	-	-	-	-	-
Total Transmission		DETT		$ -	$ -	$ -	$ -	$ -	$ -
Distribution Expenses									
Commodity	REGCR	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment									
Demand	REGCR	DEDSD	DEM04	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Mains									
Low/Medium Pressure - Demand	REGCR	DEDMD	P&ALOW	$ -	$ -	$ -	$ -	$ -	$ -
Low/Medium Pressure - Customer	REGCR	DEDMC	CUST01a	-	-	-	-	-	-
High Pressure - Demand	REGCR	DEDMD	P&AHIGH	-	-	-	-	-	-
High Pressure - Customer	REGCR	DEDMC	CUST01	-	-	-	-	-	-
Total Distribution Mains				$ -	$ -	$ -	$ -	$ -	$ -
Services									
Customer	REGCR	DESC	CUST02	$ -	$ -	$ -	$ -	$ -	$ -
Meters									
Customer	REGCR	DEMC	CUST03	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts									
Customer	REGCR	DECAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service									
Customer	REGCR	DECSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -
Total		RCR		$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
<u>Accretion Expense</u>									
Procurement Expenses									
Demand	ACCRE	DEGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	ACCRE	DEGSC	COM01	-	-	-	-	-	-
Total Procurement Expenses		DEGST		$ -	$ -	$ -	$ -	$ -	$ -
Storage									
Demand	ACCRE	DESD	DEM02	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	ACCRE	DESC	COM02	-	-	-	-	-	-
Total Storage		DEST		$ -	$ -	$ -	$ -	$ -	$ -
Transmission									
Demand Non-Storage Related	ACCRE	DETD	DEM04	$ -	$ -	$ -	$ -	$ -	$ -
Storage Related	ACCRE	DETC	DEM03	-	-	-	-	-	-
Total Transmission		DETT		$ -	$ -	$ -	$ -	$ -	$ -
Distribution Expenses									
Commodity	ACCRE	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment									
Demand	ACCRE	DEDSD	DEM04	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Mains									
Low/Medium Pressure - Demand	ACCRE	DEDMD	P&ALOW	$ -	$ -	$ -	$ -	$ -	$ -
Low/Medium Pressure - Customer	ACCRE	DEDMC	CUST01a	-	-	-	-	-	-
High Pressure - Demand	ACCRE	DEDMD	P&AHIGH	-	-	-	-	-	-
High Pressure - Customer	ACCRE	DEDMC	CUST01	-	-	-	-	-	-
Total Distribution Mains				$ -	$ -	$ -	$ -	$ -	$ -
Services									
Customer	ACCRE	DESC	CUST02	$ -	$ -	$ -	$ -	$ -	$ -
Meters									
Customer	ACCRE	DEMC	CUST03	$ -	$ -	$ -	$ -	$ -	$ -
Customer Accounts									
Customer	ACCRE	DECAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service									
Customer	ACCRE	DECSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -
Total		ACC		$ -	$ -	$ -	$ -	$ -	$ -

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
ITC Amortization									
Procurement Expenses									
Demand	ITCAM	DEGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	ITCAM	DEGSC	COM01	-	-	-	-	-	-
Total Procurement Expenses		DEGST		$ -	$ -	$ -	$ -	$ -	$ -
Storage									
Demand	ITCAM	DESD	DEM02	$ (4,857)	$ (3,235)	$ (1,456)	$ (124)	$ -	$ (42)
Commodity	ITCAM	DESC	COM02	-	-	-	-	-	-
Total Storage		DEST		$ (4,857)	$ (3,235)	$ (1,456)	$ (124)	$ -	$ (42)
Transmission									
Demand Non-Storage Related	ITCAM	DETD	DEM04	$ (293)	$ (159)	$ (73)	$ (7)	$ (2)	$ (52)
Storage Related	ITCAM	DETC	DEM03	(1,389)	(925)	(416)	(35)	-	(12)
Total Transmission		DETT		$ (1,683)	$ (1,085)	$ (489)	$ (43)	$ (2)	$ (65)
Distribution Expenses									
Commodity	ITCAM	DEDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment									
Demand	ITCAM	DEDSD	DEM04	$ (1,190)	$ (646)	$ (295)	$ (29)	$ (7)	$ (213)
Distribution Mains									
Low/Medium Pressure - Demand	ITCAM	DEDMD	P&ALOW	$ (12,183)	$ (7,448)	$ (3,624)	$ (495)	$ (93)	$ (523)
Low/Medium Pressure - Customer	ITCAM	DEDMC	CUST01a	-	-	-	-	-	-
High Pressure - Demand	ITCAM	DEDMD	P&AHIGH	(1,337)	(658)	(319)	(46)	(9)	(305)
High Pressure - Customer	ITCAM	DEDMC	CUST01	-	-	-	-	-	-
Total Distribution Mains				$ (13,520)	$ (8,105)	$ (3,943)	$ (541)	$ (102)	$ (829)
Services									
Customer	ITCAM	DESC	CUST02	$ (11,868)	$ (8,829)	$ (2,849)	$ (80)	$ (2)	$ (109)
Meters									
Customer	ITCAM	DEMC	CUST03	$ (2,752)	$ (1,849)	$ (760)	$ (62)	$ (2)	$ (79)
Customer Accounts									
Customer	ITCAM	DECAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service									
Customer	ITCAM	DECSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -
Total		ITC		$ (35,870)	$ (23,749)	$ (9,793)	$ (879)	$ (114)	$ (1,336)

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
Other Taxes									
Procurement Expenses									
Demand	OTT	OTTGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	OTT	OTTGSC	COM01	-	-	-	-	-	-
Total Procurement Expenses		OTTGST		$ -	$ -	$ -	$ -	$ -	$ -
Storage									
Demand	OTT	OTTSD	DEM02	$ 1,612,965	$ 1,074,293	$ 483,458	$ 41,140	$ -	$ 14,074
Commodity	OTT	OTTSC	COM02	-	-	-	-	-	-
Total Storage		OTTST		$ 1,612,965	$ 1,074,293	$ 483,458	$ 41,140	$ -	$ 14,074
Transmission									
Demand Non-Storage Related	OTT	OTTTD	DEM04	$ 99,301	$ 53,911	$ 24,639	$ 2,438	$ 545	$ 17,768
Storage Related	OTT	OTTTC	DEM03	470,446	313,334	141,008	11,999	-	4,105
Total Transmission		OTTTT		$ 569,747	$ 367,245	$ 165,647	$ 14,437	$ 545	$ 21,873
Distribution Expenses									
Commodity	OTT	OTTDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment									
Demand	OTT	OTTDSD	DEM04	$ 360,270	$ 195,593	$ 89,390	$ 8,844	$ 1,977	$ 64,465
Distribution Mains									
Low/Medium Pressure - Demand	OTT	OTTDMD	P&ALOW	$ 3,733,776	$ 2,282,502	$ 1,110,793	$ 151,812	$ 28,382	$ 160,288
Low/Medium Pressure - Customer	OTT	OTTDMC	CUST01a	-	-	-	-	-	-
High Pressure - Demand	OTT	OTTDMD	P&AHIGH	409,822	201,519	97,735	14,044	2,901	93,623
High Pressure - Customer	OTT	OTTDMC	CUST01	-	-	-	-	-	-
Total Distribution Mains				$ 4,143,598	$ 2,484,021	$ 1,208,528	$ 165,856	$ 31,283	$ 253,911
Services									
Customer	OTT	OTTSC	CUST02	$ 3,593,737	$ 2,673,405	$ 862,850	$ 24,082	$ 540	$ 32,860
Meters									
Customer	OTT	OTTMC	CUST03	$ 833,250	$ 559,969	$ 229,987	$ 18,901	$ 533	$ 23,859
Customer Accounts									
Customer	OTT	OTTCAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service									
Customer	OTT	OTTCSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -
Total		OTTT		$ 11,113,566	$ 7,354,527	$ 3,039,859	$ 273,260	$ 34,878	$ 411,042

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
<u>**Interest Expense**</u>									
Procurement Expenses									
Demand	INT	INTGSD	DEM01	$ -	$ -	$ -	$ -	$ -	$ -
Commodity	INT	INTGSC	COM01	-	-	-	-	-	-
Total Procurement Expenses		INTGST		$ -	$ -	$ -	$ -	$ -	$ -
Storage									
Demand	INT	INTSD	DEM02	$ 1,848,552	$ 1,231,202	$ 554,071	$ 47,149	$ -	$ 16,130
Commodity	INT	INTSC	COM02	-	-	-	-	-	-
Total Storage		INTST		$ 1,848,552	$ 1,231,202	$ 554,071	$ 47,149	$ -	$ 16,130
Transmission									
Demand Non-Storage Related	INT	INTTD	DEM04	$ 113,805	$ 61,786	$ 28,237	$ 2,794	$ 624	$ 20,364
Storage Related	INT	INTTC	DEM03	539,158	359,099	161,603	13,752	-	4,705
Total Transmission		INTTT		$ 652,964	$ 420,885	$ 189,841	$ 16,546	$ 624	$ 25,068
Distribution Expenses									
Commodity	INT	INTDEC	COM04	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Structures & Equipment									
Demand	INT	INTDSD	DEM04	$ 412,890	$ 224,162	$ 102,447	$ 10,136	$ 2,266	$ 73,881
Distribution Mains									
Low/Medium Pressure - Demand	INT	INTDMD	P&ALOW	$ 4,279,128	$ 2,615,882	$ 1,273,034	$ 173,985	$ 32,527	$ 183,699
Low/Medium Pressure - Customer	INT	INTDMC	CUST01a	-	-	-	-	-	-
High Pressure - Demand	INT	INTDMD	P&AHIGH	469,680	230,953	112,010	16,095	3,325	107,297
High Pressure - Customer	INT	INTDMC	CUST01	-	-	-	-	-	-
Total Distribution Mains				$ 4,748,807	$ 2,846,834	$ 1,385,044	$ 190,080	$ 35,852	$ 290,996
Services									
Customer	INT	INTSC	CUST02	$ 4,118,634	$ 3,063,880	$ 988,876	$ 27,600	$ 619	$ 37,659
Meters									
Customer	INT	INTMC	CUST03	$ 954,953	$ 641,758	$ 263,578	$ 21,661	$ 611	$ 27,344
Customer Accounts									
Customer	INT	INTCAC	CUST04	$ -	$ -	$ -	$ -	$ -	$ -
Customer Service									
Customer	INT	INTCSC	CUST05	$ -	$ -	$ -	$ -	$ -	$ -
Total		INTT		$ 12,736,800	$ 8,428,721	$ 3,483,857	$ 313,172	$ 39,972	$ 471,078

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
Net Operating Income -- Adjusted Forecast Period									
Operating Revenues									
Sales and Transportation			REV01	324,979,207	214,163,791	90,246,981	11,720,052	1,076,927	7,771,455
Interdepartmental Sales			REV01	2,922,301	1,925,818	811,525	105,390	9,684	69,883
Forfeited Discounts			REVFD	$ 1,168,995	953,703	194,939	20,262	91	-
Miscellaneous Revenue		REVMSR	REVMISC	477,465	137,012	340,453	-	-	-
Total Operating Revenues		TOR		$ 329,547,967	$ 217,180,325	$ 91,593,897	$ 11,845,704	$ 1,086,703	$ 7,841,338
Pro-Forma Adjustments to Revenues									
Adjustment to eliminate gas line tracker revenues			REVGLT	(4,397,745)	$ (2,965,728)	$ (1,272,142)	$ (127,900)	$ (31,974)	$ -
Adjustment to eliminate gas supply cost recoveries			REVGSC	(135,270,880)	$ (84,917,418)	$ (43,709,322)	$ (6,139,196)	$ (504,944)	$ -
Adj to eliminate GSC recoveries Interdepartmental Sales			REV01	(630,517)	$ (415,516)	$ (175,095)	$ (22,739)	$ (2,089)	$ (15,078)
Removal of DSM Revenues			REVADJ4	(5,131,908)	(2,013,224)	(1,178,168)	(1)	(10,395)	(1,930,120)
Total Revenue Adjustments				$ (145,431,050)	$ (90,311,886)	$ (46,334,727)	$ (6,289,836)	$ (549,403)	$ (1,945,198)
Total Adjusted Revenue		TREVADJ		$ 184,116,917	$ 126,868,439	$ 45,259,170	$ 5,555,867	$ 537,300	$ 5,896,140
Expenses									
Operation and Maintenance Expenses				$ 72,491,476	$ 48,928,987	$ 18,623,805	$ 1,903,039	$ 209,532	$ 2,826,112
Depreciation and Amortization Expenses				38,710,461	25,992,445	10,418,696	860,566	103,607	1,335,147
Other Expenses (ITC amortization, Reg Credits, Accretion)				(35,870)	(23,749)	(9,793)	(879)	(114)	(1,336)
Other Taxes				11,113,566	7,354,527	3,039,859	273,260	34,878	411,042
Total Operating Expenses		TOE		$ 122,279,633	$ 82,252,211	$ 32,072,568	$ 3,035,985	$ 347,903	$ 4,570,965

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential (RGS)		Commercial (CGS)		Industrial (IGS)		As Available Gas Service (AAGS)		Firm Transportation Service (FT)
Net Operating Income -- Adjusted Forecast Period (Cont.)															
Net Income Before Income Taxes				$	61,837,284	$	44,616,228	$	13,186,602	$	2,519,882	$	189,397	$	1,325,174
Income Taxes			TXINC	$	19,063,197		14,049,752		3,767,078		856,752		58,014		331,602
Net Operating Income (Pro-Forma)		TOM		$	42,774,086	$	30,566,476	$	9,419,524	$	1,663,130	$	131,383	$	993,573
Unadjusted Net Cost Rate Base				$	712,384,727	$	471,078,648	$	195,659,866	$	17,524,373	$	2,084,756	$	26,037,085
Depreciation Adjustment			DET	$	-		-		-		-		-		-
Cash Working Capital Adjustment			OMTT	$	-		-		-		-		-		-
Net Cost Rate Base				$	712,384,727	$	471,078,648	$	195,659,866	$	17,524,373	$	2,084,756	$	26,037,085
Rate of Return -- Pro-Forma					**6.00%**		**6.49%**		**4.81%**		**9.49%**		**6.30%**		**3.82%**

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
<u>Net Operating Income -- Proposed Rates</u>									
Test Year Operating Income				$ 42,774,086	$ 30,566,476	$ 9,419,524	$ 1,663,130	$ 131,383	$ 993,573
Proposed Increase				$ 13,899,452	$ 10,631,026	$ 3,183,141	$ 1,705	$ (71,575)	155,155
Increase in Miscellaneous Charges - Interdepartmental Sales			REV01	(70,922)	(46,738)	(19,695)	(2,558)	(235)	(1,696)
Incremental Income Taxes			38.64%	5,343,209	4,089,666	1,222,325	(329)	(27,747)	59,295
Incremental Uncollectable Accounts Expense			CUST04	31,253	26,651	4,487	48	1	66
Incremental Commission Fees			REV01	26,841	17,689	7,454	968	89	642
Net Operating Income Adjusted for Increase				51,201,313	37,016,759	11,348,705	1,661,590	87,230	1,087,029
Net Cost Rate Base (Same as Above)				$ 712,384,727	$ 471,078,648	$ 195,659,866	$ 17,524,373	$ 2,084,756	$ 26,037,085
Rate of Return -- Proposed				**7.19%**	**7.86%**	**5.80%**	**9.48%**	**4.18%**	**4.17%**

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector	Total System	Residential (RGS)	Commercial (CGS)	Industrial (IGS)	As Available Gas Service (AAGS)	Firm Transportation Service (FT)
Allocation Factors									
Commodity									
Procurement Expenses		COM01		31,987,085	19,516,322	10,137,906	1,948,741	384,116	-
					0.610131	0.316937	0.060923	0.012008	-
Storage		COM02		20,188,041	13,096,059	6,232,265	859,717		-
Transmission		COM03		20,188,041	13,096,059	6,232,265	859,717	-	-
Distribution		COM04		44,300,973	19,516,322	10,137,906	1,948,741	384,116	12,313,888
Adjusted Deliveries				44,300,973	19,516,322	10,137,906	1,948,741	384,116	12,313,888
Demand									
Procurement Expenses		DEM01		466,311	308,337	140,917	13,942	3,116	-
Storage		DEM02		11,840,000	7,885,866	3,548,831	301,991		103,312
					0.666036	0.299732	0.025506		0.008726
Transmission Storage Related		DEM03		11,840,000	7,885,866	3,548,831	301,991	-	103,312
Distribution Structures		DEM04		567,935	308,337	140,917	13,942	3,116	101,624
High Pressure Distribution Mains		DEM05		567,935	308,337	140,917	13,942	3,116	101,624
Low/Medium Pressure Distribution Mains		DEM05a		480,031	308,337	140,917	13,033	2,645	15,100
Customer									
High Pressure Distrib Mains		CUST01		321,597	296,513	24,735	270	6	73
Low/Med Pres. Distrib Mains		CUST01a		321,514	296,513	24,735	264	-	2
Services		CUST02		257,660,226	191,675,197	61,863,742	1,726,616	38,728	2,355,944
Meters		CUST03		145,264,687	97,622,349	40,094,790	3,295,060	92,996	4,159,492
Customer Count (Average)				321,669	296,376	24,947	268	6	73
Customer Accounts		CUST04		347,546	296,376	49,893	535	12	730
Customer Service		CUST05		347,546	296,376	49,893	535	12	730
Forfeited Discounts		REVFD		993,014	810,132	165,593	17,212	78	

LOUISVILLE GAS AND ELECTRIC COMPANY

Cost of Service Study
Class Allocation

Description	Ref	Name	Allocation Vector		Total System		Residential (RGS)		Commercial (CGS)		Industrial (IGS)		As Available Gas Service (AAGS)		Firm Transportation Service (FT)
Allocation Factors Continued															
Taxable Income															
Net Income Before Income Tax		NIBIT		$	61,837,284	$	44,616,228	$	13,186,602	$	2,519,882	$	189,397	$	1,325,174
Interest Expense		INT		$	12,736,800	$	8,428,721	$	3,483,857	$	313,172	$	39,972	$	471,078
Interest Adjustment				$	-		-		-		-		-		-
Taxable Income		TXINC		$	49,100,483	$	36,187,507	$	9,702,745	$	2,206,710	$	149,425	$	854,096
Total Distribution Expense		DISTRT		$	36,770,315	$	22,896,843	$	10,044,932	$	1,119,300	$	190,929	$	2,518,310
Number of Customers					321,597		296,513		24,735		270		6		73
Services Cost					257,660,226		191,675,197		61,863,742		1,726,616		38,728		2,355,944
						$	646.73	$	1,239.92	$	3,227.32	$	3,227.32	$	3,227.32
Actual Revenue		REV01			324,979,207		214,163,791		90,246,981		11,720,052		1,076,927		7,771,455
DSM Allocation		REVADJ4			5,131,908		2,013,224		1,178,168		1		10,395		1,930,120
Miscellaneous Revenue Allocation		REVMISC			332,763		95,489		237,274						
GSC Revenue		REVGSC			135,270,880		84,917,418		43,709,322		6,139,196		504,944		
Removal of GLT Revenue		REVGLT			(4,397,745)		(2,965,728)		(1,272,142)		(127,900)		(31,974)		
Pro-Forma Adjustments		PROFO			(145,431,050)		(90,311,886)		(46,334,727)		(6,289,836)		(549,403)		(1,945,198)
High Pressure System		RBTHP			23,892,465		11,748,496		5,697,906		818,758		169,130		5,458,174

Louisville Gas and Electric Company
Summary of Adjusted Rates of Return by Class

	Revenue	Operating Expenses	Operating Margin	Rate Base	Corrected ROR
Residential Service Rate RGS	$ 126,868,439	$ 96,301,963	$ 30,566,476	$ 471,078,648	6.49%
Commercial Service Rate CGS	45,259,170	35,839,646	9,419,524	195,659,866	4.81%
Industrial Service Rate IGS	5,555,867	3,892,738	1,663,130	17,524,373	9.49%
As Available Gas Service Rate AAGS	537,300	405,917	131,383	2,084,756	6.30%
Firm Transportation Service Rate FT	5,896,140	4,902,567	993,573	26,037,085	3.82%
	184,116,916.56	141,342,830.27	42,774,086.29	712,384,727.09	6.00%

Schedule GAW-16

LOUISVILLE GAS & ELECTRIC
Gas Residential Customer Cost Analysis

		Total Company 1/	Residential
Gross Plant			
380	Services	$374,861,864	$278,862,294
381	Meters	$57,176,384	$38,424,293
383	House Regulators	$25,550,380	$17,170,643
	Total Gross Plant	**$457,588,628**	**$334,457,230**
Depreciation Reserve			
	Services	$111,944,105	$83,275,982
	Meters	$15,760,976	$10,591,862
	House Regulators	$5,646,486	$3,794,613
	Total Depreciation Reserve	**$117,590,591**	**$87,070,595**
Total Net Plant		**$339,998,037**	**$247,386,635**
Operation & Maintenance Expenses			
878	Meter & House Regulator Expense	$1,371,331	$921,577
879	Customer Installations	$161,930	$108,822
892	Maintenance of Services	$1,072,829	$798,085
893	Maintenance of Meters & House Regulators	$15,198	$10,214
902	Meter Reading	$2,000,723	$1,706,152
903	Records & Collections	$5,889,512	$5,022,386
	Total O & M Expenses	**$10,511,523**	**$8,567,234**
Depreciation Expense 1/			
	Services	$12,285,416	$9,139,205
	Meters	$2,189,606	$1,471,483
	House Regulators	$962,550	$646,863
	Total Depreciation Expense	$15,437,572	$11,257,551
Revenue Requirement			
	Interest		$4,428,221
	Equity return		$13,511,756
	State Income Taxes @ 6.00%		$1,326,850
	Federal Income Tax @35.00%		$7,275,561
	Revenue For Return		$26,542,387
	O & M Expenses		$8,567,234
	Depreciation Expense		$11,257,551
	Subtotal Customer Revenue Requirement		$46,367,173
	Total Revenue Requirement		**$46,367,173**
	Number of Customers		296,376
	Number of Bills		3,556,512
	TOTAL MONTHLY CUSTOMER COST		$13.04

1/ Per Filing Schedule B-3.2. Total Company allocated to Residential.